An Effective Load Carrying Capability Analysis for Estimating the Capacity Value of Solar Generation Resources on the Public Service Company of Colorado System

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The following report describes the analysis Xcel Energy performed to determine the effective load carrying capability, ELCC, of solar resources on the Public Service Company of Colorado ("Public Service") system. The results provided are based on a set of assumptions and solar generation scenarios as described in this report.

Background

In the 2007 Colorado Resource Plan,[1] Xcel Energy committed to provide the Colorado Public Utilities Commission with an analysis of the capacity credit to be afforded solar resources located in Colorado in the Phase II evaluation of bids. Xcel Energy completed a similar analysis evaluating the Effective Load Carrying Capacity (ELCC) for wind resources in March, 2007.

Executive Summary

Public Service ("Company") strives to provide reliable electric service at all times to its customers. As a result, the Company works to maintain an adequate supply of electric generation capacity that will meet the expected maximum demand of its customers (i.e., the "peak" demand) under a range of circumstances. When the reserve margin (the amount of excess generating capacity above peak demand) is projected to fall below a desired amount, Public Service will acquire additional electric generating capacity or demand reduction programs to bring the reserve margin back to the desirable level. As Public Service pursues additional solar generation for its system, the capacity value ascribed to these solar resources will play an increasingly important role in this process.

This report discusses the methodology and results of a study performed by Public Service to quantify the capacity value of solar resources on the Public Service system based on the effective load carrying capability ("ELCC") calculated for these solar resources. The calculation of ELCC incorporates use of probabilistic measures of electric system reliability termed loss of load probability ("LOLP") and loss of load expectation ("LOLE") to quantify the reliability contribution that solar resources provide to the electric system. The annual sum of hourly system LOLP values results in the LOLE probabilistic measure. By comparing the annual system LOLE that results from adding solar generation to that resulting from the addition of a traditional, dispatchable gas-fired thermal unit, Public Service was able to estimate an ELCC value of solar resources.

The resulting solar resource ELCC values calculated from this study varied depending on solar technology and location within the state. Three technologies were studied (fixed panel photovoltaic ("PV"), single-axis tracking PV, and solar thermal parabolic trough) in three locations within the state (Denver, Pueblo, and Alamosa). Looking across technologies, the average capacity valuation for solar

[1] Commission Docket No. 07A-447E

resources ranged from 59 percent to 81 percent of nameplate (i.e., a 100 MW nameplate solar facility would get 59 MW to 81 MW of generation capacity credit). The lowest capacity credit values calculated were for fixed panel PV applications while solar thermal trough and single-axis tracking PV facilities exhibited the highest capacity credit values. Solar thermal facilities with thermal storage were not examined in this study since such facilities should be capable of providing full nameplate capacity (i.e., 100% capacity credit) during the system peak hours if they are designed with sufficient levels of storage capability. Solar generators located in Denver and Alamosa had similar capacity values while Pueblo showed the highest capacity values of the three locations studied.

Section 1: Introduction

The role of renewable generation resources has gained prominence in the utility industry for environmental and fuel saving benefits. With volatility in natural gas prices, potential taxes on carbon emissions, and a 30% federal investment tax credit for solar projects, the relative economics of solar generation are becoming more competitive with traditional thermal units on a dollar per megawatt hour basis. This increased competitiveness along with the Company's environmental leadership strategy has led Public Service to consider adding significant amounts of solar generation to its electric supply portfolio. Therefore, it is increasingly important for the Company to understand the operational characteristics of solar technologies and how to consider the different solar technologies in the generation capacity and reliability planning process. To further this understanding, Public Service agreed to analyze the capacity value of solar generation and has, in this study, employed the ELCC approach to do so. ELCC was previously used in the Company's analysis of the capacity credit value of wind resources that was filed with the Colorado Public Utilities Commission in March 2007.

