ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

201 South Main, Suite 2300
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October 9, 2014

VIA ELECTRONIC FILING
AND HAND DELIVERY

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts – Docket No. 12-035-100

Dear Mr. Widerburg:
Rocky Mountain Power ("Company") hereby submits for filing its Compliance Filing in the above referenced matter. An original and ten (10) copies of this filing will be provided via hand delivery. The Company will also provide an electronic version of this filing, which includes copies of the testimony and exhibits in the file formats in which they were created to psc@utah.gov.

The Company respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com
dave.taylor@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Dave Taylor at (801) 220-2923.

Sincerely,

Yvonne Hogle
Senior Attorney

cc: Service List

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Attorneys for Rocky Mountain Power

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts	)	DOCKET NO. 12-035-100 **COMPLIANCE FILING**

Pursuant to the Order on Phase II Issues in Docket No. 12-035-100 ("Avoided Cost Order") issued by the Public Service Commission of Utah ("Commission') August 16, 2013, Rocky Mountain Power ("Rocky Mountain Power" or "Company") hereby files its capacity contribution study for wind and solar resources. The Company respectfully requests that the Commission adopt the capacity contribution values derived from the capacity contribution study for purposes of calculating capacity payments for wind and solar Qualifying Facilities ("QF") projects under the currently effective Proxy/Partial Displacement Differential Revenue Requirement ("Proxy/PDDRR") method, recently approved by the Commission pursuant to the Avoided Cost Order.

In support of its request, Rocky Mountain Power states as follows:

1. Rocky Mountain Power is a division of PacifiCorp. PacifiCorp is an Oregon corporation that provides electric service to retail customers through its Rocky Mountain Power division in the states of Utah, Wyoming, and Idaho, and through its Pacific Power division in the states of Oregon, California, and Washington.

2. Rocky Mountain Power is a public utility in the state of Utah and is subject to the Commission's jurisdiction with respect to its prices and terms of electric service to retail customers in Utah. The Company serves approximately 830,000 customers and has approximately 2,400 employees in Utah. Rocky Mountain Power's principal place of business in Utah is 201 South Main Street, Suite 2300, Salt Lake City, Utah 84111.

3. Communications regarding this filing should be addressed to:

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In addition, Rocky Mountain Power requests that all data requests regarding this filing be sent in Microsoft Word or plain text format to the following:

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon 97232

Informal questions may be directed to Dave Taylor, Utah Regulatory Affairs Manager at (801) 220-2923.

4. Pursuant to the Avoided Cost Order, the Commission adopted the Proxy/PDDRR method for calculating avoided cost prices for large wind and solar QF resources between three and 100 megawatts.

5. The Commission also adopted, on an interim basis, capacity contribution values of 20.5 percent for wind QFs, 68 percent for fixed tilt solar QFs and 84 percent for single axis tracking solar QFs.

6. The Commission suggested that the interim capacity contribution values would be replaced once the Company completes a capacity contribution study using either the effective load carrying capability method or the capacity factor approximation method ("CF Method") considering loss of load probability.

7. Following the Commission's direction in the Avoided Cost Order, the Company has completed its capacity contribution study using the capacity factor method that resulted in capacity contribution values applicable to wind and solar QF projects located in Utah of 14.5 percent for wind, 39.1 percent for single axis tracking solar and 34.1 percent for fixed tilt solar.

8. The Commission should adopt the capacity contribution study, including the resulting values, because it is based on the CF Method which the Commission suggested as one of the options the Company could use in its study, and because it considers loss of load probability specific to the Company's system.

9. The capacity contribution values resulting from the Company's capacity contribution study should replace the interim values in the calculation of capacity payments for wind and solar QF projects under the currently effective and recently approved Proxy/PDDRR

method. They are based on sound methodologies and rely on data specific to the Company's system which will result in more accurate capacity payments to wind and solar QFs.

10. This request is supported by the direct testimony of Mr. Rick T. Link, who explains the Company's methodology and analysis used to calculate capacity contribution values for wind and solar resources.

RELIEF REQUESTED

11. Based on the foregoing, the Company requests that the Commission:

a. adopt the Company's capacity contribution study; and

b. replace the interim capacity contribution values with those that were derived from the Company's capacity contribution study for purposes of calculating capacity payments for wind and solar QF projects under the currently effective and recently approved Proxy/PDDRR method.

Dated: October 9, 2014.

Respectfully submitted,

ROCKY MOUNTAIN POWER

Yvonne R. Hogle
Attorney for Rocky Mountain Power

CERTIFICATE OF SERVICE

I hereby certify that on this 9th of October, 2014, a true copy of the foregoing was sent via email to parties that have signed the confidentiality agreement in this docket to the following:

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Rocky Mountain Power
Docket No. 12-035-100
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Rick T. Link

October 2014

Q. Please state your name, business address and position with PacifiCorp dba Rocky Mountain Power ("Company").

A. My name is Rick T. Link. My business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232. My present position is Director, Origination.

Q. Please describe your education and business experience.

A. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Masters of Environmental Management from Duke University in 1999. I have been employed in the commercial & trading area of PacifiCorp since 2003 where I have held positions in market fundamentals, financial valuation, planning, and origination. Currently, I direct the work of the market assessment group, the structuring & pricing group, the integrated resource planning group, the origination group, and the marketing and trading contract group. Prior to joining the Company, I was an energy and environmental economics consultant for ICF Consulting (now ICF International) from 1999 to 2003.

SUMMARY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to comply with the Commission's order in Docket No. 12-035-100 ("Commission Order") to conduct and file a capacity contribution study for wind and solar resources. I explain the Company's analysis within its recently completed capacity contribution study for wind and solar resources and present the accompanying capacity contribution values applicable to wind and solar qualifying facility ("QF") projects located in Utah. PacifiCorp's capacity contribution study is provided as Exhibit RMP___(RTL-1) to my testimony. Finally, I support and recommend the adoption and use of the Company's capacity contribution study for purposes of calculating capacity payments for wind and solar QF projects under the Proxy/PDDRR method.

Q. Please summarize your testimony in this proceeding.

A. My testimony describes what the capacity contribution of solar and wind resources represents. I then explain the methodology used by the Company in calculating its capacity contribution values for wind and solar resources and present the study results. The Company's capacity contribution values applicable to wind and solar QF projects located in Utah are as follows:

- Wind = 14.5 percent
- Single axis tracking solar = 39.1 percent
- Fixed tilt solar = 34.1 percent

BACKGROUND

Q. Please explain what the capacity contribution of wind and solar resources represents.

A. The capacity contribution of wind and solar resources is a measure of the ability for these variable energy resources to reliably meet demand. The capacity contribution is represented as a percentage of plant capacity. In the realm of resource planning, the capacity contribution is the contribution that a generating resource makes toward achieving a target planning reserve margin. In this way, the capacity contribution of wind and solar resources directly influences the timing and amount of incremental generating capacity needed to maintain reliability over time.

Q. What differentiates capacity contribution from capacity factor?

A. The capacity factor of a generating resource is a measure of how much energy that resource is expected to produce over a given period of time. Like capacity contribution, the capacity factor is represented as a percentage of plant capacity; however, the two metrics have entirely different meanings. For example, consider two hypothetical power plants operating at a 50 percent capacity factor. Both plants produce energy at half of full capability over the course of a year. However, assume one plant achieves a 50 percent capacity factor by producing energy in hours when the probability of reliability events are lowest and the other plant achieves its 50 percent capacity factor by producing energy in hours when the probability of reliability events are highest. The former would have a low capacity contribution value and the latter would have a high capacity contribution value.

METHODOLOGY

Q. What methodology did the Company use to derive its capacity contribution values for wind and solar resources?

A. There are a range of methodologies that can be used to derive capacity contribution values for variable energy resources. The methodologies differ in terms of computational complexity and data requirements. A widely accepted, but computationally intensive approach to deriving capacity contribution values is the effective load carrying capability method ("ELCC Method"). Considering the computational complexities and data requirements associated with the ELCC

Method, the Company used the capacity factor approximation method ("CF Method"), which considers loss of load probability ("LOLP"), to develop its capacity contribution values for wind and solar resources. The National Renewable Energy Laboratory ("NREL") studied the CF Method and found it to be the most dependable technique in deriving capacity contribution values that approximate those developed using the ELCC Method. The aforementioned NREL study is provided as Exhibit RMP___(RTL-2) to my testimony.

Q. What is LOLP?

A. LOLP is a reliability metric defined as the probability that load exceeds available resources over a given period of time. Hourly LOLP metrics, as needed to calculate capacity contribution using the CF Method, represent the probability of load exceeding available resources for each individual hour over the course of the year.

Q. Is the Company's use of the CF Method consistent with the Commission Order in Docket No. 12-035-100?

A. Yes. In its order in Docket No. 12-035-100, the Commission directed "…PacifiCorp to calculate capacity contribution for wind and solar resources for the Proxy/PDDRR method using either the ELCC method or the CF method considering LOLP."[1]

Q. Please describe the CF Method.

A. The CF Method, described further in Exhibit RMP___(RTL-1) and Exhibit RMP___(RTL-2), uses hourly LOLP metrics and corresponding hourly wind and

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[1] See *In the Matter of the Application of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts*, Docket No. 12-035-100, Order on Phase II Issues (August 16, 2013).

solar capacity factor data to determine the capacity contribution values for these variable energy resource technologies. Hourly LOLP data are weighted by dividing the LOLP for each hour by the total LOLP among all hours in the year. As noted by NREL in its description of the CF Method, the intuition behind weighting hourly LOLP data is that the capacity provided by a resource is especially needed during hours with the highest LOLP. Hourly weighting factors are then multiplied by the contemporaneous hourly capacity factor of each representative technology—east wind, Utah single axis tracking solar, and Utah fixed tilt solar. The capacity contribution for each technology is calculated by summing the hourly capacity factors that have been weighted by LOLP.

Q. How did the Company calculate hourly LOLP metrics?

A. Hourly LOLP metrics were determined by performing a 500-iteration hourly simulation of PacifiCorp's system using the Planning and Risk ("PaR") model for all hours in a sample calendar year. For each iteration, stochastic variables that affect system reliability are subject to a Monte Carlo random sampling process. The stochastic variables include load, hydro generation, and thermal unit outages. The hourly LOLP metrics are calculated by summing the number of hours in which load exceeds available resources, then dividing this figure by 500 (the number of iterations used to simulate dispatch of PacifiCorp system). The stochastic simulation of PacifiCorp's system resulted in 527 hours having a LOLP greater than zero (approximately six percent of 8760 hours in the year).

NREL notes that approximation techniques have been tested using between one percent and 30 percent of the highest LOLP hours in a year, with results suggesting that using the top 10 percent of the hours (876 hours) is typically sufficient. Because the LOLP of each hour is weighted when using the CF Method, hours in which the LOLP is zero receive a zero weight. Consequently, capacity contribution values calculated using the 527 hours in which LOLP exceeds zero (six percent of the hours in a year) are identical to capacity contribution values calculated using 876 hours (10 percent of the hours in a year).

As shown in Exhibit RMP___(RTL-1), the 527 hours in which load exceeds available resources occur throughout the year, but are highest in the summer and winter, when loads are high, and in the early spring, when maintenance is often planned. Within these periods, LOLP is highest during on-peak hours and during morning and evening ramp periods, when units are transitioning between off-peak and on-peak operation.

Q. Please describe the wind and solar capacity factor assumptions used in the Company's capacity contribution study.

A. Hourly capacity factor data varies by resource type and location. For wind resources, PacifiCorp has access to actual generation data from existing wind resources operating within its system. These actual generation data were used to calculate hourly capacity factors for wind resources within PacifiCorp's east and west balancing authority areas ("BAA"). Wind capacity factor data for wind resources in PacifiCorp's east BAA are most applicable to QF projects in Utah. For solar resources, the Company used hourly generation profiles, differentiated between single axis tracking and fixed tilt projects, from a feasibility study developed by Black and Veatch, provided as Exhibit RMP___(RTL-3) to my testimony. Representative profiles for projects located in Milford County, Utah and Lakeview County, Oregon were used. Considering that the Company has seen significant QF activity in and around Milford County, the representative hourly profiles for Milford County, Utah are most applicable to single axis tracking and fixed tilt QF projects located in Utah.

RESULTS

Q. Please summarize the results of the Company's wind and solar capacity contribution study as applicable to QFs located in Utah.

A. The capacity contribution for wind resources located in PacifiCorp's east BAA is 14.5 percent. The capacity contribution for fixed tilt and single axis tracking solar projects sited in Utah is 34.1 percent and 39.1 percent, respectively.

Q. How do these results compare to the capacity contribution figures adopted by the Commission in Docket No. 12-035-100?

A. Pending the Company filing a capacity contribution study using the ELCC Method or the CF Method, the Commission adopted a capacity contribution value of 20.5 percent for wind QFs, 68 percent for fixed tilt solar QFs, and 84 percent for single axis tracking solar QFs.

Q. Why are the capacity contribution values from the Company's study different from those adopted by the Commission on an interim basis?

A. Differences in wind capacity contribution values are a result of differences in methodology. The wind capacity contribution value adopted by the Commission on an interim basis was developed by the Utah Office of Consumer Services by averaging capacity factor data from wind resources in PacifiCorp's east BAA during the highest 500 load hours over a five year historical period. As discussed above, the Company's wind capacity contribution value was developed using the CF Method, which is based on hourly capacity factors from wind resources in PacifiCorp's east BAA during the highest LOLP hours that are specific to the PacifiCorp system. This method is consistent with the Commission Order in Docket No. 12-035-100.

Similarly, the solar capacity contribution values adopted by the Commission were chosen as an interim proxy based on the aforementioned NREL study. The NREL study did not have the benefit of LOLP statistics for PacifiCorp's system to analyze capacity contribution values consistent with its recommended methodology. The Company's study follows NREL's recommended CF Method and produces different values for solar resources because it is based on hourly solar profiles from areas in which PacifiCorp has seen significant solar QF activity coincident with hourly LOLP statistics specific to its system

Q. Will the capacity contribution of wind and solar resources need updating over time?

A. Yes. As variable energy resources such as wind and solar become more prevalent, it will be necessary to reexamine the capacity contribution values. A March 2014 NREL report cites studies that show the capacity contribution of solar resources is sensitive to increasing levels of deployment.[2] With increasing solar penetration levels, the timing of events in which load might exceed available resources can shift to hours in which solar resources are not generating (when solar irradiance is low). Consequently, the capacity contribution value for solar resources would fall as more solar resources are added to PacifiCorp's system. PacifiCorp will study the implications of capacity contribution levels at different penetration levels in future studies.

CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. The Company has completed a capacity contribution study that provides capacity contribution values for wind and solar resources applicable to QF projects in Utah. The study was performed using the CF Method, which considers hourly capacity factors for wind and solar resources coincident with hours having the highest LOLP among hours in the year that is specific to PacifiCorp's system. The Company performed its capacity contribution study consistent with the Commission Order in Docket No. 12-035-100. The Company's capacity contribution values applicable to wind and solar QF projects located in Utah are as follows:

- East wind = 14.5 percent
- Single axis tracking solar = 39.1 percent
- Fixed tilt solar = 34.1 percent

[2] Sigrin, B.; Sullivan, P.; Ibanez, E.; and Margolis, R. "Representation of Solar Capacity Value in the ReEDS Capacity Expansion Model" NREL/TP-6A20-61182, Denver, CO: National Renewable Energy Laboratory, March 2014. http://www.nrel.gov/docs/fy14osti/61182.pdf.

Q. What do you recommend?

A. I recommend that the Commission adopt the Company's capacity contribution values calculated using the CF Method for purposes of calculating capacity payments for wind and solar QF projects under the Proxy/PDDRR method.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(RTL-1)
Docket No. 12-035-100
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick T. Link

October 2014

2014 WIND AND SOLAR CAPACITY CONTRIBUTION STUDY

Introduction

The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. For purposes of this report, PacifiCorp defines the peak capacity contribution of wind and solar resources as the availability among hours with the highest loss of load probability (LOLP). PacifiCorp calculated peak capacity contribution values for wind and solar resources using the capacity factor approximation method (CF Method) as outlined in a 2012 report produced by the National Renewable Energy Laboratory (NREL Report)[1].

The capacity contribution of wind and solar resources affects PacifiCorp's resource planning activities. PacifiCorp conducts its resource planning to ensure there is sufficient capacity on its system to meet its load obligation at the time of system coincident peak inclusive of a planning reserve margin. To ensure resource adequacy is maintained over time, all resource portfolios evaluated in the integrated resource plan (IRP) have sufficient capacity to meet PacifiCorp's net coincident peak load obligation inclusive of a planning reserve margin throughout a 20-year planning horizon. Consequently, planning for the coincident peak drives the amount and timing of new resources, while resource cost and performance metrics among a wide range of different resource alternatives drive the types of resources that can be chosen to minimize portfolio costs and risks.

PacifiCorp derives its planning reserve margin from a LOLP study. The study evaluates the relationship between reliability across all hours in a given year, accounting for variability and uncertainty in load and generation resources, and the cost of planning for system resources at varying levels of planning reserve margin. In this way, PacifiCorp's planning reserve margin LOLP study is the mechanism used to transform hourly reliability metrics into a resource adequacy target at the time of system coincident peak. This same LOLP study was utilized for calculating the peak capacity contribution using the CF Method. Table 1 summarizes the peak capacity contribution results for PacifiCorp's east and west balancing authority areas (BAAs).

Table 1 – Peak Capacity Contribution Values for Wind and Solar

	East BAA			West BAA		
	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV
CF Method Results	14.5%	34.1%	39.1%	25.4%	32.2%	36.7%

[1] Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report). http://www.nrel.gov/docs/fy12osti/54704.pdf

Methodology

The NREL Report summarizes several methods for estimating the capacity value of renewable resources that are broadly categorized into two classes: 1) reliability-based methods that are computationally intensive; and 2) approximation methods that use simplified calculations to approximate reliability-based results. The NREL Report references a study from Milligan and Parsons that evaluated capacity factor approximation methods, which use capacity factor data among varying sets of hours, relative to the more computationally intensive reliability-based effective load carrying capability (ELCC) metric. As discussed in the NREL Report, the CF Method was found to be the most dependable technique in deriving capacity contribution values that approximate those developed using the ELCC Method.

As described in the NREL Report, the CF Method "considers the capacity factor of a generator over a subset of periods during which the system faces a high risk of an outage event." When using the CF Method, hourly LOLP is calculated and then weighting factors are obtained by dividing each hour's LOLP by the total LOLP over the period. These weighting factors are then applied to the contemporaneous hourly capacity factors for a wind or solar resource to produce a weighted average capacity contribution value.

The weighting factors based on LOLP are defined as:

$$w_i = \frac{LOLP_i}{\sum_{j=1}^{T} LOLP_j}$$

where w_i is the weight in hour i, $LOLP_i$ is the LOLP in hour i, and T is the number of hours in the study period, which is 8,760 hours for the current study. These weights are then used to calculate the weighted average capacity factor as an approximation of the capacity contribution as:

$$CV = \sum_{i=1}^{T} w_i C_i,$$

where C_i is the capacity factor of the resource in hour i, and CV is the weighted capacity value of the resource.

To determine the capacity contribution using the CF method, PacifiCorp implemented the following two steps:

1. A 500-iteration hourly Monte Carlo simulation of PacifiCorp's system was produced using the Planning and Risk (PaR) model to simulate the dispatch of the Company's system for a sample year (calendar year 2017). This PaR study is based on the Company's 2015 IRP planning reserve margin study using a 13% target planning reserve margin level. The LOLP for each hour in the year is calculated by counting the number of iterations in an hour in which system load could not be met with available resources and dividing by 500 (the total number iterations). For example, if in hour 9 on January 12th there are two iterations with Energy Not Served (ENS) out of a total of 500 iterations, then the LOLP for that hour would be 0.4%.[2]

[2] 0.4% = 2 / 500.

2. Weighting factors were determined based upon the LOLP in each hour divided by the sum of LOLP among all hours. In the example noted above, the sum of LOLP among all hours is 143%.[3] The weighting factor for hour 9 on January 12th would be 0.2797%.[4] The hourly weighting factors are then applied to the capacity factors of wind and solar resources in the corresponding hours to determine the weighted capacity contribution value in those hours. Extending the example noted, if a resource has a capacity factor of 41.0% in hour 9 on January 12th, its weighted annual capacity contribution for that hour would be 0.1146%.[5]

Results

Table 2 summarizes the resulting annual capacity contribution using the CF Method described above as compared to capacity contribution values assumed in the 2013 IRP.[6] In implementing the CF Method, PacifiCorp used actual wind generation data from wind resources operating in its system to derive hourly wind capacity factor inputs. For solar resources, PacifiCorp used hourly generation profiles, differentiated between single axis tracking and fixed tilt projects, from a feasibility study developed by Black and Veatch. A representative profile for Milford County, Utah was used to calculate East BAA solar capacity contribution values, and a representative profile for Lakeview County, Oregon was used to calculate West BAA solar capacity contribution values.

Table 2 – Peak Capacity Contribution Values for Wind and Solar

	East BAA			West BAA		
	Wind	**Fixed Tilt Solar PV**	**Single Axis Tracking Solar PV**	**Wind**	**Fixed Tilt Solar PV**	**Single Axis Tracking Solar PV**
CF Method Results	14.5%	34.1%	39.1%	25.4%	32.2%	36.7%
2013 IRP Results	4.2%	13.6%	n/a	4.2%	13.6%	n/a

Figure 1 presents daily average LOLP results from the PaR simulation, which shows that loss of load events are most likely to occur during the spring, when maintenance is often planned, and during peak load months, which occur in the summer and the winter.

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[3] For each hour, the hourly LOLP is calculated as the number of iterations with ENS divided by the total of 500 iterations. There are 715 ENS iteration-hours out of total of 8,760 hours. As a result, the sum of LOLP is 715 / 500 = 143%.

[4] 0.2797% = 0.4% / 143%, or simply 0.2797% = 2 / 715.

[5] 0.1146% = 0.2797% x 41.0%.

[6] In its 2013 IRP, PacifiCorp estimated capacity contribution values for wind and solar resources by evaluating capacity factors for wind and solar resources at a 90% probability level among the top 100 load hours in a given year.

Figure 1 - Daily LOLP

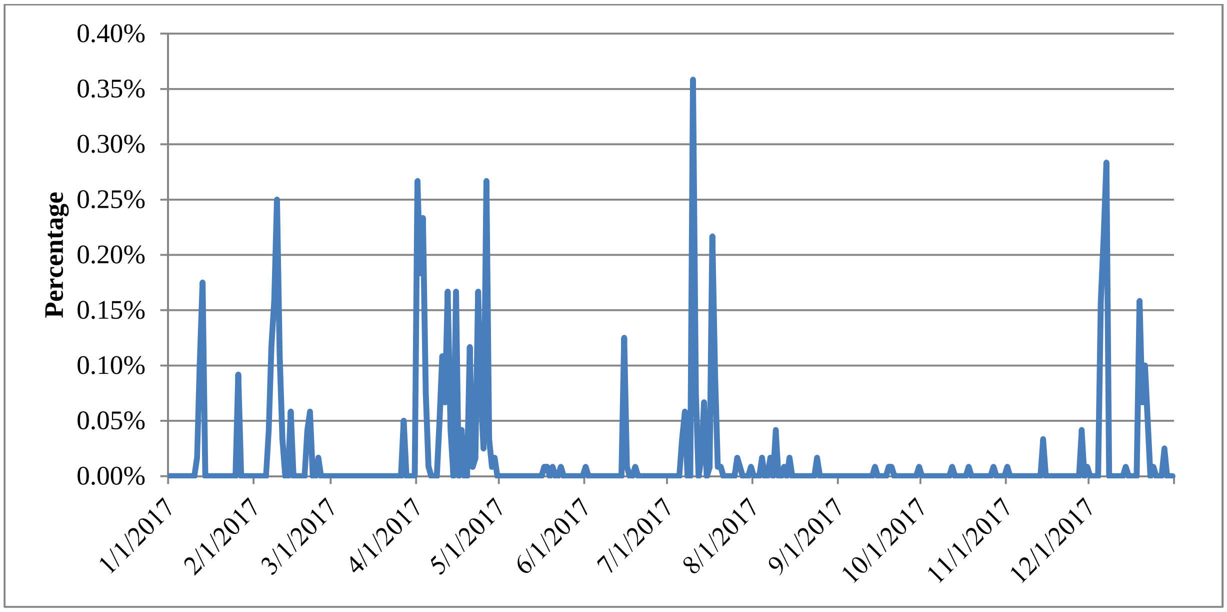
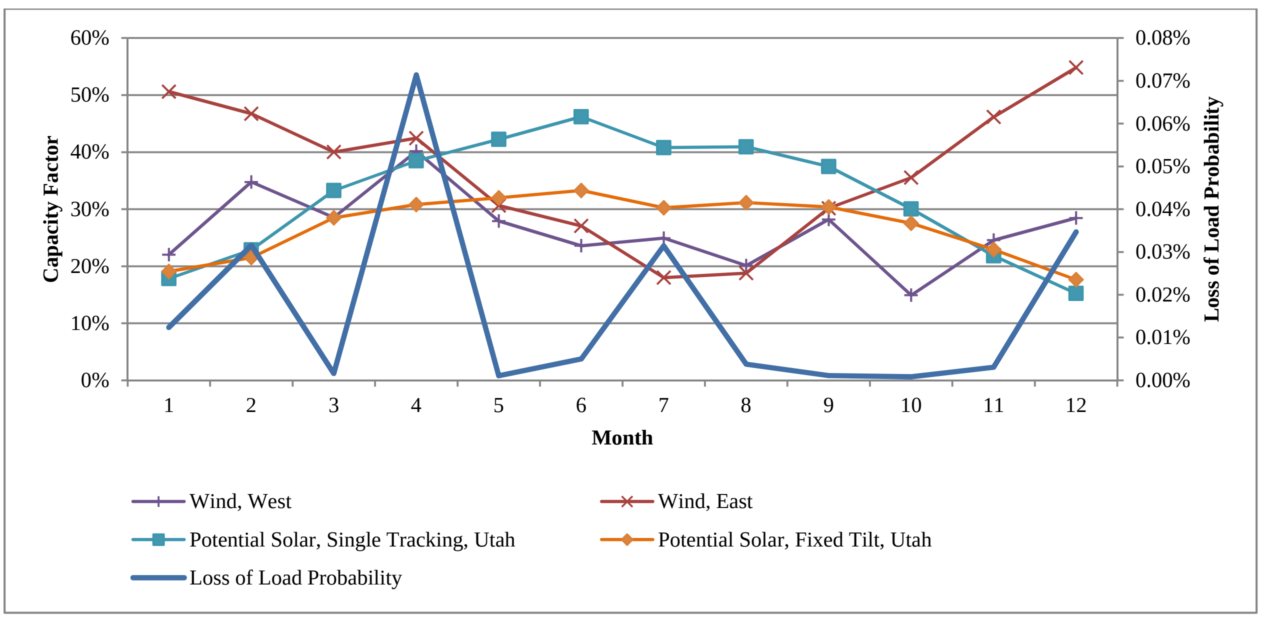


Figure 2 presents the relationship between monthly capacity factors among wind and solar resources (primary y-axis) and average monthly LOLP from the PaR simulation (secondary y-axis) in PacifiCorp's CF Method analysis. As noted above, the average monthly LOLP is most prominent in April (spring maintenance period), summer (July peak loads), and winter (when loads are high).

Figure 2 - Monthly Resource Capacity Factors as Compared to LOLP



Figures 3 through 5 present the hourly distribution of capacity factors among wind and solar resources (primary y-axis) as compared to the hourly distribution of LOLP (secondary y-axis) for a typical day in the months of April, July, and December, respectively. Among a typical day in April, LOLP events peak during morning and evening ramp periods when generating units are transitioning between on-peak and off-peak operation. Among a typical day in July, LOLP events peak during higher load hours and during the evening ramp. In December, LOLP events peak during higher load evening hours.

