Utility Solar Generation Valuation Methods

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Introduction:

Sustainable production of electricity from the sun is starting to play a larger role in the generation portfolio of many electric utilities, especially those in the southwestern United States. Tucson Electric Power (TEP) currently serves its customers with over 6 MW DC of solar photovoltaic (PV) generating capacity, a capacity amount that provides a per capita installed nameplate DC capacity of 7 watts per person served. While this level of solar generation is small compared to the 2,250 MW of traditional generation needed to support summer peak customer demand in 2006, some operational challenges have already surfaced. An example: The 4.59 MW DC Springerville Generating Station Solar System (SGSSS) is located within the control area of the aggregate 1,160 MW Springerville Generating Station coal units. With a Springerville coal unit in Automatic Generation Control (AGC) on a partly cloudy day, the swings in solar generation from cloud passings typically exceed the 0.5 MW dead band of the AGC system. This results in changes of the coal unit demand set point and a coal feed response change. As the SGSSS output can change by more than 0.5 MW in a 10 second period of time, these cloud induced solar generation changes occasionally result in fuel feed swings of the coal units and control system instability.

Solar generation output is dependent on a multitude of factors, including time of year, time of day, ambient temperature, wind speed, wind direction, installed collector elevation angle, installed collector azimuth angle, type of solar material and/or technology and solar insolation. All of these factors are predictable with a relatively high degree of accuracy, except solar insolation - as that is strongly impacted by clouds. Clouds can be characterized by their size, opacity, speed of movement, direction of movement, spacing, altitude, creation/dissipation rate and edge sharpness, among other factors. Clouds can magnify the incident solar insolation and create solar electric generation output in excess of solar module nameplate ratings for a short time. And of course opaque clouds and precipitation can dramatically reduce the output of solar generation, to levels below 5% of nameplate ratings. Cloud impacts tend to be random and probabilistic in nature as defined by the factors listed before. The impact of cloud passings on solar generation output is not fully predictable, given the current state of the art. The clouds which impact solar generation output are generally associated with specific weather patterns or events. In Arizona, the summer monsoon season typically impacts afternoon solar production rather than morning production. The Arizona monsoon is generally associated with high temperatures and high levels of solar insolation needed to energize the needed atmospheric lifting to create the monsoon. These effects also generally result in high electric utility system loads which continue to increase even after the monsoon clouds have reduced the output of solar generation. These weather patterns are typical to the southwestern US in summer. Other geographic areas will have their own weather patterns which will impact solar generation output profiles. These effects occur in a shorter time frame than the typical one hour sample used historically for utility generation capacity credit evaluation. It is absolutely essential that any method of evaluating the value of solar generation properly accounts for the locale specific effects of weather patterns and the load profile characteristics of each individual electric utility. There is no single correct solution set that is universally applicable to all utilities for determining the value of solar generation.

Several past studies of the value of solar generation have concluded that solar particularly provides energy at peak demand times of the day. That is partly true in Arizona, but not to the high degree seen in reports discussing the economic benefits and peak shaving capability of solar in other states. When the annual production of Tucson solar is given a value at the wholesale rate of spot market energy at Palo Verde and compared to the annual round the clock value of wholesale spot market energy at Palo Verde, the difference in value represents a premium over conventional generation for the annual production of solar energy of 8.6% in 2004 and 8.5% in 2005. Thus, there is a value premium for solar producing energy at peak load times, but the value to a southwestern US utility when measured against the annual wholesale price of non-firm electricity has been less than 10% in two of the past years. Further study and new methods are needed to appropriately and fairly evaluate the value of solar generation to electric utilities.

Electric utilities must have sufficient generating capacity available at all times to meet the load demands of their customers. While no generation type is 100% reliable, time variant solar generation output is not as predictable as that of traditional dispatchable generation. While solar power in a world without clouds is better than 99% predictable, the passing of clouds produces its own unique challenges to the prediction and dependability of solar electric generation. One of those challenges is the accurate, appropriate and fair evaluation of capacity credit and planning capacity. This project developed a new method for the accurate, appropriate and fair evaluation of solar generation capacity credit and reviewed integrated methods for utilities to appropriately and fairly evaluate the value of solar generation in their service territory.

Project Description:

TEP developed, tested and verified the results of a new and appropriate method for accurately evaluating the capacity credit of time variant solar generating sources and reviewed new methods to appropriately and fairly evaluate the value of solar generation to electric utilities. The project also reviewed general integrated approaches for adequately compensating owners of solar generation for their benefits to utilities. However, given the limited funding support and time duration of this project combined with the significant differences between utilities regarding rate structures, solar resource availability and coincidence of solar generation with peak load periods, it is well beyond the scope of this project to develop specific rate, rebate, and interconnection approaches to capture utility benefits for all possible utilities.

The project developed computer software based evaluation method models to compare solar generation production data measured in very short term time increments called Sample Intervals over a typical utility Dispatch Cycle during an Evaluation Period against utility system load data. Ten second resolution generation production data from the SGSSS and actual one minute resolution TEP system load data for 2006 and 2007, along with data from the Pennington Street Garage 60 kW DC capacity solar unit installed in downtown Tucson will be applied to the model for testing and verification of the evaluation method. Data was provided by other utilities, but critical time periods of data were missing making results derived from that data inaccurate. The algorithms are based on previous analysis and review of specific 2005 and 2006 SGSSS production data. The model was built, tested and verified by in house TEP personnel.

For this project, TEP communicated with, shared solar production data with and collaborated on the development of solar generation valuation tools with other utilities, including Arizona Public Service, Salt River Project, Xcel and Nevada Power Company as well as the Arizona electric cooperatives.

This is the Final Project Report documenting the solar generation capacity credit evaluation method and results of validation data runs against the model.

Previous Solar Generation Capacity Credit Evaluation Methods:

Time variant output renewable generation resources like solar, given sufficient time, will produce maximum instantaneous generating capacity equal to or exceeding the generator's nameplate rating. Again given enough time, a time variant output renewable generating resource will produce energy that will define its long term resource capacity factor. But, neither of these factors defines how much time variant output generation resource is available at the exact moments needed to support a utility's obligation to serve peak customer load demand, which would be required for time variant output generation resources to displace firm dispatchable generation resources in a utility's generation portfolio. That would be the capacity credit of the solar generation. There have been a number of different methods used to evaluate the capacity credit of solar generation to displace a firm, dispatchable generation resource. These methods apply historic or modeled time variant generation against historic or modeled utility native loads on a monthly or annual basis to determine the amount of firm dispatchable generation which can be displaced by the time variant output renewable generation resource. Effective Load Carrying Capacity (ELCC) has been applied to determine a solar generation capacity credit. The ELCC method of evaluating capacity credit uses renewable resource data specific to a given area and resource which is then compared to corresponding data of a single utility specific load data over a long period of time, generally a month or a year. Consequently, the results of a given ELCC or Capacity Value analysis are only valid for that specific renewable energy resource, that specific geographic area and that specific utility. Care must be taken when applying ELCC results from one study to another region, technology or utility. Utilities are obligated to provide customers with all requested electricity at all moments of a second, minute, hour, month or year, not simply an average amount over an hour, month or year. The ELCC capacity hourly average credit evaluation method produces monthly or annual average values. It does not fully reflect the instantaneous nature of electric demand obligations that utilities must supply with their portfolio of generation resources. Utility generation portfolios must be planned using a criterion that provides for supply of all load demands for a minimum of 99.93% of the time over a one year period. Application of that criterion results in a utility planning factor called Planning Capacity.

There have been several evaluations published of the capacity credit, also referred to as capacity value, of solar PV generation. These evaluations have typically relied upon an analysis of ELCC from calculation of Loss of Load Probability (LOLP) studies first with and then without the solar generation, which through further adjustment of comparable dispatchable generation result in no change in utility system reliability. They can also include calculation of Energy Not Served (ENS) as a proxy for loss of load. LOLP, ENS and ELCC evaluations use hourly average load and generation data. They are not currently capable of using data with a shorter time span. This has not been an impediment to use of these evaluation tools in the past, since traditional dispatchable generation does not typically have time dependence. Consequently, hourly average data is sufficient for accurate evaluation of traditional dispatchable generation resource reliability. However, cloud passings introduce significant time variant solar generation output magnitude changes, in the time frame of seconds. Therefore, use of traditional LOLP, ENS and ELCC evaluation methods to determine capacity credit for solar generation are not appropriate and result in misleading results, typically overstating the amount of capacity credit that should be assigned by a utility to solar generation. Likewise, hourly average satellite data for solar insolation, while useful for evaluation of general solar trends, is not appropriate for solar generation capacity credit evaluation. Satellite data of time resolution in the range of seconds is needed for such evaluations to provide accurate results.

Any accurate and credible evaluation of the capacity credit of electric generation, including that of solar electric generation, must include an evaluation of the generation's ability to provide support for load demand during the peak electric demand period of the year. While most generation sources are not affected by the weather effects which create high customer demand for electricity, solar generation is positively influenced by strong solar energy input which generally creates high ambient temperatures which drives demand for air conditioning. This in turn will produce higher demand for electricity. While it thus seems obvious that solar generation will help support electric demand at the peak demand times, this may not be true in areas like Alaska or other normally winter peaking locales where winter loads dictate peak demand periods. In addition, some desert southwest areas, such as Tucson, historically exhibit weather patterns which will drive high electricity demand through high ambient air temperatures and high solar energy input to a late afternoon period, when the solar energy input is no longer able to sustain atmospheric lifting. At that time the moisture laden air that has been previously lifted to the upper atmosphere starts to sink and the moisture condenses. Clouds are formed over a very large geographic area in a very short period of time as the air flow reverses. Then, within an hour the clouds have generally dissipated due to atmospheric mixing. In the past five years, this weather pattern has been exhibited three times on the peak electric demand day of the year in Tucson. During the cloudy period the sun has ceased to be an important factor in increasing electric load. However, the high ambient air temperature does not start to decrease immediately and neither does the electric load. Historic demand data indicates the electric demand continues to increase slightly for an additional 15 to 30 minutes after the cloud has formed, before it starts to decline. While this pattern is typical of Tucson, it is not necessarily typical in any other part of the desert southwest. Tucson is surrounded on three sides by mountain ranges. Its surrounding topology supports the vertical atmospheric lifting and sinking weather effects noted as occurring on a majority of annual peak electric demand days. It can not be emphasized enough that the effects of local weather patterns, including short term effects, on the ability of solar generation to provide electric demand support at the time of peak electric demand must be considered when evaluating the capacity credit of solar electric generation. Due to the generally strong influence of local topography on local weather patterns care must be taken to ensure that there is not application of the results of an evaluation of capacity credit of solar generation performed in the service territory of one local utility to another utility affected by different weather phenomenon. Each utility must be provided the opportunity and tools to perform and evaluate solar generation capacity credit based on its own unique circumstances.

By way of example, Figure 1 and Figure 2 show load and solar generation data for August 11, 2004, which includes the peak load hour of 2004 at hour ending 16:00. Figure 1 shows the minute by minute electric demand for the full day of August 11th. Note that the demand peaks just prior to 16:00 and drops a little bit for about 30 minutes before increasing again prior to 16:30. The overall shape of the curve is fairly uniform with few large changes in electric demand over the one minute intervals.