This study was performed to determine the capacity credit value of solar resources, that is, the ability of a facility or facilities converting sunlight to electricity to reliably meet customer load. It was not performed to determine the annual energy capacity factor of solar generators, that is, the total MWh of electrical energy generated in a year relative to the maximum number of MWh that could be generated if the generator operated at maximum nameplate capacity every hour of the year.

Xcel Energy's prior ELCC study of wind generators found that the capacity value of those facilities was significantly less than their annual energy capacity factor owing to the relatively poor correlation between wind generation in the Colorado region and Public Service system peak load hours. In this study however, it was anticipated that the capacity value of solar generation in the Colorado region would significantly exceed the annual energy capacity factor of such resources given the better correlation between the solar resource and system peak load hours, as prior studies have indicated.[23]

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[2] "Update: Effective Load-Carrying Capability of Photovoltaics in the United States", Perez, Margolis, Kmiecik, Schwab, Perez; NREL/CP-620-40068; June 2006 (www.nrel.gov/pv/pdfs/40068.pdf)

Section 2: Use of Loss of Load Expectation for Resource Capacity Valuation

The calculation of ELCC incorporates use of probabilistic measures of electric system reliability termed loss of load probability ("LOLP") and loss of load expectation ("LOLE") to quantify the reliability contribution that solar resources provide to the electric system. The annual sum of hourly system LOLP values results in the LOLE probabilistic measure. By comparing the annual system LOLE that results from adding solar generation to that resulting from the addition of a traditional, dispatchable gas-fired thermal unit, Public Service was able to estimate an ELCC value of solar resources.

LOLE is a probabilistic measure of an electric system's ability to maintain service to firm customer load. LOLE represents the expectation of the power system having insufficient generation supplies to serve customer load requirements. The annual LOLE for the Public Service system is calculated by summing hourly LOLP values that are derived from computer modeling of the Company's electric supply system. An electric system with a probability of being unable to serve customer load requirements one day every ten years would have an LOLE equivalent to 2.7397×10^{-4} which is derived by dividing 1 day by 3650 days (365 days per year times 10 years, leap years excluded). An LOLE equivalent to 2.7397×10^{-4} can be simply described by dividing 24 hours by the number of hours in ten years, or 2.4 hours divided by 8760 hours per year. This report generally refers to LOLP when discussing reliability on an hourly basis and LOLE when describing reliability on an annual basis. LOLE for the Public Service system will vary from year to year depending on the number of generators installed on the system, the maintenance requirements of those generators, the potential unavailability of generation, the total megawatts of generation available on the system, and characteristics of the system load requirements. Higher LOLE values result from a combination of low system operating reserve margins and high load requirements. Under these circumstances there is a higher expectation that the system will have insufficient generation capacity (once forced outages are considered) to serve load. Alternatively, when larger operating reserve margins exist and load is low, the expectation of not being able to serve load is low and LOLE values diminish.

Electric generator availability was represented in the LOLE calculations by two types of outages: unplanned and planned. Unplanned outages are represented by the expected forced outage rate ("EFOR") of the individual generators; these forced outages typically occur randomly. Planned outages represent maintenance outages that the utility schedules and therefore has some control over their occurrence. In this study, maintenance outages were either represented using actual maintenance outage schedules (i.e., the specific days for which outages are scheduled to occur) or an estimate of the number or weeks per year needed for maintenance (i.e., a maintenance rate).