Figure 3 - Hourly Resource Capacity Factors as Compared to LOLP for an Average Day in April

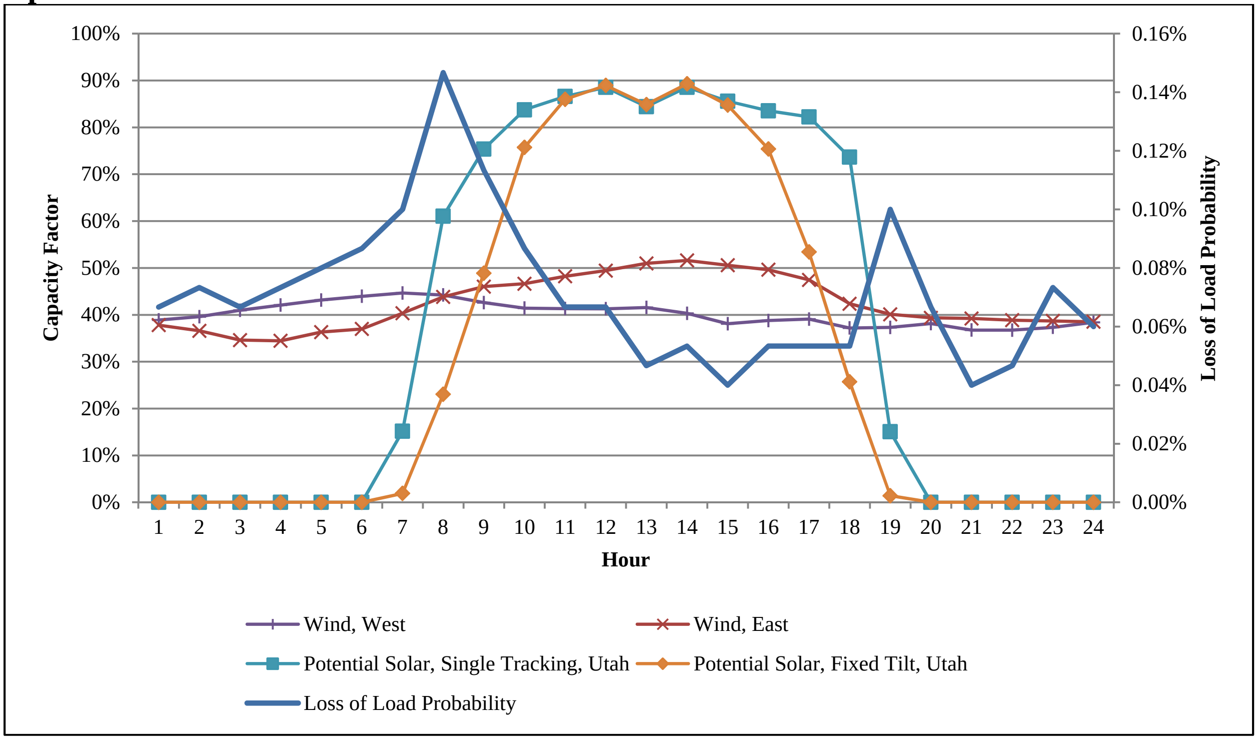


Figure 4 – Hourly Resource Capacity Factors as Compared to LOLP for an Average Day in July

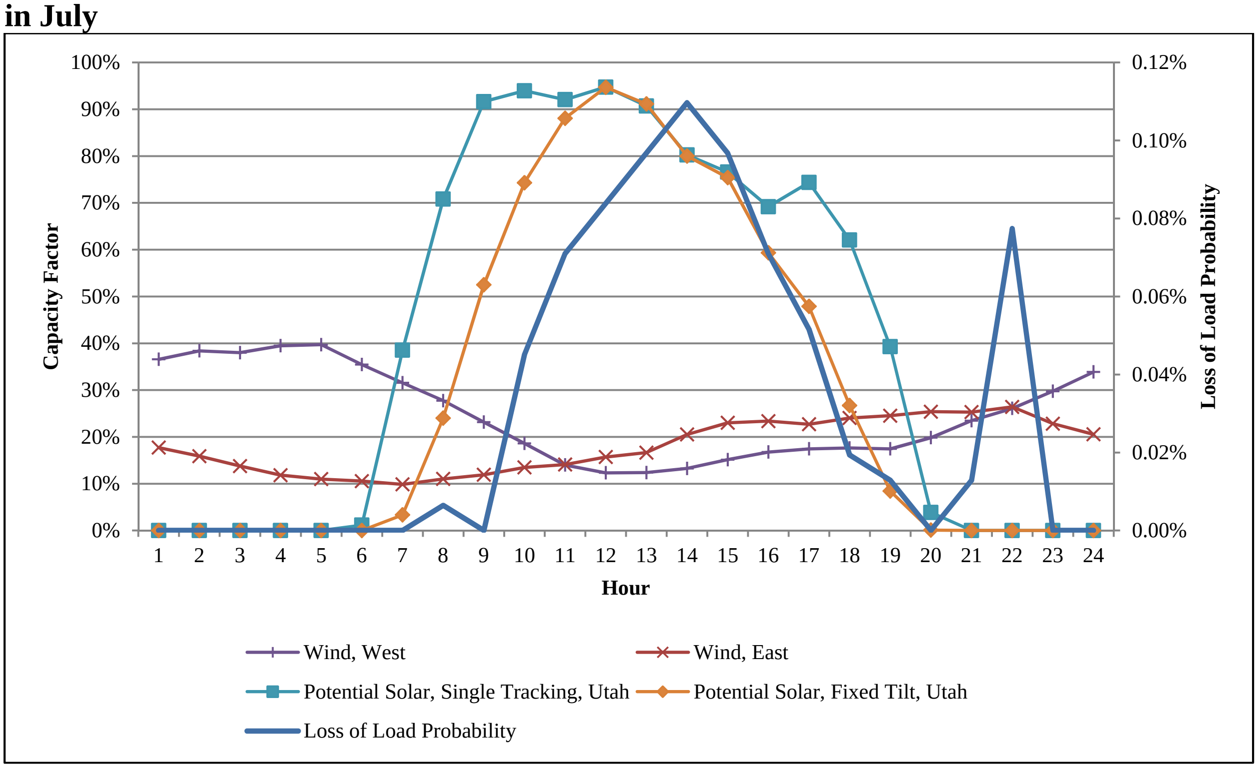
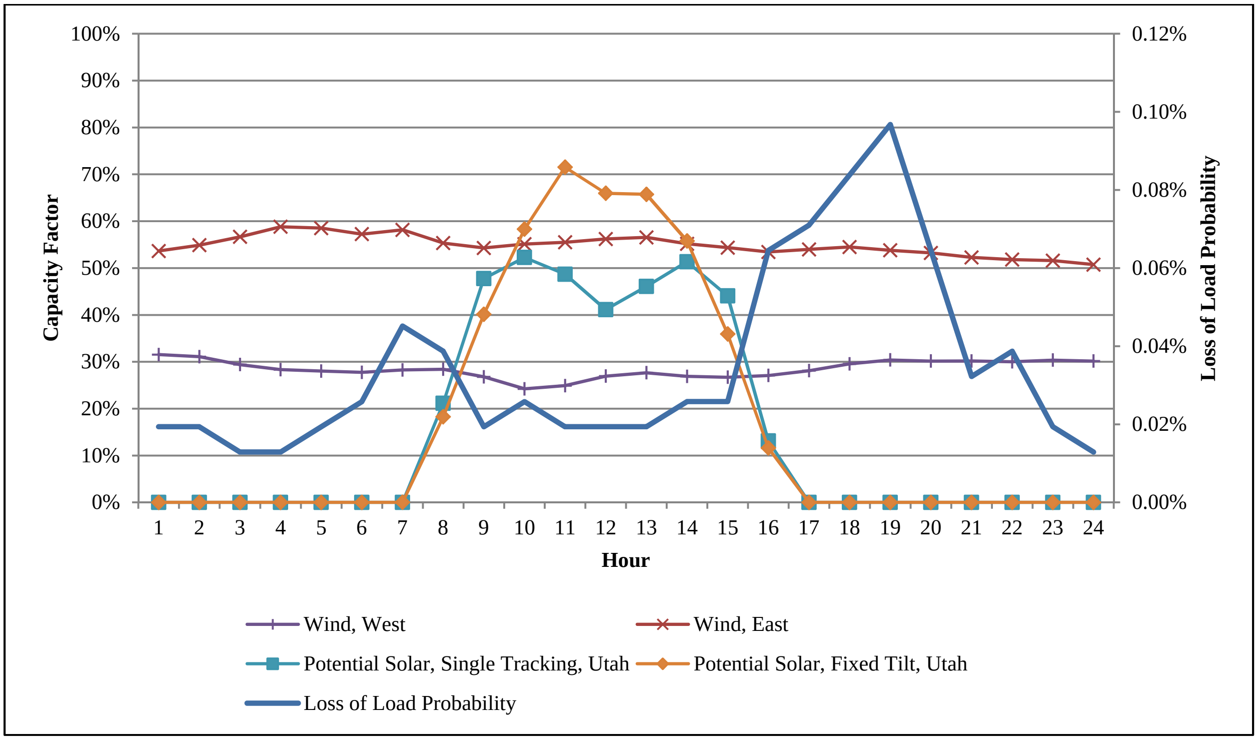


Figure 5 – Hourly Resource Capacity Factors as Compared to LOLP for an Average Day in December



Conclusion

PacifiCorp conducts its resource planning by ensuring there is sufficient capacity on its system to meet its net load obligation at the time of system coincident peak inclusive of a planning reserve margin. The peak capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is the weighted average capacity factor of these resources at the time when the load cannot be met with available resources. The peak capacity contribution values developed using the CF Method are based on a LOLP study that aligns with PacifiCorp's 13% planning reserve margin, and therefore, the values represent the expected contribution that wind and solar resources make toward achieving PacifiCorp's target resource planning criteria.

Rocky Mountain Power
Exhibit RMP___(RTL-2)
Docket No. 12-035-100
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick T. Link

October 2014

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Comparison of Capacity Value Methods for Photovoltaics in the Western United States

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Prepared under Task No. SS12.2210

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Abstract

This report compares different capacity value estimation techniques applied to solar photovoltaics (PV). It compares more robust data and computationally intense reliability-based capacity valuation techniques to simpler approximation techniques at 14 different locations in the western United States. The capacity values at these locations are computed while holding the underlying power system characteristics fixed. This allows the effect of differences in solar availability patterns on the capacity value of PV to be directly ascertained, without differences in the power system confounding the results. Finally, it examines the effects of different PV configurations, including varying the orientation of a fixed-axis system and installing single- and double-axis tracking systems, on the capacity value. The capacity value estimations are done over an eight-year running from 1998 to 2005, and both long-term average capacity values and interannual capacity value differences (due to interannual differences in solar resource availability) are estimated. Overall, under the assumptions used in the analysis, we find that some approximation techniques can yield similar results to reliability-based methods such as effective load carrying capability.

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1 Introduction

An important aspect of the benefits of renewable electricity is its capacity value, or the ability of renewable generators to reliably meet demand. Generator outages, which can occur due to mechanical failures, planned maintenance, or lack of real-time generating resources (especially in the case of renewables), may leave a power system with insufficient generating capacity to meet load. According to the North American Electric Reliability Corporation (NERC), quantifying the contribution of renewable energy resources to resource adequacy of bulk power systems is a very important and emerging issue [1]. Therefore, assessing the adequacy of renewable generation technologies and consequently estimating their capacity value is crucial for accurate reliability and planning of power systems [2]. Previous analyses have considered the capacity value of wind [1, 3–8], photovoltaic (PV) solar [9–14], and concentrating solar power (CSP) plants [15]. Partially due its maturity, the capacity value of wind has been more widely studied than solar technologies.

This report expands on previous PV analyses and details techniques that can be used to estimate the capacity value of PV plants using historical data. The techniques consist of reliability and statistical methods used to estimate the probability of a system outage event and the contribution of PV in reducing this probability. The primary purpose of this report is to provide a comprehensive comparison of different capacity value estimation techniques. Specifically, it compares more robust data and computationally intense reliability-based capacity valuation techniques to simpler approximation techniques. It compares these methods at 14 different locations in the western United States. The capacity values at these locations are computed while holding the underlying power system characteristics fixed. This allows the effect of differences in solar availability patterns on the capacity value of PV to be directly ascertained, without differences in the power system confounding the results. Finally, it examines the effects of different PV configurations, including varying the orientation of a fixed-axis system and installing single- and double-axis tracking systems, on the capacity value. The capacity value estimations are done over an eight-year running from 1998 to 2005, and both long-term average capacity values and interannual capacity value differences (due to interannual differences in solar resource availability) are estimated. The capacity values are all computed for small (100 MW) PV installations. Therefore, the estimates are for marginal PV installations and do not account for the diminishing marginal capacity value of PV that will occur with higher PV penetrations. Moreover, the capacity values at the different locations are computed in isolation, thus the capacity values do not account for the effect of spatial correlation of solar availability on capacity values.

2 Methods For Estimating Capacity Value

Methods for estimating the capacity value of renewable resources can be categorized in two major classes. These differ in terms of computational complexity and data requirements. The first class uses reliability-based methods and includes equivalent conventional power (ECP), effective load carrying capability (ELCC), and equivalent firm capacity (EFC). These methods use power system reliability evaluation techniques [16], which are based on loss of load probability (LOLP) and loss of load expectation (LOLE). LOLP is defined as the probability of a loss of load event in which the system load is greater than available generating capacity during a given time period. LOLP is typically computed in one-hour increments. The LOLE is the sum of the LOLPs during a planning period—typically one year. LOLE gives the expected number of time periods in which a loss of load event occurs.[1] Power system planners typically aim to maintain an LOLE value of 0.1 days/year (or 2.4 hours per year based on the target of one outage-day every 10 years) [17]. This value is used as the target LOLE value throughout this report. Reliability methods are widely accepted and considered accurate methods for calculating capacity value [5–8]. A second

Defining Capacity-Related Terms

This report focuses on the capacity value of PV plants. There are a number of capacity-related terms commonly used with substantially different meanings.

Capacity generally refers to the rated output of the plant when operating at maximum output. Capacity is typically measured in terms of a kilowatt (kW), megawatt (MW), or gigawatt (GW) rating. Rated capacity may also be referred to as "nameplate capacity" or "peak capacity." This may be further distinguished as the "net capacity" of the plant after plant parasitic loads have been considered, which are subtracted from the "gross capacity."

AC versus DC capacity. PV modules produce direct current (DC) voltage. This DC electricity is converted into alternating current (AC). As a result, PV power plants have both a DC rating (corresponding to the output of the modules) and an AC rating, which is always lower than the DC rating considering the various losses associated with converting DC to AC. This analysis uses the AC rating, which better corresponds to traditional power plant capacity ratings.

Capacity factor is a measure of how much energy is produced by a plant compared to its maximum output. It is measured as a percentage, generally by dividing the total energy produced during some period of time by the amount of energy it would have produced if it ran at full output over that period of time.

Capacity value is the focus of this report and refers to the contribution of a power plant to reliably meeting demand. Capacity value is the contribution that a plant makes toward the planning reserve margin, with a more comprehensive technical definition provided in Section 2. The capacity value (or capacity credit) is measured either in terms of physical capacity (kW, MW, or GW) or the fraction of its nameplate capacity (%). Thus, a plant with a nameplate capacity of 150 MW could have a capacity value of 75 MW or 50%. Solar plants can be designed and operated to increase their capacity value or energy output.

Capacity payment is a monetary payment to a generator based on its capacity. The capacity payment is generally in terms of $/MW where the MW is the amount of capacity sold into the market.

[1] This also may consider the need to import electricity. For example an International Energy Agency document describes a "risk level" as "a probability of the power system under investigation not to be able to cover its peak demand without electricity import. Here 'without import into the system' needs to be highlighted. It means that the criteria not being met do not automatically lead to a blackout in the system. Instead, cross border transit capacities have to be used in a fact that links adequacy to market and regulatory aspects" [18].

class of methods uses approximations that are simpler but vary in accuracy, especially for variable generation. These methods include Garver's ELCC approximation [19], Z method [20], and capacity factor-based methods [21].

Conventional generator outages are typically modeled using an equivalent forced outage rate (EFOR), which is the probability that a particular generator can experience a failure at any given time. When renewables are added to a system, the system reliability models must also capture the variability of real-time resource availability. To do this, renewable resource availability is typically estimated using historical data or by simulating such data.

The following sections discuss common techniques for estimating capacity value of renewable and conventional generators in greater detail.

2.1 Equivalent Conventional Power

One of the most robust and widely accepted definitions of capacity value is the ECP of a generator. The ECP of a generator is defined as the amount of a different generating technology that can replace the new generator while maintaining the same system reliability level [7]. In the context of a renewable generator, this is attractive because it allows the capacity value of a renewable generator to be measured in terms of a conventional dispatchable generator.

The steps used to calculate the ECP of a PV generator[2] are as follows:

1. For a given set of conventional generators, the LOLE of the system without the PV plant is calculated as:

   $$LOLE = \sum_{i=1}^{T} P(G_i < L_i) \qquad (1)$$

   where T is the total number of hours of study, G_i represents the available conventional capacity in hour i, and L_i is the amount of load. $P(G_i < L_i)$ indicates the probability of available generating capacity being less than demand, which is the LOLP in each hour. Adding these LOLPs together gives the LOLE. The calculated LOLE will represent the original reliability level of the system. In order to meet the standard planning target of one outage-day every 10 years [17], we adjust the loads in each hour so the LOLE of the base system, given by equation (1) is 0.1 days/year. This load adjustment is done by applying a fixed percentage change to each hourly load, with the load adjustments ranging between 0.1% and 5% between the different study years.

2. The PV plant is added to the system and the new LOLE, which is denoted $LOLE_{PV}$, is calculated as:

   $$LOLE_{PV} = \sum_{i=1}^{T} P(G_i + C_i < L_i) \qquad (2)$$

[2] This method can be applied to any generating resource, including non-PV renewables. This is done by substituting the candidate generator, for which the ECP is being calculated, in place of the PV plant.

where C_i denotes the output of the PV plant in hour *i*. Since the PV plant has been added to the system, $LOLE_{PV}$ will be lower than the LOLE of the base system (indicating a more reliable system with lower LOLPs).

3. The PV plant is "removed" from the system and a conventional generator is added. The LOLE of the new system, which is denoted as $LOLE_{Gen}$ is computed as:

$$LOLE_{Gen} = \sum_{i=1}^{T} P(G_i + X_i < L_i) \qquad (3)$$

where X_i is the available generating capacity in hour *i* from the added conventional generator. This added conventional generator is assumed to have a fixed EFOR, but the nameplate capacity of the plant is adjusted until the LOLE of the system with the PV plant and the conventional generator are equal (i.e., until $LOLE_{PV} = LOLE_{Gen}$). The nameplate capacity of the conventional generator that achieves this equality is defined as the ECP of the PV plant. We assume that the benchmark generator to which the PV plant is compared is a natural gas-fired combustion turbine because such generators are often built for peak capacity purposes. The ECP of the PV plant will be sensitive to this assumption because different generation technologies against which it could be benchmarked will have different EFORs.

2.2 Effective Load Carrying Capability

The ELCC of a generator is defined as the amount by which the system's loads can increase (when the generator is added to the system) while maintaining the same system reliability (as measured by the LOLP and LOLE) [7]. The steps used to calculate the ELCC of a PV generator[3] are as follows:

1. For a given set of conventional generators, the LOLE of the system without the PV plant is calculated using equation (1).
2. The PV plant is added to the system and the LOLE is recalculated. This is shown in (2). Again, $LOLE_{PV}$ will be lower than the LOLE of the base system because we have added generation to the system.
3. Keeping the PV plant in the system a constant load is added in each hour. The LOLE of the new system, which is denoted as $LOLE_{Load}$ is computed as:

$$LOLE_{Load} = \sum_{i=1}^{T} P(G_i < L_i + D) \qquad (4)$$

where *D* is the load added in each hour. The value of *D* is adjusted until the LOLEs calculated in steps 1 and 3 (i.e., the LOLE of the base system and the system with the added PV and load) equal each other. The value of *D* that achieves this equality is defined as the ELCC of the PV plant.

2.3 Equivalent Firm Capacity

The EFC of a generator is defined as the amount of a different fully reliable generating technology (i.e., a generator with an EFOR of 0%) that can replace the new generator while

[3] As with ECP, this method can be applied to any generating resource, including non-PV renewables. This is done by substituting the candidate generator, for which the ELCC is being calculated, in place of the PV plant.

maintaining the same system reliability level [7, 22–23]. The steps used to calculate the EFC of a PV generator[4] are as follows:

1. For a given set of conventional generators, the LOLE of the system without the PV plant is calculated using equation (1).
2. The PV plant is added to the system and the LOLE of the system, which is denoted $LOLE_{PV}$, is calculated according to (2).
3. The PV plant is "removed" from the system and a fully reliable conventional generator (EFOR of 0%) is added. The LOLE of the new system, which is denoted as $LOLE_{Gen}$ is computed according to (3) with the difference that X_i is the available generating capacity in hour i from the added fully reliable conventional generator.
4. The nameplate capacity of the plant is adjusted until the LOLE of the system with the PV plant and the conventional generator are equal (i.e., until $LOLE_{PV} = LOLE_{Gen}$). The nameplate capacity of the conventional generator that achieves this equality is defined as the EFC of the PV plant. Note that a generator's EFC and ELCC will generally differ because changing the generation mix of a system will change the distribution of the available capacity in a given hour whereas adjusting loads will not [6].

Reliability-based methods, such as ECP, ELCC, and EFC, require detailed system data, including EFORs of all of the generators in the system, generator capacities, and loads. Moreover, due to seasonal and annual weather pattern changes, one will typically need several years' worth of data to accurately estimate the capacity value of any type of renewable generation technology including PV.

2.4 Approximation Methods

Computational challenges associated with full reliability-based calculations have led to the development of approximation techniques. These techniques often require less data and analytical effort and are typically used by utilities and system operators for capacity planning purposes [1]. These approximation methods reduce the computational burden by focusing on the hours in which the system faces a high risk of not meeting load—typically hours with high loads or LOLPs. While ignoring transmission constraints reduces the computational burden both from an operational and reliability perspective, iterative calculation of LOLE in the ELCC and ECP methods still requires extensive calculations. Several studies have compared the accuracy of approximation methods and reliability-based approaches, such as the ELCC method, for calculating capacity value of wind and CSP. For example, Bernow et al. [24] and El-Sayed [25] estimate the capacity value of a wind plant by considering only the peak-load hours. They use the average capacity factor of wind during peak-load hours, defined as the actual output of the plant during those hours divided by its nameplate capacity, as a proxy for the capacity value. Milligan and Parsons [21] calculate the capacity value of wind by considering a set of "risky" hours, as opposed to only peak-load hours. They introduce three different techniques, which will be explained in Section 2.4.1. They recommend using the top 10% of hours for proper approximation of capacity value. In a similar study Madaeni et. al. [15] have applied the same techniques to CSP plants and found that only considering the top 10 hours is sufficient for a

[4] As with ECP and ELCC, this method can be applied to any generating resource, including non-PV renewables. This is done by substituting the candidate generator, for which the EFC is being calculated, in place of the PV plant.

reasonable approximation of capacity value. This is due to stronger correlation between CSP and loads.

The following sections describe some of these approximation techniques in further detail. Note that all of these techniques are intended to approximate a generator's ELCC. In Section 5.2, we explicitly compare the accuracy of these methods to the ELCC method.

2.4.1 Capacity Factor Approximation Method

A common approximation technique considers the capacity factor of a generator over a subset of periods during which the system faces a high risk of an outage event. These techniques have been applied to wind [24–25] and PV [9] and compared with reliability-based methods to assess their accuracy. Milligan and Parsons [21] introduce three different approximation methods, which differ based on the set of hours examined. One technique uses the average capacity factor during the peak-load hours, whereas another uses the capacity factor during the peak-LOLP hours. A third technique uses the highest-load hours but normalizes the capacity factors by the LOLPs. This technique places higher weight on the capacity factor of the wind plant during hours with high LOLPs. Milligan and Parsons have applied these techniques to the top 1% to 30% of hours and have shown that the approximation can approach the ELCC metric if a suitable number of hours is considered. Their results suggest that using the top 10% of hours is typically sufficient. In this report we use the third technique to approximate the capacity value of PV. Henceforth we will refer to this technique as CF approximation.

The intuition behind the weighting in CF approximation is that the capacity provided by the PV is especially needed during hours with higher LOLPs. The weights are obtained as:

$$w_i = \frac{LOLP_i}{\sum_{j=1}^{T} LOLP_j} \qquad (5)$$

where w_i is the weight in hour i, $LOLP_i$ is the LOLP in hour i, and T is the number of hours in the study. These weights are then used to calculate the weighted average capacity factor of the PV plant in the highest-load hours as:

$$CV = \sum_{i=1}^{T'} w_i C_i \qquad (6)$$

where T' is the number of hours used in the approximation and CV is the weighted generation of the PV plant during the high-load hours and is considered as an approximation for capacity value.

2.4.2 Garver's Approximation Method

Garver proposes an approximation for the full ELCC calculation [19], which Hoff et al. [10] use to determine the capacity value of PV. The aim of Garver's method is to quantify ELCC without needing to recalculate LOLEs when the new generator is added to the system. This dramatically reduces the computational burden because it does not require iterative LOLE calculations to achieve the equality between the LOLEs computed in steps 2 and 3 of the ELCC method.

Garver's method uses a linearized risk function to relate the LOLE of a system to its excess generation capacity when plotted on a logarithmic basis. The slope of this risk function, *m*, represents the necessary capacity for an annual LOLE that is *e* times greater than the original LOLE.

Garver's method approximates the ELCC of a PV plant by first estimating the LOLE of the system when the PV plant is added as:

$$\sum_{i=1}^{T} exp\left(\frac{-(PL - L_i + C_i)}{m}\right) \qquad (7)$$

where *PL* is the annual peak load, L_i is the hourly load, and C_i is the hourly PV output. If we substitute the output of the PV plant with a constant, denoted *ELCC*, the system LOLE would change to:

$$\sum_{i=1}^{T} exp\left(\frac{-(PL - L_i + ELCC)}{m}\right) \qquad (8)$$

The ELCC approximation is given by the value of *ELCC*, which yields equality between equations (7) and (8). A closed-form solution for the value of *ELCC* is given by:

$$\text{ELCC} = \text{m} \times Ln\left[\frac{\sum_{i=1}^{T} exp\left(\frac{-(PL - L_i)}{m}\right)}{\sum_{i=1}^{T} exp\left(\frac{-(PL - L_i + C_i)}{m}\right)}\right] \qquad (9)$$

Henceforth this method is denoted as GA.

2.4.3 Garver's Approximation Method for Multi-State Units

D'Annunzio and Santoso [26] generalize Garver's approximation method to model multi-state generators. This can include conventional generators that can experience different outage states (e.g., operating at reduced capacity due to an outage) or renewables, which can operate at reduced capacity due to resource availability. The methodology has two main assumptions:

1. The probability distribution of renewable availability remains the same in different time periods.
2. The LOLE of a system can be approximated as Be^{md}, where *d* as the annual peak load and *B* and *m* are parameters. These parameters can be estimated by estimating the LOLE of the system using equation (1) with different system peaks (e.g., by increasing all loads proportionally) and fitting values for *B* and *m* to the LOLE values.

Their method approximates the ELCC of a generator as:

$$ELCC = -\frac{1}{m} \times Ln\left[\sum_{i=1}^{T} p_i e^{-mC_i}\right] \qquad (10)$$

where P_i is the probability of the PV plant to generate C_i. In this report we consider an empirical probability distribution for PV generation. The empirical distribution that we consider assigns probabilities P_i to each generating state C_i by counting the number of occurrences of C_i divided by the total number of hours used in the analysis. We also construct the distribution with a certain resolution defined as the number of megawatts between two generating states. The lower the resolution the more accurate the PV is modeled. While we conduct our analysis based on an empirical distribution with 1 MW resolution, we further study the sensitivity of the method with respect to changes in the resolution. Henceforth this technique will be referred to as GAM.

2.4.4 Z Method

The Z method [20] considers the difference between available generating capacity and load in peak hours as a random variable, *S*, with a Gaussian distribution and assuming small additional PV capacity [27]. The z statistic for this random variable, defined as mean divided by standard deviation, is considered to be a reliability metric of the power system. This is shown in equation (11) where μ_s and σ_s refer to the mean and standard deviation of *S*.

$$z_0 = \frac{\mu_s}{\sigma_s} \qquad (11)$$

The Z method is based on the major assumption that the shape of probability distribution of *S* does not change when a new generator is added to the system, although the mean and variance of the distribution can change.

Assuming that the above assumption holds, the ELCC of a new generator can be defined as the amount of incremental load that keeps the z statistic constant after the addition of that generator to the system. Reference [20] elaborates on the derivations required to reach to a closed form solution, which approximates ELCC based on the above assumption. We only provide the closed form solution here, which is shown in (12) where $\overline{\mu}_{PV}$ and $\overline{\sigma}_{PV}$ are mean and standard deviation of PV availability.

$$ELCC = \overline{\mu}_{PV} - \frac{z_0 \overline{\sigma}_{PV}^2}{2\sigma_s} \qquad (12)$$

The Z method is only valid when its underlying assumption is satisfied. For small PV penetration this will not be an issue. However, as penetration increases, the shape of distribution for surplus is subject to change and therefore the method will no longer be valid.

2.5 Comparison of Reliability-Based Methods and Approximation Techniques

Each of the methods described in Section 2 differ in terms of computational burden. Table 1 summarizes and contrasts the requirements of each technique. Additional comparison and discussion of the applicability of several of these different methods is provided by Zachary and Dent [27].

Table 1. Comparison Between Reliability-Based Methods and Approximation Techniques for Quantifying Capacity Value

Method	Type	Computational Burden	Data Requirements
Equivalent Conventional Power (ECP)	Relia.	High—LOLPs have to be iteratively computed to achieve equality between LOLEs when PV and benchmark units are added	Load and generator capacities and EFORs
Effective Load-Carrying Capability (ELCC)	Relia.	High—LOLPs have to be iteratively computed to achieve equality between LOLEs when PV and load are added	Load and generator capacities and EFORs
Equivalent Firm Capacity (EFC)	Relia.	High—LOLPs have to be iteratively computed to achieve equality between LOLEs when PV and perfectly reliability benchmark unit are added	Load and generator capacities and EFORs
Capacity Factor-Based Approximation (CF)	Approx.	Low—At most, LOLPs must be computed once, if highest-LOLP or LOLP-weighted methods are used	Loads only for highest-load method, otherwise generator capacities and EFORs
Garver's ELCC Approximation (GA)	Approx.	Medium—LOLPs must be computed a handful of times to estimate the slope of the risk function	Load and generator capacities and EFORs
Garver's Approximation for Multi-State Units (GAM)	Approx.	Medium—LOLPs must be computed a handful of times to estimate the relationship between LOLE and system peak	Load and generator capacities and EFORs
Z Method	Approx.	Low—The mean and standard deviation of the surplus of the system without PV and output of the PV must be computed	Load and generator capacities and EFORs

3 Photovoltaic Model

This study uses PV generation profiles produced by the National Renewable Energy Laboratory's System Advisor Model (SAM) [28].[5] SAM is a software platform capable of simulating dynamics of solar resources, including PV. Historical weather data are input to SAM in order to simulate hourly electrical output of the PV plant. These generation profiles are then used as inputs for the capacity valuation methods discussed in Section 2. For the purposes of estimating capacity values, we assume the base PV plant has a nameplate capacity of 100 MW-DC. This corresponds to an AC capacity of 83.4 MW under standard test conditions (STC), which are 1,000 W/m^2 of solar irradiation and a cell temperature of 25^{o}C [28]. This AC rating is used to normalize the capacity values we estimate throughout the report. Note that the AC capacity under STC is not necessarily the maximum AC capacity of the plant. There could be conditions wherein the PV plant generates more than 83.4 MW, which would yield a capacity value of more than 100%. The assumption of a 100 MW-DC PV plant implies that this analysis only considers the capacity value of adding a small 'marginal' amount of PV to the system. This study does not consider the effect of higher PV penetrations on reducing the marginal capacity value of additional PV.

SAM includes four different PV performance models [28]. Our analysis is based on the California Energy Commission model. Inverter characteristics are based on the Sandia Inverter Performance model (SIPM). These inverters have a non-linear behavior, making them significantly more efficient at high power outputs.[6] Figure 1 illustrates the efficiency of the inverter under different operating conditions.[7]

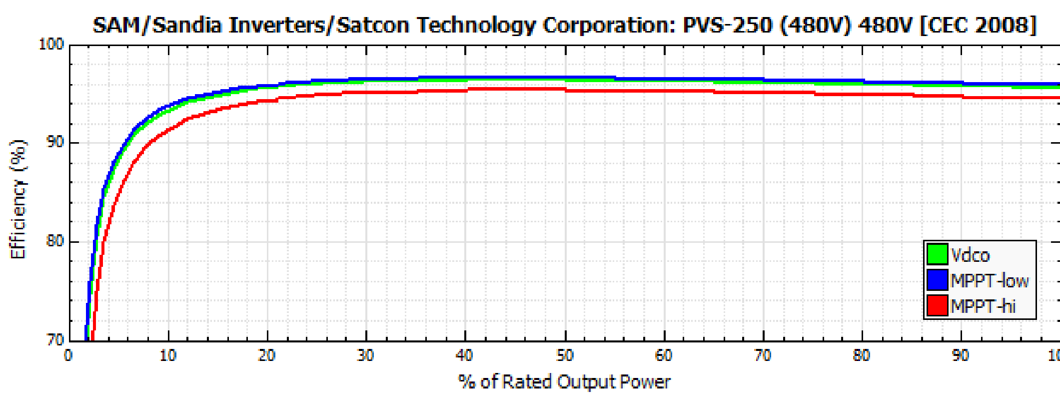

Figure 1. Inverter efficiency curve[8]

[5] SAM is available for download at https://sam.nrel.gov/. This analysis was conducted with version 2011.6.30.
[6] The base inverter type used is the Satcon Technology Corporation PVS-250. Results are fairly insensitive to different inverters offered by other manufacturers. We compared the total annual generation of a fixed-axis PV plant located in Bartsow, California (coordinates in Table 3) with three additional inverters (Eaton SM1003, Kacon New Energy Blue Planet XP 100U, and Xantrex Technologies GT 100.) The maximum change in the generation profile was less than 0.6%.
[7] Where MPPT-low corresponds to manufacture specified minimum DC operating voltage, MPPT-hi corresponds to manufacture-specified maximum DC operating voltage and Vdco corresponds to the average of MPPT-low and MTTP-hi.
[8] Derived from the SAM model documentation in version 2011.6.30.