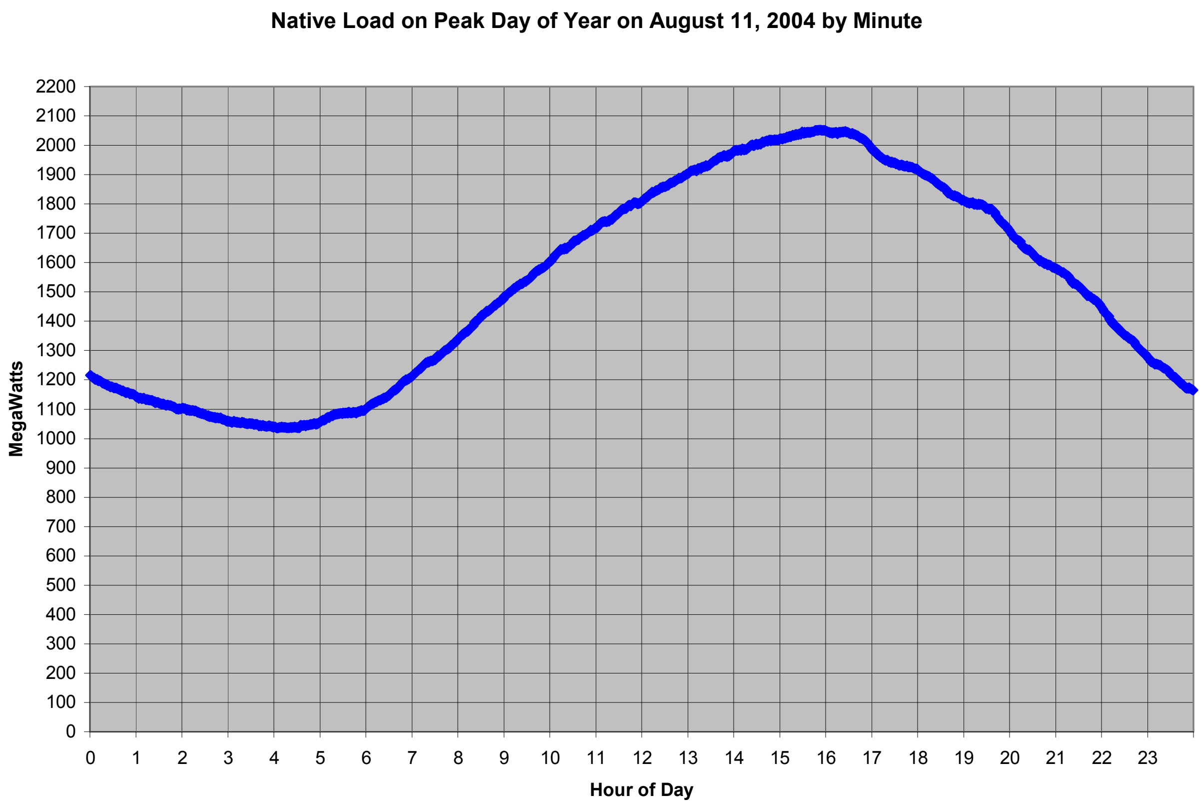

Figure 1

Time of use rate customers will experience a decrease in rates from shoulder hour to off peak rates at 21:00, yet there is little change in the rate of demand reduction as that time period is crossed. This indicates that even on the highest peak demand day of the year in 2004, customers did not shift any significant amount of demand from the on-peak rate period of 13:00 through 18:00 to the off peak period after 21:00. Contemplated time of use rates which convey stronger pricing signals to customers may give sufficient incentive to customers to shift more demand into the post 21:00 hours. If this occurs, the peak load hour of the year for TEP could be after the sun has set, which should be evaluated as solar energy providing zero contribution in support of TEP peak load demand. Factors of this type must be considered in any method developed for evaluation of the capacity credit of solar generation and in utilities providing value to the owners of solar DG systems.

Figure 2 is a minute by minute graph of the solar generation of the SGSSS on August 11, 2004. While the SGSSS is located about 200 miles from Tucson, smaller solar generators in Tucson with data taken on 5 minute intervals demonstrated a similar output pattern on August 11th, so the use of SGSSS data for comparison to TEP electric demand data is appropriate for this day. Note the short term drop in solar output from a cloud passing just after 15:00. Followed by a long term drop in output from a large cloud grouping passing just prior to 16:00, with a rise in output at about 16:30 as the cloud group cleared, followed by an additional output reduction from new cloud passings after 16:30. Given the short duration of the cloud passings, hourly average data of solar generation for the date would simply show a slight drop in hourly average solar output from that which would be expected if the day was cloudless. Yet, it can be plainly seen from the one minute data in Figure 2 that the effective demand support provided by the SGSSS at the time of peak annual demand in hour ending 16:00 was about 500 kW AC, or about 11% of nameplate DC rating. The solar output dropped further during hour ending 17:00, the second highest demand hour of 2004, to 300 kW AC or about 7% of the SGSSS nameplate capacity rating. Clearly, cloud effects on short term solar generation output must be considered when evaluating the capacity credit of solar generation. One hour average solar generation output data does not show these short time frame effects and is therefore insufficient for use in determining solar generation capacity credit.

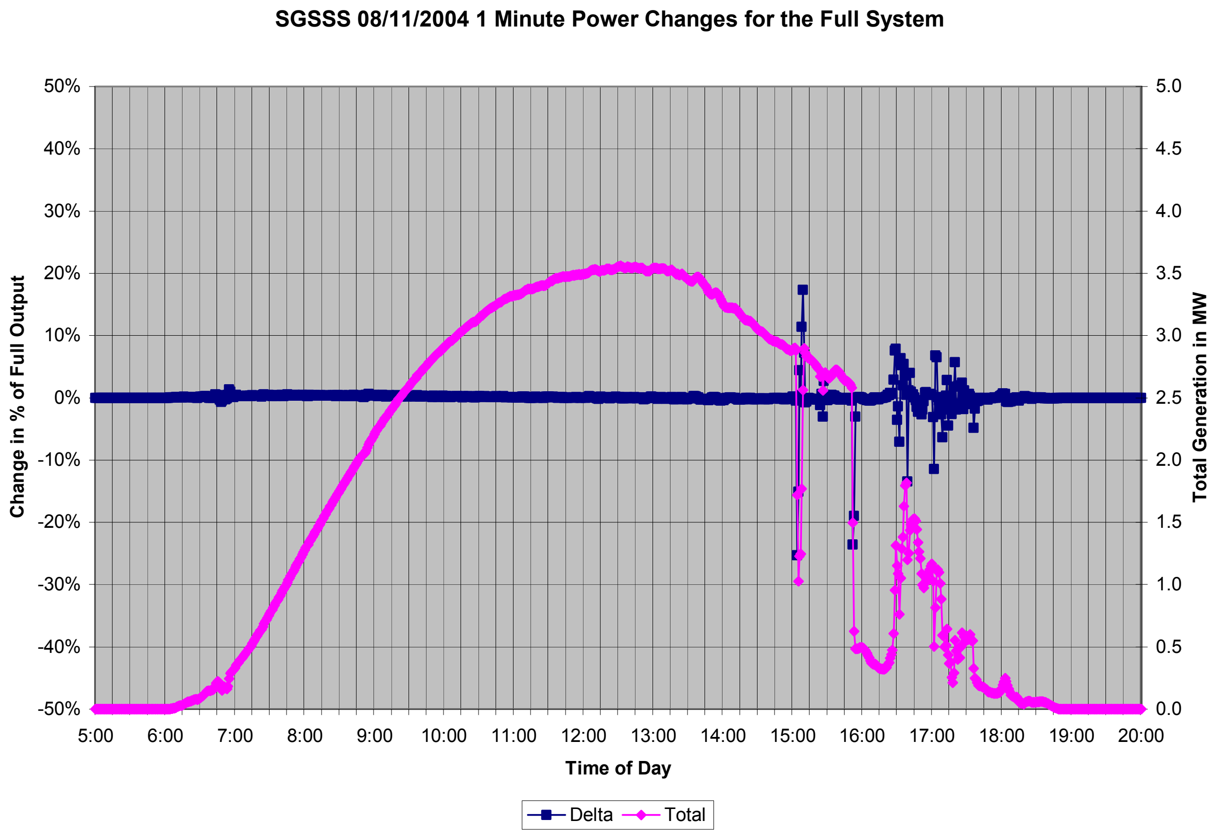

Figure 2

As noted earlier, use of traditional LOLP, ENS and ELCC evaluation methods to determine capacity credit for solar generation use hourly average load and generation data for the evaluation which is not appropriate and creates misleading results, typically overstating the amount of capacity credit that should be assigned by a utility to solar generation. The examples presented of the impact of short term cloud passing effects on solar generation output during periods of high electrical demand clearly demonstrate why traditional ELCC/ENS/LOLP methods are not appropriate for evaluation of the capacity credit of solar generation.

There is a compelling need to include short term cloud passing generation output effects in the method of any evaluation of capacity credit of solar generation. Regulation requirements and their effect on maximum generation ramp rate capabilities are a consideration in development of the cost impact of supporting high penetration percentages of solar generation in a distribution system. They are a necessary component of an evaluation of the cost and benefits of solar generation to a given specific utility, but are beyond the scope of the project proposed here to develop a method for evaluation of solar generation capacity credit.

Other methods of evaluating solar generation capacity credit can be found in utility applications. The Mid Continent Area Power Pool (MAPP) has issued guidelines for evaluating capacity credit for time variant generation sources including solar generation. These can be found in their MAPP Reliability Handbook, Volume 3, Section 3.4.7.2. Essentially, the capacity credit is calculated on a monthly basis from hourly generation and system load data. A four hour period is chosen which includes the highest system load hour of the typical day in that month. The median value of generation is found from the output of the generator to be evaluated over those four hours of each day of that month. That is then the capacity credit assigned to that generator for that month. This evaluation method does not appropriately factor into the evaluation the effects of cloud passings on the output of the solar generators in any time frame of less than an hour, and will result in overestimation of solar capacity credit. TEP used the MAPP method of capacity credit evaluation as applied to the 2005 SGSSS solar generation. The results are shown below in Figure 3. The monthly capacity credit values range from a low of 10% in December to a high of 37% in April. The MAPP evaluation method was modified and applied to determine an annual capacity credit which was 25%. This overestimates the capacity benefit of the SGSSS at the time of peak system load hours.

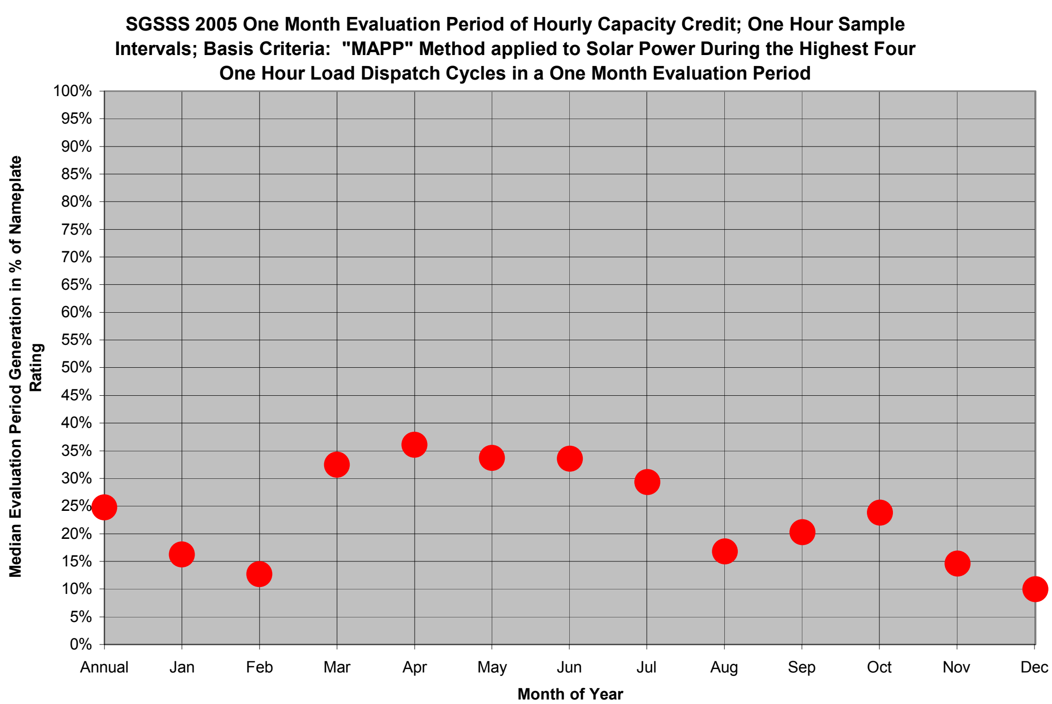

Figure 3

The MAPP capacity credit evaluation method does provide for a comparison of the ability of the generator being evaluated to provide support for load demand at the time the load is at a peak during the overall period of evaluation, in the MAPP case, one month. However, the MAPP method does not allow for review of that coincidence over a period of less than one hour. As noted from the TEP example of August 11th, 2004, failure to consider the effects of cloud passings on time intervals of less than one hour results in higher values of capacity credit than are otherwise indicated. Thus the MAPP method is not accurate and appropriate for evaluating the capacity credit of solar generation.

The Planning Council of the Essential Services Commission of South Australia (ESCOSA) evaluated the planning capacity of wind generation in a report issued in April, 2005. While solar generation and wind generation are both time variant generation sources, they do have different characteristics regarding the rate of change of output over time. Photons have much less inertia than spinning blades and thus solar generation output can change magnitude at much higher rates than wind generation. Planning capacity is the amount of generation capacity that is effectively firm at times of peak load demand and should not be confused with capacity credit, as noted in Appendix 2, page 54 of the ESCOSA report. Capacity credit is a measure of the contribution to support of load demand that a given generation system will provide in a given period of time. The ESCOSA planning capacity evaluation method effectively compares hourly average generation and load data. The generation output of the generator under evaluation during the 10% highest load hours of the year are entered in rank order. The planning capacity is then defined as the level of generation that is met or exceeded in at least 95% of those hours. TEP evaluated the planning capacity of the SGSSS using 2005 data applied using the ESCOSA method. The result is shown in Figure 4, below. Note that even if the criteria was reduced to a level of generation that was met or exceeded in at least 85% of the hours, the result would still be that the 4.59 MW DC nameplate rated SGSSS has a planning capacity of 0 MW.