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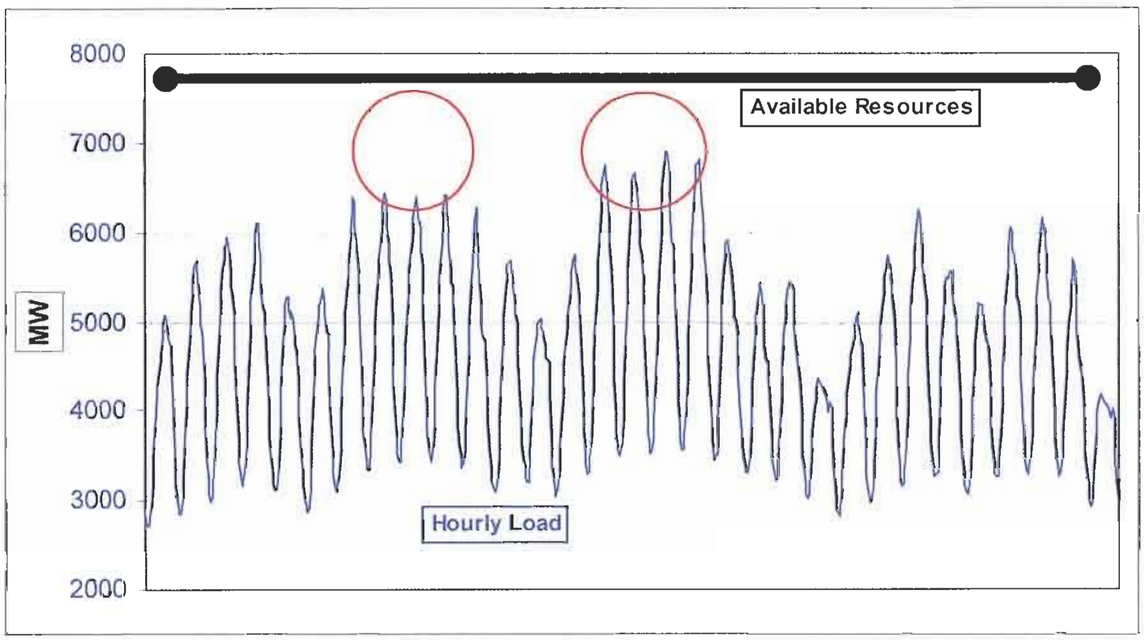
[3] "Photovoltaic Capacity Valuation Methods", Hoff, Perez, Ross, Taylor; SEPA Report #02-08; May 2008 (http://www.solarelectricpower.org/docs/PV%20CAPACITY%20REPORT.pdf).

Key Drivers of LOLP/LOLE

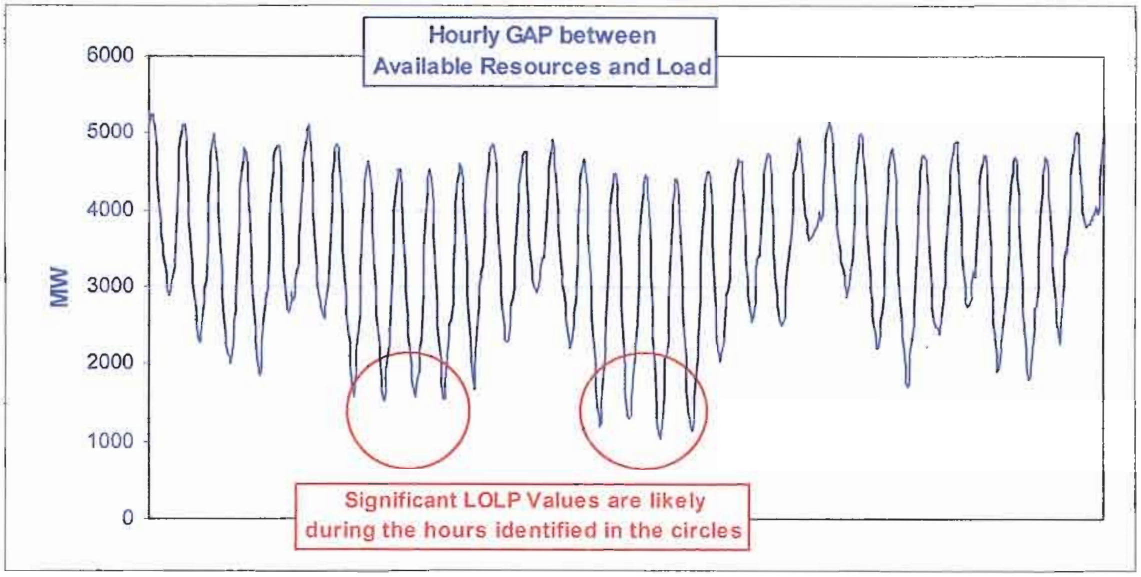
The amount of generation capacity available to a system each hour relative to the system load requirements that same hour has a significant influence on the LOLP/LOLE of the system. Figure 1 provides a graphical representation of the difference between available generation and load over a month for a fictitious electric system. The areas identified in circles show periods where the gap between available generation and load are relatively small. As this gap decreases and the relative magnitude of load increases, LOLP increases.