4 Data Requirements

This study focuses on the sites in the western United States listed in Table 2. These sites were chosen to represent a mix of locations across the western U.S. with at least one of two key characteristics: relatively good solar resource or within urban areas. PV in urban areas can be attractive because transmission capacity might not be available to transfer power from areas with relatively high solar resource. Moreover, rooftop PV can be more easily deployed in populated areas.

All of the PV sites that we model are in the Western Interconnection, which we refer to here as the Western Electricity Coordinating Council (WECC) region.[9] This analysis uses the entire WECC footprint to determine system loads and LOLPs. Because this assumption keeps the underlying system fixed, **differences in the capacity value of PV at different locations can be attributed entirely to differences in solar resource**, without system characteristics confounding the results. This essentially assumes utilities have the ability to share capacity resources across the entire Western Interconnect. Utilities and system planners typically use a smaller footprint because they are primarily interested in ensuring reliability within the limited territory that they serve. Thus, the capacity values reported here can be different from such an analysis. This is because PV output may be more or less coincident with the 'local' load of a more limited system than it is with the WECC-wide load. Previous analyses of PV have tended to use more limited system footprints as well and have in some cases shown differences in capacity values that stem from coincidence between PV output and the local load [29].

Table 2. Location of PV Plants

PV Site	Coordinates	Characteristic
Bartsow, CA	35.15° N, 117.35° W	High Solar Resource
Congress, AZ	34.15° N, 113.15° W	High Solar Resource
Yucca Flat, NV	37.25° N, 116.15° W	High Solar Resource
Hanover, NM	33.05° N, 107.75° W	High Solar Resource
Cheyenne, WY	41.35° N, 104.95° W	Urban Area
Salt Lake City, UT	41.05° N, 112.05° W	Urban Area
Boise, ID	43.85° N, 116.25° W	Urban Area
Los Angeles, CA	34.45° N, 118.45° W	Urban Area
San Francisco, CA	37.85° N, 122.45° W	Urban Area
Seattle, WA	47.75° N, 122.45° W	Urban Area
Denver, CO	39.95° N, 104.85° W	Urban Area
Albuquerque, NM	35.25° N, 106.65° W	Urban Area
Phoenix, AZ	33.45° N, 111.95° W	Urban Area
Las Vegas, NV	36.25° N, 115.15° W	Urban Area

The ECP and ELCC metrics, along with approximation techniques described in Section 2.4, are used to estimate the capacity value of the PV plant during the years 1998–2005. Data requirements and sources used for this analysis are listed below.

[9] The Western Interconnection is one of the three U.S. interconnected grids and is largely isolated from the other two interconnects—ERCOT and the Eastern Interconnect.

1. Conventional generator data
    A. This analysis uses the rated capacity and EFOR of each generator in the WECC region. The rated capacities are obtained from Form 860 (Annual Electric Generator Report) data filed with the U.S. Department of Energy's Energy Information Administration (EIA) [30]. The EIA data specifies a winter and summer capacity, which capture the effect of ambient temperature on the maximum operating point of thermal generators. The EIA data also specify the prime mover and generating fuel of each generator. These data are combined with the NERC's Generating Availability Data System (GADS) to estimate the EFOR of each generator [31]. The GADS data give historical average EFORs for generators based on generating capacity and technology.
    B. The conventional generator used as the benchmark unit in the ECP calculation is a natural-gas-fired combustion turbine with an EFOR of 7%, which is based on the EFOR reported in GADS.
2. Hourly load data
    A. Hourly historical WECC load data for the years 1998–2005 are obtained from Form 714 filings with the Federal Energy Regulatory Commission (FERC) [32]. The FERC data includes load reports for nearly all of the load-serving entities (LSEs) and utilities in the WECC, although some smaller municipalities and cooperatives are not reflected in the data.
3. PV generation profile
    A. In order to provide the most robust capacity value estimates, multiple years of PV generation data is needed. Because no PV plants are operating at the exact study locations, we model the operation of a PV plant using SAM. As part of input data for SAM, hourly weather data for each location are obtained from the National Solar Radiation Data Base.[10]

[10] These data are available for download at http://rredc.nrel.gov/solar/old_data/nsrdb/.

5 Capacity Value of Photovoltaic Solar Plants

This section details results regarding the capacity value of a 100 MW-DC PV located at the sites listed in Table 2 and illustrated in Figure 2. All capacity values are normalized by the 83.4 MW-AC capacity of the plant under STC. We examine systems with different sun-tracking capabilities. For PV arrays with fixed axis, arrays are set to face south with a tilt angle equal to the site's latitude.[11] Changing the orientation (facing east, south, or west) or the tilt angle of such PV systems can affect capacity value. This is due to the fact that different orientations will favor either morning or afternoon production. An analysis of the effects of PV orientation for such systems, including the optimal orientation in terms of energy yield and capacity value, is provided in Section 6.1. For PV systems with single-axis tracking, the tilt angle is set to 0, meaning that the array is completely horizontal but it rotates about the azimuth angle in order to follow daily movement of the sun. For PV systems with double-axis tracking the array rotates about both azimuth and tilt angles to follow daily and seasonal movement of the sun.

5.1 Capacity Value of Photovoltaic Power using Reliability-Based Methods

Two different reliability-based techniques, ECP and ELCC, are used to determine the capacity value of PV. Capacity values are estimated for fixed-axis, single-axis, and double-axis tracking PVs. Table 3 summarizes average capacity values over the eight years of study using ECP and ELCC. An intuitive finding is that capacity values are highest for double-axis tracking PVs. Moreover, Table 3 reveals that ELCCs are less than ECPs. This is because when calculating ECP, PV is benchmarked against a fictitious generator with a positive EFOR, which we assume to be 7%. With ELCC, on the other hand, PV is compared to a constant load, which is akin to a fully reliable generator with an EFOR of 0. Hence a PV plant would have a lower capacity value when compared to a fully reliable generator, as shown in Table 3.

Depending on the location and the sun-tracking capability of the PV, the ECP of the plant can range from 56% to 92% and ELCC can range from 51% to 82%. In a similar study conducted by Xcel Energy for the Public Utility Commission of Colorado, the ELCC of a 100 MW-DC PV plant located in Denver is found to be in the range of 53% to 68% (depending on sun-tracking capability), which is consistent with our results [29]. Perez et al. [10] approximate the ELCC of PV for Nevada Power (NP) and Portland General Electric (PGE) as a function of penetration using the GA method in year 2002. They assume the PV to be southwest oriented with a tilt angle of 30^{o} and fixed axis. NP is summer peaking utility with large commercial air conditioning demand. For a 2% PV penetration in NP, which is approximately equivalent to 100 MW PV capacity, they estimate the ELCC of PV to be 70%. For PGE, under a 3% penetration scenario, which is equivalent to 100 MW PV capacity, they estimate ELCC to be around 30%. The Perez et al. [10] results are significantly lower than our estimates, in Table 3, in large part due to the fact that we consider a wider footprint, which covers the entire WECC region. In contrast, Perez et al. conduct their analysis within a utility service territory or balancing area (which would be more typical of how a utility would consider the capacity value of a generation resource.) For example, while the solar resource in Portland, Oregon, in the summer appears to correlate well with the WECC-wide load, PGE was a winter peaking utility in the years analyzed by Perez et al

[11] For PV systems with either fixed-axis or single-axis tracking, tilt angle is the angle from horizontal to the inclination of the PV array. Note that tilt angle is not defined for double-axis tracking PVs.

[10], resulting in a low capacity value. As noted previously, the primary purpose of this analysis is to compare methods of capacity credit analysis.

Table 3. Average Annual Capacity Value of PV (% - Based on System AC Rating) with Fixed-Axis, Single-Axis, and Double-Axis Tracking in Different Locations

PV Site	ECP			ELCC		
	Fixed-Axis	Single-Axis Tracking	Double-Axis Tracking	Fixed-Axis	Single-Axis Tracking	Double-Axis Tracking
Bartsow, CA	64.2	78.3	79.4	59.7	72.7	73.7
Congress, AZ	75.1	82.7	85.7	69.7	76.8	79.5
Yucca Flat, NV	61.0	74.2	76.1	56.6	68.9	70.7
Hanover, NM	61.0	70.3	71.2	56.7	65.3	66.2
Cheyenne, WY	55.8	77.9	80.5	51.8	72.4	74.8
Salt Lake City, UT	65.7	84.7	88.6	61.0	78.7	82.2
Boise, ID	71.1	87.4	92.2	66.0	81.2	85.6
Los Angeles, CA	56.0	83.4	85.0	52.0	77.4	78.9
San Francisco, CA	60.1	83	84.5	55.8	77.1	78.4
Seattle, WA	62.0	87.2	92.7	57.6	80.9	86.1
Denver, CO	64.6	75.1	77.9	60.0	69.8	72.3
Albuquerque, NM	72.6	84.6	86.5	67.4	78.5	80.3
Phoenix, AZ	69.4	77.1	78.2	64.4	71.6	72.6
Las Vegas, NV	64.6	82.6	84.6	60.0	76.7	78.5

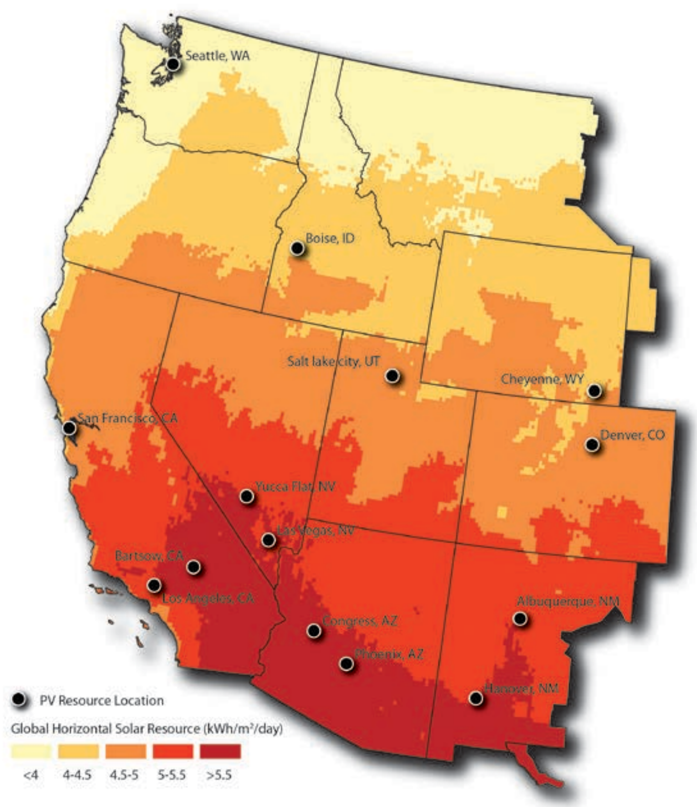

Figure 2. Location of PV sites evaluated

Because this analysis uses the same load pattern for all locations, the different ECP and ELCC values depend on the regional variation in solar resource. For instance, PV with fixed axis located in Congress, Arizona, which has a relatively high solar irradiation, has an average annual ECP of 75.1%. PV located in an urban area, such as Los Angeles, California, only has an ECP of 56%. This difference is due to lower correlation between WECC loads and PV generation in Los Angeles compared to Congress. To illustrate this, Figure 3 shows the output of a PV plant in Congress and Los Angeles on July 20, 2005. This is the day with the highest WECC-wide load of 2005. As Figure 3 shows, PV generation and load are more correlated in Congress compared to Los Angeles. In hour 14 when load reaches its annual peak, the PV in Congress is producing 66 MWh whereas the PV in Los Angeles is only producing 16 MWh. Since the capability of producing during peak load hours has a direct impact on the capacity value of a plant, one can expect that PV in Los Angeles would have a lower capacity value compared to PV located in Congress. It is important to stress that any correlation between local loads in Los Angeles and Congress and local solar resource are not captured in our analysis because we use a WECC-wide footprint.

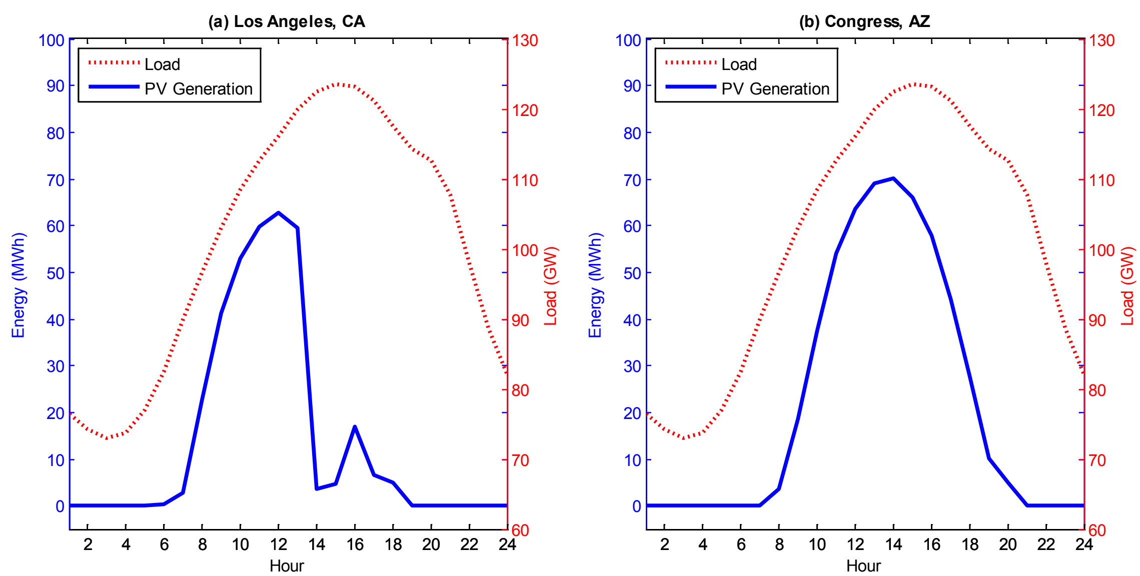

Figure 3. Hourly loads and dispatch of a fixed-axis PV plant located in Los Angeles, California, and Congress, Arizona, on July 20, 2005

As can be seen from Table 3, there are areas with high capacity values despite having a relatively low average solar resource, such as Boise, Idaho, and Seattle, Washington. These are locations in which PV generation has a relatively high correlation with the Western Interconnect loads. As expected, such a high correlation would result in higher capacity values. As an example, Figure 4 shows the output of a fixed-axis PV plant located in Boise, Idaho, and Seattle, Washington, during July 10, 2002. This is the day on which the load reaches its peak value in year 2002. The relatively high correlation between load and PV generation is observable from this figure.

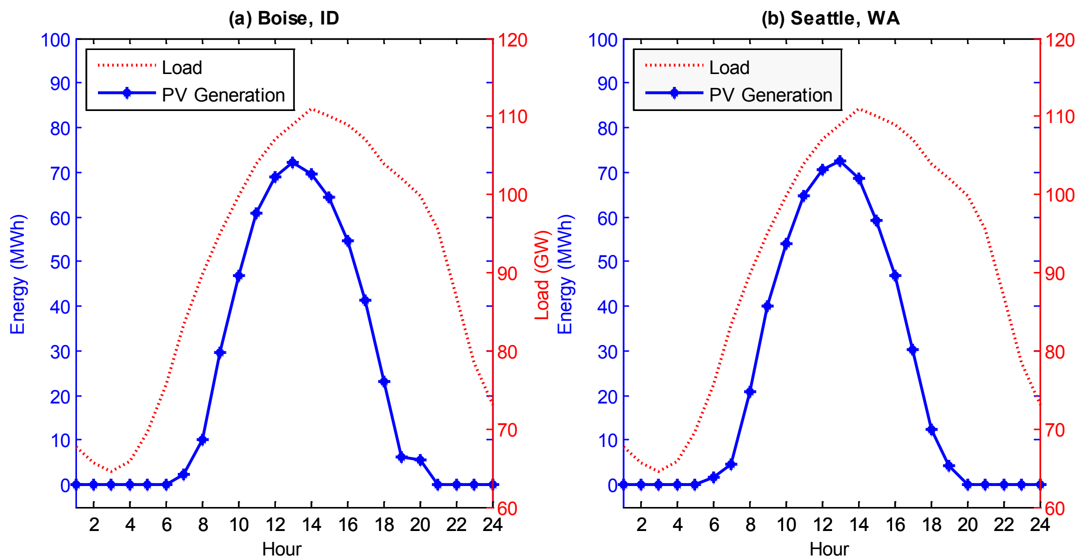

Figure 4. Hourly loads and dispatch of a fixed-axis PV plant located in Boise, Idaho, and Seattle, Washington, on July 10, 2002

The values shown in Table 3 are annual averages. We find significant interannual variation in capacity values between the years studied. This indicates that several years of data are necessary for an accurate and robust long-term estimate of capacity value (this includes both renewable supply data and conventional generator EFOR estimates). For instance, the ECP of PV in Congress, Arizona, ranges from 48% in the year 1999 to 85% in the year 2002. In each year, solar availability during peak load hours can change, which affects the capacity value of PV. To demonstrate this, Figure 5 depicts the output of a fixed-axis PV plant during July 12, 1999, and July 10, 2002. These are days on which the load reaches its peak value in the years 1999 and 2002. As Figure 5 shows, the correlation between PV generation and load is greater in the year 2002 compared to 1999. This explains the significantly greater capacity value in 2002 than in 1999.

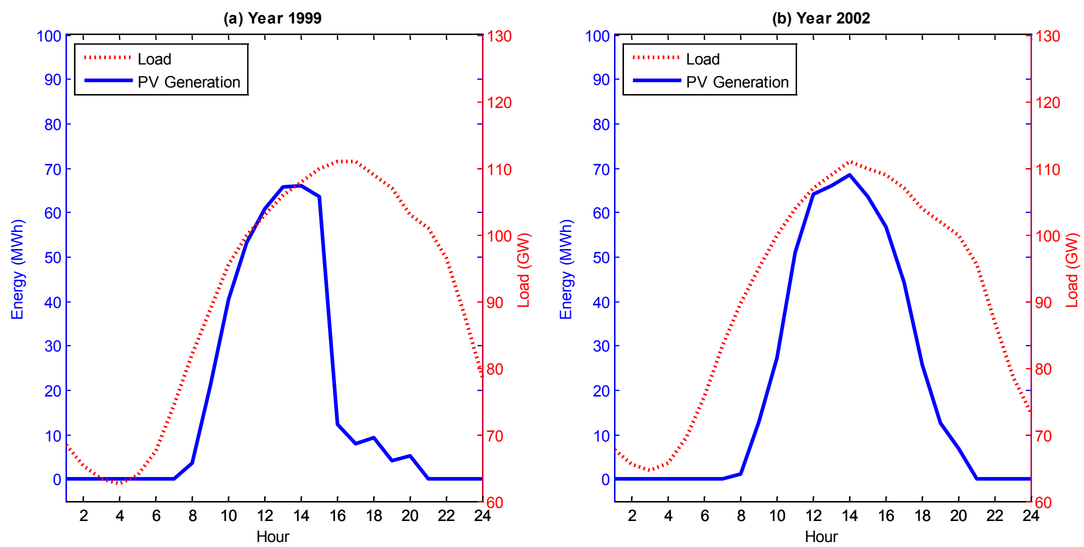

Figure 5. Hourly loads and dispatch of a fixed-axis PV plant located in Congress, Arizona, on July 12, 1999, and July 10, 2002

Although the robustness of capacity value estimates increases with more data, there is an inherent tradeoff because multiple years of accurate and time-synchronized load and solar data may be difficult to obtain. We can demonstrate the benefits of having additional load data by using a root mean squared error (RMSE) metric to measure the difference in the ECP estimated using all years of data as opposed to a subset of the data. This RMSE metric is defined as:

$$\sqrt{\frac{1}{|\Lambda|.|O|}\sum_{\lambda\in\Lambda}\sum_{o\in O}\left(ECP_{\lambda,o,Y}-ECP_{\lambda,o,Y'}\right)^2} \qquad (13)$$

where Λ is the set of locations modeled, O is the set of sun-tracking capabilities modeled (fixed-axis and single- and double-axis tracking), and $ECP_{\lambda,o,Y}$ is the ECP at location λ with sun-tracking capability o using years from dataset Y. Y is the set with all eight years and Y' is a subset of these years. Table 4 summarizes this metric for a subset of two to seven years. The RMSE is averaged over different possible sets of consecutive data that can be used.

Table 4. Average RMSE Estimates Between ECP Estimates using all Eight Years and a Subset of the Data

Years Used	RMSE
2	6.6
3	5.4
4	4
5	2.9
6	1.8
7	0.8

The table shows that having more years of data available provides more robust capacity value estimates because the RMSE decreases when more data are included in the ECP calculation. The table can further be used to measure the benefit of gathering additional data (in terms of reduced ECP error) against the cost of gathering such data and conducting additional capacity value estimation calculations.

5.2 Capacity Value of Photovoltaic Power using Approximation Techniques

This section details the capacity value of PV using the approximation techniques described in Section 2.4, using all eight years of data. Since the methods are known to be approximations of ELCC, their accuracy is compared to the actual ELCC values shown in Table 3.

5.2.1 Capacity Value of Photovoltaic Power using Capacity Factor Approximation

Although CF approximation requires an initial LOLP calculation to obtain weights, there is no need for iterative LOLP calculations. This will inevitably reduce computational time and complexity. This type of approximation is sensitive to the number of hours considered. Previous studies have shown that considering only the top 10 hours is sufficient for CSP plants [15]. We conduct a similar comparison here by considering the top 10, 100, and 10% peak-load hours and find that the top 10 hours yield approximations that are closest to the actual ELCC values. For the sake of brevity, only results regarding top 10 hours are reported in this section. Table 5 summarizes average annual capacity value of PV using CF approximation for the sites listed in Table 2.

Table 5. Average Annual Capacity Value of PV (% Based on System AC Rating) with Fixed-Axis, Single-Axis, and Double-Axis Tracking in Different Locations using CF Approximation

PV Site	Fixed-Axis	Single-Axis Tracking	Double-Axis Tracking
Bartsow, CA	60.4	71.8	75.5
Congress, AZ	70.4	77.1	79.7
Yucca Flat, NV	57.9	69.4	72.8
Hanover, NM	57.3	65.2	68.1
Cheyenne, WY	57.3	75.5	75.9
Salt Lake City, UT	67.7	81.4	84.4
Boise, ID	72.6	84.5	86.5
Los Angeles, CA	56.8	73.9	74.9
San Francisco, CA	61.2	77.0	78.4
Seattle, WA	66.2	82.8	86.0
Denver, CO	61.6	71.0	73.9
Albuquerque, NM	69.8	80.6	82.1
Phoenix, AZ	65.9	71.6	74.2
Las Vegas, NV	62.8	78.1	79.5

5.2.2 Capacity Value of Photovoltaic Power using Garver's Approximation Method

Garver's approximation for ELCC, explained in Section 2.4.2, is used to estimate capacity value of PV for years 1998–2005. Table 6 shows average annual capacity values using this method for the sites listed in Table 2.

Table 6. Average Annual Capacity Value of PV (% Based on System AC Rating) with Fixed-Axis, Single-Axis, and Double-Axis Tracking in Different Locations using GA

PV Site	Fixed-Axis	Single-Axis Tracking	Double-Axis Tracking
Bartsow, CA	58.3	73.5	75.7
Congress, AZ	62.7	73.6	75.8
Yucca Flat, NV	55.5	71.7	74.1
Hanover, NM	50.1	60.1	61.4
Cheyenne, WY	55.8	61.6	65.8
Salt Lake City, UT	60.9	69.9	71.0
Boise, ID	60.1	67.3	69.1
Los Angeles, CA	54.6	65.4	68.7
San Francisco, CA	45.0	58.6	59.8
Seattle, WA	54.7	69.1	70.6
Denver, CO	60.6	70.4	77.5
Albuquerque, NM	51.8	70.6	71.6
Phoenix, AZ	51.9	64.7	67.8
Las Vegas, NV	50.7	68.0	70.2

5.2.3 Capacity Value of Photovoltaic Power using Garver's Approximation Method for Multi-State Units

The GAM method described in Section 2.4.3 is fairly sensitive to the probability distribution utilized for PV generation. Although using an empirical distribution with a 1 MW resolution seems to be reasonable, our results show a large gap between actual ELCC values and the ones obtained from this method. Thus, GAM does not appear to be a reliable method for capacity value estimation of PV. Table 7 summarizes average annual capacity values using GAM for the sites listed in Table 2.

Table 7. Average Annual Capacity Value of PV (% Based on System AC Rating) with Fixed-Axis, Single-Axis and Double-Axis Tracking in Different Locations using GAM

PV Site	Fixed-Axis	Single-Axis Tracking	Double-Axis Tracking
Bartsow, CA	25.4	32.5	36.5
Congress, AZ	24.6	31.3	35.1
Yucca Flat, NV	25.2	32.4	36.6
Hanover, NM	24.3	30.7	34.4
Cheyenne, WY	22.1	26.0	30.2
Salt Lake City, UT	24.7	30.7	34.3
Boise, ID	23.3	29.7	32.4
Los Angeles, CA	24.0	28.7	34.0
San Francisco, CA	22.0	27.9	30.3
Seattle, WA	20.9	27.7	29.0
Denver, CO	20.6	26.2	29.2
Albuquerque, NM	23.1	30.4	32.0
Phoenix, AZ	19.9	24.1	26.6
Las Vegas, NV	14.9	19.2	20.0

In order to demonstrate the effect of how the distribution of PV availability is modeled on the GAM, we conduct a set of analyses for cases in which the empirical probability distribution is represented using a coarser resolution. We built an empirical probability distribution with 10, 20, and 33 MW blocks by aggregating PV generation accordingly. Table 8 summarizes these results for PV plants with fixed-axis. PV plants with tracking systems have similar results.

Table 8. Average Annual Capacity Value of PV (% Based on System AC Rating) with Fixed-Axis in Different Locations using GAM Assuming PV Probability Distribution with 1, 10, 20, and 33 MW Resolution

PV Site	1 MW Res.	10 MW Res.	20 MW Res.	33 MW Res.
Bartsow, CA	25.4	34.8	43.9	57.6
Congress, AZ	24.6	33.9	43.6	56.5
Yucca Flat, NV	25.2	34.6	44.0	57.2
Hanover, NM	24.3	33.6	43.1	56.2
Cheyenne, WY	22.1	31.5	40.9	54.7
Salt Lake City, UT	24.7	34.0	43.2	57.1
Boise, ID	23.3	32.6	42.5	54.9
Los Angeles, CA	24.0	33.3	42.9	55.7
San Francisco, CA	22.0	31.3	40.8	54.5
Seattle, WA	20.9	30.1	40.0	53.0
Denver, CO	20.6	30.0	39.7	53.1
Albuquerque, NM	23.1	32.4	41.3	55.7
Phoenix, AZ	19.9	29.2	38.8	52.3
Las Vegas, NV	14.9	24.2	33.9	48.3

5.2.4 Capacity Value of Photovoltaic Power using the Z Method

Table 9 summarizes average annual capacity values using the Z method for the sites listed in Table 2.

Table 9. Average Annual Capacity Value of PV (% Based on System AC Rating) with Fixed-Axis, Single-Axis, and Double-Axis Tracking in Different Locations using the Z Method

PV Site	Fixed-Axis	Single-Axis Tracking	Double-Axis Tracking
Bartsow, CA	46.8	67.6	68.4
Congress, AZ	61.8	77.9	79.2
Yucca Flat, NV	44.5	68.9	69.9
Hanover, NM	48.4	64.5	65.1
Cheyenne, WY	46.8	61.2	61.7
Salt Lake City, UT	52.4	63.9	64.9
Boise, ID	56.6	67.1	67.3
Los Angeles, CA	49.5	72.6	72.7
San Francisco, CA	53.4	71.2	71.9
Seattle, WA	62.2	76.1	76.5
Denver, CO	66.6	78.3	79.3
Albuquerque, NM	52.6	69.5	70.6
Phoenix, AZ	58.3	73.3	74.4
Las Vegas, NV	60.2	80.1	81.3

5.2.5 Comparison Between Different Approximation Techniques

In order to understand the accuracy of each of the approximation techniques, we use an RMSE metric. The RMSE metric is defined as:

$$\sqrt{\frac{1}{|\Lambda|.|O|}\sum_{\lambda\in\Lambda}\sum_{o\in O}\left(ELCC_{\lambda,o}-A_{\lambda,o}\right)^2} \qquad (14)$$

where Λ is the set of locations modeled, O is the set of tracking capabilities modeled (fixed-axis and single- and double-axis tracking), $ELCC_{\lambda,o}$ is the ELCC at location λ with tracking capability o, and $A_{\lambda,o}$ is the approximation method used at location λ with tracking capability o. Table 10 rank orders different approximation techniques based on this metric.[12] According to Table 10, CF approximation yields the closest approximations to ELCC and GAM_1 is the least accurate in this manner.

Table 10. Average RMSE of ELCC for Different Approximation Techniques

Approximation Technique	RMSE
CF	4.12
GA	11.9
Z	13.5
GAM_33	14.9
GAM_20	25.8
GAM_10	34.4
GAM_1	44.4

[12] GAM_1, GAM_10, GAM_20, and GAM_33 refer to the GAM method assuming an empirical PV probability distribution with 1, 10, 20, and 33 MW resolutions, respectively.

6 Sensitivity Analysis

This section examines the sensitivity of changes in PV orientation and the inverter model on capacity value.

6.1 Sensitivity of Capacity Value of Photovoltaic Power with Respect to Array Orientation

The results reported in Section 5 were under the assumption that the PV array is oriented to face south (azimuth angle of 0) and tilt angle equivalent to the latitude of the site. Changing the orientation of the PV array would affect both the energy yield and capacity value. An azimuth angle of zero typically maximizes energy yield [33]. In the northern hemisphere, increasing the azimuth angle will favor afternoon energy production and decreasing it will favor morning energy production.

The ability of a generator to produce energy during peak load hours directly impacts its capacity value. All of the sites considered in this study are located in the western United States where load tends to peak in summer afternoons. As a result, an increased azimuth angle tends to increase energy production in the afternoon and potentially increase capacity value but with the penalty of decreased energy yield. We examine this effect by estimating the capacity value and annual energy yield for four sites—Bartsow, California, Congress, Arizona, Yucca Flat, Nevada, and Hanover, New Mexico—as a function of azimuth and tilt angles. Note that we use ECP as an estimate for capacity value and we also assume that the PV is fixed-axis. We define the azimuth angle as ranging from -90 (facing east) to 90 (facing west) with 0 facing due south and sweep over these angles in 10-degree increments. However, we only report results for azimuth angles ranging from 0 to 90 because systems facing toward east are not efficient in terms of capacity value and energy yield.

Figure 6 depicts the average capacity value and annual energy yield as a function of azimuth and tilt angles for a site located in Bartsow, California, with coordinates shown in Table 2. Figure 6 shows that some orientations yield to a capacity value greater than 100%. As explained in Section 3, capacity values are normalized by the STC AC capacity of the PV plant, which we find to be 83.4 MW. This is not necessarily the maximum AC output of the PV, and depending on solar irradiance and cell temperature, it is possible for the PV plant to generate more than 83.4 MW.