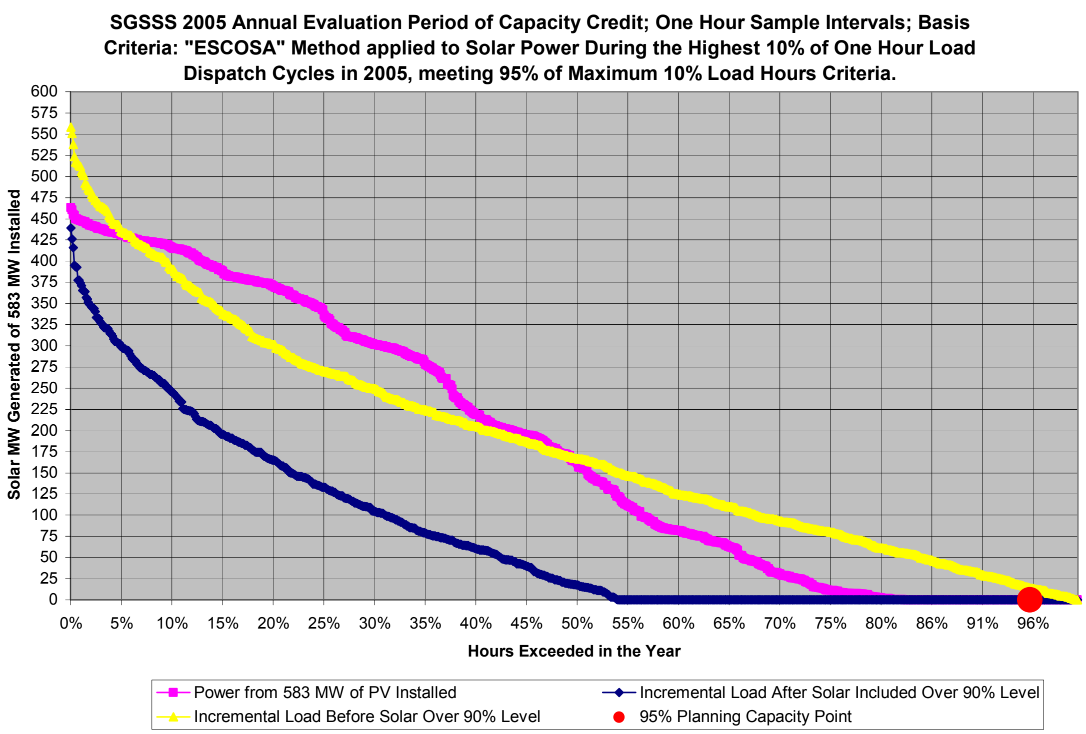

Figure 4

However, unlike wind generation which can fall to zero at any time interval, solar generation very, very rarely falls to zero during the mid-day daylight hours. The ability of solar generation to provide some level of electrical output during periods of cloud passings must be considered in any accurate and representative method of evaluating capacity credit of solar generation. Likewise, if a utility normally experiences its highest annual load period during non-daylight hours, the expected capacity credit of solar generation would be zero. Consequently, the ESCOSA method appears to undervalue the capacity benefit of the SGSSS at peak load hours and is also not a valid method for evaluation of capacity credit of solar generation.

Proposed Solar Generation Capacity Credit Evaluation Method:

Very little high resolution solar generation output data from outside TEP is available to determine the short time frame effects of cloud passings on solar power output. Consequently, we will use TEP data in the following example. The SGSSS is a 44 acre PV generating facility located at 6,600' elevation in eastern Arizona. The system is heavily instrumented and collects production output data on 10 second intervals. It is instructive to review the impact of the apparent data averaging time period chosen on the resulting period indicated power production levels. The following series of graphs show the power output of the SGSSS on December 3, 2005, a relatively typical partly cloudy day, in average 60 minute, 15 minute, 4 minute, 1 minute and 10 second sample intervals. The magenta line in the figures is the total power output of the SGSSS. The blue line in the figures represents the variation in output from the previous data averaging time period in % of the system nameplate capacity rating. Figure 5 represents the 60 minute average output of the SGSSS on December 3, 2005. The solar power output low of 2.6 MW and high of 3.25 MW is relatively even from hour ending 11:00 through hour ending 15:00. The maximum hour to hour change of 46%, or 2.2 MW in 60 minutes – 0.03 MW per minute - is well within the ability of a 380 MW coal unit capable of 10 MW per minute load changes to manage. Given the minimum amount of generation output from the hourly data, the SGSSS would be expected to provide a firm output of 2.6 MW from 10:00 through 15:00 with little need for management of output variations with any generation other than a 380 MW coal unit.

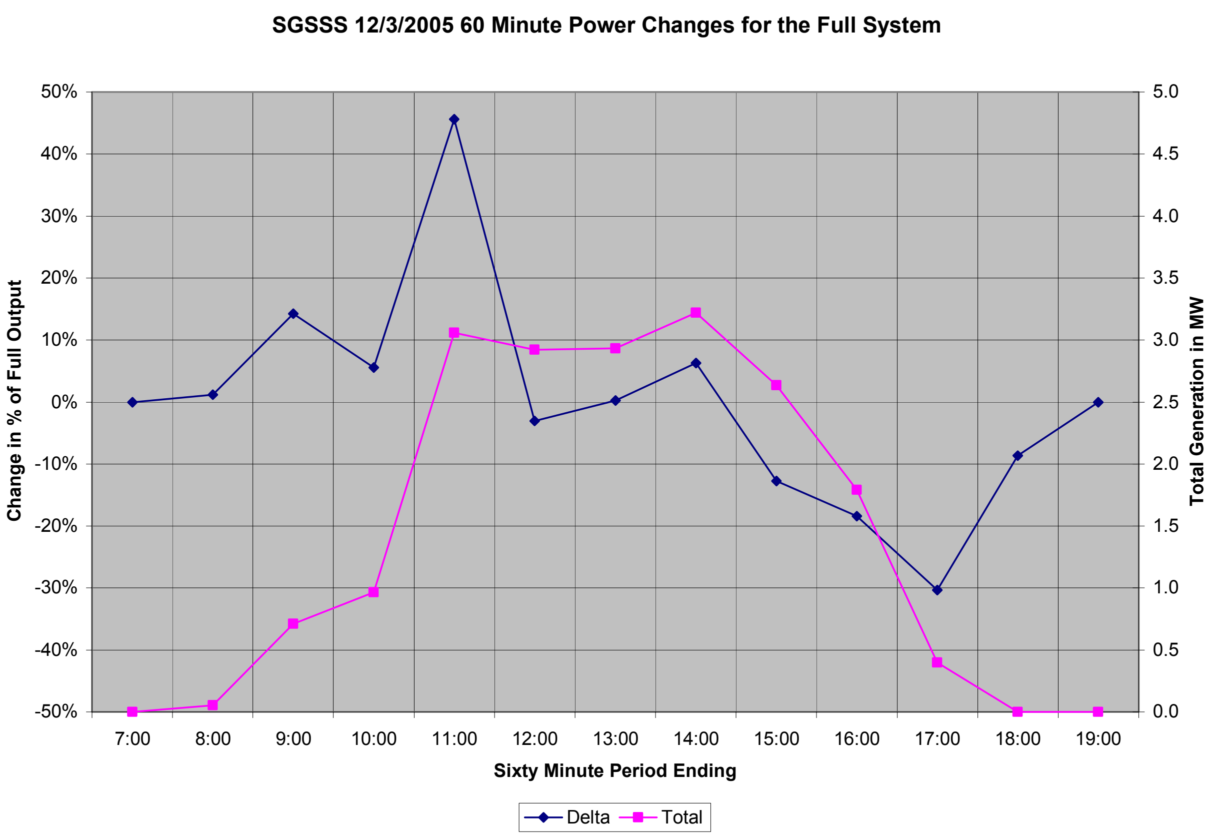

Figure 5

Figure 6 represents the 15 minute average solar generation output of the SGSSS on December 3, 2005. The solar power output shows considerable variation from 10:00 through 15:00, varying from a low of 2.05 MW to a high of 4.0 MW. The maximum period to period change of 31%, or 1.4 MW in 15 minutes – 0.1 MW per minute - is well within the ability of a 380 MW coal unit capable of 10 MW per minute load changes to manage. Given the minimum amount of generation output from the 15 minute data, the SGSSS would be expected to provide a firm output of 2.05 MW from 10:00 through 15:00 with little need for management of output variations with any generation other than a 380 MW coal unit.

It is clear from a comparison of the power output data in Figure 5 with the appropriate data in Figure 6, that there is considerably more variation in the 15 minute average solar generation output data than is evident in the 60 minute average solar generation output data. Sixty minute average solar generation output data does not accurately capture the variations that are possible from cloud passing induced effects in solar generation output.

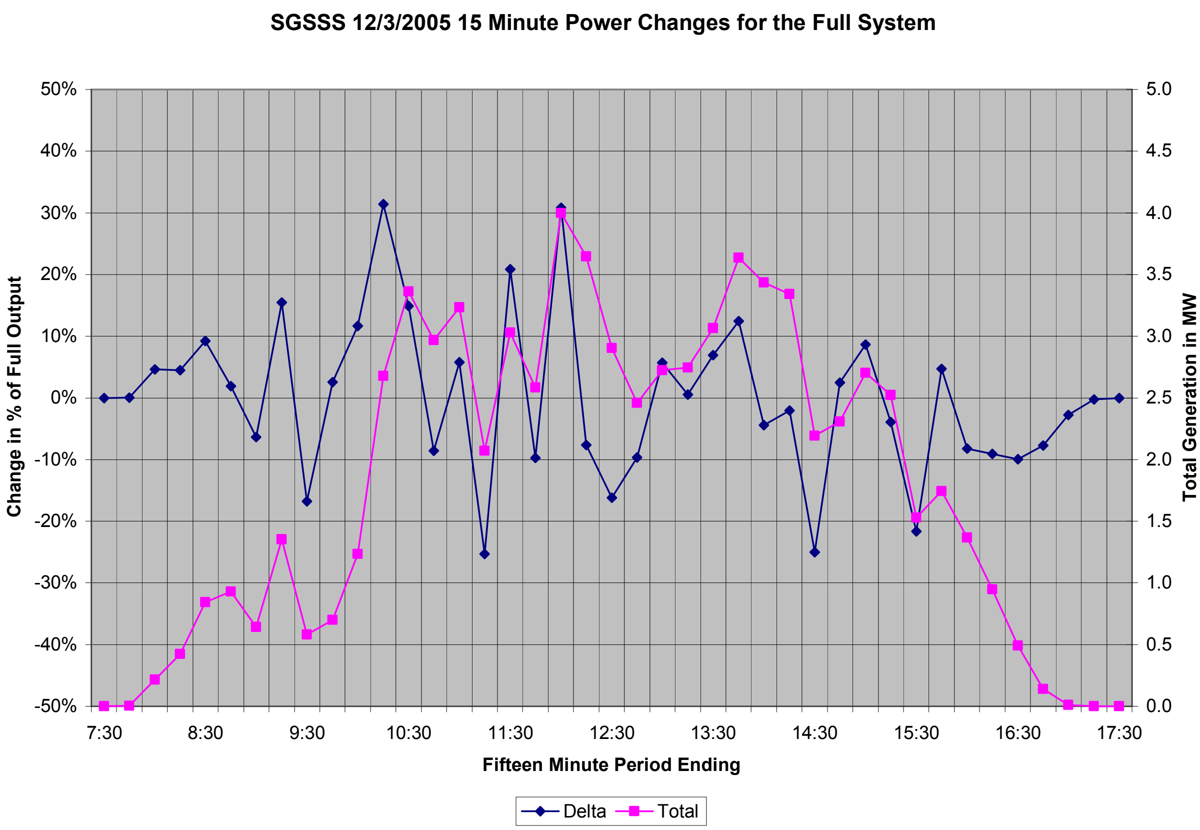

Figure 6

Figure 7 represents the 4 minute average solar generation output of the SGSSS on December 3, 2005. The solar power output shows significant variation from 10:00 through 15:00, varying from a low of 0.85 MW to a high of 4.25 MW. The maximum period to period change of 65%, or 3.1 MW in 4 minutes – 0.8 MW per minute - is well within the ability of a 380 MW coal unit capable of 10 MW per minute load changes to manage. Given the minimum amount of generation output from the 4 minute data, the SGSSS would be expected to provide a firm output of 0.85 MW from 10:00 through 15:00 with little need for management of output variations with any generation other than a 380 MW coal unit.

It is clear from a comparison of the power output data in Figure 6 with the appropriate data in Figure 7, that there is considerably more variation in the 4 minute average solar generation output data than is evident in the 15 minute average solar generation output data. Fifteen minute average solar generation output data does not accurately capture the variations that are possible from cloud passing induced effects in solar generation output, although it shows those variations far better than 60 minute average solar generation output data.