Figure 1: Resources versus Load



An alternative representation of the difference between available generation and load is shown in Figure 2. As can be seen in the figure, several segments are near the 1000 MW reserve level and are hours where LOLP values may be significant.

Figure 2: Hourly Resources less Hourly Load (GAP)



Section 3: Modeling Assumptions and Methods

The general study methodology was to utilize a computer model[4] representation of the Public Service system containing the system parameters required for LOLP calculation (e.g. generators, EFORs, load, etc) to determine ELCC values for solar resources and compare those with ELCC values for thermal resources.

The data, assumptions, scenarios, and modeling method are developed further below.

Required Data

Data collected for this analysis included:

- Hourly solar energy production estimates for fixed PV, single-axis tracking PV, and solar thermal trough without storage for historical years 2004 and 2005 and for three Colorado location; Alamosa, Pueblo and Denver,
- Historical, hourly Public Service loads for 2004 and 2005,
- Planned and expected maintenance for the portfolio of generation resources in the years 2013-2015,

Hourly solar energy production estimates for the various solar technologies were generated using the National Renewable Energy Laboratory's Solar Advisor Model ("SAM")[5] employing historical, hourly meteorological data (e.g., solar irradiance and

[4] Ventyx's ProSym software.
[5] https://www.nrel.gov/analysis/sam/

air temperature) for the three examined locations from the Perez satellite data set.[6] In order to reduce the total number of cases examined but still capture the effects of the various cell technologies mounted in various orientations and interconnected to the Public Service system, the hourly energy production profiles employed in the study were generated from multiple SAM model runs and then averaged. Energy production profiles for the fixed PV cases were an average of profiles generated by the SAM model from polycrystalline silicon and thin-film CdTe modules with orientations facing due south and 20 degrees west of south; single-axis tracking PV cases were an average of profiles generated by the SAM model for polycrystalline silicon modules mounted in tracking systems in both horizontal and latitude-tilt orientations.

Higher capacity values for fixed (i.e., non-tracking) PV facilities can be obtained by orienting the panels to face west of south in order to capture more direct sunlight later in the afternoon during typical peak load hours. However, this orientation results in lower annual energy capacity factors. A detailed analysis would need to be conducted to determine if higher capacity values are sufficient to cover the overall higher solar energy prices (caused by the reduction in electricity generation) that results from an orientation other than due south. This study did not attempt to determine the optimum, west-of-south position that would maximize the relative value of increased capacity versus the cost of decreased electrical output.

This study also did not attempt to determine the impact that sub-hourly variations in PV generation (intermittency) might have on that technology's capacity valuations; a discussion of these potential impacts is presented in the SEPA Report #02-08. [3]

Modeling Assumptions

In addition to the model input data listed above, certain key assumptions were used in this analysis.

- Public Service's system reliability measure was set to an annual LOLE of 1 day in 10 years, [7] ($2.7397 X10^{-4}$),
- Public Service loads for the years 2013-2015 were generated within the ProSym model based on historical 2004 and 2005 loads,
- 2013-2015 load shapes generated from 2004 load were matched with solar generation profiles based on 2004 meteorological data and 2013-2015 load shapes generated from 2005 load were matched with solar generation profiles based on 2005 meteorological data,
- PV cases were assessed a three (3) percent unavailability rate within the ProSym model which is a rate similar to PV system unavailability in NREL's PV Watts model,

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[6] https://rpm.nrel.gov/

[7] A study conducted in 2008 by Ventyx provides the basis for the PSCo system reserve margin. The study determined that an appropriate reserve margin for PSCo is 16%. For this study, a LOLE of one day in ten years, a traditional industry value, 2.7397 X 10-4 = 1day / (365 days X 10 years) was used.