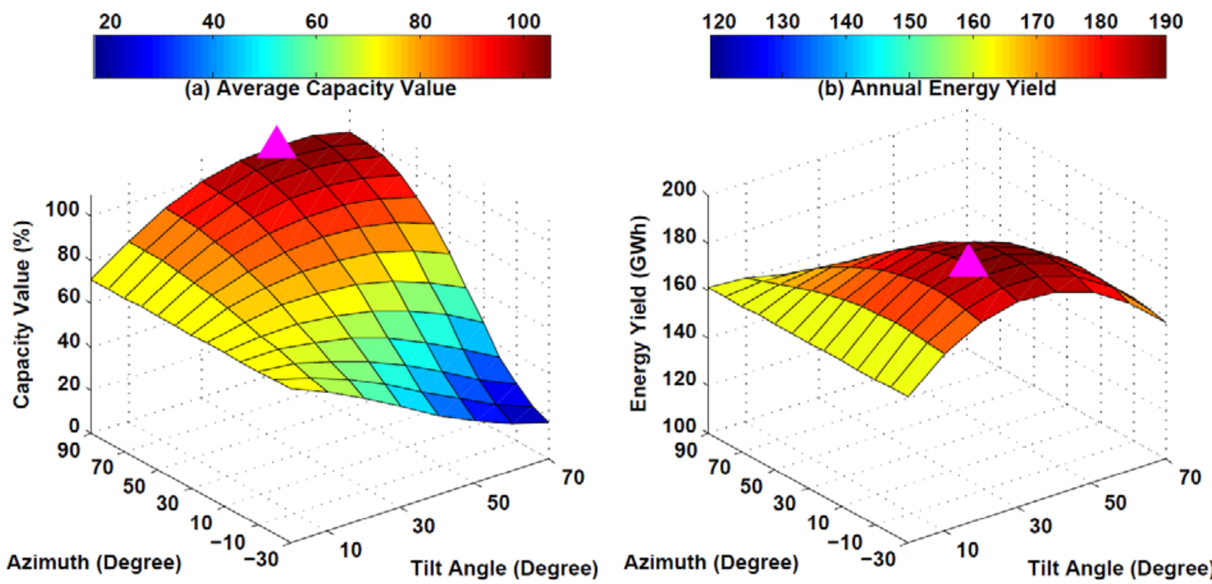

Figure 6. Average annual capacity value and energy yield of PV at Bartsow, California, as a function of azimuth and tilt angles. Magenta triangles show the maximum.

Figure 7 depicts the average capacity value and annual energy yield as a function of azimuth and tilt angles for a site located in Congress, Arizona, with coordinates shown in Table 2.

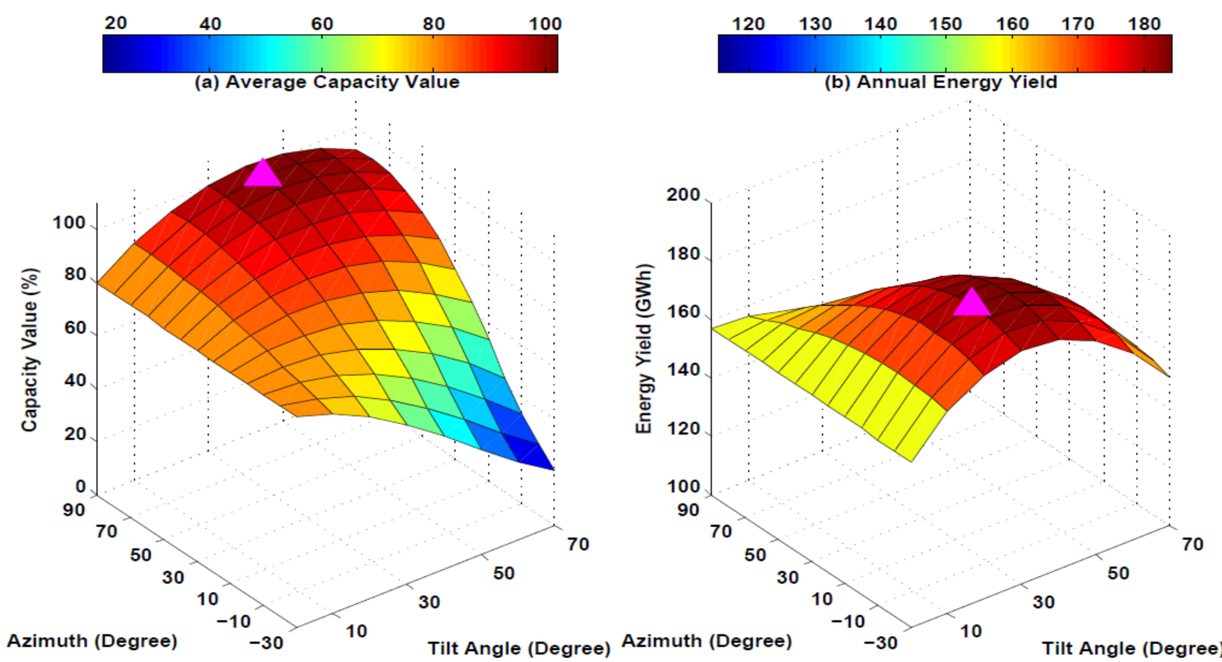

Figure 7. Average annual capacity value and energy yield of PV at Congress, Arizona, as a function of azimuth and tilt angles. Magenta triangles show the maximum.

Figure 8 depicts the average capacity value and annual energy yield as a function of azimuth and tilt angles for a site located in Yucca Flat, Nevada, with coordinates shown in Table 2.

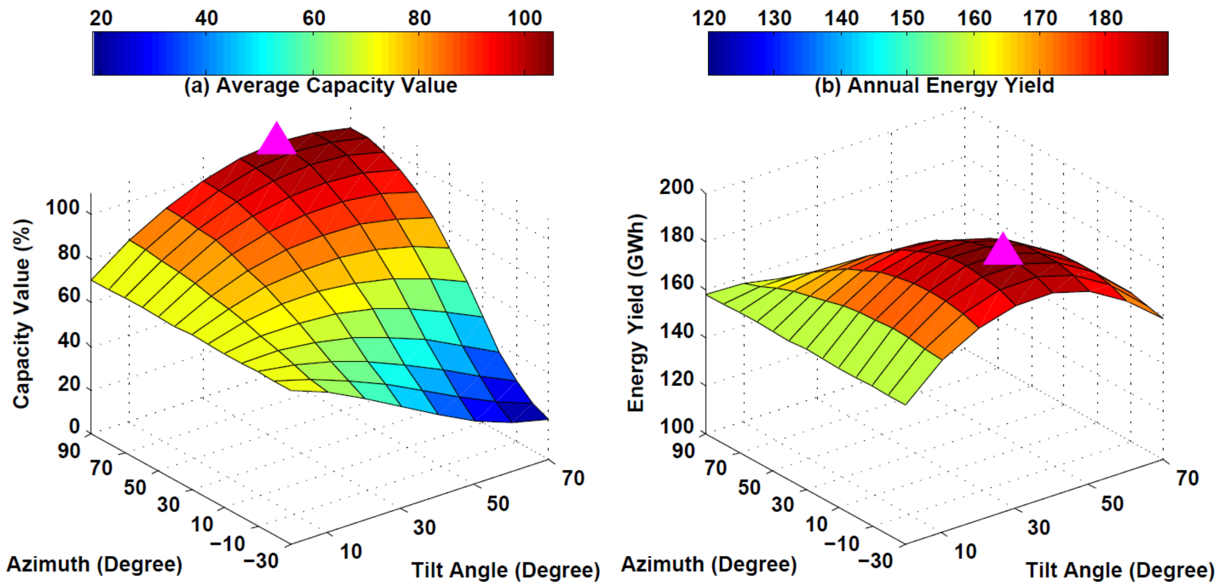

Figure 8. Average annual capacity value and energy yield of PV at Yucca Flat, Nevada, as a function of azimuth and tilt angles. Magenta triangles show the maximum.

Figure 9 depicts the average capacity value and annual energy yield as a function of azimuth and tilt angles for a site located in Hanover, New Mexico, with coordinates shown in Table 2.

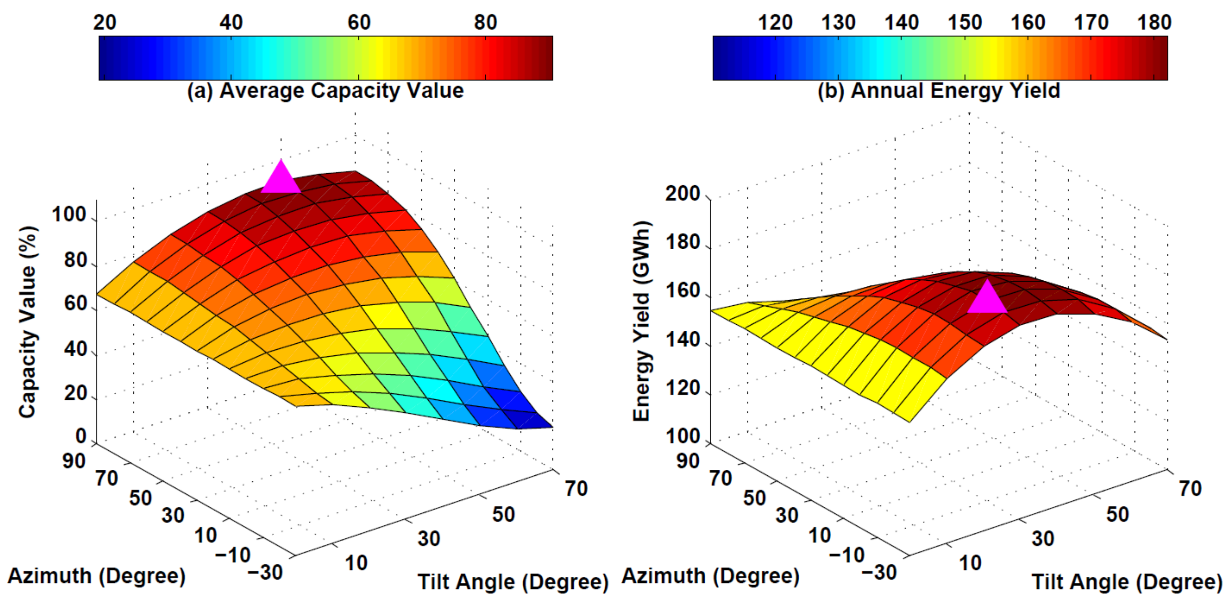

Figure 9. Average annual capacity value and energy yield of PV at Hanover, New Mexico, as a function of azimuth and tilt angles. Magenta triangles show the maximum.

As expected, Figures 6–9 reveal a tradeoff between capacity value and energy yield. Capacity value increases with azimuth angle while the reverse is true for annual energy yield. Therefore, the orientation of PV array represents a tradeoff driven by market conditions including the presence of energy or capacity markets and other incentives for energy production. Table 11 summarizes the orientations that maximize average annual capacity value and annual energy yield for the four locations analyzed in Figures 6–9. The maximum average annual capacity value and annual energy yield are also identified in Table 11. As shown in the table, orientations that maximize annual capacity value and energy yield are similar with respect to the tilt angle; they differ at most by 20 degrees. However, the azimuth angles are significantly different showing the tradeoff between capacity value and energy yield.

Table 11. Orientation that Maximizes Average Annual Capacity Value and Annual Energy Yield Along with Maximum Average Annual Capacity Value (%) and Energy Yield (GWh) in Different Locations

PV Site	Capacity Value		Energy Yield	
	Maximum Value (%)	Orientation (Azimuth,Tilt)	Maximum Value (GWh)	Orientation (Azimuth,Tilt)
Bartsow, CA	105.0	(90°,50°)	190.0	(0°,30°)
Congress, AZ	102.2	(80°,40°)	184.2	(0°,30°)
Yucca Flat, NV	105.3	(90°,50°)	189.2	(0°,40°)
Hanover, NM	90.5	(90°,50°)	181.8	(-10°,30°)

6.2 Sensitivity of Capacity Value of Photovoltaic Power with Respect to Inverter Model

The SIPM used throughout our analysis has a non-linear behavior, which is depicted in Figure 1. The inverter is more efficient at higher power outputs. Simpler single point efficiency inverter models (SPEIM) are occasionally used to model PV systems. If the single efficiency used in a SPEIM is properly set, the total simulated energy yield over the year can closely match the result of using a SIPM. This is because the inverter efficiency will be over- and under-estimated in some hours but will balance each other out over the course of the year. Using an SPEIM can introduce significant errors when estimating the capacity value of PV, however, because the capacity value is highly sensitive to the timing of PV output. In order to demonstrate this, we substitute the SIPM used in our analysis with an SPEIM with a 94% efficiency, based on the default value in SAM. Table 12 summarizes the average annual change in ECP of PV plants as a result of this substitution.

Table 12. Average Annual Change in Capacity Value when SPEIM is Utilized as Opposed to SIPM for Fixed-Axis, Single-Axis, and Double-Axis Tracking PVs in Different Locations

PV Site	Fixed-Axis	Single-Axis Tracking	Double-Axis Tracking
Bartsow, CA	-3.2	3.4	1.5
Congress, AZ	0	3.9	3.0
Yucca Flat, NV	-2.1	3.8	3.1
Hanover, NM	-0.5	5.4	3.0
Cheyenne, WY	-3.8	3.8	3.2
Salt Lake City, UT	-5.0	0.6	1.8
Boise, ID	-5.1	0	1.8
Los Angeles, CA	-3.6	8.7	8.0
San Francisco, CA	-4.1	4.9	3.3
Seattle, WA	-7.5	1.5	4.0
Denver, CO	-2.0	2.0	2.2
Albuquerque, NM	-2.3	2.8	1.2
Phoenix, AZ	-1.2	2.3	1.0
Las Vegas, NV	-6.5	1.4	-0.4

Table 12 shows that for PV with fixed-axis, SPEIM yields a higher capacity value, whereas SIPM yields a higher capacity value when PV is equipped with a double-axis tracking system. The reason is due to the non-linear behavior of SIPM. For lower power outputs, as for the case with fixed-axis, SPEIM has higher efficiency compared to SIPM, whereas the reverse is true for high power outputs. This is because the SPEIM uses an average efficiency, which will understate inverter efficiency at high output levels and overstate it at lower levels.

7 Conclusions

This study compares several approaches for estimating the capacity value of PV. It applies these methods at a variety of locations within WECC during the years 1998–2005, while assuming the load is fixed to evaluate the variation in performance based on the solar resource. This is done by simulating hourly PV generation and using it as an input for reliability-based methods and approximation techniques that quantify capacity value. While ECP and ELCC are well recognized and widely used due to their robustness, we find that some approximation techniques can yield similar results. Our results show that PV, on average, can have ECPs between 61% and 92% and ELCCs between 52% and 86%, depending on the location and sun-tracking capability of the plant and using the system's AC rating. PV plants with two-axis tracking have the highest capacity value. Similar to other renewable resources, we find high interannual variation (±16%), indicating that multiple years of data are required for a robust estimation of capacity value. Out of the approximation techniques that we study, we find the CF approximation to be the most dependable technique, followed by GA, Z method, and GAM. We show this by rank ordering these techniques by means of an RMSE metric compared to an actual ELCC calculation.

Our analysis also examines the sensitivity of the capacity value of PV with respect to orientation and inverter model. By calculating ECP as a function of azimuth and tilt angles, we recognize a tradeoff between capacity value and annual energy yield. Orienting PV arrays toward the west favors afternoon energy production and therefore maximizes capacity value, at the expense of reduced annual energy yield. We also study the effect of inverter efficiency on ECPs. We compare average annual ECPs of PV with two different inverter models, SIPM and SEIPM. We find that for PV plants with fixed-axis, simulating PV generation with SEIPM will overestimate capacity value, while for PV plants with double-axis tracking, simulating PV generation with SEIPM will underestimate capacity value.

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Exhibit RMP___(RTL-3)
Docket No. 12-035-100
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick T. Link

October 2014

FINAL

FEASIBILITY STUDY UPDATE

Solar Power Plants in Utah and Oregon

B&V PROJECT NO. 181745

PREPARED FOR

PacifiCorp Energy

9 DECEMBER 2013

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1.0 Executive Summary

Black & Veatch Corporation (Black & Veatch) was retained by PacifiCorp to provide estimates of the capital and O&M costs and electric generation profiles of 5 MW (AC) and 50 MW (AC) solar photovoltaic (PV) plants located at three sites in Utah and one site in Oregon. This report evaluates PV systems based on crystalline silicon modules mounted in both fixed tilt and single axis tracking configurations at these four specific locations. Due to changes in the cost of PV solar components during the past five years, significant focus shall be given to the current costs of PV components and construction costs.

Black & Veatch provides current capital and O&M costs and generation performance of 5 MW and 50 MW utility-scale PV systems. PV systems at the following locations are evaluated:

- Veyo, UT (5 MW and 50 MW)
- Milford, UT (5 MW and 50 MW)
- Salt Lake City, UT (5 MW only)
- Lakeview, OR (5 MW and 50 MW).

Black & Veatch previously prepared a study for 50 MW projects at two Utah sites (Veyo and Milford). In that study, the datasets originally selected were assessed and expected to be the best source representing the typical solar radiation at site. That data formed the starting point for this study. To preserve consistency among all sites in this study, Black & Veatch used the same source to select solar datasets for the Salt Lake City and Lakeview sites. Black & Veatch provides a summary of the selection criteria and parameters of these datasets. Black & Veatch created generic conceptual layouts for the 50 MW fixed tilt and single axis configurations in the previous study. The specifications of these systems are based on the parametric analysis used to identify the most attractive design parameters. Black & Veatch used the same design at Veyo and Milford due to their close geographical proximity. Due to the difference in latitude between the Salt Lake City (UT) and Lakeview (OR) sites, the inter-row distance was adjusted. The other main system specifications are still appropriate for all four sites.

A summary of the relevant system specifications are shown in Table 1-1 for the fixed tilt system and Table 1-2 for the single-axis tracker system. The solar modules selected for performance and cost estimating purposes are representative of Tier-1 manufacturers. The use of these modules as well as other specific Balance of Systems (BoS) equipment does not imply a recommendation on the part of Black & Veatch to select or engage with any of these vendors.

Based on the system specifications developed for the PV power plant, Black & Veatch built a model of the systems using PVsyst software. The models were used to estimate the annual energy production of each system. The results are shown in Table 1-1 and Table 1-2.

Black & Veatch also developed Engineering, Procurement and Construction (EPC) cost estimates, as well as Operation and Maintenance (O&M) cost estimates assuming a 25-year life of the PV power plants. Table 1-1 and Table 1-2 show these results for each system. The O&M costs reflect better information on tracker O&M costs than we had access to previously. Also, we included insurance and taxes, which were not included previously. For O&M, a typical labor rate was used to represent the labor rates for different regions rather than showing small differences between the sites. Labor rates in this region vary from 62.3 to 82.8 percent of the national average (see section 6.2).

1.1 CONCLUSIONS

All the costs presented in this report are EPC and O&M scopes only. Actual projects would have additional costs due to:

- Land ownership would determine plant layout, likely of an irregular shape.
- For the 50 MW plants, transmission would not be adjacent to the array and a transmission line would be required with associated transformers and switchgear. For the 5 MW design, connection to an adjacent distribution line is assumed at the distribution voltage and no additional costs are necessary.
- Client decisions about providing maintenance or operations buildings
- Additional access roads
- Consideration of actual elevation change and need for additional site preparation
- Consideration of soil conditions and impact on foundation design
- If washing water is not available at the site RO systems would be provided or the cost of trucking in water would be included.
- Inclusion of spare parts
- Inclusion of project development costs and financing and legal fees
- Inclusion of land costs, either purchase or lease.
- Inclusion of interest during construction
- Insurance and taxes

Table 1-1 Summary of Results (Fixed Tilt)

SITE, SIZE	INSOLATION (KWh/m²/Y)	SYSTEM SPECIFICATIONS	ENERGY PRODUCTION (UNCLIPPED) (MWh/year)*	EPC ESTIMATES (USD$/KWac)	O&M ESTIMATES (USD $1000/YR1)
Site 1 Veyo, UT 50 MW	2,015	Capacity (MWac) 50.4 Tilt 27 deg ILR: 1.37 Pitch (ft): 31 to 36 # modules: 230,580 # inverter: 70 Acres: 297	127,690	2,526	2,595
Site 2 Milford, UT 50 MW	1,905		121,330	2,526	2,595
Site 4 Lakeview, OR 50 MW	1,737		112,170	2,629	2,595
Site 1 Veyo, UT 5 MW	2,015	Capacity (MWac) 5 Tilt 27 deg ILR: 1.37 Pitch (ft): 31 to 36 # modules: 23,058 # inverter: 7 Acres: 29.7	12,769	2,977	260
Site 2 Milford, UT 5 MW	1,905		12,133	2,977	260
Site 3 Salt Lake City, UT 5 MW	1,710		10,592	2,977	260
Site 4 Lakeview, OR 5 MW	1,737		11,217	3,082	260

Notes:
Values for the year zero of energy production do not include module degradation during the first year of operation(estimated to be 0.7% per year over project life.)

Table 1-2 Summary of Results (Single-Axis Tracker)

SITE, SIZE	INSOLATION (KWh/m²/Y)	SYSTEM SPECIFICATIONS	ENERGY PRODUCTION (MWh/year)*	EPC ESTIMATES (USD$/KWac)	O&M ESTIMATES (USD $1000/YR1)
Site 1 Veyo, UT 50 MW	2,015	Capacity (MWac) 50.4 Tilt ±45 deg ILR: 1.34 Pitch (ft): 19.5 to 24 # modules: 225,540 # inverter: 70 Acres: 297	153,310	2,682	3,226
Site 2 Milford, UT 50 MW	1,905		145,250	2,682	3,226
Site 4 Lakeview, OR 50 MW	1,737		129,080	2,798	3,226
Site 1 Veyo, UT 5 MW	2,015	Capacity (MWac) 5 Tilt:± 45 deg ILR: 1.34 Pitch (ft): 19.5 to 24 # modules: 22,554 # inverter: 7 Acres: 29.7	15,331	3,153	323
Site 2 Milford, UT 5 MW	1,905		14,525	3,153	323
Site 3 Salt Lake City, UT 5 MW	1,710		12,730	3,153	323
Site 4 Lakeview, OR 5 MW	1,737		12,908	3,271	323

Notes:
Values for the year zero of energy production do not include module degradation during the first year of operation(estimated to be 0.7% per year over project life.)

2.0 Solar Resource

The location of the four sites is shown in Figure 2-1 below. The maximum difference in latitude between the sites (Veyo and Lakeview) is approximately 4.87 degrees.

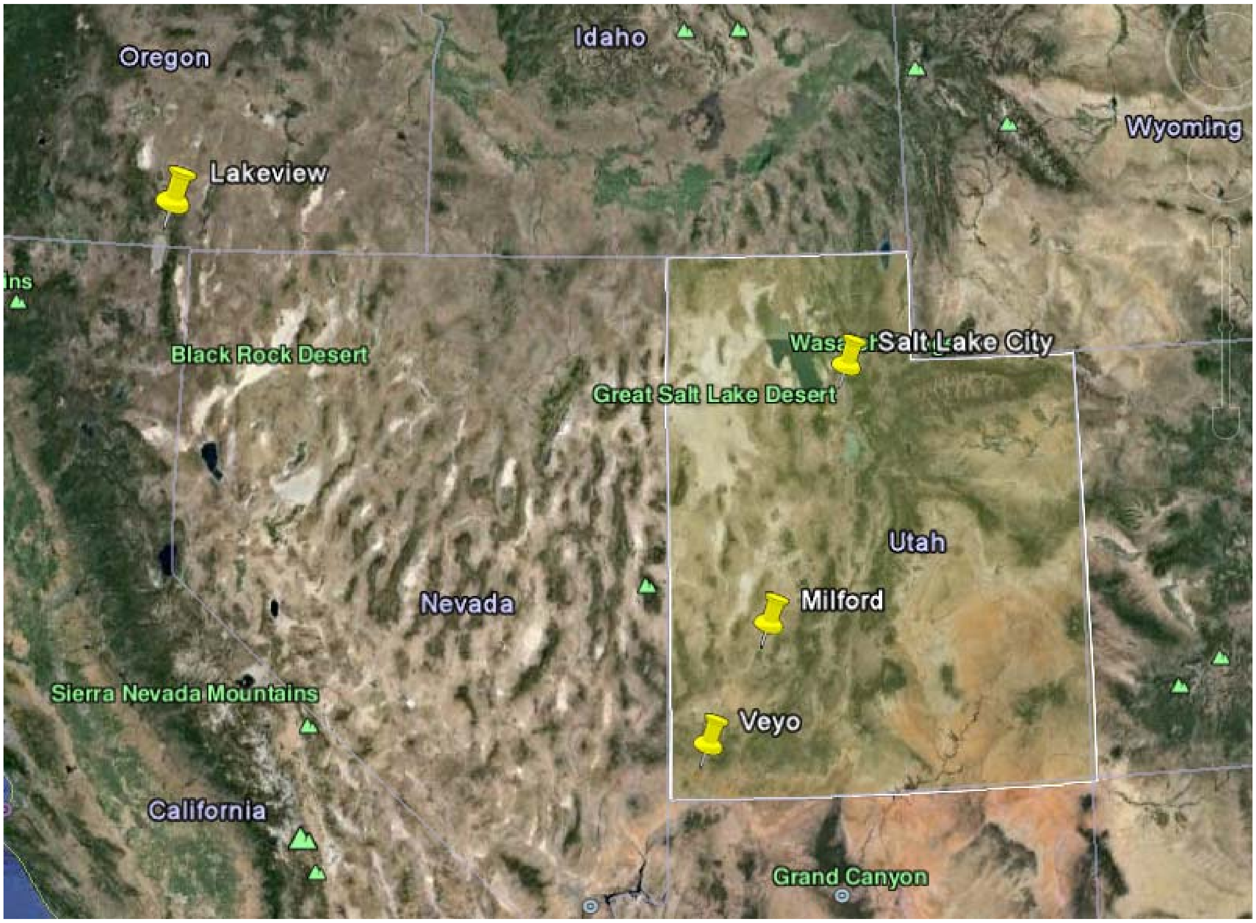

Figure 2-1 Site Locations

The first two sites are located approximately 85 miles from each other in Utah's southwest region. Site 1 (Veyo) is located approximately 2.5 miles south from the town of Veyo, UT and Site 2 (Milford) is located approximately 1.5 miles northeast from the town of Milford, UT. Site 3 (Salt Lake City) is located 1 mile south of the Salt Lake City airport, at the southeast corner of the interchange between Interstate 80 and Bangerter Hwy. Site 4, (Lakeview) is located approximately 2 miles southwest of the town of Lakeview in Oregon.

No property boundaries, which might increase project complexity and cost, were considered for this feasibility study. The specific site coordinates are indicated in Table 2-1 Site Locations.

Table 2-1 Site Locations

SITE NAME	LATITUDE	LONGITUDE
Site 1 Veyo	37.35	-113.65
Site 2 Milford	38.45	-112.95
Site 3 Salt Lake City	40.75	-111.95
Site 4 Lakeview	42.15	-120.35

2.1 SOLAR DATA

Due to their geographical location, the solar resource and meteorological conditions at each site are different. In the original study, Black & Veatch assessed several solar resource databases applicable to the two initial sites, Veyo and Milford. These sources are also applicable to the additional two sites, Salt Lake City and Lakeview. The main characteristics of the datasets provided by each database are described in Table 2-2 below.

Table 2-2 Solar Resource Databases

DATA SOURCE	DATABASE FEATURES	TIME SERIES	UNCERTAINTY GHI
TMY2	Datasets compiled by the National Renewable Energy Laboratories (NREL) and publicly available. The meteorological data source is observed weather and measured data from ground stations. The Typical Meteorological Year second edition (TMY2) datasets comprise hourly meteorological data for a year (8760 data points) including global horizontal irradiance (GHI), ambient temperature, wind speed and other parameters. TMY2 data is available for 239 stations across the United States.	1961 1990	5%
TMY3	Datasets compiled by NREL and publicly available. The meteorological data source is observed cloud cover, satellite data and measured data from ground stations. The Typical Meteorological Year third edition (TMY3) datasets comprise hourly meteorological data for a year (8760 data points) including GHI, ambient temperature, wind speed and other parameters. TMY3 data is available for 1020 stations across the United States. The TMY3 dataset has several inconsistencies. Ceilometers were used from 1991 to 1997 to measure cloud cover, while from 1998 to 2005 satellite-based measurements of cloud cover were	1953 2005	5-10%

	implemented. This compilation of different measurement techniques into a single dataset causes TMY3 data to often be of inconsistent quality. Due to the historical depth and quality of TMY2 data, Black & Veatch considers TMY2 to be one of the best available solar resource dataset. When sites are in close proximity to a TMY2 site, it is Black & Veatch's preference to utilize this dataset to forecast production from PV power plants.		
TGY	Datasets compiled by NREL and publicly available through NREL's Solar Power Prospector tool. The meteorological data source is satellite data and measured data from ground stations. The Typical Global Horizontal Year (TGY) datasets comprise hourly meteorological data for a typical year (8760 data points) including GHI, ambient temperature, wind speed and other parameters. Direct normal irradiance (DNI) and individual year datasets (1998 to 2009) are also available. The datasets are available on a 10 by 10 kilometer grid resolution across the United States. The TGY datasets were released in September 2012 as an update to NREL's existing datasets based on satellite data. It is a revision of the satellite modeled dataset which it replaced. Black & Veatch has experience with the revised database as well, since it was previously available as a commercial product.	1998 2009	6%
Meteonorm	Datasets compiled by Meteotest, a private company specialized in weather analysis for renewable energy technologies. Datasets are generated with Meteonorm, a licensed program. The meteorological data source is measured data from ground stations. Meteonorm generates a typical meteorological year (8760 data points) dataset based on a proprietary interpolation algorithm that makes use of measured data from the closest ground stations. The datasets comprise GHI, ambient temperature, wind speed and other parameters. Meteonorm has access to an ample database of ground stations. The datasets are available for any point in the United States and internationally. Due to the use of available data close to the selected location, Black & Veatch finds that Meteonorm datasets have a variable quality depending on the proximity, quantity and quality of data sources to the selected location.	Varies	Varies according to location and stations available
3Tier	Datasets compiled by 3Tier, a private company specialized in weather analysis for renewable energy technologies. Datasets are available for purchase. The meteorological data source is	1998 To date	As low as 4%

	satellite data. The datasets provided by 3Tier comprise hourly meteorological data for a typical year (8760 data points) including GHI, ambient temperature, wind speed and other parameters. DNI datasets are also available. The datasets are available for any point in the United States and internationally. Black & Veatch believes that the data sources and data processing algorithms used by 3Tier provide high quality datasets.		

2.1.1 Solar Resource Analysis

In order to select a dataset for each of the sites, Black & Veatch assessed the solar resource provided by four databases: TMY2, TMY3, TGY and Meteonorm. Datasets provided by NREL are publicly available while Meteonorm is licensed to Black & Veatch. Datasets provided by 3Tier and Solar Anywhere are normally purchased.

Black & Veatch selected the dataset for each site based on the following criteria:

- Data quality (length of time series, measured data sources, data consistency and compilation algorithm).
- Distance from site.

In the original study, Black & Veatch chose to use the TGY satellite dataset for Site 1 and Site 2 (Veyo and Milford) because this database best satisfies the criteria above. The closest TMY2 dataset is significantly far from the original project sites and is therefore not expected to represent site resource effectively. The closest TMY3 datasets are also significantly far from the original project sites with the exception of St George, which is approximately 15 miles south of Veyo. However, Black & Veatch generally does not use TMY3 data as the data quality is not considered as good as other sources and thus, this dataset was not considered (see TMY3 in Table 2-2). The dataset provided by Meteonorm makes use of TMY2 and TMY3 datasets, some of them remarkably far from the selected location. Therefore, Black & Veatch did not consider Meteonorm datasets as they are not expected to represent site resource accurately. To provide consistency for comparison of results, Black & Veatch also selected the TGY satellite datasets for the two additional sites, Salt Lake City and Lakeview. The annual GHI value for each of the four sites is reported in Table 2-3.