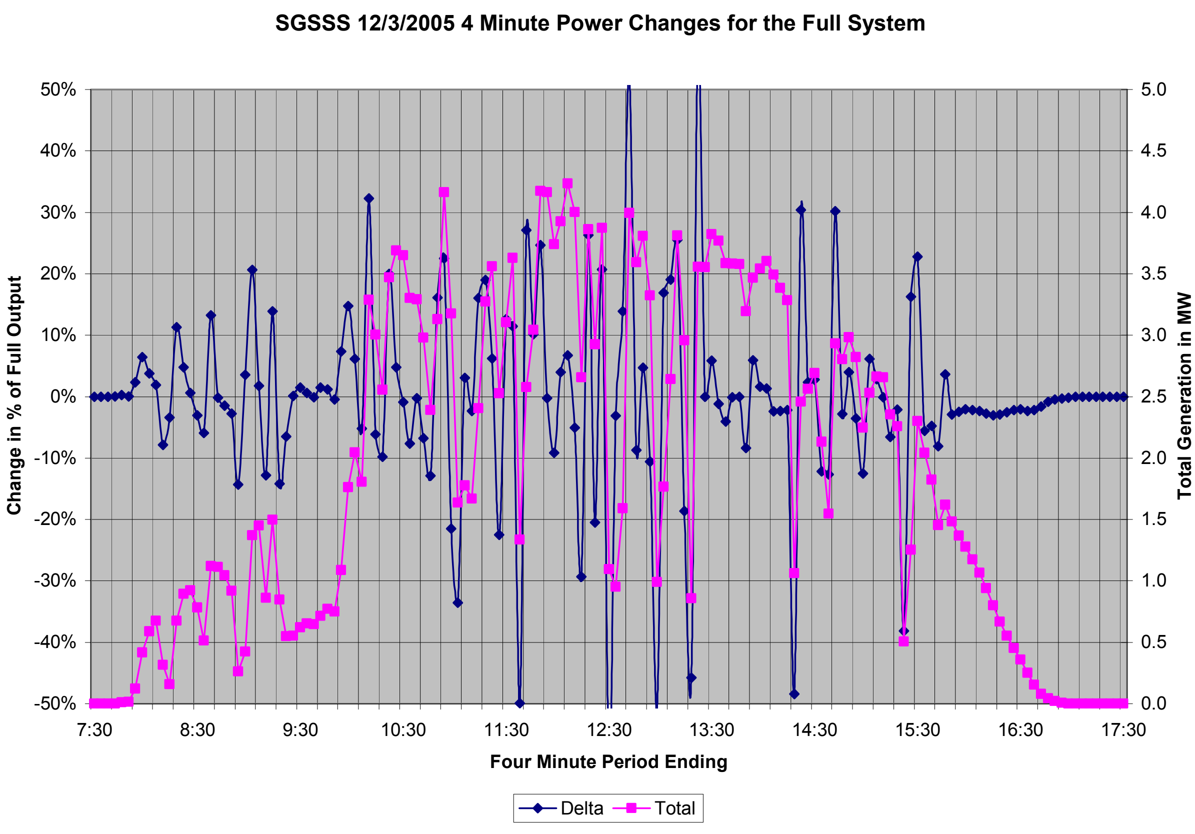

Figure 7

Figure 8 represents the 1 minute average solar generation output of the SGSSS on December 3, 2005. The solar power output shows extreme variation from 10:00 through 15:00, varying from a low of 0.30 MW to a high of 4.45 MW. The maximum period to period change of 55%, or 2.4 MW in 1 minute – 2.4 MW per minute - is within the ability of a 380 MW coal unit capable of 10 MW per minute load changes to manage, but starts to create control instability from the repeated output magnitude changes and changes in direction. Given the minimum amount of generation output from the 1 minute data, the SGSSS would be expected to provide a firm output of 0.30 MW from 10:00 through 15:00 with generally little need for management of output variations with any generation other than a 380 MW coal unit.

It is clear from a comparison of the power output data in Figure 7 with the appropriate data in Figure 8, that there is considerably more variation in the 1 minute average solar generation output data than is evident in the 4 minute average solar generation output data. Four minute average solar generation output data does not accurately capture the variations that are possible from cloud passing induced effects in solar generation output, although it shows those variations far better than 60 minute average solar generation output data.

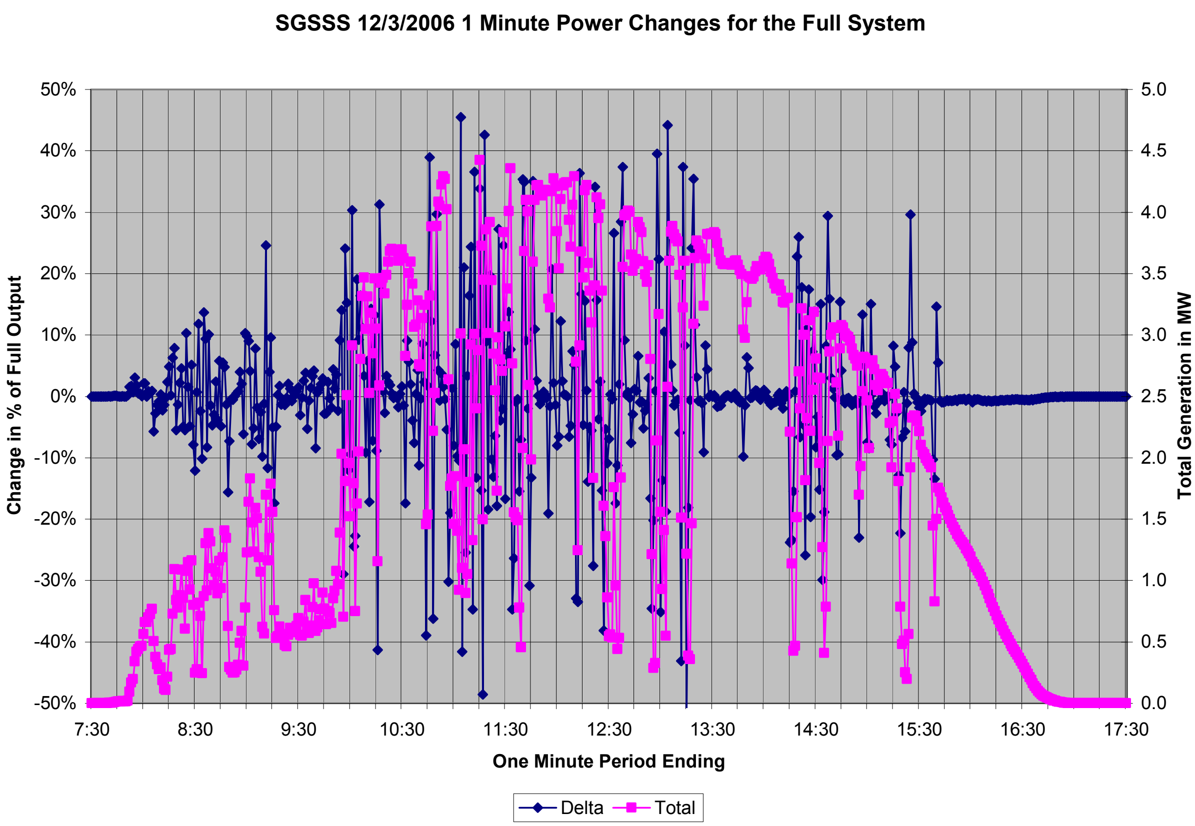

Figure 8

Figure 9 represents the 10 second average solar generation output of the SGSSS on December 3, 2005. The solar power output shows very extreme variation from 10:00 through 15:00, varying from a low of 0.25 MW to a high of 4.6 MW. The maximum period to period change of 30%, or 1.4 MW in 10 seconds – 8.4 MW per minute - is pushing the limits of the ability of a 380 MW coal unit capable of 10 MW per minute load changes to manage, and creates control instability from the repeated output magnitude changes and changes in direction. Given the minimum amount of generation output from the 10 second data, the SGSSS would be expected to provide a firm output of 0.25 MW from 10:00 through 15:00 with generally some need for management of output variations with fast response generation in addition to a 380 MW coal unit. This effect was observed on December 3, 2005 prior to the Springerville coal unit being taken out of AGC to restore coal unit control system stability.

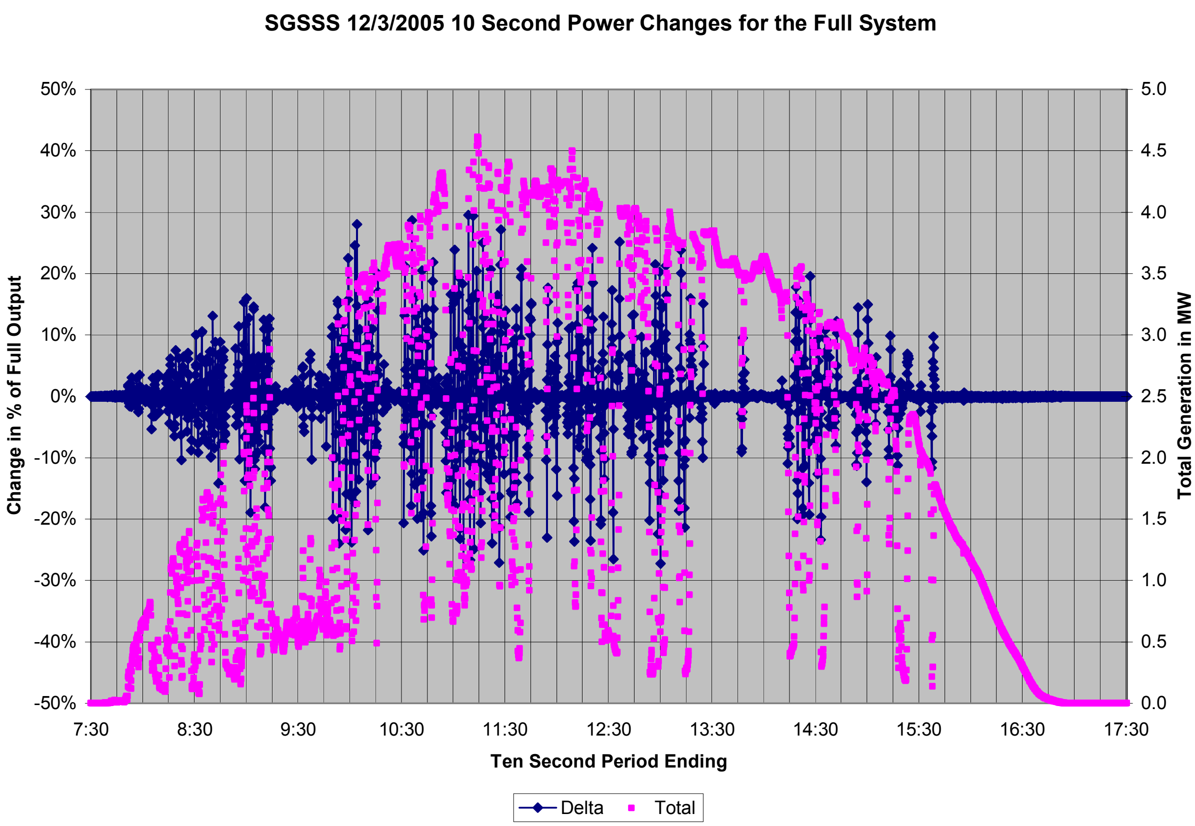

Figure 9

As demonstrated by the previous examples, as the data sampling times are reduced for data used in evaluations of solar capacity capability, the solar capacity capability is also reduced on days when cloud passings affect solar generation output. In this example, a one hour sample interval resulted in a capacity credit of 2.6 MW and ramping rate capacity requirements of only 0.03 MW/min. A 10 second sample interval resulted in 0.25 MW of capacity credit and ramping rate capacity requirements of 8.4 MW/min. This represents a reduction by a factor of 10 in the capacity credit and an increase in the ramping rate capacity requirement by a factor of 280. This example clearly demonstrates why hourly data of solar generation is not appropriate for use in evaluations of solar generation capacity credit or planning capacity.

Based on the foregoing three concepts presented – the need to use short sample intervals for data collection, comparison of solar output at the time of peak electric utility load over a given period of evaluation time and the reasonable existence of a minimum solar generation characteristic - TEP proposes a new method for evaluating the capacity credit of solar generation. The method is based on three separate and distinct, but related, time periods: Sample Intervals (SI), Dispatch Cycles (DC) and Evaluation Periods (EP). Solar generation output will be sampled in Sample Intervals.

The Sample Interval should be at least 1 second, but no more than 60 seconds in length. This allows for collection of data that accurately reflects the variations in solar generation output created from cloud passing events over a PV system. A 10 second SI would capture the generation output variations of a cloud moving at 60 mph over a PV system of over 880 feet in linear dimension parallel to the cloud motion and would be appropriate for a PV system of 4 MW DC or more. For example, the SGSSS covers 44 acres of ground and is 1200 feet in the north-south dimension and 2500 feet in the east-west dimension. A one second SI would be appropriate for a PV system of at least 88 feet in size if 60 mph cloud level winds are the normal maximum expected. While residential systems would not likely be even 88 feet in their longest dimension, a series of PV systems in a neighborhood could be simulated by a single lower efficiency array of size greater than 88 feet.

The Dispatch Cycle would be the basic time interval used by the utility for its electric dispatch decisions, accounting, reliability index calculations and transmission transactions. It typically is one hour and should be no less than 60 times the SI used for solar generation output data gathering. Thus, a one hour DC would be appropriate for use with a 10 second SI. But, if a 15 minute DC is used by a utility, an SI of not more than 15 seconds should be used for evaluation of solar capacity credit to ensure a sufficiently large number of samples are available for accurate data analysis. Dispatch Cycles represent the time span of the solar generation and system load data to be compared to develop the fundamental unit period of the capacity credit definition. In the case of TEP, the DC is one hour. There must be an integral number of Dispatch Cycles in a 24 hour day.