- Parabolic trough cases were assessed a six (6) percent unavailability rate within the ProSym model based on the unavailability rates provided in the generic parabolic trough cases provided with the SAM model,

Solar Scenarios Modeled

Three solar technologies were examined in the study: fixed PV, single-axis tracking PV, and solar thermal trough without storage. For each of these three technology scenarios the study considered three possible Colorado locations; Denver, Pueblo, and Alamosa. Three separate technologies and three separate locations resulted in nine (9) independent scenarios per analytical year; an analytical year is the historical year from which the load and solar pattern data is developed. For this study, historical 2004 and 2005 data were used to develop two sets of hourly load and solar data. Considering two analytical years doubles the nine modeled scenarios for a total of eighteen (18) scenarios.

Capacity values were calculated at a single level of installed solar (100 MW nameplate). This level of solar on the Public Service system in the 2013-2015 time frame studied represents a penetration level of approximately 1.4% based on peak demand. As shown in the SEPA #02-08 report, the capacity value attributed to solar generation at higher penetration rates decreases from values calculated at lower penetration rates.

Modeling Method

Base LOLE model runs of the Public Service system for years 2013-2015 were performed prior to the addition of the solar facilities identified in Table 1. An iterative process was applied to get these base runs set to a LOLE of one day in ten years by either increasing or decreasing load, as needed, equally over all hours of the year. This process of shifting the hourly load retains the hourly load shape while setting the base models' starting LOLE to one day in ten years.

Next, for each of the eighteen scenarios, a 100 MW solar facility was added to the system resource mix. The addition of this 100 MW resource acted to increase the overall system reliability (and thus reduce the system LOLE). For example, the addition of 100 MW of fixed PV in Denver was added to the system resource mix resulting in an increase in system reliability from 1 day in 10 years to 1 day in 14 years.

Next, the solar facility was removed from the model and a single dispatchable thermal unit was added in 5 MW increments from 45 MW up to 250 MW resulting in forty-two (42) separate model runs per scenario year.

The LOLE values from these forty-two thermal unit model runs were put into a matrix of LOLE values at 5 MW increments. A sample of the thermal unit matrix is shown in Table 2.

Table 1: Thermal Unit LOLE Matrix

CT Capacity	2013	2014	2015
45	2.005E-04	2.022E-04	2.029E-04
50	1.936E-04	1.954E-04	1.960E-04
55	1.871E-04	1.888E-04	1.895E-04
60	1.807E-04	1.826E-04	1.832E-04
65	1.745E-04	1.766E-04	1.772E-04
70	1.687E-04	1.709E-04	1.714E-04
75	1.631E-04	1.651E-04	1.660E-04
80	1.576E-04	1.596E-04	1.604E-04
85	1.523E-04	1.544E-04	1.550E-04
90	1.472E-04	1.493E-04	1.500E-04
95	1.423E-04	1.443E-04	1.450E-04
100	1.374E-04	1.398E-04	1.403E-04

The 100 MW solar LOLE values were then compared to those in the thermal unit LOLE matrix to obtain a corresponding thermal unit capacity equivalence value. The corresponding thermal unit capacity was divided by the nameplate capacity of the solar scenario to estimate the percentage annual capacity credit value, or ELCC. An exact solar LOLE to thermal unit LOLE match rarely occurs, however by bounding the solar LOLE value between two successive 5 MW increments in the Thermal Unit LOLE matrix, linear interpolation can be used to obtain a reasonably accurate estimate of LOLE.

Continuing the example from above, the 100 MW solar LOLE annual values were 1.9020E-04, 1.8841E-04, and 1.9257E-04 for years 2013-2015 respectively. Looking up and interpolating in the Thermal Unit Matrix for each year's LOLE results in equivalent thermal unit capacity of 52.6 MW, 55.3 MW, and 52.7 MW respectively. For this scenario, the average of these thermal-unit capacities versus the 100 MW nameplate solar facility results in an average capacity value of 53.5%.