Table 2-3 Solar Resource Data

SITE NAME	ANNUAL TYPICAL GHI (FROM SOLAR POWER PROSPECTOR) ($kWh/m^2/year$)
Site 1 Veyo	2,015
Site 2 Milford	1,905
Site 3 Salt Lake City	1,710
Site 4 Lakeview	1,737

2.2 WEATHER PATTERNS

The weather patterns identified for the sites are used to estimate the amount of soiling that is developed on the modules on a monthly basis. This parameter is used in the energy production model to account for the loss of PV module efficiency due to the accumulation of dust or snow on the modules. The weather information is collected from publicly available weather conditions databases. Temperature is not used in the soiling model but it is an important parameter used in the modeling of the PV system[1].

The annual average, high and low climate conditions at both sites are summarized in Table 2-4 and in the graphs in Figure 2-4 through Figure 2-7.

Site 1, has hot and dry summers with minimal rain, while the winters are typically cold with intermittent rainfall and snow. Site 2 receives slightly less rain than Site 1 but receives more than double the amount of snow received at Site 1. Site 3 has a similar weather pattern as Site 1 and 2, with mild summers and minimal rain. Site 4 has less extreme weather between summer and winter and the rainfall is more evenly distributed over the year. The rainfall and snow fall at site 4 is the highest of all sites.

[1] The efficiency of the PV module decreases wen the operating temperature of the cell is higher than 25°C

Table 2-4 Site Climate Conditions

SITE NAME	AVERAGE ANNUAL TEMPERATURE (C)	AVERAGE SUMMER HIGHS (C)	AVERAGE WINTER LOWS (C)	AVERAGE ANNUAL RAINFALL (cm)	AVERAGE ANNUAL SNOWFALL (cm)
Site 1 Veyo	12.90	32.20	-3.30	35.10	22.00
Site 2 Milford	9.30	31.30	-8.70	14.00	114.60
Site 3 Salt Lake City	11.20	31.50	-5.30	39.80	152.10
Site 4 Lakeview	7.40	26.70	-6.30	29.00	131.00
Source: Weatherbase (updated from 2012 report)					

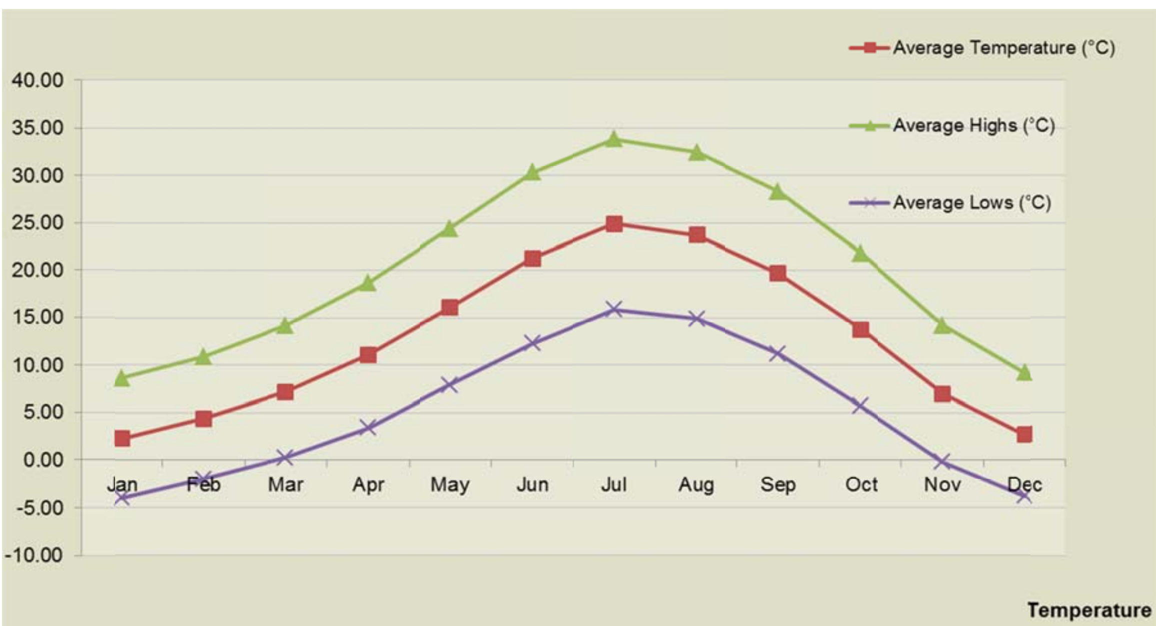

Figure 2-2 Site 1 Veyo: Typical Temperature Conditions

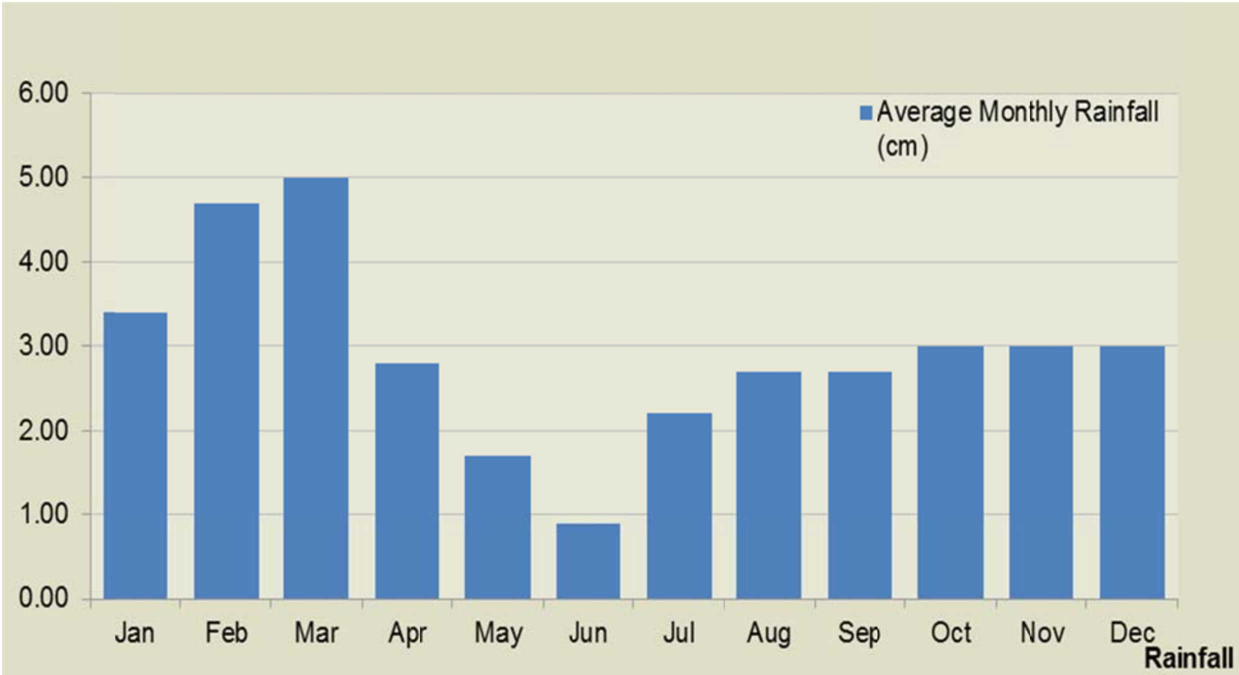

Figure 2-3 Site 1 Veyo: Typical Rainfall Conditions

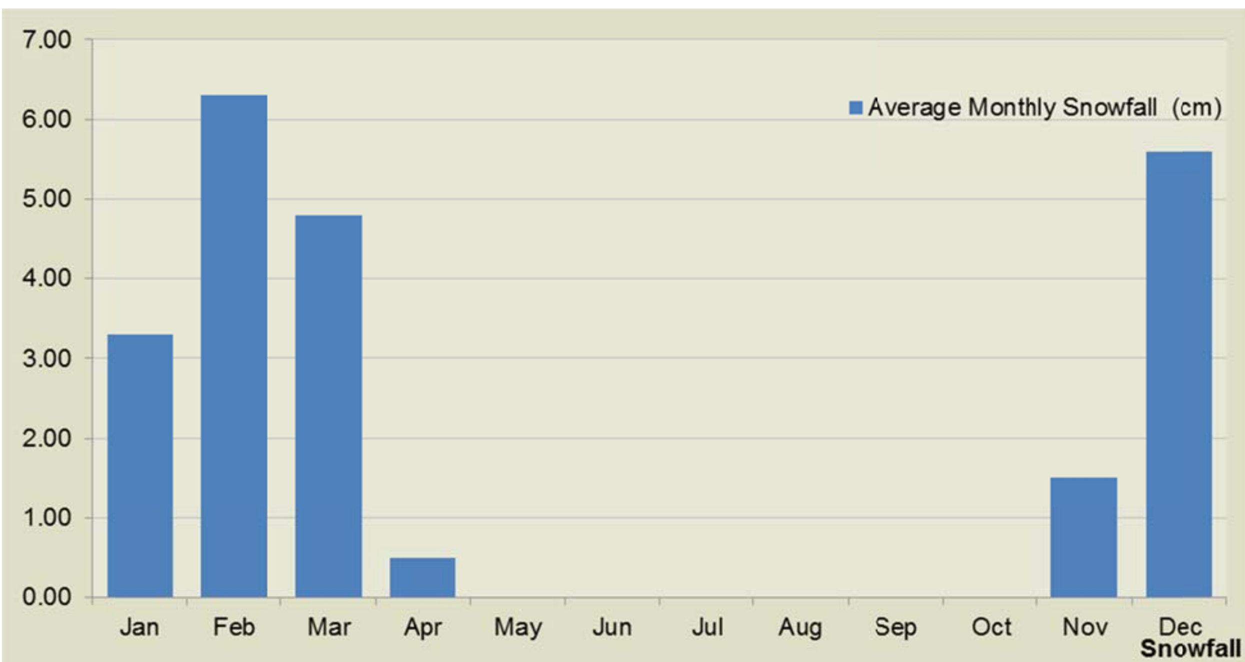

Figure 2-4 Site 1 Veyo: Typical Snowfall Conditions

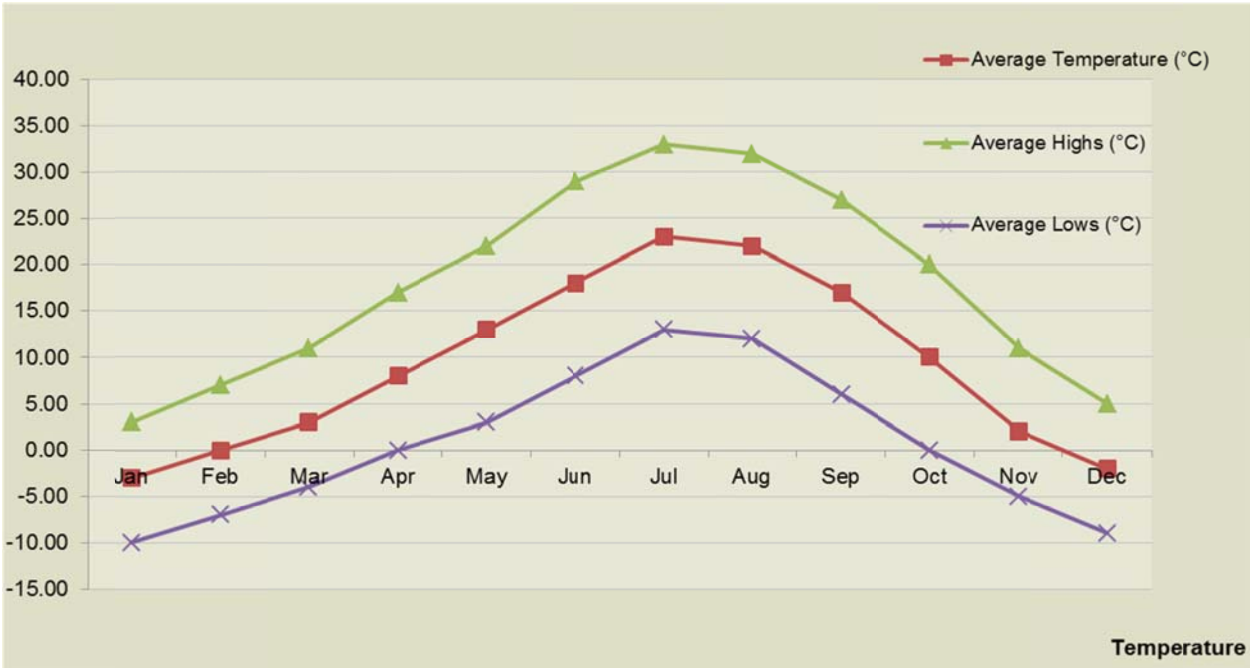

Figure 2-5 Site 2 Milford: Typical Temperature Conditions

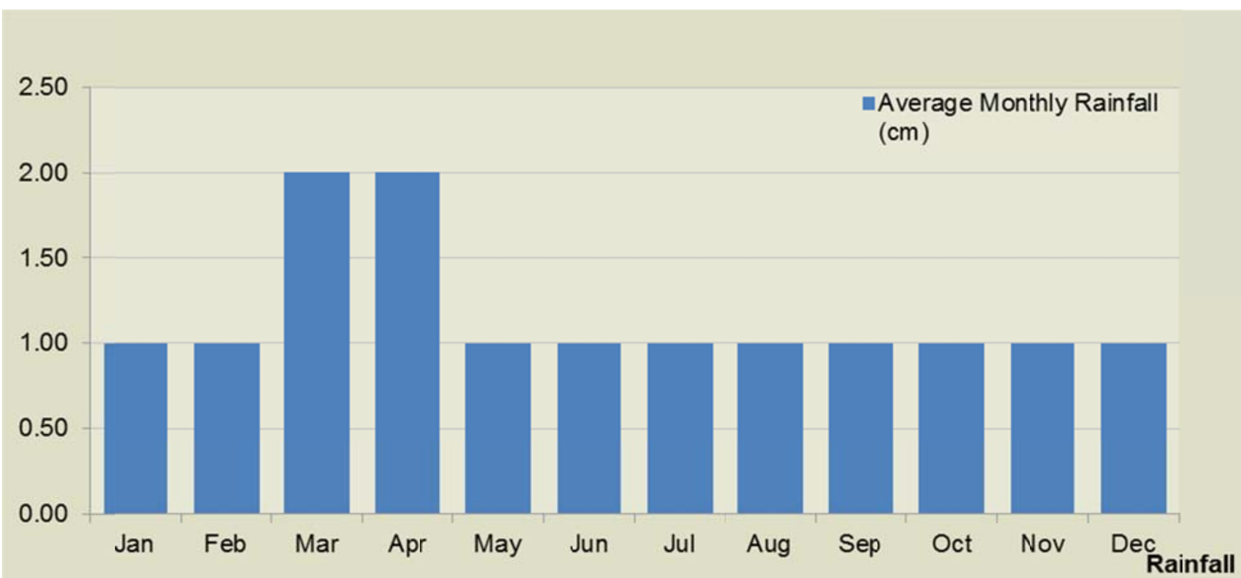

Figure 2-6 Site 2 Milford: Typical Rainfall Conditions

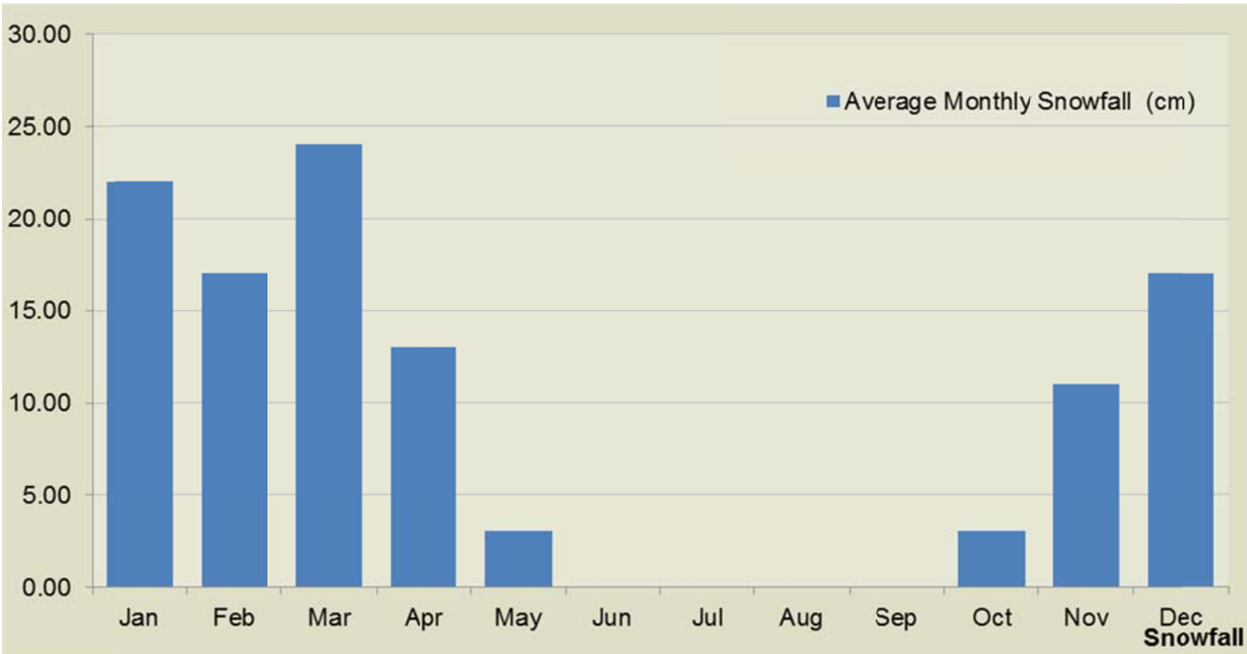

Figure 2-7 Site 2 Milford: Typical Snowfall Conditions

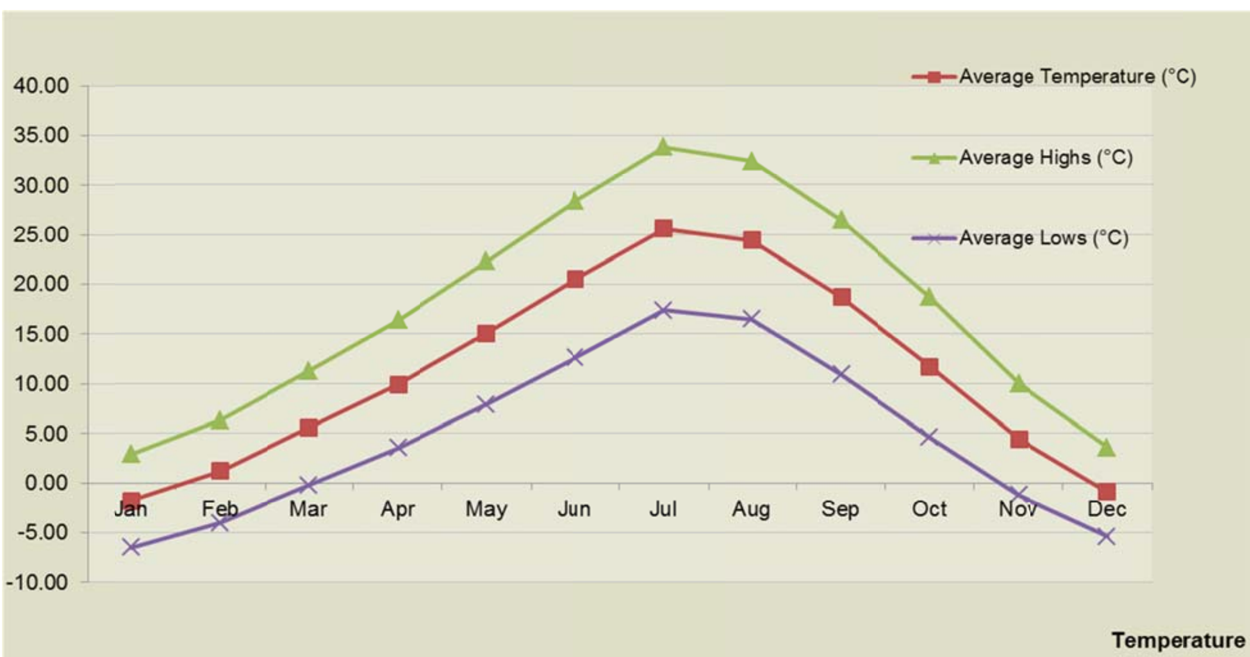

Figure 2-8 Site 3 Salt Lake City: Typical Temperature Conditions

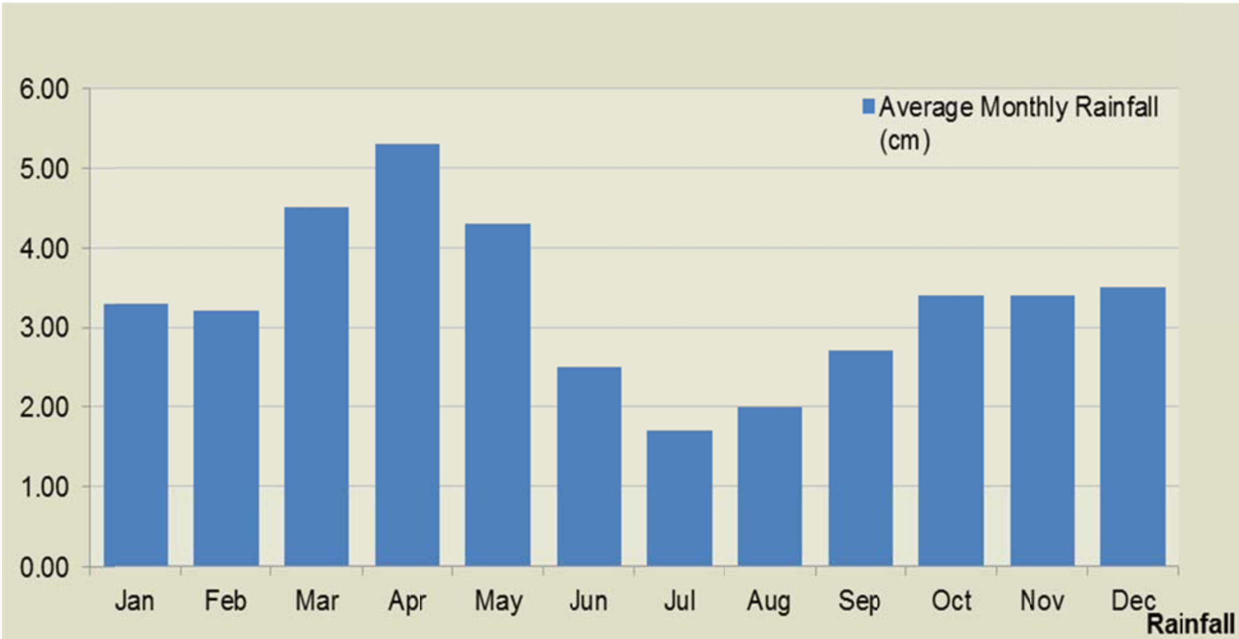

Figure 2-9 Site 3 Salt Lake City: Typical Rainfall Conditions

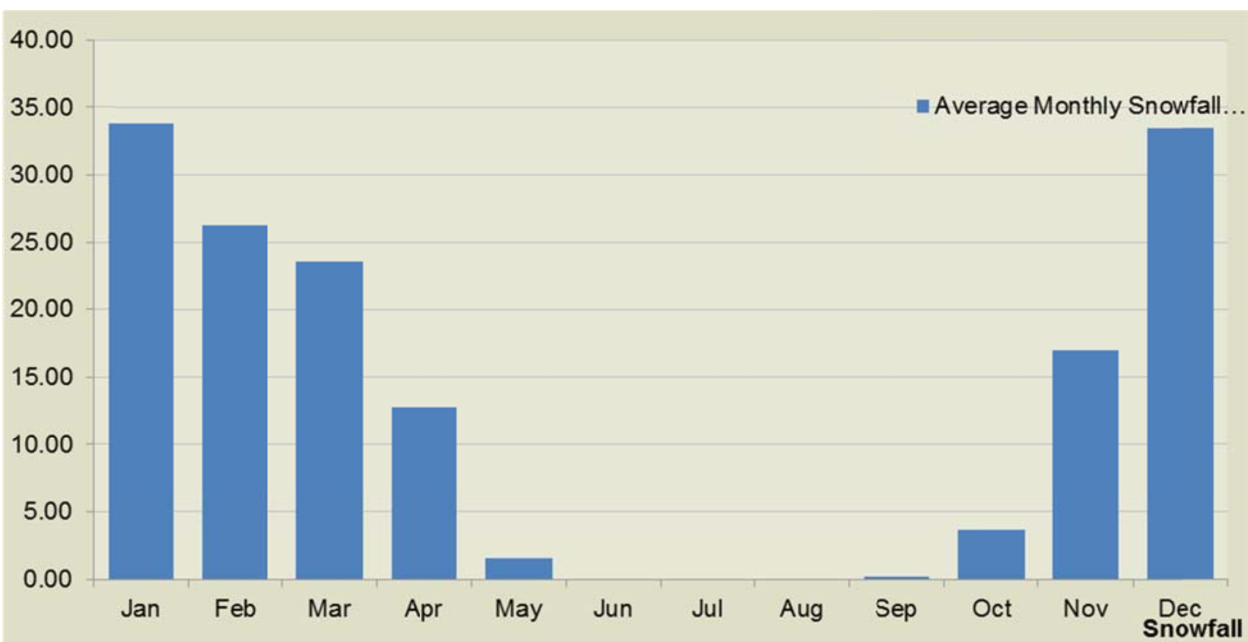

Figure 2-10 Site 3 Salt Lake City: Typical Snowfall Conditions

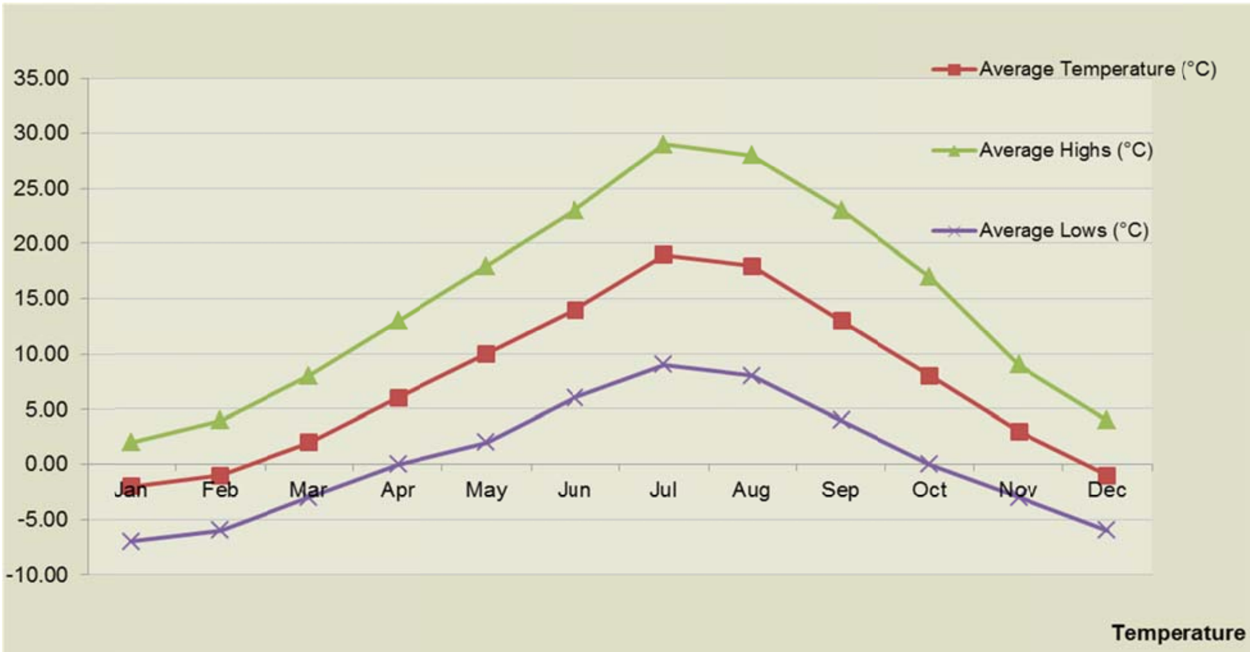

Figure 2-11 Site 4 Lakeview: Typical Temperature Conditions

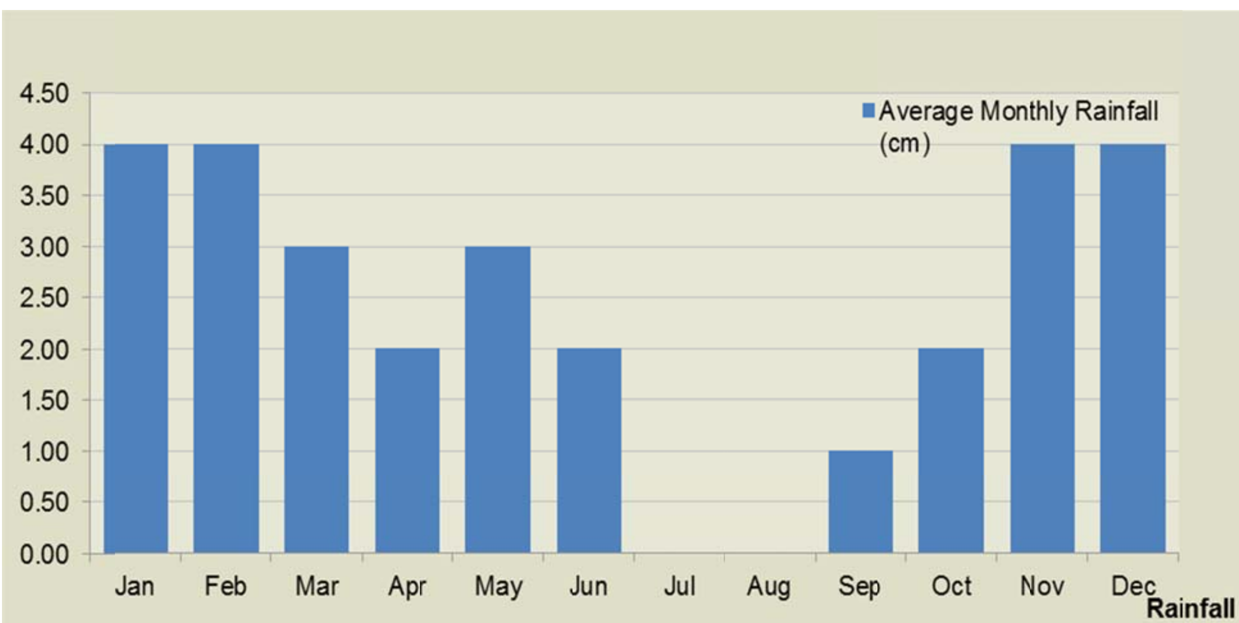

Figure 2-12 Site 4 Lakeview: Typical Rainfall Conditions

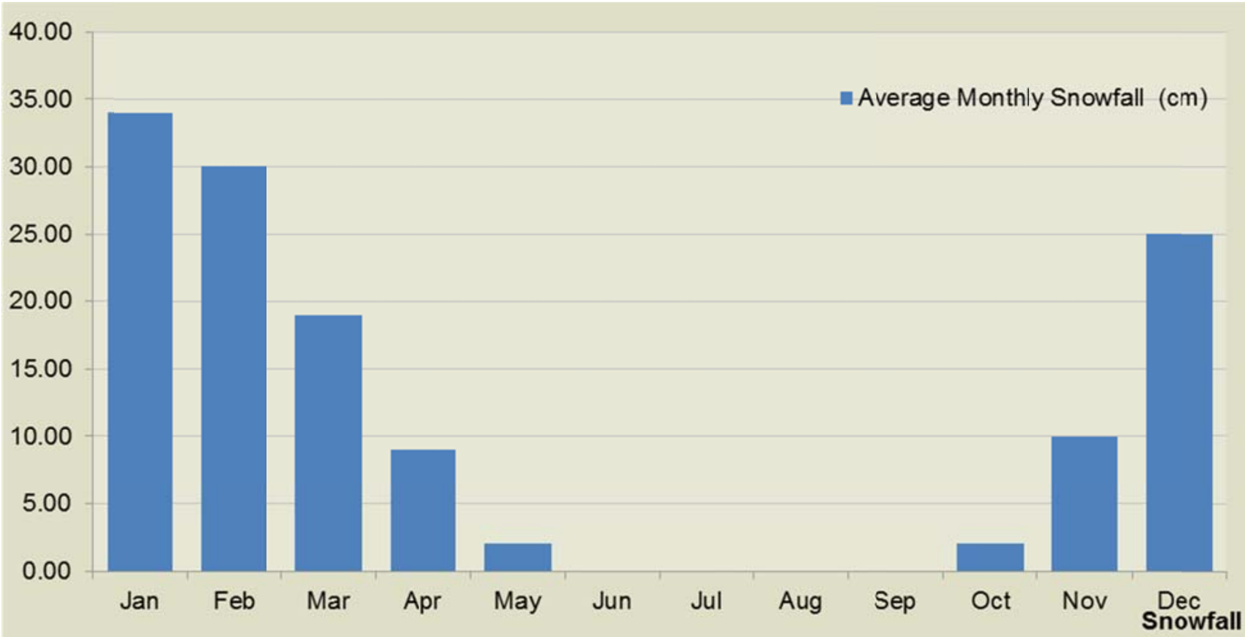

Figure 2-13 Site 4 Lakeview: Typical Snowfall Conditions

3.0 Conceptual Design

The specifications of the PV system for the each of the 50 MW power plants at Site 1 and Site 2 were derived from an optimization process based on a parametric analysis. Although Site 3 and Site 4 are located further north, the relatively small difference in latitude (less than 5 degrees) does not have a significant impact on the solar position. Therefore, Black & Veatch applied the results of the original optimization process with a minor adjustment on the distance between rows in Site 3 and Site 4 to minimize inter-row shading.