The Evaluation Period is of arbitrary length, and should be selected by evaluating a utility's fundamental operating periods. The EP should represent a specific basic time interval that has fundamentally similar Dispatch Cycle weather related characteristics. The EP should be long enough to result in a manageable number of calculations and capacity credit factors. The EP should be short enough to keep essential solar generation output weather characteristics similar throughout all of the Dispatch Cycles in the EP. For example, creation of an EP that encompasses both winter and summer weather may be appropriate for evaluation of planning capacity, but would not produce relevant capacity credits for either the summer season or the winter season individually. Typical EP length would be a month to coincide with typical utility billing periods, or could be a season in length to correspond to a specific local weather pattern. TEP is using both the standard calendar month and a one year period as its EP for purpose of evaluating solar generation capacity credits. TEP will use a 10 year EP for determination of planning capacity. For evaluating capacity credit, there must be an integral number of evaluation periods in a year. For evaluating planning capacity, there must be an integral number of years in the EP.

Proposed Demand Time Interval Method (DTIM) Solar Generation Capacity Credit Evaluation Algorithms:

The proposed solar generation capacity credit evaluation method would be implemented as follows:

Solar generation output data collected in Sample Interval length time periods would be assembled into relational data blocks identified by Dispatch Cycle number of the day and by day number during the Evaluation Period. A calculation of the minimum level of Sample Interval solar generation data over each separate Dispatch Cycle will be calculated and recorded by Dispatch Cycle number in a day and by the day number as $\boldsymbol{MinSolarPower_{DC}}$. A calculation of the maximum level of Sample Interval solar generation data over each separate Dispatch Cycle will also be calculated and recorded by Dispatch Cycle number in a day and by the day number as $\boldsymbol{MaxSolarPower_{DC}}$. For example using SI = 10 seconds, for hour ending 13:00 on December 3, 2005 the minimum solar generation output recorded as $\boldsymbol{MinSolarPower_{DC}}$ = 0.25 MW and the maximum solar generation output recorded as $\boldsymbol{MaxSolarPower_{DC}}$ = 4.00 MW. The maximum system load during each separate Dispatch Cycle will be calculated and recorded by Dispatch Cycle number in a day and by the day number as $\boldsymbol{MaxLoad_{DC}}$.

At the end of the Evaluation Period, a comparison of all the $\boldsymbol{MaxSolarPower_{DC}}$ values will be made on a maximum basis and the maximum of the maximums, representing the highest level of solar generation output during the Evaluation Period will be recorded as $\boldsymbol{MaxSolarPower_{EP}}$ for the Evaluation Period. Similarly, all Dispatch Cycle system load maximums $\boldsymbol{MaxLoad_{DC}}$ recorded will be maximum compared for all Dispatch Cycles in the EP to determine the maximum system load in the EP which will be recorded as $\boldsymbol{MaxLoad_{EP}}$ for the Evaluation Period. Then, $\boldsymbol{MaxSolarPower_{EP}}$ will be subtracted from $\boldsymbol{MaxLoad_{EP}}$ to calculate the base non-solar generation support level needed to support load demand throughout the Evaluation Period. This will be called $\boldsymbol{BaseLoad_{EP}}$.

A minimum comparison of all Dispatch Cycle actual system loads in the Evaluation Period will be made with $\boldsymbol{BaseLoad_{EP}}$ and $\boldsymbol{MaxLoad_{EP}}$ and $\boldsymbol{MaxSolarPower_{EP}}$ and $\boldsymbol{MaxSolarPower_{DC}}$ and $\boldsymbol{MaxLoad_{DC}}$ as input factors. Performing this calculation for all Dispatch Cycles in the EP will determine the solar generation capacity credit for that EP. The comparison would be made according to the following formula:

Where: During Dispatch Cycle, i = *Number of Sample Intervals*
Where: During Evaluation Period, n = *Number of Dispatch Cycles*

Then:

$$\boldsymbol{Minimum \sum_{x = 1 \rightarrow i} [SolarPower_x] = MinSolarPower_{DC}}$$

$$\textbf{\textit{Maximum}} \sum_{x = 1 \to i} \textbf{\textit{[SolarPower}}_{\textbf{\textit{x}}}\textbf{\textit{] = MaxSolarPower}}_{\textbf{\textit{DC}}}$$

$$\textbf{\textit{Maximum}} \sum_{x = 1 \to n} \textbf{\textit{[MaxLoad}}_{\textbf{\textit{DC x}}}\textbf{\textit{] = MaxLoad}}_{\textbf{\textit{EP}}}$$

$$\textbf{\textit{Maximum}} \sum_{x = 1 \to n} \textbf{\textit{[MaxSolarPower}}_{\textbf{\textit{DC x}}}\textbf{\textit{] = MaxSolarPower}}_{\textbf{\textit{EP}}}$$

Then, where: $\textbf{\textit{MaxLoad}}_{\textbf{\textit{EP}}} \textbf{\textit{ – MaxSolarPower}}_{\textbf{\textit{EP}}} \textbf{\textit{ = BaseLoad}}_{\textbf{\textit{EP}}}$

For: $\boldsymbol{x = 1 \to n}$, Conditional Test: $\textbf{\textit{SystemLoad}}_{\textbf{\textit{x}}} \geqq \textbf{\textit{BaseLoad,}}$ then:

m = Number of Dispatch Cycles **where the conditional criteria is met.**

Then:

Where: $\textbf{SystemLoad}_{\textbf{x}} \geqq \textbf{BaseLoad}$

$$\textbf{\textit{Minimum}} \sum_{x = 1 \to m} \textbf{\textit{\{[(MaxSolarPower}}_{\textbf{\textit{EP}}} \textbf{\textit{ – (SystemLoad}}_{\textbf{\textit{DC x}}} \textbf{\textit{ – BaseLoad}}_{\textbf{\textit{EP}}}\textbf{\textit{)] + MinSolarPower}}_{\textbf{\textit{DC x}}}\textbf{\textit{\}}}$$

$$= \textbf{\textit{SolarCapacityCredit}}_{\textbf{\textit{EP}}}$$

The capacity credit comparison is made at a solar generation output level required to meet only the level of load above the $\textbf{\textit{BaseLoad}}_{\textbf{\textit{EP}}}$ amount. Consequently, the Dispatch Cycle with the highest system load level is the primary determinant of the capacity credit, the Dispatch Cycle with the next highest system load level is the next determinant of the capacity credit and so on until all Dispatch Cycles with a load above the $\textbf{\textit{BaseLoad}}_{\textbf{\textit{EP}}}$ are evaluated for their impact on the solar generation capacity credit for the Evaluation Period. If a calculation of the solar generation capacity credit is needed on the basis of the Dispatch Cycle number of a day during the Evaluation period, the same comparison could be made for each set of same number of the day Dispatch Cycles in the Evaluation Period. If Dispatch Cycles are in hours and Evaluation Periods are months, the largest possible number of capacity credit evaluation comparisons would be the maximum number of hours of daylight in a day during the month.

Results of DTIM Evaluation Analysis Modeling Software:

Excel spreadsheet macros were developed to perform the evaluation analysis using the TEP proposed Demand Time Interval Method (DTIM) evaluation method. These macros were based on the algorithms presented above. The data from the SGSSS and the Pennington Street Garage Solar System were processed with TEP load data at various time intervals using the DTIM model and results developed. Each model run results in an 80 MB size spreadsheet. To date more than seventy TEP proposed DTIM model runs have been performed. The Evaluation Period was set at one year and also at one month to demonstrate any differences in use of annual or monthly Evaluation Periods. There was only a minor difference in the annual and the monthly peak capacity value results, as expected. The difference is related to the maximum solar energy output being higher in the spring – the annual model - than in the summer when loads are peak for TEP. Thus, annual capacity value results expressed in a percent of peak solar output during the Evaluation Period are lower for annual periods than for monthly periods. Graphical results of several DTIM model runs with the Sample Interval set at 60 minutes, 15 minutes, 10 minutes, 5 minutes and 1 minute are included below. Use of 10 second data for the Sample Interval resulted in a solar capacity value in 2007 of 0.689 MW (14.47%) as compared to 0.698 MW (14.69%) using a 60 second Sample Interval. This is a small but definite difference in the evaluated capacity value of solar generation from the SGSSS, which is to be expected as the SGSSS has a maximum output variation time constant of about 20 seconds with 120 mph winds aloft at the cloud deck. The SGSSS is located about 200 miles from Tucson, so solar output at SGSSS and load in Tucson are expected to be less directly linked than a solar unit located in Tucson, such as Pennington, would have correlation with load.

The first graph below, Figure 10, shows the results of 2006 SGSSS DTIM model data using monthly Evaluation Periods as well as an annual Evaluation Period in the rightmost block. The Dispatch Cycle Period in this model run was one hour. The DTIM results using different Sample Interval time periods are plotted in different colors. The data indicates a trend that capacity value is reduced as the Sample Interval is shortened. July 21st was the day of highest peak system load, and the loss of solar power on that day due to monsoon driven clouds is reflected in the very low July and Annual capacity value of 3%, when SI = 60 minutes. The DTIM analysis indicated a 0% capacity value in July and Annual for shorter SI values as expected given the short duration of significant cloud passings in July 2006. Note also that January, February and December capacity values are all zero, as to be expected with evening peak loads in winter months. The DTIM model correctly evaluated the winter month solar capacity value to 0%. Note also that September had a very high capacity value from over 90% using hourly average Sample Interval data to 60% using one minute average Sample Interval data. Monsoon weather typically ends in August in Arizona, so capacity values would be expected to be better in September than during monsoon season. Likewise, June is generally prior to monsoon season and shows good solar capacity values for the month, again indicating good correlation of solar output with high load periods during spring months.

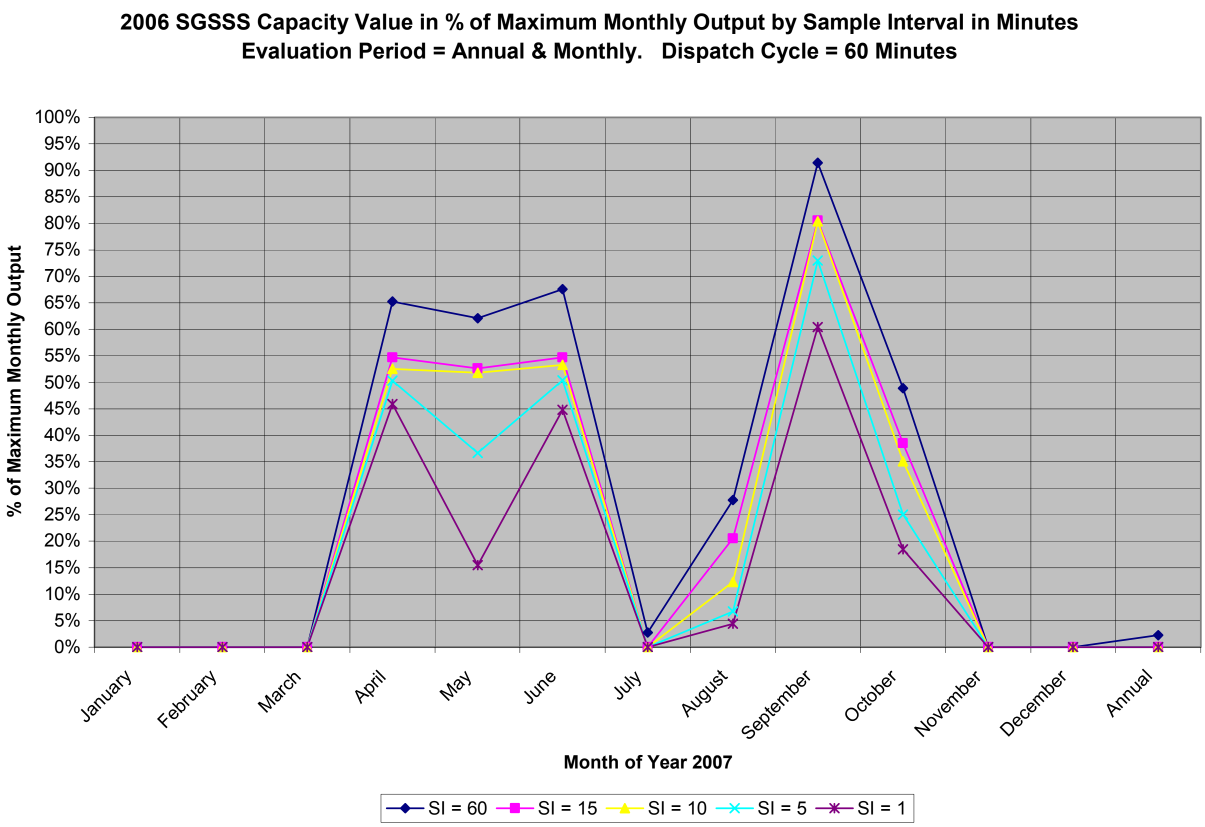

Figure 10

The next graph below, Figure 11, shows the results of 2007 SGSSS DTIM model data using monthly Evaluation Periods as well as an annual Evaluation Period in the rightmost block. The Dispatch Cycle Period in this model run was also one hour. The DTIM results using different Sample Interval time periods are plotted in different colors. The results also indicate a trend that capacity value is reduced as the Sample Interval is shortened. July 18th was the day of highest peak system load, and the partial loss of solar power on that day due to monsoon driven clouds is reflected in the low July and Annual capacity value of 15% when Sample Interval of one minute is used.. There is a significant difference in the Annual capacity value for 2007 given different Sample Intervals used: 40% when a one hour average Sample Interval is used and 15% when a one minute Sample Interval is used. This is very much related to the rapid spread of monsoon clouds at time of peak loads during monsoon season. Note also that again January, February and December capacity values are all zero, as to be expected with evening peak loads in winter months. The DTIM model again correctly evaluated the winter month solar capacity value to 0%. Note also in 2007 September had a very high capacity value from 55% using hourly average Sample Interval data, to 38% using one minute average Sample Interval data.