Section 4: Analysis Results

Table 2 presents the solar capacity credit calculated in this study in terms of thermal-unit equivalent percentages by modeled year.

Table 2: Solar – Thermal Unit Equivalent Capacity Values

	2004 Pattern Year			2005 Pattern Year			2004 / 2005 Averges		
Location	Fixed PV	1-Axis PV	Trough	Fixed PV	1-Axis PV	Trough	Fixed PV	1-Axis PV	Trough
Denver	53.5%	69.5%	69.7%	63.6%	68.0%	70.7%	59%	69%	70%
Pueblo	55.7%	74.2%	79.5%	69.8%	76.3%	83.3%	63%	75%	81%
Alamosa	53.4%	66.8%	65.7%	66.4%	70.7%	71.2%	60%	69%	68%

Examination of the results shows several relevant findings:

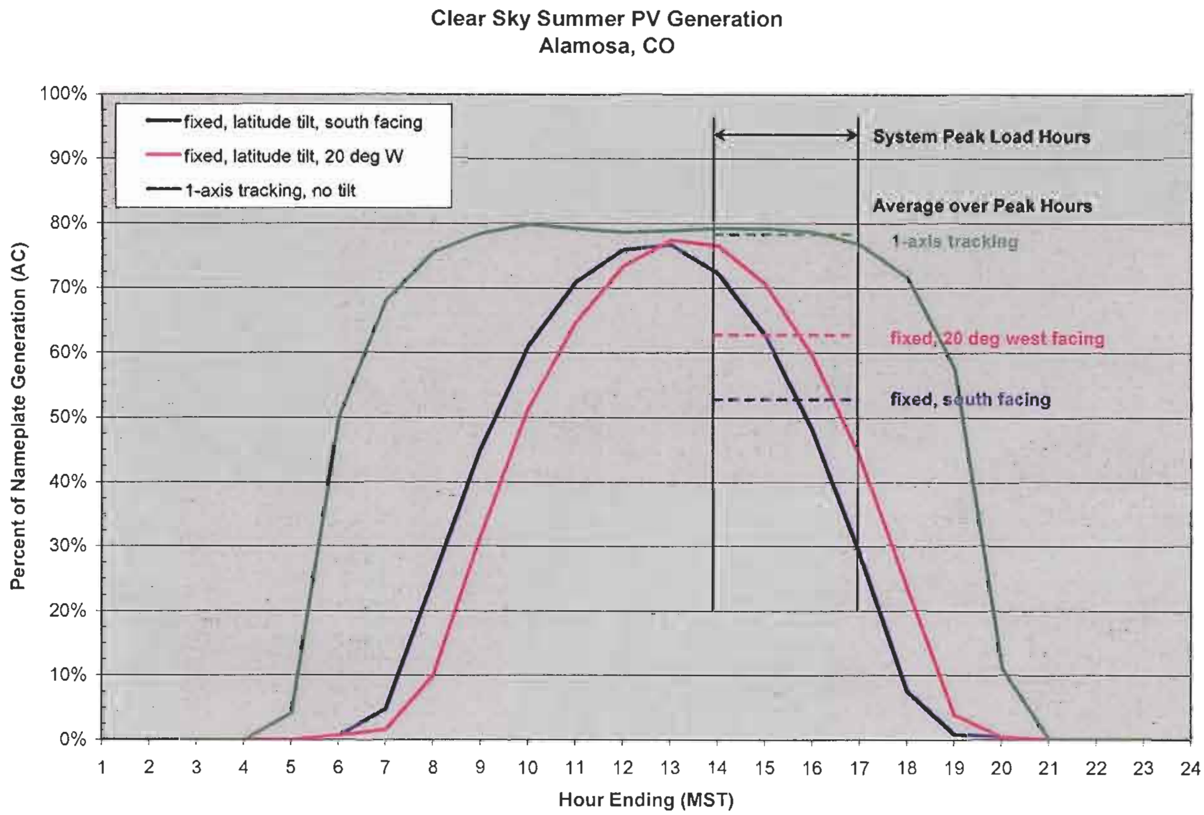
- As expected, single-axis tracking PV and solar thermal trough technologies exhibit higher capacity values than fixed PV.
- Capacity values calculated using 2004 historical load and meteorological data are lower than those values using 2005 historical data; capacity values for the fixed PV cases were markedly lower.
- Capacity values across all technology types for solar facilities located in Pueblo were higher than for Denver or Alamosa.