The optimization process conducted by Black & Veatch identifies the most attractive tilt, and inverter loading ratio (ILR). The tilt is not a variable in the analysis of the single-axis tracker. The effects of these parameters on the performance of the PV system are:

- Annual energy yield due to module tilt and row spacing.
- Inverter clipping losses due to solar input.

The optimization process focused on achieving the lowest cost of energy. It used optimal tilt to maximize annual energy yield and used the most attractive ILR to maximize inverter capacity while minimizing clipping. In this analysis it was considered that the inverters are able to provide an extra 10 percent of capacity if there is enough energy available. The inverters have a nameplate capacity of 720 kWac and a maximum capacity of 792 KVA (or 792 kW at PF=1). The optimization process assumed that land is available as necessary in order to prioritize the above parameters.

Based on these results, Black & Veatch developed conceptual designs for 5 MW and 50 MW plants, with fixed tilt and single axis tracking. The design approach followed is based on blocks. Each block is an independent power unit within the power plant that is aggregated in parallel to others until the design capacity (5 MW or 50 MW) is achieved. The AC power output from all blocks is collected in a central switchgear before delivering it to the point of interconnection (POI). The building blocks were designed with poly-crystalline Silicon modules each with a nominal power of 300 Watts, inverters with a nominal power output of 720 kW ac and maximum of 792 kVA, medium voltage transformers rated at 1.6 MVA, hot-dip galvanized mounting structures (fixed tilt and single-axis tracker) and hot-dip galvanized I-beam foundations for the mounting structures. The specific commercial equipment selected for the purposes of conceptual design, system modeling and cost estimates is representative of Tier-1 manufacturers. The remaining balance of systems equipment and materials were assumed to be typical for this type of project. The specific equipment used in this feasibility study does not imply a recommendation on the part of Black & Veatch to select or engage with any of these vendors.

In order to provide a level comparison, Black & Veatch designed the blocks for the fixed tilt and the single-axis tracker systems to be as similar as possible in terms of capacity. There are some differences between the blocks of these two technologies due to the inherent differences in the mounting structures and system layout. Each block consists of approximately 6,500 polycrystalline Silicon modules (300 W dc), two inverters (720 kW ac each) and one medium voltage transformer (1.5 MVA). The block size is 1.44 MW ac with an ILR of nearly 1.4 for both the fixed tilt and single-axis tracker.

The 50MW conceptual designs are built from 35 blocks of identical design. The 5MW conceptual designs are built from 3.5 blocks of identical design.

3.1 PARAMETRIC ANALYSIS

A parametric analysis was completed in the previous study for the Utah sites and the results were applied to all four sites in this study. Black & Veatch used a parametric analysis to identify good design parameters for use in the conceptual block designs. Sensitivity studies were performed to identify the response of the design's yield to tilt angle and to identify the response of the design's economics to inverter loading ratio.

3.1.1 Models

Prior to the parametric analysis, Black & Veatch created basic block designs for analysis. These designs were driven by the technology selection, Black & Veatch experience and good engineering practice. They defined the following.

- Number of modules connected into strings
- Number of strings on each row of fixed rack or tracker
- Orientation and configuration of modules as mounted on the rack or tracker
- Spacing of rows
- Number and size of inverters

A pre-conceptual level performance model was generated for a single block of each configuration based on the basic design. This model was set to analyze performance of the plant at the project site to provide insight into the impact of the site-specific solar resource on the design of the plant. In addition, a levelized cost of energy calculator was used in conjunction with a basic capital cost model for some of the studies.

The levelized cost of energy calculator is not meant to be precise for the purposes of this parametric analysis, but is used to generate a metric which captures the tradeoff between cost and performance.

For the basic capital cost model used in the parametric analysis, Black & Veatch used assumptions from its proprietary costs estimator. The results from that study are scalable cost values for technology configurations including the configurations studied here.

3.1.2 Parametric analysis of tilt angle

The first parametric analysis held all design parameters constant and varied the angle of tilt for the fixed tilt configurations. The predicted annual energy output of the block was recorded.

Figure 3-1 is the graphical results from the tilt angle analysis for Veyo. The analysis for Milford yielded the same results. The graph is normalized to the maximum predicted energy output seen during the analysis.

Black & Veatch chose a tilt angle of 27 degrees as the low end of the broad maximum. As shown in Figure 3-1, the optimal tilt for maximum annual generation is close to 29 degrees, however, 27 degrees allows for a slightly higher module density, which increases system capacity[2].

It should also be noted that systems with higher tilt also experience higher wind loads, and may require higher structural reinforcement.

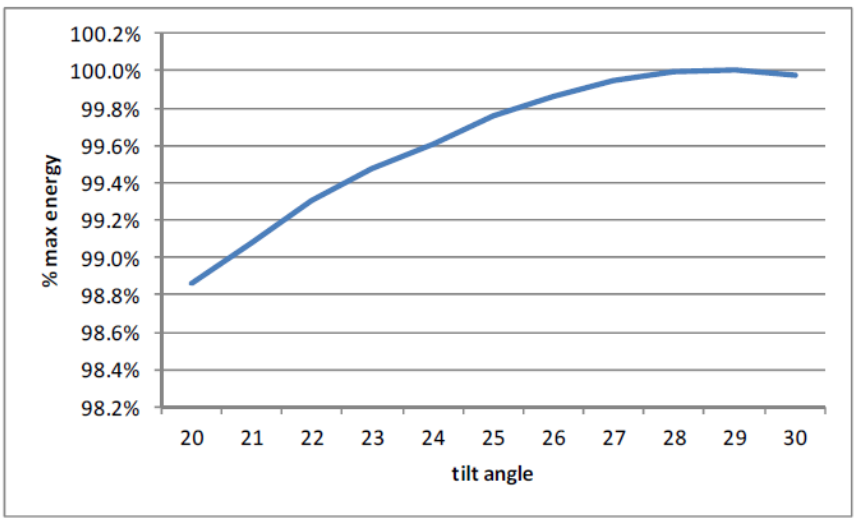

Figure 3-1 Tilt angle parametric analysis (Veyo)

3.1.3 Parametric analysis of inverter loading ratio

The second parametric analysis was to identify an economically attractive inverter loading ratio. The goal is to determine the number rows, strings, and consequently modules to include in each block. Black & Veatch carried the tilt angles from the first analysis forward into this analysis. All design parameters were held constant with the exception of the number of strings in the block. The number of strings was incremented by the number of strings in a row of racks or tracker. Black & Veatch therefore analyzed the effect of adding or removing a row of modules from the block. The levelized cost of energy was recorded. Figure 3-2 and Figure 3-3 in the next page are the graphical results for the fixed, and tracking configurations, respectively at the Veyo site. The analysis for Milford yielded the same results. To maintain consistency in the cost estimates, only the row spacing was adjusted for the minor difference in latitude seen for the Salt Lake City and Lakeview

[2] A module tilt equal to latitude does not necessarily generate the highest output.

sites. The levelized cost of energy values have been normalized to the minimum value seen in each analysis.

To determine the most attractive inverter loading ratio is to determine how many modules it is possible to connect to the inverter before the marginal energy contribution of the next module is not realized because the array produces more than the inverter capacity for too much of the year. Comparing the results of the fixed and tracking analyses, the most attractive inverter loading ratio for the tracking system is lower than that for the fixed system. The tracking system boosts the output of the modules over a broad period during the day. Therefore, excess module capacity, which will increase the energy production, would at the same time result in longer periods of clipping (or energy losses) and less return on the additional capacity of the system[3].

Black & Veatch chose a 23 row conceptual design for the fixed system and a 20 row conceptual design for the tracking system.

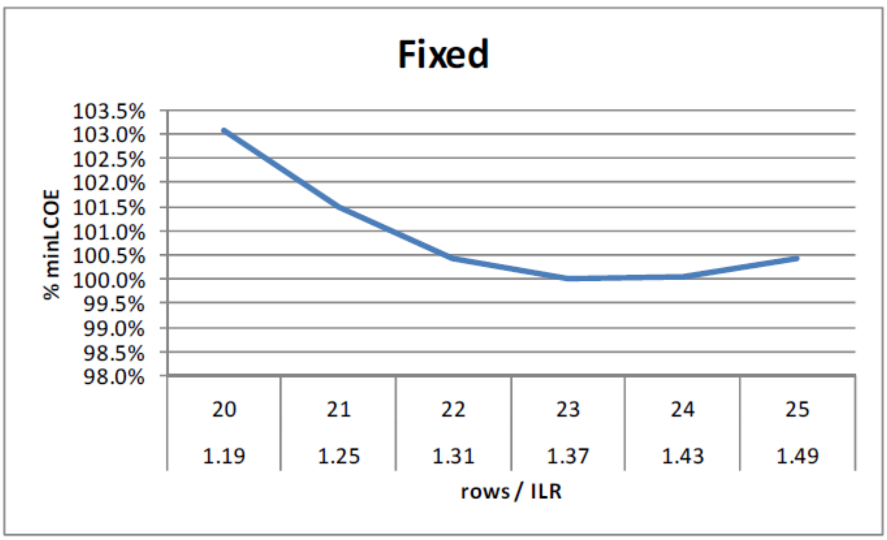

Figure 3-2 Fixed tilt inverter loading ratio parametric analysis (Veyo)

[3] Clipping is a typical inverter feature that limits the power output to the nominal AC capacity of the inverter even if there is more power available on the DC input. This extra power on the DC input is lost. For this reason clipping is often avoided.

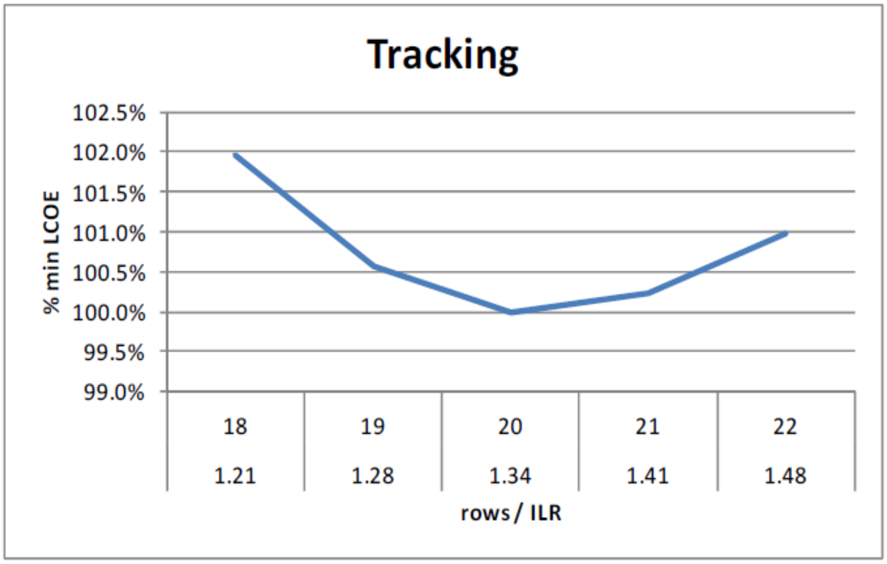

Figure 3-3 Tracking inverter loading ratio parametric analysis (Veyo)

3.2 SYSTEM SPECIFICATIONS AND LAYOUTS

Table 3-1 includes the main system specifications. This design is applicable to all four sites. The system design and layout assumes a mostly flat terrain, which is less than 5 percent East-West slope (or W-E slope) and less than 2 percent South to North slope for both fixed tilt and single-axis tracker systems. A slope of maximum 5 degrees North to South would not significantly change the conceptual layout. Greater slope would alter the design. The geotechnical conditions assumed are solid/hard soils, which are well compacted or naturally grown and medium density. Soft soils or hard rock will increase the project cost. For the 50 MW plant, the infrastructure included in the conceptual design stops at the line side of the 138 kV disconnect switch of the PV power plant main substation, which connects to the 138 kV transmission line, which is assumed provided by others. The PV power plant main substation includes the 138 kV power circuit breaker, 50 MVA main step-up transformer, 34.5 kV AC collection switchgear, relay and metering, and other associated substation equipment. For estimating purposes, Black & Veatch assumed that the transmission/distribution line is immediately adjacent to the PV power plant main substation. Assuming a different location would increase project cost. For the 5 MW plant, the intermediate voltage is 12.7 kV AC. The infrastructure included in the conceptual design includes the interconnection to a distribution line at 12.7 kV AC that is located within the boundaries of the PV plant.

Table 3-1 System Specifications

PARAMETER	50 MW FIXED TILT	50 MW SINGLE AXIS TRACKING	5 MW FIXED TILT	5 MW SINGLE AXIS TRACKING
System DC Rating (MWdc)	69.17	67.66	6.92	6.77
System AC Rating (MW ac)	50.4	50.4	5.04	5.04
Block size (kW ac)	1,440	1,440	1,440	1,440
Number of Blocks	35	35	3.5	3.5
System DC voltage (V)	1000	1000	1,000	1,000
System AC voltage (kVrms)	34.5	34.5	12.7	12.7
Module nominal power (W dc)	300	300	300	300
Modules per string	18	18	18	18
Total number of modules	230,580	225,540	23,058	22,554
Number of Inverters	70	70	7	7
MV voltage transformer (MVA)	1.5	1.5	1.5	1.5
Number of MV transformers	35	35	4	4
Total number of tables/trackers	6,405	210	640	21
Total number of foundations	25,620	54,600	2,562	5,460
Tilt (degrees)	27	NA	27	NA
Inverter Loading Ratio (ILR)	1.37	1.34	1.37	1.34
Pitch (ft) (Veyo/Milford)	31	19.5	31	19.5
Pitch (ft) Salt Lake City	34.1	22.5	34.1	22.5
Pitch (ft) Lakeview	36	24	36	24
Ground Coverage Ratio (GCR)(Veyo/Milford)	37%	33%	37%	33%
GCR Salt Lake City	34%	29%	34%	29%
GCR Lakeview	32%	27%	32%	27%
Surface area (acres)(Veyo/Milford)	297	373	29	37
Surface area SLC	316	423	32	42
Surface area Lakeview	336	454	34	45

Acres/MW ac (Veyo/Milford)	5.8	7.4	5.8	7.4
Acres/MW (Salt Lake City)	6.3	8.4	6.3	8.4
Acres/MW (Lakeview)	6.7	9.0	6.7	9.0

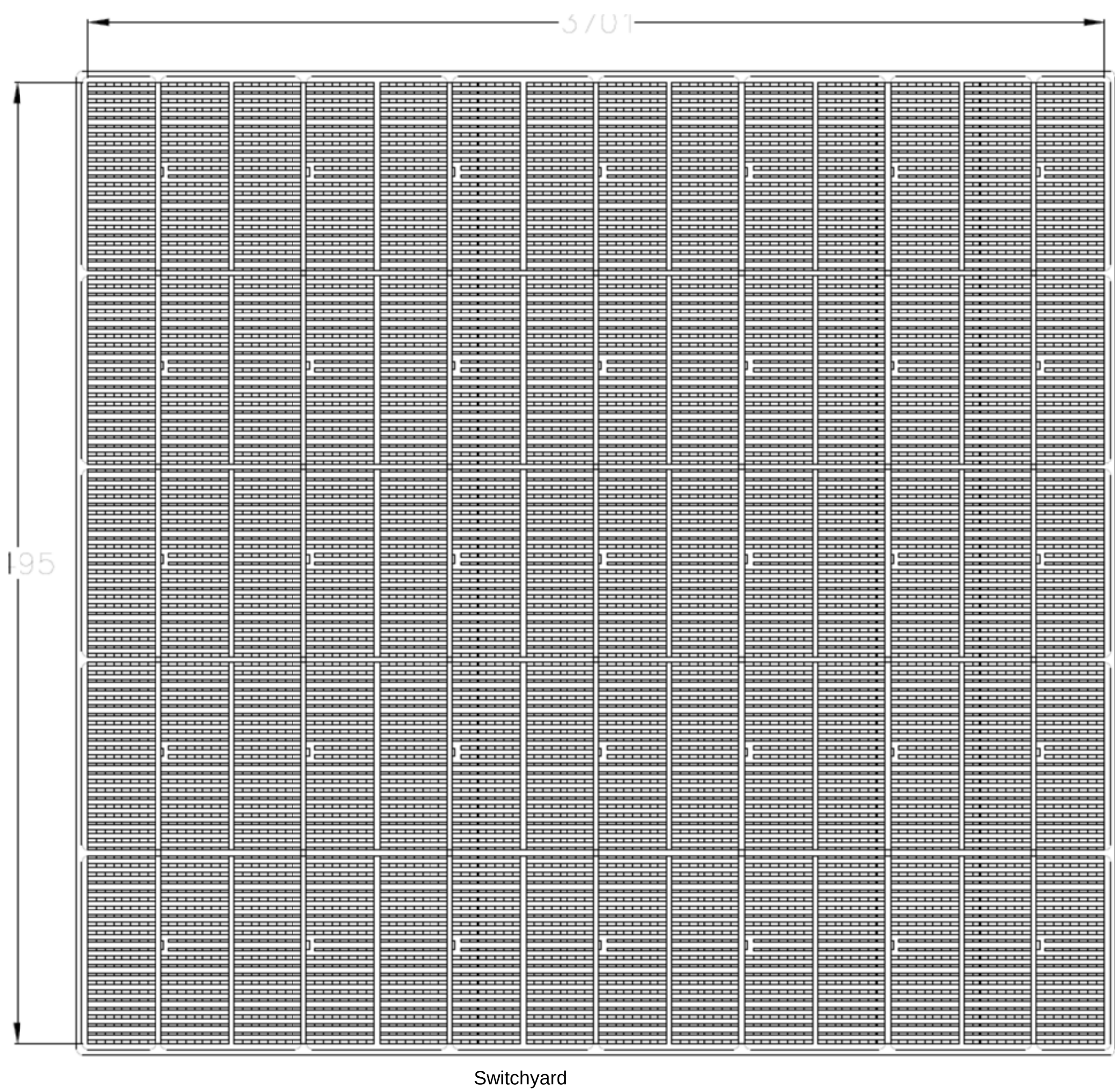

Figure 3-4 50 MW Fixed Tilt System

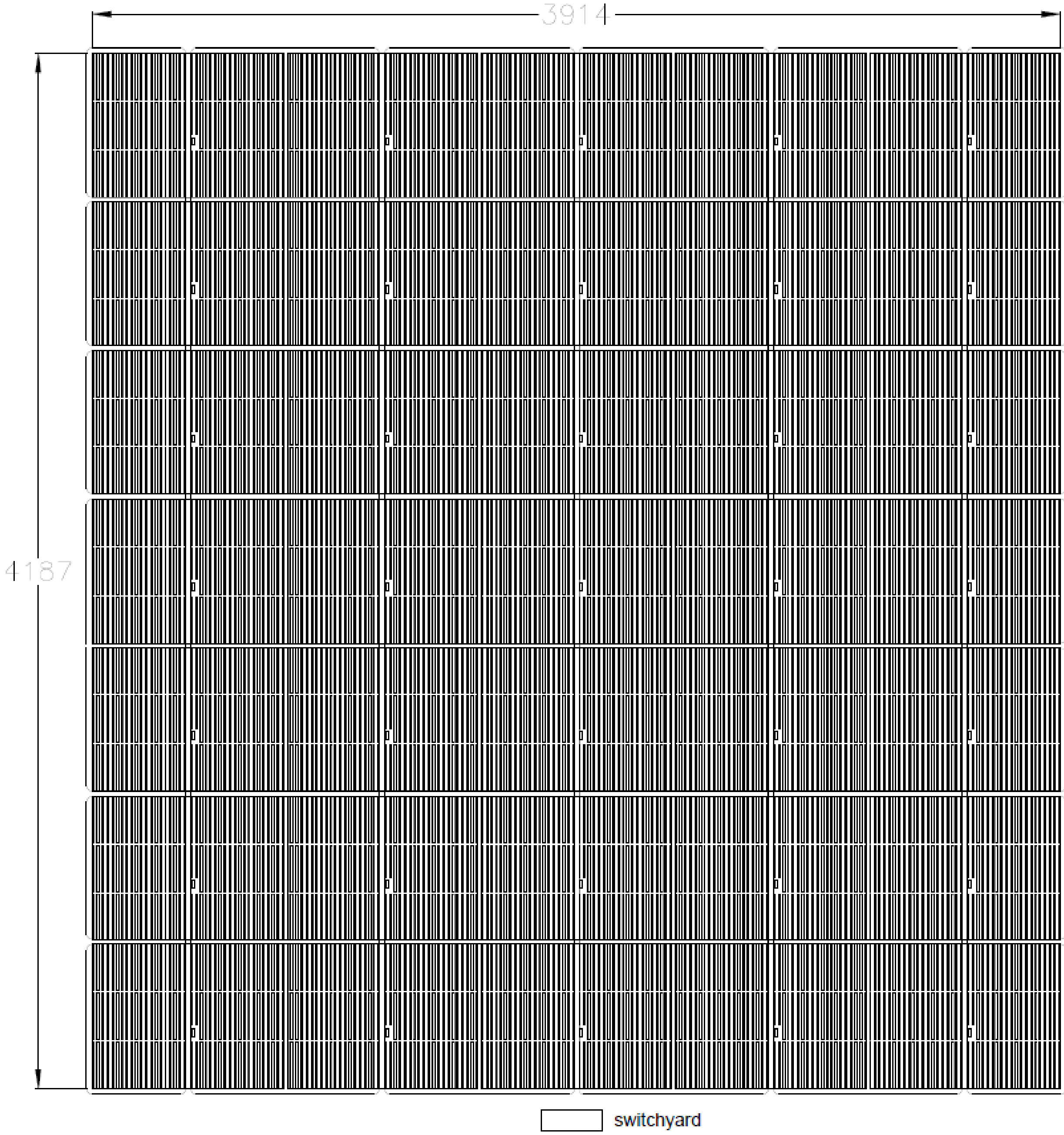

Figure 3-5 50 MW Single Axis Tracking System

3.3 COMPONENT DESCRIPTION

This section provides a general description of the module, inverter, and tracking system equipment used to develop the conceptual design and layouts. The conceptual design is the basis to develop the system model for the energy production estimate analysis and cost estimate.

3.3.1 PV Modules

The crystalline silicon modules proposed for the conceptual design are manufactured by Yingli Solar. Yingli is a vertically integrated PV module manufacturer and one of the largest in China and globally. They currently have the capacity to produce over 2.4 GW of modules per year. To date, approximately 7 GW of Yingli modules are installed worldwide. The module proposed for the design is the YL300p-35b, which consists of poly-crystalline Silicon cells rated at a nominal power output of 300 Watts. The module comes with a 10-year limited product warranty and a 25-year limited power warranty.

3.3.2 Inverter

The inverters proposed for the conceptual design are manufactured by SMA Solar Technology. SMA was founded in 1981 with its headquarters located in Niestetal, Germany. SMA is the largest solar inverter manufacturer with over 254 GW of installed inverters and a manufacturing capacity of 11.54 GW. SMA is publicly traded with revenues of €1.5 billion in 2012. The inverters proposed for the design will be the SMA Sunny Central 720 CP which are UL listed and comply with international standards. The SC-720 inverter has a nominal ac power rating of 720 kW, a maximum capacity of 792 kVA and an efficiency rating of 98.7 percent (maximum).

3.3.3 Single Axis Tracker

The single axis tracker proposed for the design is manufactured by Array Technologies, Inc (ATI). ATI, a privately owned company based out of Albuquerque, New Mexico, manufacturers residential, commercial, and utility-scale PV tracking products. Founded in 1992, ATI is also one of the oldest tracker manufacturers in the United States and as part of its commitment to expand solar energy, installed 1.7 GW of trackers. The single axis tracking system proposed for the design will be the Duratrack HZ. This system consists of a hot-dipped galvanized steel structure, articulating drive joints and drive lines, rotating gears, dry slide bearings, ac motor and electronic controller.

3.3.4 Mounting Structure

There are several experienced vendors in the market, each with proven track records of several MW of capacity installed. The products have the same operating features and similar materials specifications. Prices, installation features and guarantees vary from vendor to vendor. Given the nature of the present study, Black & Veatch did not develop a selection matrix among the different vendors, rather, the decision was made to develop the design and costs estimates with a generic product.

3.3.5 50 MW Substation (138 kV)

The AC collection switchgear will be metal-clad type with draw-out, vacuum power circuit station step-up transformers. A total of four 34.5 kV feeder breakers is assumed for a PV plant in the 50 MW range. Thus, each 34.5 kV feeder will control and protect approximately 12.5 MW of inverters, if divided equally. The actual MW on each 34.5 kV feeder will be adjusted up or down to accommodate the block design of 1.5 MW, the solar field array layout, and also to minimize voltage drop considerations. While it is certainly possible to have only two 34.5 kV feeder breakers at 25 MW each, the design for four feeder breakers is to allow a level of redundancy should one feeder breaker fail or be out of service for maintenance, or even a 35 kV cable fault. Thus, with four feeder breakers, a loss of one feeder would only drop 25 percent of the output of the PV plant. Reputable and proven 34.5 kV switchgear manufacturers include Eaton Cutler-Hammer, Siemens, and General Electric.

The main step-up transformer will convert the 34.5 kV power collected at the AC switchgear to the adjacent transmission line voltage of 138 kV. The rating of the main step-up transformer will be 30/40/50 MVA, 34.5-138 kV, liquid-filled, with two stages of cooling fans. A nominal transformer impedance of approximately 10 percent will limit the short circuit duty on the 34.5 kV switchgear bus to a lower level, thereby allowing a lower cost of switchgear. Reputable and proven main step-up transformer manufacturers include GE/Prolec, Delta Star, Waukesha, Hico, and Iljin.

Above the main step-up transformer will be 138 kV equipment at the interconnection point to the adjacent 138 kV transmission line. This major equipment includes a 138 kV power circuit breaker and two 138 kV disconnect switches, one above and one below the 138 kV power circuit breaker for full isolation. Reputable and proven manufacturers of the 138 kV power circuit breakers and switches include Siemens, ABB, and S&C Electric.

Other electrical equipment associated with the main substation includes current transformers, capacitively-coupled voltage transformers, surge arresters, relays and metering, lightning protection, ground grid, auxiliary power transformer, distribution panel board, supervisory control.

3.3.6 5 MW Interconnection at 12.47 (kV)

Inverter step-up transformers at each skid will have a low voltage secondary winding to match the inverter AC output voltage and a 12.47 kV primary winding for the AC collection system. All step-up transformers will be interconnected in a daisy-chain manner throughout the array field with one or two feeder circuits as necessary. The feeder circuits will terminate onto a 12.47 kV power circuit breaker with an over current protective relay in a 12.47 kV switchgear line-up with a utility metering section and plant main disconnect switch. The plant main disconnect switch will interconnect to a nearby utility 12.47 kV distribution line. (Note: For a typical 12.47 kV distribution line with a design capacity of approximately 7-8 MW, the injection of 5 MW of generation may exceed nominal generation to peak demand limits of approximately 15 to 30 percent. System impact studies are necessary to determine specific system limits.)

4.0 Energy Production Estimates

Black & Veatch estimated the electrical energy output for design at each site. This section summarizes the modeling inputs used by Black & Veatch for the production estimates.

Black & Veatch used PVsyst software version 5.60 to estimate production. PVsyst is an industry standard modeling tool for PV systems developed by the University of Geneva in Switzerland. The software is currently maintained by PVSYST SA. The solar resource data, module and inverter models, array design characteristics, shading models, and several loss assumptions are input to PVsyst. Post-inverter losses were accounted for outside of PVsyst using industry standard algorithms.

4.1 SYSTEM COMPONENTS

The following table summarizes the electrical characteristics of the modules, inverters and tracking system used in this feasibility study. Black & Veatch referenced datasheets from Yingli Solar and SMA Solar Technology to validate the models included in the PVsyst database.

Table 4-1 Module Characteristics

PARAMETER	FIXED TILT & SINGLE AXIS TRACKING CRYSTALLINE
Model	YL300P-35b
Nominal Power	300W
Voltage at max power	36.7
Current at max power	8.17
Modules per string	18
String Voltage at max power	660.6

Table 4-2 Inverter Characteristics

PARAMETER	FIXED TILT AND SINGLE AXIS TRACKING CRYSTALLINE
Model	SC-720CP-US
Nominal Continuous Power (KW)	720
Maximum Continuous Power (KVA)	792
Maximum input voltage (V)	1,000
CEC Efficiency (%)	98.0
Standby power at night (W)	100

Table 4-3 Mounting System and Tracker Characteristics

PARAMETER	FIXED TILT	SINGLE AXIS TRACKER
Manufacturer	Generic	Array Technologies
Model	NA	Duratrack (Includes backtracking)
Power Consumption	NA	350 kWh per MW per year
Tables/Trackers per Block	183	6
Foundations per Block	732	1,560
Note: Backtracking is an algorithm embedded in the controller to minimize inter-row shading during the mornings and evenings. This tracker behavior is available in PVsyst and was modeled for the production estimate.		