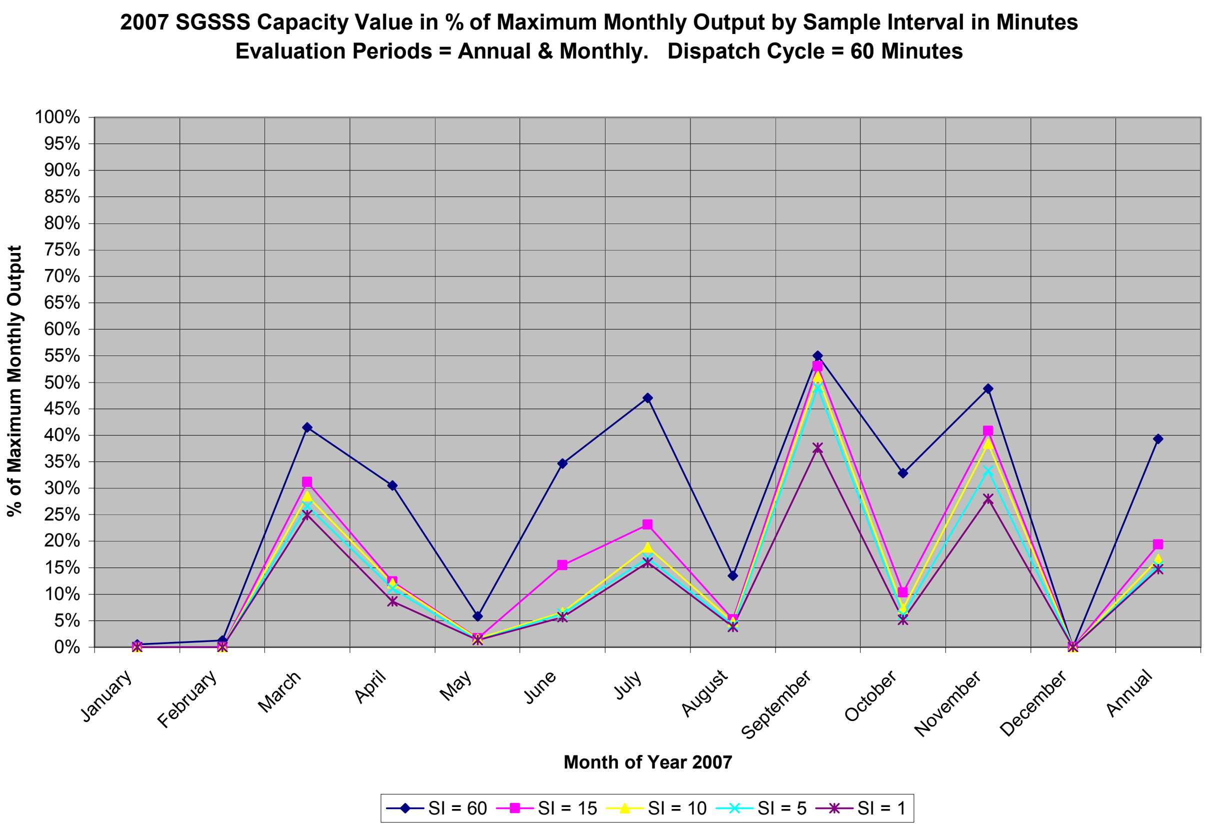

Figure 11

The next graph below, Figure 12, shows the results of 2007 SGSSS DTIM model data using monthly Evaluation Periods as well as an annual Evaluation Period in the rightmost block. The Dispatch Cycle Period in this model run was changed to 10 minutes, a shorter time period than in Figure 2. The DTIM results using different Sample Interval time periods are plotted in different colors. The data still indicates a trend that capacity value is reduced as the Sample Interval is shortened. Note, however, that use of shorter Dispatch Cycle load data results in generally higher monthly solar capacity values, as expected, since the solar input is driving loads and closer alignment of load and solar data in short time frames is more representative of the capacity value of the solar generation. Note also that again January, February and December capacity values are all zero with the shorter Dispatch Cycle, as to be expected with evening peak loads in winter months. The DTIM model again correctly evaluated the winter month solar capacity value to 0%.

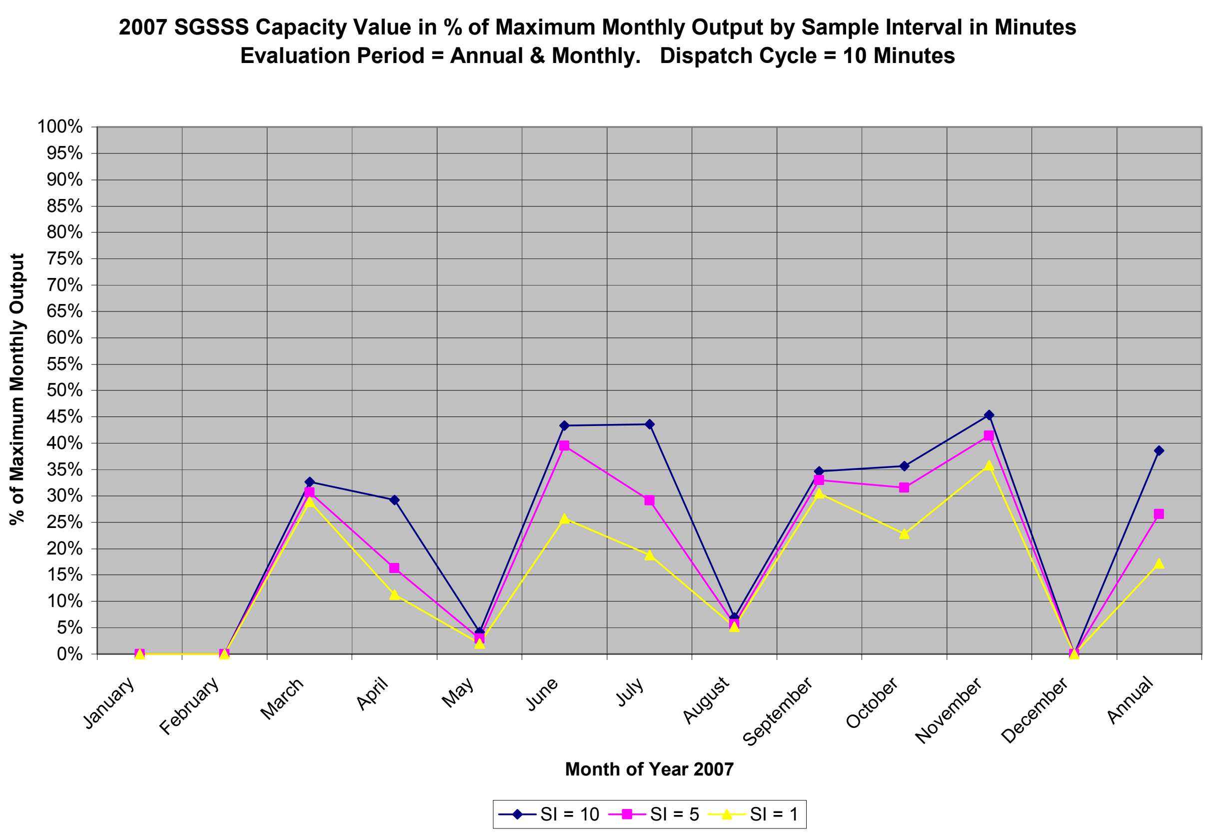

Figure 12

The next graph below, Figure 13, shows the results of 2007 Pennington Street Garage Solar System DTIM model data using monthly Evaluation Periods as well as an annual Evaluation Period in the rightmost block. This system is located in downtown Tucson, approximately in the geographic center of the load served by TEP. The Dispatch Cycle Period in this model run is 60 minutes, the same time period used in Figure 11. The DTIM results using different Sample Interval time periods are plotted in different colors. The data continues to indicate a trend that capacity value is reduced as the Sample Interval is shortened. Use of solar output data from a system closer to the load served results in generally higher capacity values than a solar unit located 200 miles away, as expected. Note also that again January and December capacity values are zero as is to be expected with evening peak loads in winter months. But, February has a small non-zero capacity value when hourly Sample Intervals are used. While a full year of data was not available for Pennington Street in 2006, data for the peak load day of July 21st was available and analysis of that data using the DTIM model and a Sample Interval of 5 minutes showed an annual 2006 capacity value of 13.0%, as compared to 2007 annual solar capacity value of 37% with a 5 minute Sample Interval. This points out that the solar capacity value will vary greatly from year to year, depending upon the exact cloud conditions at the time of peak loads. 2006 had a stronger monsoon statewide on peak load day than occurred in 2007 on peak load day. Both SGSSS and Pennington data demonstrate that relation. Thus, solar capacity value will need to be evaluated over several years if the DTIM model is used for utility planning capacity requirements study purposes.

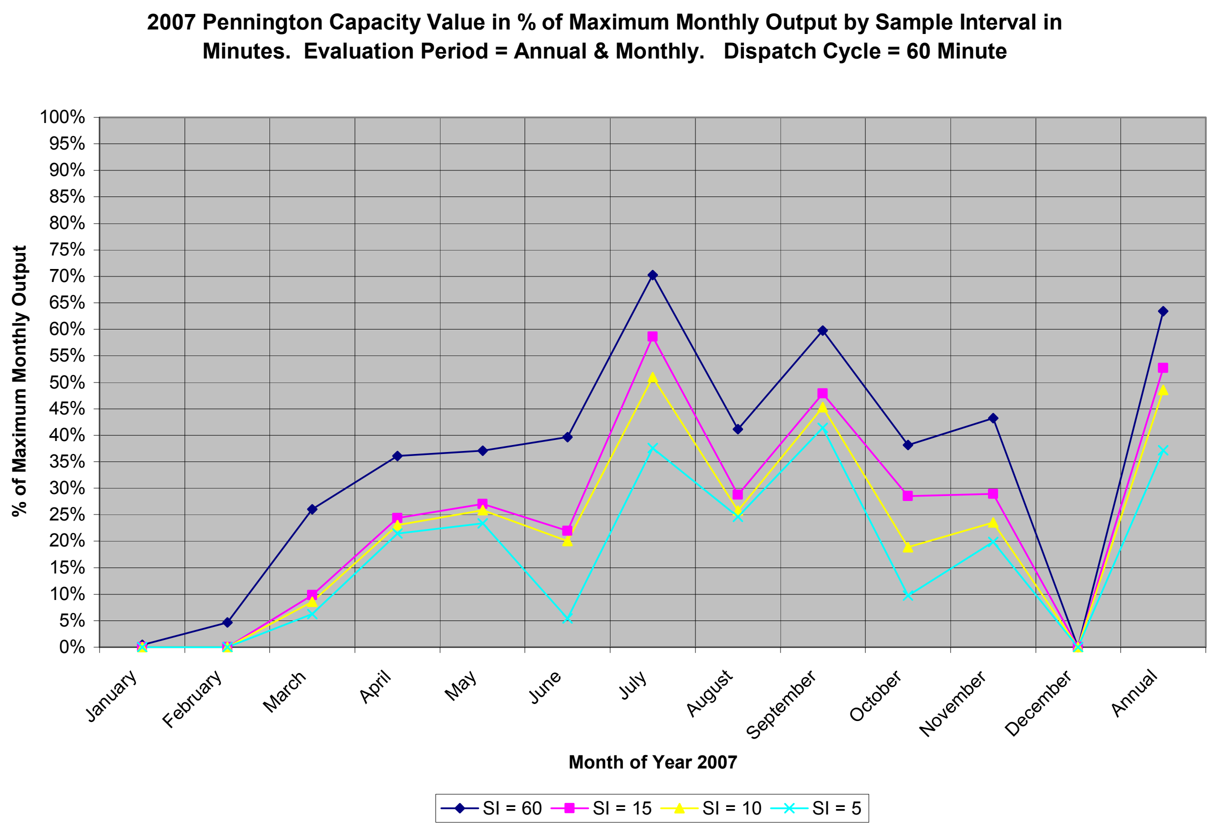

Figure 13

The next graph below, Figure 14, shows the results of 2007 Pennington Street Garage Solar System DTIM model data using monthly Evaluation Periods as well as an annual Evaluation Period in the rightmost block. The Dispatch Cycle Period in this model run is 10 minutes, the same time period used in Figure 12. The DTIM results using different Sample Interval time periods are plotted in different colors. The data continues to indicate a trend that capacity value is reduced as the Sample Interval is shortened, but with Dispatch Cycle and Sample Interval very close to each other, this is not a universal trend, again indicating use of shorter Dispatch Cycle and Sample Interval time periods results in more accurate solar capacity value results.