2004 Results vs. 2005 Results

The most likely explanation for the higher capacity value calculations from the 2005 historical data sets is that in 2005, system peak load hours (or alternatively, those hours resulting in the largest levels of LOLP) occurred earlier in the day than in 2004. The effect of system peak load occurring earlier in the day on LOLP can be illustrated with Figure 3.

Figure 3 shows the hourly generation on a clear-sky day in Alamosa from identically sized, single-axis tracking PV and fixed PV facing due south and 20 degrees west of south solar facilities. Figure 3 also indicates the typical summer peak system load hours (HE 14 – 17, MST). Generation for the south-facing, fixed PV facility drops from 72% of nameplate during HE 14 to 29% of nameplate during HE 17; generation from the fixed PV facing west of south drops from 77% of nameplate during HE 14 to 44% of nameplate during HE 17 (illustrating the capacity value benefits of positioning fixed PV in a west of south orientation); generation from the single-axis tracking PV system drops from 79% to 77% in the same period. The pattern of large changes from the 2004 load shapes to the 2005 load shapes for fixed PV matches the effects shown in Table 2 if the high LOLP hours occur earlier in the day for the 2005 load shapes.

Figure 3 Clear Sky, Summer PV Generation in Alamosa, CO



Given the variation noted between 2004 and 2005 load shapes in the final result, future studies may need to evaluate data from more than two years. Currently, studies are limited by historical meteorological data in that 2005 is the most recent year for which data are available.

Capacity Value Results by Location

As previously indicated, capacity values for facilities located in Pueblo were consistently higher than for Denver or Alamosa. An examination of hourly weather conditions in both 2004 and 2005 indicate a significantly higher correlation of peak system load hours with clear skies in Pueblo than with clear skies in Alamosa. That is, the chances of afternoon, monsoon conditions in Alamosa during Public Service peak load conditions appear to be greater than such conditions occurring in Pueblo. Thus, even though the annual energy capacity factor from a solar facility located in Alamosa is higher than the same plant located in Pueblo; generation from the Pueblo plant is better correlated to Public Service's peak loads.

SunE Alamosa Generation during 2008 Peak Load Hours

SunEdison operates an 8.2 MW (dc) PV facility north of Alamosa in the San Luis Valley. The facility is primarily constructed of single-axis trackers (no tilt) with smaller portions constructed of both two-axis tracking modules and south-facing fixed modules (with tilt angles manually repositioned on a seasonal basis). Thus, it would be expected that the capacity value of generation from this facility would be approximately 65-70% based on the data shown in Table 2.

An analysis of SCADA-quality, hourly average generation data from the SunEdison facility for the 2008 summer generation period was conducted to estimate the capacity value. The average generation from the facility over the top 50 load hours during 2008 was found to be 70% of the AC nameplate.

Section 5: Summary

Xcel Energy believes that this analysis provides a good foundation for determining the reliability contribution that solar resources are likely to provide to the Public Service system. Based on the analyses performed to date and discussed in this report, average capacity values ascribed to solar generators for the Company's Phase II evaluations are:

- for facilities near Denver: 59% for fixed panel PV, 69% for single-axis PV, and 70% for trough facilities,
- for facilities near Pueblo: 63% for fixed panel PV, 75% for single-axis PV, and 81% for troughs,
- and for facilities near Alamosa: 60% for fixed PV, 69% for single-axis PV, and 68% for troughs.