4.2 LOSSES AND GAINS

This section summarizes the modeling methodology and the loss and gain input assumptions to the production model.

4.2.1 Transposition Model

Black & Veatch implemented the Perez transposition model. Radiation data is typically provided in terms of global horizontal irradiance, or incident power on a horizontal plane (measured in kW/m_2). To calculate radiation on a tilted surface, it is necessary to transpose the radiation model from a horizontal plane to a tilted plane. The two most commonly applied transposition models are the Hay model and the Perez model. Black & Veatch chose to use the Perez transposition model as it provides the best agreement with measured data.

4.2.2 Albedo

The albedo is a coefficient used to calculate the amount of sunlight that is reflected onto the modules from the ground or surrounding surfaces. A value of 0.20 is typical for ground mounted, open field situations. Snow is more reflective than other surfaces which can increase the albedo coefficient from 0.55 to 0.82 depending on snow type (fresh, wet, etc.). Overall, albedo is a very small component of the total incident irradiance on the modules. Black & Veatch assumed typical ground cover conditions and analyzed snow data. Based on this information, the albedo values developed for the energy production are in Table 4-4 on a monthly basis.

Table 4-4 Albedo

MONTH	SITE 1 VEYO	SITE 2 MILFORD	SITE 3 SALT LAKE CITY	SITE 4 LAKEVIEW
January	0.51	0.74	0.69	0.70
February	0.42	0.61	0.56	0.65
March	0.29	0.48	0.36	0.52
April	0.20	0.26	0.20	0.35
May	0.20	0.2	0.20	0.20
June	0.20	0.20	0.20	0.20
July	0.20	0.20	0.20	0.20
August	0.20	0.20	0.20	0.20
September	0.20	0.20	0.20	0.20
October	0.20	0.20	0.20	0.26
November	0.30	0.52	0.42	0.48
December	0.49	0.70	0.65	0.65

4.2.3 Shading

Shading of modules reduces energy production. Modules can be shaded by external objects such as buildings or trees (referred to as external shading) or internal objects such as other modules (referred to as inter-row shading).

There are two methods to model shading: linear and string. The linear method calculates the area of the array that is shaded at any given hour and linearly reduces the production of the array accordingly. The string method accounts for the fact that an array’s output can be non-linear when one module in a string is partially shaded; the string's output is limited by the current of the worst, or most shaded, module on the string. The decision of which shading method to choose is based on the orientation of the cells within the module and the modules within the array.

Black & Veatch modeled shading in PVsyst to account for internal shading losses. It was assumed that external shading would not be an issue. The characteristics of the shading scene are displayed in the following table.

Table 4-5 Shading Scene Characteristics

PARAMETER	FIXED TILT	SINGLE AXIS TRACKING
Module dimensions (m)	1.97 (L)*0.99 (W)	
Pitch (m)	9.3 – 10.9	5.9 – 7.3
Tilt	27°	0°
Module Orientation	2 modules in Portrait	1 module in Portrait
Collector Width (M)	3.94	1.97
External Shading	NA	NA
Shading Model (PVsyst)	String with 80%Electrical Effect	Linear

4.2.4 Incidence Angle Modifier

The incidence angle modifier (IAM) is a curve that models the loss of insolation due to a reduction of radiation by the module's glass surface. The curve is based on the angle at which radiation is incident and the type of glass used in the encapsulation of the module. The loss obeys Fresnel's Laws of optics and is accurately modeled by a parameterization defined by the American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE). The parameterization can be defined with a single parameter, b_0. For most modules, a value of $b_0 = 0.05$ has been shown to accurately characterize this loss.

4.2.5 Irradiance Loss

PV modules are rated at Standard Test Conditions (STC), which are defined as 1,000 W/m_2, 25° C, and an air mass of 1.5. Module efficiency is a function of irradiance level; for most PV technologies module efficiency decreases with lower irradiances.

4.2.6 Soiling Loss

Dirt, snow, and other particles that cover modules, referred to as soiling, reduce the energy production. Rainfall of adequate magnitude typically reduces the effect of soiling, whereas snowfall increases the magnitude. There is scarce literature and data available on the effect of snow on PV system energy production. It is understood that the effect of snow is complicated and governed by several weather factors such as daily snowfall, snow depth, wind, temperature, temperature cycles, and irradiance. In addition to weather, system design (tilt and module height) and operations and maintenance plans (snow clearing) play a role in production during snow months as well.

Using publically available weather data from close to the Project sites, Black & Veatch developed soiling loss assumptions. Soiling losses caused by snow were calculated by estimating the time snow would "linger" during daylight hours on panels after falling, based on wind speed, temperature, insolation, and other factors. Black & Veatch assumed 0 module washings and clearings per year. Estimated monthly soiling values are shown in the table below.

Table 4-6 Soiling

MONTH	SITE 1 VEYO	SITE 2 MILFORD	SITE 3 SALT LAKE CITY	SITE 4 LAKEVIEW
January	2.4%	12.6%	28.1%	3.7%
February	2.0%	9.5%	18.0%	4.0%
March	0.6%	2.2%	3.9%	1.2%
April	0.9%	0.8%	0.3%	1.3%
May	1.2%	1.0%	0.5%	1.2%
June	2.5%	1.8%	0.8%	1.9%
July	1.0%	1.1%	1.3%	3.7%
August	0.7%	1.0%	1.1%	9.5%
September	1.2%	1.4%	0.7%	5.1%
October	1.2%	1.3%	0.6%	1.8%
November	1.0%	0.7%	4.7%	1.2%
December	3.0%	9.5%	21%	3.9%

4.2.7 Module Quality

Module quality is a parameter entered into PVsyst to account for first year degradation, light induced degradation (LID), and the probability of the actual module output being above or below than the nameplate rating. The calculation of the module quality value is shown Table 4-7 below. Note that a positive module quality value represents a loss while a negative module quality value represents a gain.

Table 4-7 Module Quality

PARAMETER	YINGLI 300
Power Tolerance	0-3% (0 to +5W)
Light Induced Degradation	1.5%
Total MQ Value	0.4% (loss)

4.2.8 Mismatch

Mismatch loss is another loss that can be defined in PVsyst. Mismatch loss accounts for four different mismatch components:

- Inter-module mismatch related to maximum power point current
- Array mismatch related to maximum power point voltage
- Functionality of the maximum power point tracking algorithm of the inverter
- Voltage mismatch due to varying cable lengths of home runs and jumpers

The first two mismatch losses account for losses due to variations in the voltage and current performance of modules installed in strings and arrays. These modules have different maximum power voltages and maximum power currents. When modules are connected in series (known as a string), the module with the lowest maximum power point current limits, or reduces, the overall current of the other modules on that same string. This current limitation causes a reduction in power production of that particular string. When strings of modules are connected in parallel (known as an array), the string with the lowest maximum voltage limits the overall voltage (and therefore power production) of other strings on that array. These first two mismatch parameters total approximately 0.5 percent.

The remaining two components of mismatch account for efficiency of the inverter's maximum power point algorithm and the variation in cable lengths. These losses total approximately 0.5 percent.

4.2.9 DC Wire Loss

For the level of analysis required for this report, Black & Veatch did not calculate dc wiring losses. Black & Veatch assumed a two percent dc wiring loss. This is a typical value for systems of this size.

4.2.10 Transformer Loss

For the level of analysis required for this report, Black & Veatch estimated transformer loss to be one percent annually. This is a typical loss value seen for systems of this size. Black & Veatch uses a post processing tool to assess the losses after the inverter output. These are not shown in PVSyst.

4.2.11 AC Wire Loss

For the level of analysis required for this report, Black & Veatch estimated ac wire loss values to be 0.5 percent annually. This assumes there are no excessive lengths for gen-tie interconnection lines. This is a typical loss value seen for systems of this size. This loss was applied outside of PVsyst.

4.2.12 Auxiliary Losses

Black & Veatch estimated 23.7 MWh auxiliary losses due to energy consumption of tracker for single axis tracking off the energy production of the system. Black & Veatch estimated auxiliary losses due to inverter and transformer nighttime losses and SCADA losses to be 250 MWh per year. Perimeter lighting, O&M building and any other site infrastructure demand is assumed to be metered separately and is not included in the analysis. (Negative generation can be seen in PVsyst in the 12x24 production estimates due to these losses.)

4.2.13 Availability

Availability is included in the production estimate calculation.

Fixed Tilt

Black & Veatch assumed the system to have a 99 percent availability factor (net of the availability loss), which is measured at the utility meter. An availability factor of 99 percent means that one percent of the time the plant is expected to be down for unscheduled maintenance and planned maintenance. This value does not include force majeure events or curtailment. The availability value is consistent with Black & Veatch's experience with availability of utility scale solar plants to date, although availability may be lower in the first three months of operation due to startup issues. The assumed availability is approximately 40 hours of downtime during daylight hours per year.

Tracking

Black & Veatch assumed the system to have a 98.5 percent availability factor (net of the availability loss), which is measured at the utility meter. An availability factor of 98.5 percent means that one and a half percent of the time the plant is expected to be down for unscheduled maintenance and planned maintenance. This value does not include force majeure events or curtailment. This value includes lost energy due to tracking system downtime. The availability value is consistent with Black &

Veatch's experience with availability of utility scale solar plants to date, although availability may be lower in the first three months of operation due to startup issues. The assumed availability is approximately 60 hours of downtime during daylight hours per year.

4.3 PRODUCTION ESTIMATE RESULTS

This section summarizes the results of the production estimate including estimated annual losses and annual production. Production values are net yields anticipated at the AC collector station.

Performance ratio (PR) is a metric that normalizes energy output relative to system capacity. The performance ratio takes into account the irradiance on site and the overall effect of losses on the rated output due to inverter inefficiency, wiring, mismatch, temperature effects and other losses when converting from DC power to AC to power[4]..

Table 4-8 Site 1 Veyo -Year Zero Production Estimate Results*

PARAMETER	50 MW FIXED TILT	50 MW SINGLE AXIS TRACKING	5 MW FIXED TILT	5 MW SINGLE AXIS TRACKING
Current System STC Rating (MWp)	69.2	67.7	6.92	6.77
Current System AC Rating (MWac)	50.4	50.4	5.04	5.04
Annual Generation (MWH/year)	127,690	153,310	12,769	15,331
DC Capacity Factor	21.1%.	25.9%	21.1%	25.9%
AC Capacity Factor**	28.9%	34.7%	28.9%	34.7%
Annual Yield (kWh/kWp)	1,846	2,813	1,846	2,813
Performance Ratio	78.0%	80.5%	78.0%	80.5%

***Values are for the year zero of energy production and include availability impact but do not include module degradation during the first year of operation (estimated to be 0.7% per year over the project life).**
****The ac capacity factor is calculated using the inverter nameplate rating.**

Table 4-9 Site 2 Milford- Year Zero Production Estimate Results*

PARAMETER	50 MW FIXED TILT	50 MW SINGLE AXIS TRACKING	5 MW FIXED TILT	5 MW SINGLE AXIS TRACKING
Current System STC Rating (MWp)	6.92	67.7	6.92	6.77
Current System AC Rating (MWac)	50.4	50.4	5.04	5.04

[4] For a detail explanation of PR see: B. Marion et al (2005). Performance Parameters for Grid Connected PV Systems. Golden, Colorado, National Renewable Energy Laboratories (NREL/CP-520-37358)

Annual Generation (MWH/year)	121,330	145,250	12,133	14,525
DC Capacity Factor	19.3%	23.6%	19.3%	23.6%
AC Capacity Factor**	26.5%	31.6%	26.5%	31.6%
Annual Yield (kWh/kWp)	1,691	2,063	1,691	2,063
Performance Ratio	75.4%	77.7%	75.4%	77.7%

***Values are for the year zero of energy production and include availability impact but do not include module degradation during the first year of operation (estimated to be 0.7% per year over the project life).**
****The ac capacity factor is calculated using the inverter nameplate rating.**

Table 4-10 Site 3 Salt Lake City-Year Zero Production Estimate Results*

PARAMETER	5 MW FIXED TILT	5 MW SINGLE AXIS TRACKING
Current System STC Rating (MWp)	6.92	6.77
Current System AC Rating (MWac)	5.04	5.04
Annual Generation (MWH/year)	10,592	12,730
DC Capacity Factor	17.5%	21.5%
AC Capacity Factor**	24.0%	28.8%
Annual Yield (kWh/kWp)	1,531	1,881
Performance Ratio	77.5%	80.5%

***Values are for the year zero of energy production and include availability impact but do not include module degradation during the first year of operation (estimated to be 0.7% per year over the project life).**
****The ac capacity factor is calculated using the inverter nameplate rating.**

Table 4-11 Site 4 Lakeview-Year Zero Production Estimate Results*

PARAMETER	50 MW FIXED TILT	50 MW SINGLE AXIS TRACKING	5 MW FIXED TILT	5 MW SINGLE AXIS TRACKING
Current System STC Rating (MWp)	69.17	67.66	6.92	6.77
Current System AC Rating (MWac)	50.40	50.40	5.04	5.04
Annual Generation (MWH/year)	112,170	129,080	11,217	12,908
DC Capacity Factor	18.9%	21.8%	18.9%	21.8%
AC Capacity Factor**	25.4%	29.2%	25.4%	29.2%
Annual Yield (kWh/kWp)	1,560	1,930	1,560	1,930
Performance Ratio	81.3%	77.5%	81.3%	77.5%

***Values are for the year zero of energy production and include availability impact but do not include module degradation during the first year of operation (estimated to be 0.7% per year over the project life).**
****The ac capacity factor is calculated using the inverter nameplate rating.**

5.0 EPC Cost Estimates

Black & Veatch maintains a proprietary model for estimating construction costs for utility scale photovoltaic (PV) plants. The model is based on detailed cost estimates derived from Sage Timberline Estimating software, updated with current PV market data. The model inputs are customized based on the specific system design features, location, characteristics of the site and available pricing information. The inputs include equipment and materials costs and quantities as well as the labor costs directly related to the installation of these components. Design and engineering costs are included in the labor category. The model also includes civil engineering costs involved in the preparation of the site, as well as fencing, road construction and other civil infrastructure typically required in utility scale PV plants. Similarly, the model takes into account the electrical infrastructure typical of these projects such as AC collection switchgear, grounding and lightning requirements, interconnection systems and other electrical infrastructure.

The cost estimates produced by Black & Veatch for the PV power plants are presented in the following categories:

- Photovoltaic modules: The single most expensive item in a PV system.
- Mounting structure: This category also includes the foundations and all other accessories necessary to install the structure and attach the modules.
- Inverter: This category also includes the medium voltage transformer, civil infrastructure and all other construction items and parts required to install this component.
- Balance of Systems (BoS) for the DC side: This category includes all the remaining equipment, materials and construction activities required on the DC field (from the module output to the inverter input) such as module wiring, combiner boxes, trenching for cabling, medium voltage cable, connectors, etc.
- Balance of Systems (BoS) for the AC side: This category includes all the equipment, materials and construction activities after the high side of the medium voltage transformer (typically connected on the low side to the inverter output) to the point of interconnection, including the capital costs of the switchyard to deliver at 138 kV. It includes items such as medium voltage cable, trenching, grounding and lighting protection, AC collection switchgear, interconnection system, terminations, etc.
- Other Balance of Systems: This category includes the site preparation work, fencing and other security infrastructure, road construction, site drainage and any other equipment or infrastructure that is not directly related to the design of a PV power plant but that it is necessary to install or build for the overall development of the project.
- Labor: The cost estimating model separates labor from equipment and materials costs as much as possible. For certain activities it is difficult to clearly separate the equipment or part cost from labor. The labor rates are derived from Sage

Timberline based on geographical location, labor type (union, non-union, skilled, etc) or specific labor cost rates available from the project location.

- The labor category also includes design and engineering and construction management.
- Indirect costs: The items included by Black & Veatch in this category are construction insurance, equipment taxes, contingency and escalation and EPC profit and overhead.
- Owner's costs such as project development, interconnection, advisory and legal fees, spare parts and plant infrastructure (like water wells for module washing) and permitting were not included. Inclusion of these site and project specific-costs would likely increase the overall cost estimate between zero and 10 percent.

Table 5-1 through 5-4 show the EPC cost estimates in the categories indicated above. Black & Veatch assumed similar construction costs for all four sites considering same site conditions. The single-axis tracker system is more expensive due to the higher cost of the mounting structure and larger construction area. These factors increase the installation and site preparation costs, as well as the BOS on the DC side (mostly related to more cable).

Table 5-1 EPC cost estimates for 5MW sites-fixed tilt

ITEM	SUBTOTAL	$/KWP	$/KWAC	% TOTAL
Modules	4,796	693.3	951.6	32.0
Mounting structure	2,216	320.4	439.7	14.8
Inverter	1,505	217.6	298.6	10.0
BOS (DC)	1,000	144.6	198.4	6.7
BOS (AC)	650	94.0	129.0	4.3
Other BOS[1]	1,010	146.0	200.4	6.7
Labor (Utah)[2,3]	1,509	218.1	299.4	10.1
Labor (Oregon)[2,3]	2,037	294.0	404.0	
Indirect Costs	2,317	335.0	459.7	15.4
Owner's Costs	0	0	0	0
Total (Utah)	**15,003**	2,169	2,977	100
Total (Oregon)	**15,531**	2,245	3,082	100

1: This category includes the remaining Balance of Systems items such as site preparation, fencing, roads, etc.
2: This category includes design and engineering, construction management and balance of systems labor
3: Black & Veatch estimated an average difference of approximately 1.35 percent in wages

between Oregon and Utah (higher wages in OR), according to data from the US Bureau of Labor Statistics.

Table 5-2 EPC cost estimates for 5MW- SAT

ITEM	SUBTOTAL	$/KWP	$/KWAC	% TOTAL
Modules	4,691	693.3	930.8	29.5
Mounting structure	2,754	407.0	546.5	17.3
Inverter	1,505	222.4	298.6	9.5
BOS (DC)	1,050	155.2	208.3	6.6
BOS (AC)	682	100.9	135.4	4.3
Other BOS[1]	1,061	156.8	210.5	6.7
Labor (Utah)[2,3]	1,696	250.7	336.6	10.7
Labor (Oregon)2,3	2,290	338.0	454.0	
Indirect Costs	2,453	362.5	486.6	15.4
Owner's Costs	0	0	0	0
Total (Utah)	**15,892**	2,349	3,153	100
Total (Oregon)	**16,486**	2,437	3,271	100

1: This category includes the remaining Balance of Systems items such as site preparation, fencing, roads, etc.
2: This category includes design and engineering, construction management and balance of systems labor
3: Black & Veatch estimated an average difference of approximately 1.35 percent in wages between Oregon and Utah (higher wages in OR), according to data from the US Bureau of Labor Statistics.

Table 5-3 EPC cost estimates for 50 MW sites- fixed tilt

ITEM	SUBTOTAL	$/KWP	$/KWAC	% TOTAL
Modules	41,963	606.7	832.7	33.0
Mounting structure	19,726	285.2	391.4	15.5
Inverter	13,054	188.7	259.0	10.3

ITEM	SUBTOTAL	$/KWP	$/KWAC	% TOTAL
BOS (DC)	8,999	130.1	178.6	7.1
BOS (AC)	5,850	84.6	116.1	4.6
Other BOS[1]	9,079	131.3	180.2	7.1
Labor (Utah)[2,3]	14,849	214.7	294.6	11.7
Labor (Oregon)[2,3]	20,046	290.0	398.0	
Indirect Costs	13,764	199.0	273.1	10.8
Owner's Costs	0	0	0	0
Total (Utah)	**127,286**	1,840	2,526	100
Total (Oregon)	**132,483**	1,915	2,629	

1: This category includes the remaining Balance of Systems items such as site preparation, fencing, roads, etc.
2: This category includes design and engineering, construction management and balance of systems labor
3: Black & Veatch estimated an average difference of approximately 1.35 percent in wages between Oregon and Utah (higher wages in OR), according to data from the US Bureau of Labor Statistics.

Table 5-4 EPC cost estimates for 50 MW sites- SAT

ITEM	SUBTOTAL	$/KWP	$/KWAC	% TOTAL
Modules	41,047	606.7	814.5	30.4
Mounting structure	24,643	364.2	489.0	18.2
Inverter	13,055	192.9	259.0	9.7
BOS (DC)	9,450	139.7	187.5	7.0
BOS (AC)	6,142	90.8	121.9	4.5
Other BOS[1]	9,488	140.2	188.3	7.0
Labor (Utah)[2,3]	16,725	247.2	331.8	12.4
Labor (Oregon)[2,3]	22,2578	33.7	448.0	
Indirect Costs	14,598	215.8	289.6	10.8
Owner's Costs	0	0	0	0
Total (Utah)	**135,146**	1,997	2,682	100
Total (Oregon)	**141,000**	2,084	2,798	

1: This category includes the remaining Balance of Systems items such as site preparation,

fencing, roads, etc.
2: This category includes design and engineering, construction management and balance of systems labor
3: Black & Veatch estimated an average difference of approximately 1.35 percent in wages between Oregon and Utah (higher wages in OR), according to data from the US Bureau of Labor Statistics.

5.1 CAPITAL COST FORECASTS

Black & Veatch prepared 10 Year forecasts of capital cost for the 5MW and 50MW designs based on the forecasted reductions included in a study Black and Veatch prepared for the National Renewable Energy Laboratory[5]. This study addressed a number of factors contributing to future cost decreases, including expected improvement in module efficiency, inverter and BOS cost improvements, as well as improvement in the softer Owner's costs. These forecasts are presented in Table 5-5 Cost Forecast.

Table 5-5 Cost Forecast

YEAR	50 MW FIXED TILT TOTAL $/KWAC	5 MW FIXED TILT TOTAL $/KWAC	50MW SINGLE AXIS TRACKER TOTAL $/KWAC	5MW SINGLE AXIS TRACKER TOTAL $/KWAC
1	2,317	2,926	2,633	3,100
2	2,276	2,882	2,591	3,035
3	2,235	2,838	2,549	2,970
4	2,195	2,794	2,507	2,905
5	2,153	2,750	2,465	2,840
6	2,112	2,706	2,423	2,775
7	2,071	2,662	2,381	2,710
8	2,030	2,618	2,339	2,645
9	1,989	2,574	2,297	2,580
10	1,951	2,531	2,251	2,515

[5] http://bv.com/docs/reports-studies/nrel-cost-report.pdf

6.0 Operations and Maintenance Estimates

Black & Veatch maintains a proprietary model for estimating operations and maintenance costs for utility-scale photovoltaic plants. This model generates site specific cost estimates based on project characteristics. Model inputs include project size, location, PV module technology, design characteristics such as row spacing and inverter configuration, warranty configuration, and the distance of the plant from service personnel. Business model characteristics such as the contractual structure of the operations and maintenance agreement (in-house vs. subcontracted) are also considered in the model.

Inputs can be varied to perform sensitivity analyses, comparing the impact on operations and maintenance costs attributable to changes in project design variables, extended warranties, insurance, performance and availability guarantees, third party subcontracting, and different response strategies over a range of operational alerts, alarms, and service requests.

6.1 TYPICAL O&M APPROACHES

Operations and maintenance (O&M) activities can be divided into three main categories. These categories are: corrective or reactive maintenance; preventative maintenance; condition based maintenance. Corrective or reactive maintenance (CRM) activities essentially focus on making repairs to the system once failures occur. Preventative maintenance (PM) focuses on routine inspections and adjustments of equipment with CRM as necessary. Condition based maintenance (CBM) will use more sophisticated remote monitoring systems to track system operation and predict when maintenance is necessary. Regular PM activities will still be required, but CRM is expected to decrease with a CBM approach.

These maintenance concepts are well known for various mechanical systems and studies and routinely show a positive return on investment by graduating from a CRM approach to a PM approach, and from a PM approach to a CBM approach. It is necessary to understand the operation of a solar power plant to design an appropriate maintenance methodology. Lower maintenance program costs are typically achieved when critical design elements of the maintenance approach are included in the initial construction of the project. These design elements include selection of electrical and structural systems as well as monitoring and control systems. Black & Veatch notes that upfront costs increase from CRM to PM to CBM maintenance approaches, but these costs are generally balanced out by increased plant availability and decreased maintenance requirements.

Black & Veatch typically models the PM approach for solar power plants, but can help develop CBM-based activities and infrastructure with the intention of improving plant performance and reducing total maintenance and operating costs.

6.1.1 Critical O&M Components

Solar power plants are comprised of myriad systems that must work in concert to maximize the output of the plant. As with most mechanical systems, it is common that eighty percent of the downtime or lost generation of a solar power plant will be caused by only twenty percent of the failures or equipment.

Figure 6-1 and Figure 6-2 below show a typical breakdown of preventive and corrective maintenance activity frequencies for a 5 MWac PV plant for 12 months.

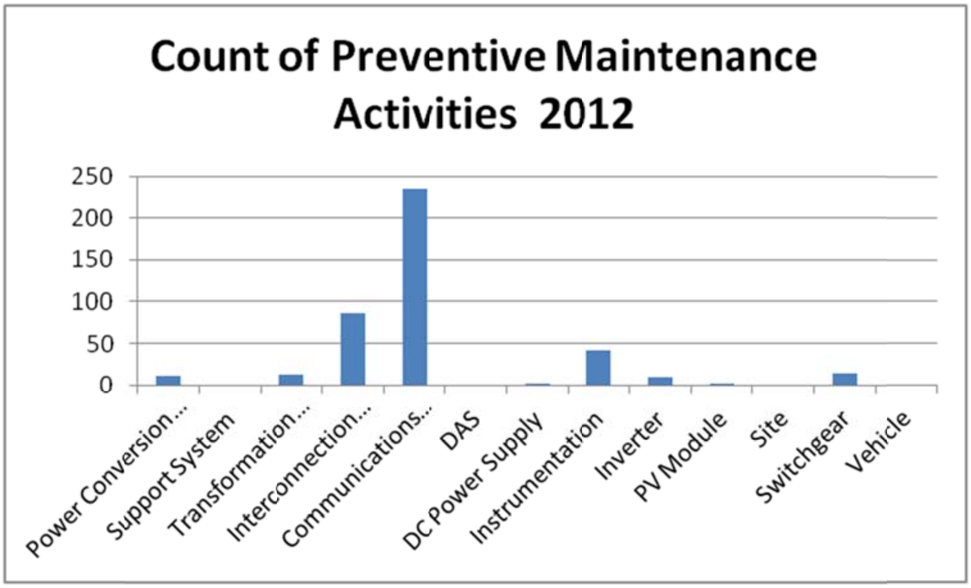

Figure 6-1 Count of Preventative Maintenance Activities 2012

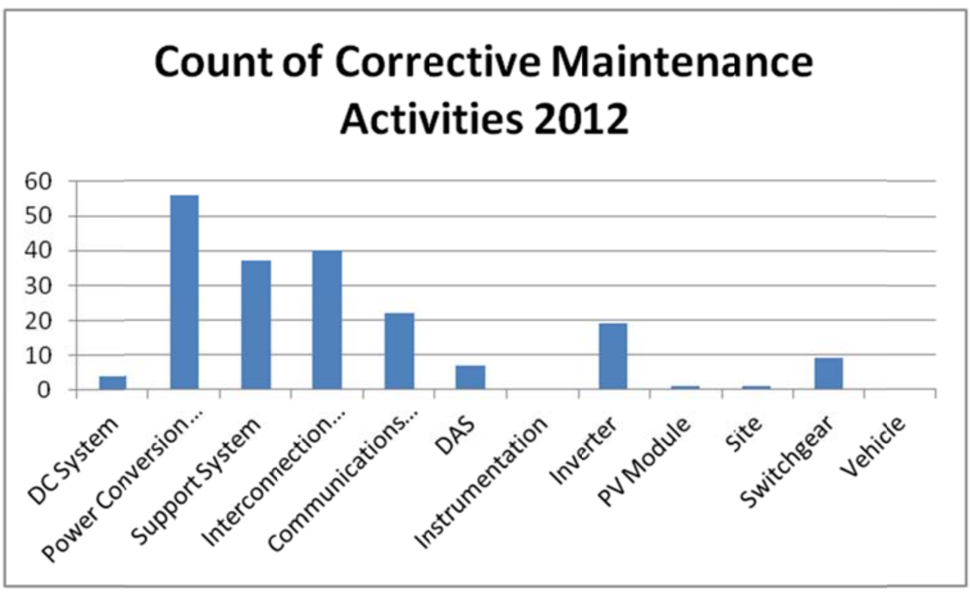

Figure 6-2 Count of Corrective Maintenance Activities 2012

It can be seen from the figures above that, for the utility scale PV plant under consideration, the number of preventive maintenance activities (411) exceeds the number of corrective maintenance activities (196). Preventive maintenance activities tend to focus on communications and interconnection facilities. Corrective maintenance activities tend to focus on AC systems and interconnection facilities. This example is early in a plant's life, and it should also be noted that if problems are addressed early, annual maintenance costs can significantly drop off in later years of asset life.

It is known through literature review and field experience that alternating current systems and inverters combined can account for almost eighty percent of lost energy production. Inverters alone may contribute to half of all plant maintenance costs. A study by the Electrical Power Research Institute (EPRI) and SunEdison came to the same conclusion and a graph from that study is shown in Figure 6-3 which demonstrates the relationship between lost energy and the responsible systems[6].

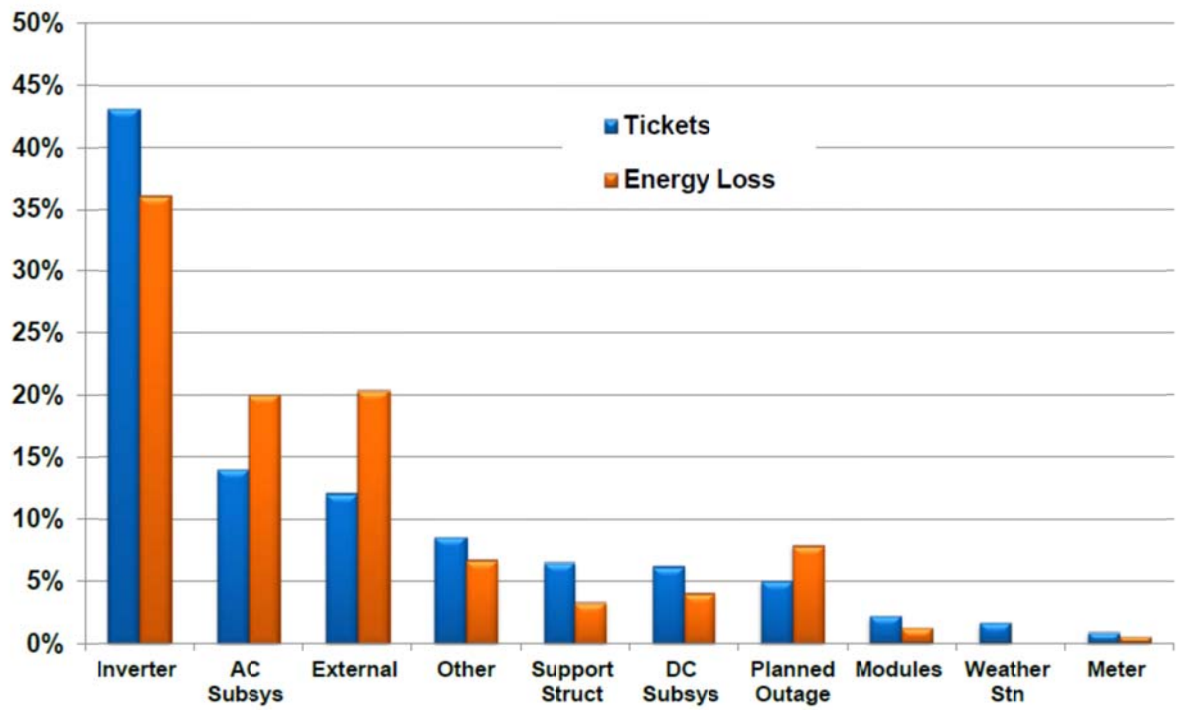

Figure 6-3 Main Causes of Energy Loss in PV Power Plants. (Source: SunEdison, 2013)

Figure 6-4 below shows a representative time history of cumulative energy lost[7] for different O&M approaches for the same PV plant. It can be seen from this figure that higher levels of attention result in significant cumulative energy revenue gains over the life of the asset.