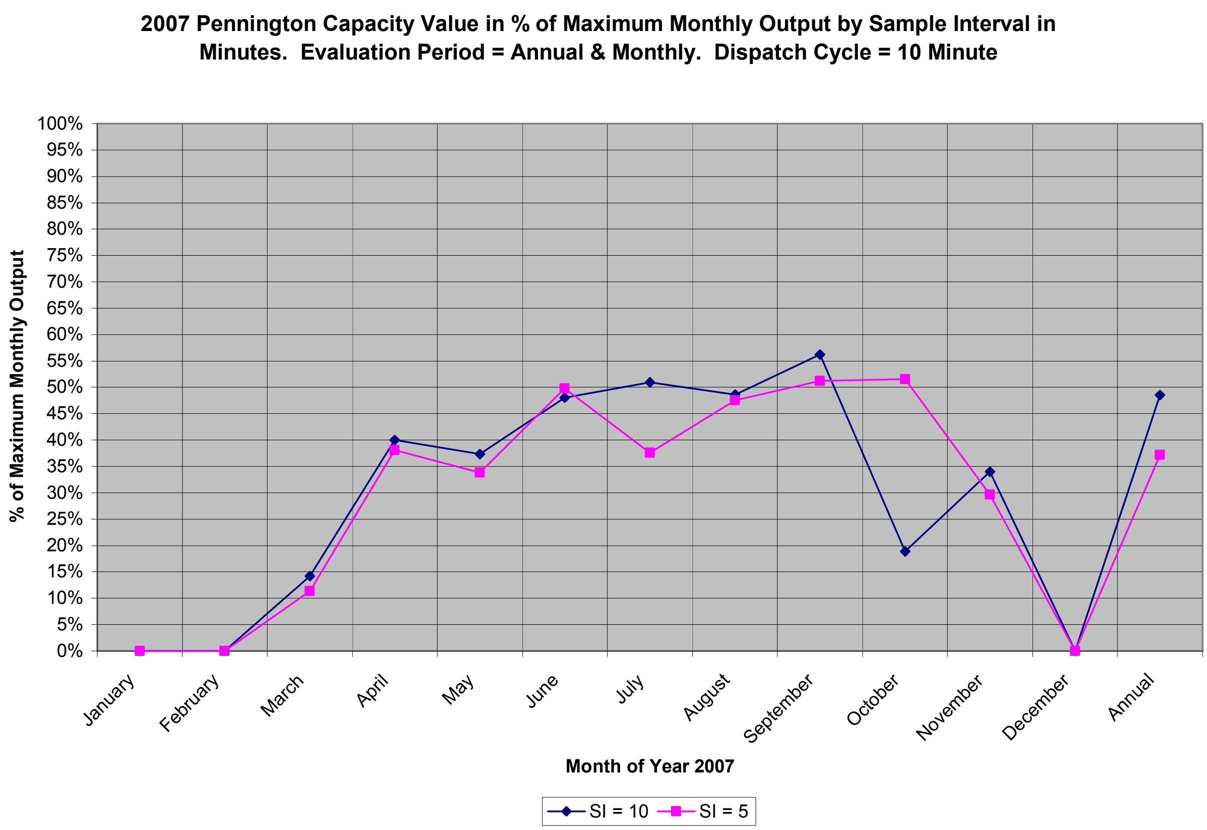

Figure 14

In addition, the SGSSS power output data and TEP utility load data for 2007 was used in a standard utility PROMOD Loss of Load Probability (LOLP) and Energy Not Served (ENS) model using one hour and 15 minute Dispatch Cycles and Sample Intervals. The PROMOD model could not function correctly with data of Sample Interval or Dispatch Cycle less than 15 minutes, so only the one hour and 15 minute time scales were used for these evaluation analysis runs. The results from the first set of runs proved to be invalid and subsequent analysis showed some model switches were incorrectly set. Subsequent runs with the switches correctly set show reasonable agreement with the results of the DTIM runs using similar Sample Intervals and Dispatch Cycles for a Sample Interval of 60 minutes, but not appropriate or accurate for a Sample Interval of 15 minutes, reflecting the inconsistencies in use of traditional LOLP and ENS models in evaluating data of time frame shorter than 60 minutes. The table below shows a comparison of the results of the capacity value of solar for the SGSSS using DTIM and LOLP and ENS methods with traditional Dispatch Cycles of one hour and Evaluation Periods of one year. Note that while the LOLP and ENS methods provide similar capacity value results to the DTIM method for 60 minute sample intervals, the LOLP and ENS methods do not result in accurate and appropriate capacity values for sample intervals of 15 minutes when using Springerville data.

2007 SGSSS Data Based Results: Annual Capacity Value in % of Maximum PV Array Capacity Rating

Sample Interval Time	60 Min	15 Min	10 Min	5 Min	1 Min	10 Sec
DTIM Evaluation Method	39.31%	19.33%	16.66%	15.27%	14.69%	14.47%
LOLP Evaluation Method	32.74%	31.18%	--------	-------	-------	--------
ENS Evaluation Method	29.95%	31.98%	--------	-------	-------	--------

2006 SGSSS Data Based Results: Annual Capacity Value in % of Maximum PV Array Capacity Rating

Sample Interval Time	60 Min	15 Min	10 Min	5 Min	1 Min	10 Sec
DTIM Evaluation Method	2.28%	0.00%	0.00%	0.00%	0.00%	0.00%

Figure 15 shows graphically the results of the LOLP evaluation using 15 minute Sample Intervals and Figure 16 shows the results of the LOLP evaluation using 60 minute Sample Intervals:

2007 SGSSS LOLP based on 15 Minute Sample Intervals and Dispatch Cycles

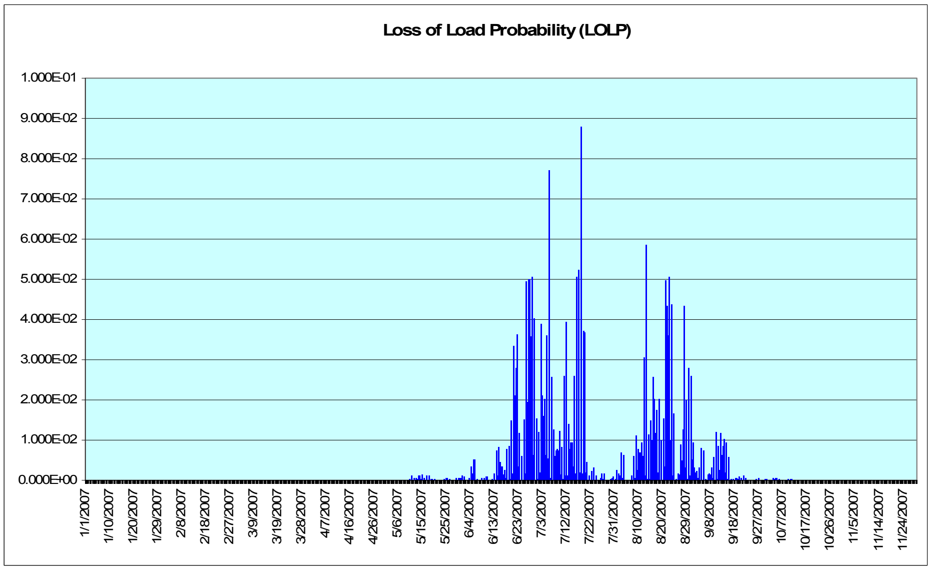

Figure 15

2007 SGSSS LOLP based on 60 Minute Sample Intervals and Dispatch Cycles

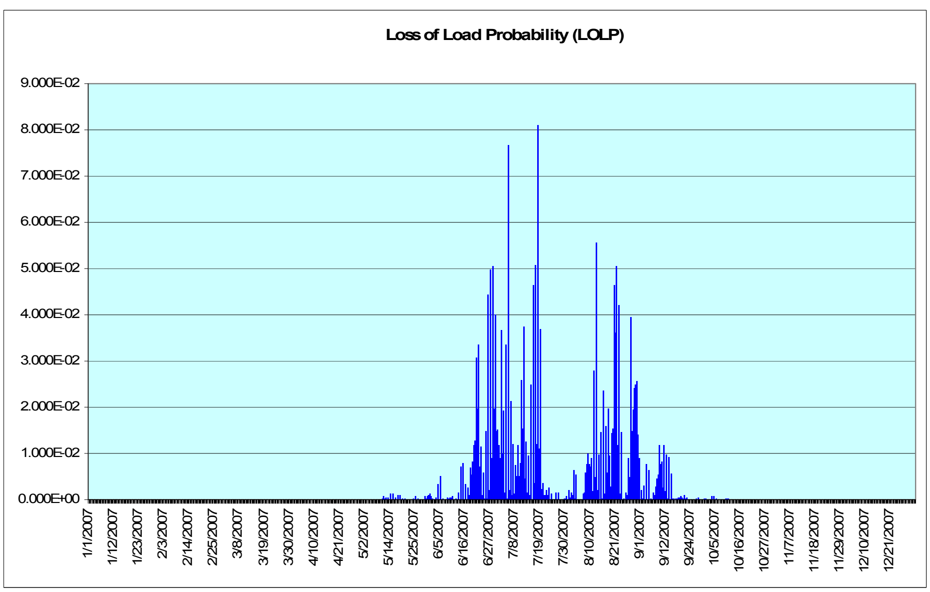

Figure 16

General Review of DG Costs and Benefits:

Distributed Generation (DG) can provide benefits to both the customers owning the DG as well as to the utility in whose distribution system the DG has been installed. There are also costs from the installation of DG to both the owner of the DG and the utility. If the DG output is not time variant or a function of weather patterns which can affect peak utility system demand, the benefits are demonstrably higher and the costs lower to both the DG owner and the utility. Benefits to the owner of distributed generation come almost exclusively from reductions of energy and capacity charges from the utility. A possible additional benefit is also available to the owner of DG from the ability to have continuous electrical service during utility power outages if the DG is designed with that feature. Standard grid connected solar DG systems will not continue to operate when the grid has failed due to the need to meet IEEE-929 requirements for interconnection with the utility grid, which shut the solar generator off during power outages for safety reasons. If annual capacity factor of the DG system is higher, more electricity use will be displaced from the utility and the benefit to the DG owner will increase.

Costs of DG to the owner include the cost of any required fuel, operation and maintenance costs (O&M), initial installation costs and ownership costs including financing, taxes and insurance associated with ownership of a generation system. Net metering programs provide a greater benefit to the DG owner by providing a credit at retail rate for generation output produced in excess of use over a given time period. For time variant non dispatchable DG systems like solar or wind, this can be a large benefit as DG output can not be easily scheduled by the owner to match demand. Provided that benefits are greater than costs over the long term, a customer will choose to install a DG system. The primary risks associated with the decision to install a DG system include the accuracy of the estimate of cost of operation and maintenance and the annual generation capacity factor of the DG system. If O&M costs are higher than estimated or annual capacity factor is less than estimated, costs will be higher and benefits lower for the owner of the DG system, possibly making it uneconomic over time. Utilities can positively impact a decision to install DG by offering net metering programs for time variant DG systems and by eliminating or reducing the cost of the interconnection to the utility grid. Utilities can also positively support installation of DG by eliminating or reducing backup capacity and energy fees, charged to a DG customer when the DG system is not operational for planned or unplanned reasons. Utilities positively support renewable DG systems, such as solar generation, through providing rebate programs to reduce the initial cost of a DG system or through providing production based Renewable Energy Credit (REC) purchase programs to provide an ongoing revenue stream for the owner to offset O&M and ownership costs.

Utilities receive a benefit from DG systems primarily from dependable reductions in peak annual demand from the generation output of DG systems during high load demand hours. Firm, guaranteed reductions in peak demand allow utilities to reduce requirements for building generation, transmission and distribution capacity. However, if the DG generation is not firm and guaranteed to a very high degree of confidence, typically one day of failure in ten years, the utility can not reduce its planned capacity requirements from customer use of DG, and no benefit is provided to the utility from this factor. Utilities will benefit from fuel use reductions and reductions in distribution losses through DG installation. There can also be a benefit to utilities from a small increase in operational life for various distribution components, such as transformers and underground cables whose life is reduced by operation at elevated temperatures, created in part by high electrical loads. However, this benefit is also heavily dependent upon the ability of the DG to provide firm, highly reliable output during the highest load demand hours of the year. Thus, to a utility, the benefit of DG is a large function of the capacity credit assigned a generator based on its proven ability to provide electrical generation output during the peak load demand hours of the year for that utility. This gives additional support to the premise that any accurate and appropriate method for evaluating capacity credit of a solar generator must include a comparison of the 10 second Sample Interval solar output profile of that generator with utility peak load profiles.

Five years of historical Tucson solar data matched with Tucson native load data indicates that about 75% of annual solar energy is produced during TEP TOU rate off peak and shoulder periods and only 25% of annual solar energy is produced during peak load periods, with much less than 10% of annual solar energy produced during summer peak load periods, since Tucson has an afternoon summer monsoon storm climate which further reduces the available solar energy during summer peak periods.

The costs of solar DG to a utility include the direct cost of any rebates or production payments made for renewable generation, as well as internal and external labor or consultant costs of reviewing interconnection plans and providing interconnection devices to DG installers. However, in many cases the largest cost to a utility from installation of DG systems is lost revenues from energy only based utility rates as a DG system reduces the energy consumption of the owner, especially those time variant DG systems where the owner depends upon the grid for electricity during periods of low or no DG production, like nighttime for solar generation. The DG owner still must have a distribution drop to their premises, the distribution, transmission and generation capacity must still be available to fully support their peak demand, the meter must still be read and bills prepared, remittances processed and administration of the utility provided. The time variant DG system does reduce utility annual fuel use and line losses in the distribution system. However, since the energy based utility rate DG owner uses less energy per billing cycle, they will be providing lower amounts of revenue to the utility to compensate for those services which the utility is obligated to continue providing and the DG owner requires for continuity of service. As the total cost of service for a utility to support a customer can be comprised of 70% fixed monthly utility expenses and 30% energy production related utility expenses, the utility can be significantly under-compensated for providing electric service to DG owners as the utility would only receive DG created savings for a maximum of only 30% of the total expense of serving that customer. This can be addressed through partial requirements tariffs, backup service charges, an increase in the monthly fixed service charge and other rate mechanisms designed to provide a decoupling of the fixed cost of providing electrical service from energy related charges. A per kWh tariff equal to the average per kWh of the fixed monthly charges, applied to the DG output could also be used to compensate utilities for the loss of fixed charge revenue from DG installers. All of these mechanisms will be viewed by DG advocates and owners as providing a disincentive for installation of DG systems. However, in the case of time variant DG sources whose capacity credit may be near zero, failure to charge appropriate cost of service based revenue recovery electric rates to DG owners who directly benefit from the installation of their DG systems for the fixed cost of their electrical service will result in those utility customers who do not directly benefit from the DG system paying for the otherwise un-reimbursed costs to the utility through future rate adjustments.

The cost of installation and operation of natural gas fired high ramp rate capability firming generation, or electrical energy storage is an additional cost to utilities for support of time variant DG sources in its service territory. The installation of rapid change time variant DG coupled with the current inability of solar generation systems to provide reactive power may also adversely impact the ability of existing utility voltage control devices, primarily slow response capacitor banks, to adjust reactive power flows to support local distribution system voltage in a sustainable, reliable manner during cloud passing events. Excessive local grid voltage variations have previously been reported in Japan and England in areas of high PV installation density. If this is found to be a factor in the future as solar generation installation densities increase in the US, utility costs will increase from a need to install fast reactive power control devices, such as Static Var Compensators (SVC), in the distribution system in lieu of lower cost capacitor banks. Additional grid regulation support requirements, such as low voltage ride through, droop support and frequency stability regulation are not currently provided by grid connected solar generation systems and may as solar generation installation densities increase in the future need to be provided in greater quantities by utilities, with the associated cost of installation, maintenance and operation of these additional control devices.

If solar generation capacity credit to utilities is minimal, the proper management of the previously mentioned grid reliability impacts from time variant solar generation will very likely increase the cost of providing continuous, reliable electric service to all electric utility customers as the penetration percentage of solar generation increases as compared to reliance on additional conventional dispatchable generation sources to meet demand growth. That said, there are no present grid operational indications that the addition of solar generation in high penetration percentages can not be technically managed. The question is what will be the cost of that management at various levels of solar generation penetration percentage. There must be a balance to fairly compensating those customers who directly benefit from ownership of solar DG systems for their benefits provided to the electric utility and increasing the costs to those customers who do not directly benefit from the solar DG systems. The accurate and appropriate evaluation of solar generation capacity credit to a specific electric utility is central to the determination of the benefit of solar DG installations to the utility and to those utility customers who do not own a solar DG system. This again reflects the importance of adopting the DTIM for evaluating the capacity value of solar for electric utilities.

Solar Generation Benefits and Value to Electric Utilities:

The principal investigator formally met with three interested parties and five individuals during the reporting period in Phoenix on August 2nd, 2007and in Tucson on August 14th, 2007. These individuals represented Arizona Public Service, Salt River Project; and Venture Catalyst.

All parties were provided in advance with a summarized report of the Demand Time Interval Method for solar capacity value evaluation proposed by TEP. Additionally, questions were provided in advance to the parties prior to the meetings for the parties to review and be prepared to discuss at the meeting. Those questions were:

- Your thoughts on the solar capacity value evaluation methodology proposed by TEP. Additions, deletions, concerns, etc.
- Discussion of factors that you believe should be considered in evaluating the capacity value of solar generation to an electric utility.
- Solar production and native load data you have that could be made available to TEP for use in application to the Solar Capacity Value model for verification of the evaluation methodology.
- Your thoughts on the value of benefits, and costs, of distributed solar generation to an electric utility.
- Discussion of factors you believe should be considered in a determination of the benefits/costs of distributed solar generation to an electric utility.
- Your thoughts on how actual values can be assigned/determined for the benefits/costs of distributed solar generation to an electric utility.
- (Venture Catalyst only) Your thoughts on what tools utilities can use in providing proper and appropriate financial benefit to customers who install solar generation systems on their homes or businesses for the net benefits they provide to a utility.

During the discussion, categories of Benefits and Costs were specifically raised for discussion. These included:

Benefits: Energy losses, emissions reductions, fuel reductions, voltage support, extension of useful life of transformer and other heat related degradation components, capacity value at time of coincident peak load and reduction of required spinning reserve requirements.

Costs: Incentive programs, lost revenue, firming generation capacity, spinning reserve costs, reactive voltage support, circuit protection modifications.

Methods of providing value to customers for their solar generation systems were also specifically raised for discussion, including net metering, interconnection requirements, partial requirements tariffs, incentives, renewable energy credit purchases, decoupling of sales and profits through higher fixed monthly charges or a per kWh charge on self generated electricity.

The meetings resulted generally in an agreement that much work remained to be done in developing specific quantified benefit and cost data for determining the value of solar generation to an electric utility and that the current penetration percentages of solar generation in the utility generation portfolio are not sufficient to provide accurate data for that analysis. Further general discussion on this topic was held informally with a larger number of electric utility representatives in March, April and May of 2008 with the same general results. However, all parties were optimistic that over time the data needed will be available as solar generation installations continue to increase.

Regarding the methods of utilities providing value to customers for the benefit a customer sited solar generation system provided to the utility, there was no universal agreement on any one method. Most parties expressed a need to reflect on the issue at more length.

Only two individuals were prepared to discuss the DTIM solar capacity value evaluation method proposed by TEP. Those individuals expressed their belief that the TEP proposal was an accurate and appropriate method for the evaluation of solar capacity value. It was suggested by those individuals that the analysis should include review of the data using one minute Sample Intervals as well as 10 second Sample Intervals to compare the difference in the results using the two different time intervals. TEP included that suggestion in its analysis as the results reported here indicate. It was expressed by some individuals that their internal Automatic Generation Control (AGC) correction interval was in the range of 5 to 15 seconds, supporting the use of 10 second Sample Intervals as a reasonable basic time unit for solar capacity value evaluation.

Discussions were held with other electric utility representatives during the reporting period regarding the proposed DTIM solar capacity value evaluation method, the level of intermittencies in solar power output created by cloud passings and the value of solar generation to an electric utility. These discussions included representatives of four Arizona utilities, one Nevada utility, one Colorado utility, one Washington utility and two California utilities. All parties agreed that the impact of cloud passings on the output of utility scale PV systems is an area of concern to utilities and should be given further review with additional data from several geographic areas of the US needed. It was recommended that further review and analysis of the value of distributed solar generation to an electric utility be evaluated when additional operational experience and utility specific data with high concentrations of distributed PV generation is available.

Application was made for presentation of this project's results at Solar Power 2008 in October, but it was not accepted for presentation at the conference.

Summary:

Many studies have been performed of the capacity credit of solar generation to utilities. Much work has previously been done in developing tools and methods for demonstrating the value of distributed solar generation to electric utilities. Reports of the impact of modern highly flexible electric meters, integrated distribution system design, time-based dynamic tariffs and smart grid capability have been praised as providing tools for improving the value of solar generation to electric utilities. However, seldom has an electric utility using high resolution solar generation data of a time scale less than one hour averages been involved in the development of those studies, tools and methods and consequently utilities are not accepting the results of those studies without review from the service obligation perspective and traditional revenue recovery requirement needs of an electric utility.

Prior studies of the benefit of solar generation to utilities have always used hourly average solar production data. Yet, electric utilities must provide reliable electric service to all customers by continuously balancing supply and demand of electric energy on a time scale of milliseconds. With the acquisition of high resolution solar output data in time intervals as short as 10 seconds, there is solid evidence that cloud passings create very short time scale, high MW/minute impact changes in solar generation output which can have adverse impacts on the grid if not managed correctly. The full range of these impacts have not yet been fully evaluated, given that those effects are not a concern at the generally low penetration percentage levels of solar generation currently installed in the service territories of electric utilities. However, even at a level of only 5% of annual energy production for a utility, these estimated cloud passing effects are expected to have a significant impact on local grid regulation support requirements. Cloud passing created output power variations of a relatively small, in utility terms, 4.59 MW DC solar generator are adversely affecting the AGC controls of a nearby regulating 380 MW coal fired generation unit to the extent that on many partly cloudy days that coal plant can not be used for regulation by itself. Use of hourly average based solar generation capacity credit evaluation tools, like satellite based solar insolation measurements, ELCC, ENS or LOLP are not appropriate or accurate for evaluating the capacity credit to be assigned to solar generation. Past evaluations of solar generation capacity credit which used hourly average solar generation output as a basis should be reviewed in the light of the clear evidence demonstrated in this report of short time frame impacts of cloud passing effects on solar generation. TEP has studied these effects and recommends that its Demand Time Interval Method for evaluating solar generation capacity credit for an electric utility be adopted as the standard for that purpose. The DTIM is the only capacity credit evaluation tool currently available that fully accounts for the short time scale of cloud passing events and their impact on the output of solar generation. It is more accurate at short time scales than the traditional LOLP, ENS or ELCC methods used for evaluation of traditional generation capacity credit.

The effects of the variability of solar generation on utility load regulation requirements and grid voltage control methods have not been given proper review and consideration to date. Again, this has not been a concern at the generally low penetration percentage levels of solar generation currently installed. However, as additional solar generation is installed and connected to the electrical grid, especially distribution system connected solar generation, addressing the impact and development of management tools for mitigation of these effects will become important to support the continued high reliability of the electric grid. While high voltage transmission interconnections between utilities will allow for regulation support from a wide area of the grid for an individual utility experiencing cloud passing effects to solar generation output within its service territory, there is a limit to the regulation support that should be provided across transmissions lines. Reactive power support must be met by local control assets and will need to be addressed by each utility as appropriate. There is nearly no current high resolution data available for evaluation of future utility needs in the areas of regulation support or reactive power support for solar generation output variation created from short time frame cloud passing events. Inverters are capable of being designed to provide reactive power support and low voltage ride through with only changes to software. Standards need to be developed to bring solar generation inverters with those capabilities to market, just as standards for wind turbine grid support functions brought positive changes related to reduction of the impact on grid operations from wind generation technologies.

Methods for prediction of solar generation in the short term of seconds and minutes as well as the long term of hours and days need to be developed. These tools will be required to allow for future successful cost effective management of integration of high penetration percentages of solar generation into the TEP generation portfolio and those of other electric utilities. Future projects should be initiated to develop cloud effect models to study the effects of clouds over a larger geographic area on solar generation. While wind generation output variations are generally reduced by distribution of wind generation over a wider geographic area, it is not currently clear that same effect will universally be observed with solar generation scaled to larger geographic areas within an area that experiences similar general meteorological patterns. Development of tools for evaluation of the minimum ramp rate requirements for firming capacity needed to manage the relatively high rate of power output variation associated with cloud passings events should be part of future solar development support research. Probability confidence and overall electric grid reliability factors such as CPS1 and CPS2 criteria will need to be part of that evaluation. Evaluation of the effects of cloud passings on distribution feeder voltage, power factor and harmonics of a section of an electrical distribution system with a high concentration of solar PV generation should also be part of future solar development support research.

Solar energy can provide 100% of our nation's future energy needs, given the proper support technologies of energy storage and cloud passing effect management. Continued Solar America Initiative support in developing these enabling technologies will provide for reliable integration of significant percentages of solar power into our nation's electrical grid when the cost of solar is competitive with traditional energy sources in the near future.