[6] 2013 O&M Workshop Hosted By Sandia National Labs and EPRI. http://energy.sandia.gov/?page_id=14860

[7] http://energy.sandia.gov/wp/wp-content/gallery/uploads/6-Granata_PVROM.pdf

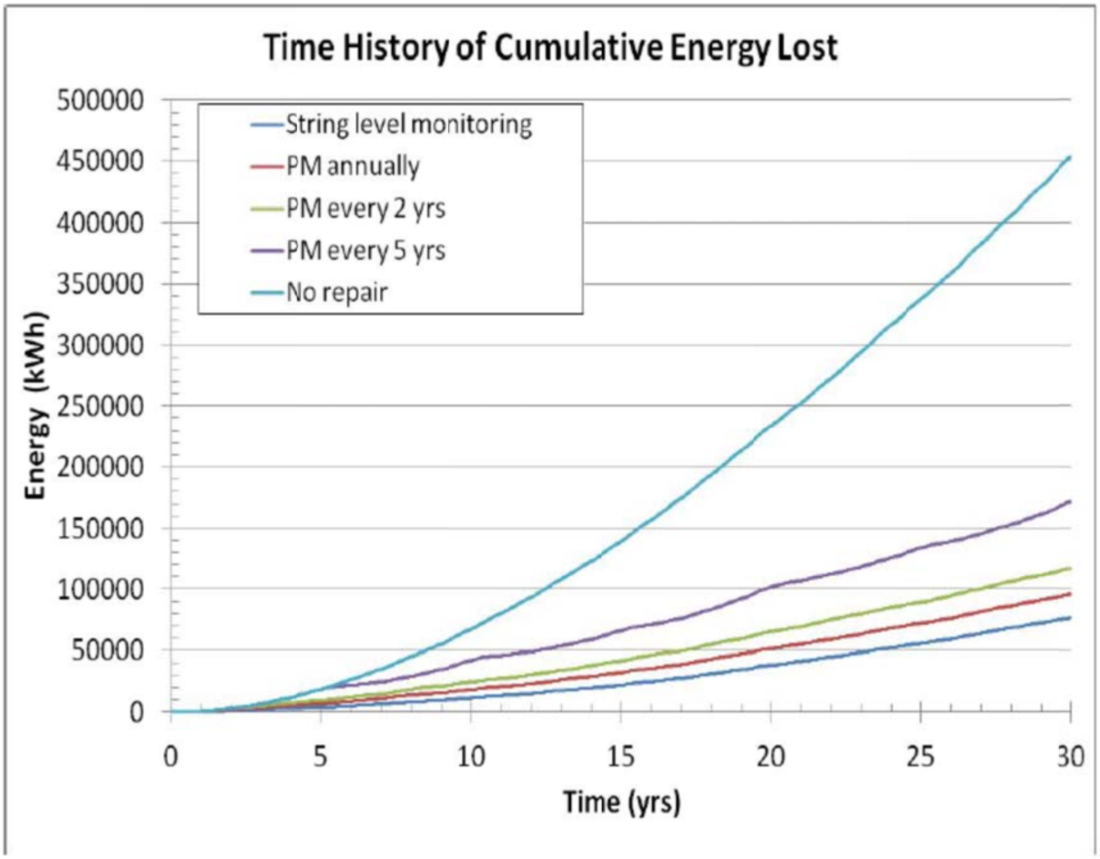

Figure 6-4 Cumulative energy lost over the life of the asset, for varying levels of maintenance

Black & Veatch recommends a proactive approach to O&M, in order to maximize return on investment for the asset or portfolio of assets.

6.1.2 In-House Versus Contracted Maintenance

Maintenance considerations for solar power plants typically involve a decision on the part of the Owner to either contract maintenance labor to third party vendors or to perform that work with existing in-house staff. Keeping maintenance activities in house can potentially reduce labor if an existing and successful maintenance program is currently in place by the solar power plant owner for other solar power plants or similar industries. This may be the most attractive approach if the Owner's business model includes cultivating and developing a dedicated team of skilled operating staff long-term. However, smaller portfolios, low levels of applicable experience or geographically diverse installations can lead to higher costs than contracting out to existing and efficient maintenance providers with widespread operations. The O&M provider might also be asked to cover the costs of warranty support within their existing support services, which could be a cost prohibitive department for an owner to set up. For solar power plant Owners that are developing their portfolios it might be wise to train internal staff over a given timeframe to take over management of O&M activities once they are trained and once the owner has developed a sufficient portfolio of projects.

Black & Veatch collected data from operating solar power plants showing that the majority of solar power plant owners choose to perform O&M activities in-house. Thirty nine percent of plant owners hire the EPC contractor that built the plant to provide O&M services. However, only six percent of owners hire in a third party O&M provider (Table 6-1).

Table 6-1 O&M Provider Share

O&M PROVIDER	PLANTS BETWEEN 1-5 MW PER SITE (93 TOTAL)	PLANTS BETWEEN 5-20 MW PER SITE (48 TOTAL)	PLANTS GREATER THAN 20 MW PER SITE (13 TOTAL)
Owner	58%	67%	31%
EPC	39%	33%	62%
Third Party	6%	2%	15%

6.2 O&M COSTS AND CONSIDERATIONS

For the PacifiCorp O&M cost estimate, the following conceptual characteristics were assumed:

Table 6-2 O&M Model Inputs and Assumptions

PROJECT CHARACTERISTIC	FIXED TILT	SINGLE-AXIS TRACKING
Project Capacity	69.2 MW dc/50.5 MW ac	67.7 MW dc/50.4 MW ac
Inverter Loading Ratio (kWp/kWac)	1.37	1.34
Trackers (axis, supplier)	none	Single-axis
On-site security guard or remote surveillance	On-site	On-site
Availability guarantee	Annual	Annual
Monitoring and reporting	Continuous monitoring, reporting and diagnostics	Continuous monitoring, reporting and diagnostics
Warranty management	Assumed to be performed in-house by project owner	Assumed to be performed in-house by project owner
Inverter Warranty period	5 yr	5 yr
Module Warranty period	25 yr	25 yr
Number of washes per year	1	1

Water available on-site	yes	yes

Within the O&M cost model, typical industry labor rates were assumed for skilled electrical contractors, with a regional multiplier for Price, UT which is 145 miles from Milford and 225 miles from Veyo. Regional labor and materials multipliers from the RS Means cost estimating handbook were applied. The regional multiplier for labor in Price, Utah is 72.3 percent of the national average for skilled electrical labor. The regional multiplier for Salt Lake City is 62.3 percent of the national average, and for Klamath Falls Oregon (nearest location to the Lakeview site) it is 82.8 percent of the national average. Black & Veatch selected Price, Utah for representative lab or rates for the Milford and Veyo sites because it is the closest location with cost information reported in RS Means that is within the state of Utah. Other locations in neighboring states may be closer, but the labor rates for neighboring states as reported in RS Means are substantially different. The labor for O&M work at the Veyo and Milford sites can likely be sourced locally from within Utah, so Utah-specific labor rates were deemed most appropriate. Black & Veatch assumed that all scheduled and unscheduled maintenance would be performed by subcontractors, except for work that is covered by vendor warranty. Travel distance to the Milford plant is assumed to be fifty seven miles originating from Cedar City, Utah, which is the nearest town with a sufficient population (approximately 30,000) to have skilled labor that can support a solar power plant. Travel distance to the Veyo plant is assumed to be ten miles originating from St. George, Utah which has a population of approximately 73,000. Travel distance for Salt Lake City is assumed to be five miles (labor from within Salt Lake City), and for Lakeview it is assumed to be seventy miles (labor from Klamath Falls, pop 21,005).

6.2.1 Inverter Warranty Period

The inverter warranty period may be extended depending on the inverter provider and the warranties available. However, upon the conclusion of the warranty period, a reserve fund must be available to handle inverter repairs. Utility scale inverters are typically not replaced, rather they are treated as repairable items so failed internal components are replaced as needed. Black & Veatch has created an estimated inverter reserve to be held by PacifiCorp to fund inverter repairs once the inverter is no longer covered by warranty.

6.2.2 Annual Inspections/Maintenance

This cost item includes labor and consumables associated with one whole-plant annual inspection (dc and ac components, weather station and mounting structure), plus monthly inspections of certain components (collector station transformers, voltage regulators, oil circuit breakers, air break and disconnect switches, bypass switches, insulators, buses, connections, control room, security cameras, fences, gates, signage, vegetation, roadways). Black & Veatch arrived at this labor estimate based on publicly available information from EPRI as well as Black & Veatch experience.

6.2.3 Inverter Extended Warranty

This cost item is an optional annual fee to cover an extended warranty with long-term parts and preventive maintenance labor for the inverter. Black &Veatch did not include this cost in the analysis. Instead, a typical five year inverter warranty combined with an inverter reserve fund was used in the cost model.

6.2.4 Unscheduled Maintenance

This cost item includes labor and consumables for “Level 1” service requests and “Level 2” service requests. Level 1 service requests are those associated with a non-critical reduction in performance of the plant. Level 2 service requests are considered to be critical events, typically associated with loss of inverter operation.

6.2.5 Routine Cleaning (Washing)

This cost item includes labor and water cost for one wash of the Project per year, which is on par with projects of similar location and size. The single module wash is based on historic weather data that shows sufficient precipitation to clean the modules throughout the year with the exception of the mid-summer months. Black & Veatch has modeled one module wash with specific timing dependent upon measured plant performance, but occurring in the time frame between early June and early July. Black & Veatch arrived at this conclusion by performing a PVsyst energy production analysis and a Black & Veatch proprietary soiling analysis tool. This module washing timeframe coincides with the peak generation season for the power plant.

Well water or irrigation canals are recommended for module wash water due to cost savings for trucking unless a water source is in close proximity. On-site water treatment is typically necessary to ensure the wash water is sufficiently filtered to clean the modules. The water must be de-ionized or filtered to remove particulates and sediment matter. The Veyo site is approximately one quarter of a mile from a nearby reservoir, but could have access to irrigation water. The Milford site appears to neighbor current agricultural land, and may itself be existing farmland. Options for agricultural water supply may exist for the Milford site. The volume of water estimated by Black & Veatch for one module cleaning per year is 720,540 gallons for the fixed tilt system and 913,460 gallons for the tracking system.

Black & Veatch recommends that module wash water be sourced and treated on site if possible. The cost of trucking water in for module wash is generally prohibitively expensive. Typical water costs for the state of Utah are $1.34 per 1,000 gallons of water. Water treatment will likely be around $30,000 per year and required in either instance to decrease sediments.

A rule of thumb for array washing is the following: if time from last cleaning to next predicted rain is not greater than 2X breakeven period, then it is not cost effective to clean panels. Breakeven period can be calculated in units of number of days, based on daily insolation, daily accumulation of soiling, daily energy lost, PPA price, and cost of washing. The cost of washing is typically higher for tracking systems than for fixed tilt systems.

6.2.6 Tracker Maintenance

For single-axis tracking, this cost item includes routine maintenance, for example lubrication of moving parts and troubleshooting, plus parts and labor for periodic motor replacement. Typical tracker maintenance costs are about $3.69/kW

6.2.7 Owner's Costs

This cost item includes site maintenance (vegetation abatement, etc), monitoring/reporting, and warranty and insurance claim management.

It also includes insurance and property taxes. PacifiCorp should use their actual experience to confirm these costs, as they can vary widely.

Black & Veatch used insurance cost based on publicly available data used in utility resource planning models is estimated at $6.14/kW-yr for fixed and $6.96/kW-yr for tracking PV systems. Property tax is assumed to be $15.35/kW-yr for fixed and $17.4/kW-yr for tracking (no property tax exemptions in UT).

6.2.8 Inverter Reserve Fund

Black & Veatch recommends creating an inverter reserve fund to handle inverter repairs at the conclusion of the inverter warranty period. This fund should be created and contributed to starting in the first year of plant operation. Black & Veatch recommends contributing to this fund at the rate of approximately $6.73/kW ac /year. This fund should be held by the owner and not the O&M subcontractor, in order to mitigate the risk of termination of contract with the O&M vendor.

6.2.9 The Cost of Single Axis Tracking

It can be seen from this table that the SAT has a higher O&M cost than the fixed system. This is partially due to the field layout for the fixed system placing two modules side by side on each structural row while the SAT system has only single module rows. This creates additional module washing costs and technician maintenance time. There are also additional costs associated with a SAT installation that a fixed structure will not incur such as motor repair and replacement as well as maintenance for bearings and drive systems.

6.3 O&M RESULTS

The following table summarizes annual O&M cost estimate results for southern Utah for the first year of operation. Tables 6-4 through 6-5 show the cash flows over the project lifetime.

Escalation is included at 2.5 percent.

Table 6-3 Estimated O&M Costs for 50 MW Sites (2013$)

ANNUAL MAINTENANCE	FIXED TILT $1,000/YEAR	SINGLE AXIS TRACKING $1,000/YEAR	NOTES
DC Component PM	217.1	302.3	
Inverter PM	419.0	406.1	
Inverter Warranty	-	-	No extended warranty
Inverter Repair	-	-	Under warranty until year 6
Unscheduled Maintenance	23.8	23.8	
Switchgear/Transformer	25.9	25.2	Under warranty until year 6
Site maintenance (vegetation abatement, fence repair)	54.0	110.0	Trackers require more land
Snow removal	-	-	
Tracker Maintenance	-	249.7	Under warranty until year 6 for SAT. Preventive maintenance is less than the post warranty maintenance shown.
Monitoring and Reporting	24.7	24.7	
Array Washing	73.4	136.4	Washing tracking systems is more complex than fixed tilt systems, partially due to the increased number of rows per acre, and partly due to the presence of moving parts.
Telephone and Data Communication	2.3	2.3	
Scheduling/Forecasting	18.0	17.0	
Security	27.7	27.1	
Site Maintenance (waste disposal, road maintenance)	95.6	154.3	
Asset management	61.7	61.7	
Owner's costs			
Electricity	25.0	27.3	
Environmental services; SPCC, SWPP	34.6	33.8	
Training	5.5	5.5	

Insurance*	424.9	470.9	
Property Tax	1062.2	1177.3	
Total not including owner's costs	1043.2	1511.5	
Total including owner's costs	2595.3	3226.4	
Total per kWdc	**37.5/kWdc**	**47.68/kWdc**	
Total per kWac	**51.91/kWac**	**64.53/kWac**	

* PacifiCorp should use its actual experience. Black & Veatch would assume 0.2% of capital cost for insurance and land lease at 6.40 $/kW(ac)-yr for fixed systems and 6.59 $/kW(ac)-yr for SAT systems.

Table 6-4 Veyo Fixed Tilt

O&M cost summary ($1000USD)

Annual Maintenance													
DC Component PM	$217.1	$222.5	$228.0	$233.7	$239.6	$245.6	$251.7	$258.0	$264.5	$271.1	$277.9	$284.8	$291.9
Inverter PM	$419.0	$429.5	$440.3	$451.3	$462.5	$474.1	$486.0	$498.1	$510.6	$523.3	$536.4	$549.8	$563.6
Inverter Warranty	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Inverter Repair	$0.0	$0.0	$0.0	$0.0	$0.0	$400.5	$607.6	$826.8	$1,010.9	$1,114.7	$1,116.9	$1,032.5	$906.2
Unschediled Maintenance	$23.8	$24.4	$25.0	$25.6	$26.3	$26.9	$27.6	$28.3	$29.0	$29.7	$30.5	$31.2	$32.0
Switchgear/Transformer	$25.9	$26.6	$27.2	$27.9	$28.6	$29.3	$30.1	$30.8	$31.6	$32.4	$33.2	$34.0	$34.9
Site Maintenance (vegetation abatement, fence repair)	$54.0	$55.4	$56.8	$58.2	$59.7	$61.1	$62.7	$64.2	$65.8	$67.5	$69.2	$70.9	$72.7
Snow Removal	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Tracker Maintenance	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Monitoring & Reporting	$24.7	$25.3	$25.9	$26.5	$27.2	$27.9	$28.6	$29.3	$30.0	$30.8	$31.6	$32.3	$33.2
Array Washing	$73.4	$75.2	$77.1	$79.0	$81.0	$83.0	$85.1	$87.2	$89.4	$91.6	$93.9	$96.3	$98.7
Telephone and Data Communication	$2.3	$2.4	$2.5	$2.5	$2.6	$2.7	$2.7	$2.8	$2.9	$2.9	$3.0	$3.1	$3.2
Scheduling/Forecasting	$18.0	$18.5	$18.9	$19.4	$19.9	$20.4	$20.9	$21.4	$21.9	$22.5	$23.0	$23.6	$24.2
Security	$27.7	$28.4	$29.1	$29.8	$30.6	$31.3	$32.1	$32.9	$33.7	$34.6	$35.4	$36.3	$37.2
Site Maintenance (waste disposal, road maintenance)	$95.6	$98.0	$100.4	$102.9	$105.5	$108.1	$110.8	$113.6	$116.4	$119.3	$122.3	$125.4	$128.5
Asset Management	$61.7	$63.2	$64.8	$66.4	$68.1	$69.8	$71.5	$73.3	$75.2	$77.0	$79.0	$80.9	$83.0
Owner's Costs													
Electricity	$25.0	$25.6	$26.2	$26.9	$27.6	$28.3	$29.0	$29.7	$30.4	$31.2	$32.0	$32.8	$33.6
Environmental services; SPCC, SWPP	$34.6	$35.5	$36.4	$37.3	$38.2	$39.1	$40.1	$41.1	$42.2	$43.2	$44.3	$45.4	$46.5
Training	$5.5	$5.6	$5.8	$5.9	$6.1	$6.2	$6.4	$6.5	$6.7	$6.9	$7.0	$7.2	$7.4
Insurance	$424.9	$435.5	$446.4	$457.6	$469.0	$480.7	$492.7	$505.1	$517.7	$530.6	$543.9	$557.5	$571.4
Property Tax	$1,062.2	$1,088.8	$1,116.0	$1,143.9	$1,172.5	$1,201.8	$1,231.8	$1,262.6	$1,294.2	$1,326.6	$1,359.7	$1,393.7	$1,428.6
Total O&M (not including Owner's costs)($/yr)	$1,043.2	$1,069.2	$1,096.0	$1,123.4	$1,151.5	$1,580.7	$1,817.4	$2,066.8	$2,281.8	$2,417.4	$2,452.3	$2,401.2	$2,309.1
Total O&M (including Owner's costs)($/yr)	$2,595.3	$2,660.2	$2,726.7	$2,794.9	$2,864.8	$3,336.9	$3,617.4	$3,911.8	$4,173.0	$4,355.9	$4,439.2	$4,437.8	$4,396.6

Annual Maintenance												
DC Component PM	$299.2	$306.7	$314.4	$322.2	$330.3	$338.5	$347.0	$355.7	$364.6	$373.7	$383.0	$392.6
Inverter PM	$577.7	$592.1	$606.9	$622.1	$637.6	$653.6	$669.9	$686.6	$703.8	$721.4	$739.4	$757.9
Inverter Warranty	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Inverter Repair	$791.6	$728.4	$729.8	$783.3	$861.4	$933.1	$973.0	$966.5	$910.4	$811.9	$685.4	$547.6
Unschediled Maintenance	$32.8	$33.6	$34.5	$35.3	$36.2	$37.1	$38.0	$39.0	$40.0	$41.0	$42.0	$43.0
Switchgear/Transformer	$35.7	$36.6	$37.5	$38.5	$39.4	$40.4	$41.4	$42.5	$43.5	$44.6	$45.7	$46.9
Site Maintenance (vegetation abatement, fence repair)	$74.5	$76.4	$78.3	$80.2	$82.2	$84.3	$86.4	$88.6	$90.8	$93.0	$95.4	$97.8
Snow Removal	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Tracker Maintenance	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Monitoring & Reporting	$34.0	$34.8	$35.7	$36.6	$37.5	$38.4	$39.4	$40.4	$41.4	$42.4	$43.5	$44.6
Array Washing	$101.1	$103.7	$106.3	$108.9	$111.6	$114.4	$117.3	$120.2	$123.2	$126.3	$129.5	$132.7
Telephone and Data Communication	$3.2	$3.3	$3.4	$3.5	$3.6	$3.7	$3.8	$3.8	$3.9	$4.0	$4.1	$4.2
Scheduling/Forecasting	$24.8	$25.4	$26.1	$26.7	$27.4	$28.1	$28.8	$29.5	$30.2	$31.0	$31.8	$32.6
Security	$38.2	$39.1	$40.1	$41.1	$42.1	$43.2	$44.3	$45.4	$46.5	$47.7	$48.8	$50.1
Site Maintenance (waste disposal, road maintenance)	$131.7	$135.0	$138.4	$141.9	$145.4	$149.0	$152.8	$156.6	$160.5	$164.5	$168.6	$172.8
Asset Management	$85.0	$87.2	$89.3	$91.6	$93.9	$96.2	$98.6	$101.1	$103.6	$106.2	$108.8	$111.6
Owner's Costs												
Electricity	$34.4	$35.3	$36.2	$37.1	$38.0	$38.9	$39.9	$40.9	$41.9	$43.0	$44.1	$45.2
Environmental services; SPCC, SWPP	$47.7	$48.9	$50.1	$51.4	$52.6	$54.0	$55.3	$56.7	$58.1	$59.6	$61.1	$62.6
Training	$7.6	$7.8	$8.0	$8.2	$8.4	$8.6	$8.8	$9.0	$9.2	$9.5	$9.7	$9.9
Insurance	$585.7	$600.4	$615.4	$630.7	$646.5	$662.7	$679.2	$696.2	$713.6	$731.5	$749.8	$768.5
Property Tax	$1,464.3	$1,500.9	$1,538.4	$1,576.9	$1,616.3	$1,656.7	$1,698.1	$1,740.6	$1,784.1	$1,828.7	$1,874.4	$1,921.3
Total O&M (not including Owner's costs)($/yr)	$2,229.6	$2,202.3	$2,240.6	$2,331.9	$2,448.7	$2,560.1	$2,640.7	$2,675.8	$2,662.4	$2,607.8	$2,526.1	$2,434.4
Total O&M (including Owner's costs)($/yr)	$4,369.3	$4,395.5	$4,418.6	$4,636.1	$4,810.5	$4,981.0	$5,122.1	$5,219.2	$5,269.5	$5280.0	$5,265.1	$5,241.9

Table 6-5 Veyo Single Axis Tracking

O&M cost summary ($1000USD)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Annual Maintenance																									
DC Component PM	$302.3	$309.9	$317.6	$325.6	$333.7	$342.0	$350.6	$359.4	$368.3	$377.6	$387.0	$396.7	$406.6	$416.7	$427.2	$437.8	$448.8	$460.0	$471.5	$483.3	$495.4	$507.8	$520.5	$533.5	$546.8
Inverter PM	$406.1	$416.2	$426.6	$437.3	$448.2	$459.4	$470.9	$482.7	$494.8	$507.1	$519.8	$532.8	$546.1	$559.8	$573.8	$588.1	$602.8	$617.9	$633.3	$649.2	$665.4	$682.0	$699.1	$716.6	$734.5
Inverter Warranty	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Inverter Repair	$0.0	$0.0	$0.0	$0.0	$0.0	$400.5	$607.6	$826.8	$1,010.9	$1,114.7	$1,116.9	$1,032.5	$906.2	$791.6	$728.4	$729.8	$783.3	$861.4	$933.1	$973.0	$966.5	$910.4	$811.9	$685.4	$547.6
Unscheduled Maintenance	$23.7	$24.3	$24.9	$25.6	$26.2	$23.7	$24.3	$24.9	$25.6	$26.2	$26.9	$27.5	$28.2	$28.9	$29.6	$30.4	$31.1	$31.9	$32.7	$33.5	$34.4	$35.2	$36.1	$37.0	$38.0
Switchgear/Transformer	$0.0	$0.0	$0.0	$0.0	$0.0	$29.2	$29.9	$30.7	$31.4	$32.2	$33.0	$33.8	$34.7	$35.6	$36.4	$37.4	$38.3	$39.3	$40.2	$41.2	$42.3	$43.3	$44.4	$45.5	$46.7
Site Maintenance (vegetation abatement, fence repair)	$110.0	$112.7	$115.5	$118.4	$121.4	$124.4	$127.5	$130.7	$134.0	$137.3	$140.8	$144.3	$147.9	$151.6	$155.4	$159.3	$163.2	$167.3	$171.5	$175.8	$180.2	$184.7	$189.3	$194.0	$198.9
Snow Removal	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Tracker Maintenance	$249.7	$255.9	$262.3	$268.9	$275.6	$255.9	$262.3	$268.9	$275.6	$282.5	$289.5	$296.8	$304.2	$311.8	$319.6	$327.6	$335.8	$344.2	$352.8	$361.6	$370.6	$379.9	$389.4	$399.1	$409.1
Monitoring & Reporting	$24.7	$25.3	$25.9	$26.5	$27.2	$27.9	$28.6	$29.3	$30.0	$30.8	$31.6	$32.3	$33.2	$34.0	$34.8	$35.7	$36.6	$37.5	$38.4	$39.4	$40.4	$41.4	$42.4	$43.5	$44.6
Array Washing	$136.4	$139.8	$143.3	$146.9	$150.6	$154.4	$158.2	$162.2	$166.2	$170.4	$174.6	$179.0	$183.5	$188.1	$192.8	$197.6	$202.5	$207.6	$212.8	$218.1	$223.6	$229.1	$234.9	$240.7	$246.8
Telephone and Data Communication	$2.3	$2.4	$2.5	$2.5	$2.6	$2.7	$2.7	$2.8	$2.9	$2.9	$3.0	$3.1	$3.2	$3.2	$3.3	$3.4	$3.5	$3.6	$3.7	$3.8	$3.8	$3.9	$4.0	$4.1	$4.2
Scheduling/Forecasting	$17.0	$17.4	$17.9	$18.3	$18.8	$19.2	$19.7	$20.2	$20.7	$21.2	$21.8	$22.3	$22.9	$23.4	$24.0	$24.6	$25.2	$25.9	$26.5	$27.2	$27.9	$28.6	$29.3	$30.0	$30.7
Security	$27.1	$27.7	$28.4	$29.1	$29.9	$30.6	$31.4	$32.2	$33.0	$33.8	$34.6	$35.5	$36.4	$37.3	$38.2	$39.2	$40.2	$41.2	$42.2	$43.3	$44.3	$45.5	$46.6	$47.8	$49.0
Site Maintenance (waste disposal, road maintenance)	$150.6	$154.3	$158.2	$162.1	$166.2	$170.3	$174.6	$179.0	$183.4	$188.0	$192.7	$197.5	$202.5	$207.5	$212.7	$218.0	$223.5	$229.1	$234.8	$240.7	$246.7	$252.9	$259.2	$265.7	$272.3
Asset Management	$61.7	$63.2	$64.8	$66.4	$68.1	$69.8	$71.5	$73.3	$75.2	$77.0	$79.0	$80.9	$83.0	$85.0	$87.2	$89.3	$91.6	$93.9	$96.2	$98.6	$101.1	$103.6	$106.2	$108.8	$111.6
Owner's Costs																									
Electricity	$27.3	$28.0	$28.7	$29.4	$30.2	$30.9	$31.7	$32.5	$33.3	$34.1	$35.0	$35.9	$36.8	$37.7	$38.6	$39.6	$40.6	$41.6	$42.6	$43.7	$44.8	$45.9	$47.1	$48.2	$49.5
Environmental services; SPCC, SWPP	$33.8	$34.7	$35.5	$36.4	$37.3	$38.3	$39.2	$40.2	$41.2	$42.2	$43.3	$44.4	$45.5	$46.6	$47.8	$49.0	$50.2	$51.5	$52.8	$54.1	$55.4	$56.8	$58.2	$59.7	$61.2
Training	$5.5	$5.6	$5.8	$5.9	$6.1	$6.2	$6.4	$6.5	$6.7	$6.9	$7.0	$7.2	$7.4	$7.6	$7.8	$8.0	$8.2	$8.4	$8.6	$8.8	$9.0	$9.2	$9.5	$9.7	$9.9
Insurance	$470.9	$482.7	$494.8	$507.1	$519.8	$532.8	$546.1	$559.8	$573.8	$588.1	$602.8	$617.9	$633.3	$649.2	$665.4	$682.0	$699.1	$716.6	$734.5	$752.8	$771.6	$790.9	$810.7	$831.0	$851.8
Property Tax	$1,177.3	$1,206.7	$1,236.9	$1,267.8	$1,299.5	$1,332.0	$1,365.3	$1,399.4	$1,434.4	$1,470.3	$1,507.0	$1,544.7	$1,583.3	$1,622.9	$1,663.5	$1,705.1	$1,747.7	$1,791.4	$1,836.2	$1,882.1	$1,929.1	$1,977.3	$2,026.8	$2,077.4	$2,129.4
Total O&M (not including Owner's costs) ($/yr)	**$1,511.5**	**$1,549.3**	**$1,588.0**	**$1,627.7**	**$1,668.4**	**$2,110.1**	**$2,360.0**	**$2,622.9**	**$2,851.9**	**$3,001.7**	**$3,051.2**	**$3,015.1**	**$2,938.4**	**$2,874.6**	**$2,863.5**	**$2,918.2**	**$3,026.5**	**$3,160.7**	**$3,289.8**	**$3,388.7**	**$3,442.5**	**$3,448.3**	**$3,413.3**	**$3,351.8**	**$3,280.7**
Total O&M (including Owner's costs) ($/yr)	**$3,226.4**	**$3,307.0**	**$3,389.7**	**$3,474.4**	**$3,561.3**	**$4,050.3**	**$4,348.7**	**$4,661.4**	**$4,941.3**	**$5,143.4**	**$5,246.4**	**$5,265.2**	**$5,244.7**	**$5,238.5**	**$5,286.5**	**$5,401.8**	**$5,572.2**	**$5,770.0**	**$5,964.4**	**$6,130.2**	**$6,252.5**	**$6,328.6**	**$6,365.6**	**$6,377.8**	**$6,382.4**

Appendix A. 8760 and 12x24 Tables

The Tables are submitted separately for 5MW systems. Tables are not submitted for the 50MW systems. The production for these systems is approximately 10 times as high, although preparation of more detailed designs would provide data for analysis showing a few more losses for the substations at the larger plants.