# The Value of Distributed Solar Electric Generation to San Antonio

**March 2013**

**Nic Jones**

Solar San Antonio

San Antonio, Texas

**Ben Norris**

Clean Power Research

Napa, California

Acknowledgment: "This material is based upon work supported by the Department of Energy under Award Number DE-EE0005702

Acknowledgements

The authors wish to express their appreciation to Liza Meyer of the City of San Antonio for coordinating the project status meetings, to Chris Winland of Good Company Associates for providing technical leads associated with the Texas power market, and to Phil Gruenhagen of Clean Power Research for implementing the custom cost components into the DGValuator tool.

# Executive Summary

This report presents an analysis of value provided by grid-connected, distributed PV in San Antonio from a utility perspective. The study quantified six value components, summarized in Table ES- 1. These components represent the benefits that accrue to the utility, CPS Energy, in accepting solar onto the grid. This analysis does not treat the compensation of value, policy objectives, or cost-effectiveness from the retail consumer perspective. Methodologies for quantifying these values are described further in the Appendix.

**Table ES- 1. Value component overview.**

| Value Component | Basis |
|---|---|
| Fuel Cost Savings | The cost of natural gas fuel that would have to be purchased for a gas turbine (CCGT) plant operating on the margin to meet electric loads and T&D losses. |
| O&M Cost Savings | The operations and maintenance costs for the CCGT plant. |
| Generation Capacity Value | The cost to build CCGT generation capacity. |
| T&D Capacity Value | The cost of money savings resulting from deferring T&D capacity additions. |
| Avoided Reserve Capacity | The cost to build CCGT capacity to meet reserve margin. |
| Fuel Price Hedge Value | The cost to minimize natural gas fuel price uncertainty. |

Four different system configurations (e.g., fixed, south-facing, 15-degree tilt angle) were evaluated under two penetration scenarios: current penetration (1.1% of peak load) and “high penetration” (2.2% of peak load).

PV was modeled using SolarAnywhere®, a solar resource data set and modeling service that provides time- and location-correlated PV output with utility loads. Load data was taken from ERCOT and scaled to represent the load profile of the CPS Energy service territory. Economic inputs were derived from a CPS Energy Annual Report, the EIA and the Bureau of Labor Statistics (producer price indices). Details of input assumptions and data collection methods are provided in the Appendix.

Levelized value results are shown in Figure ES-1, and the impacts of penetration level on peak day load profile is shown in Figure ES- 2. These results were obtained from DGValuator, a utility value assessment tool.

**Figure ES- 1. Levelized value ($/MWh)**

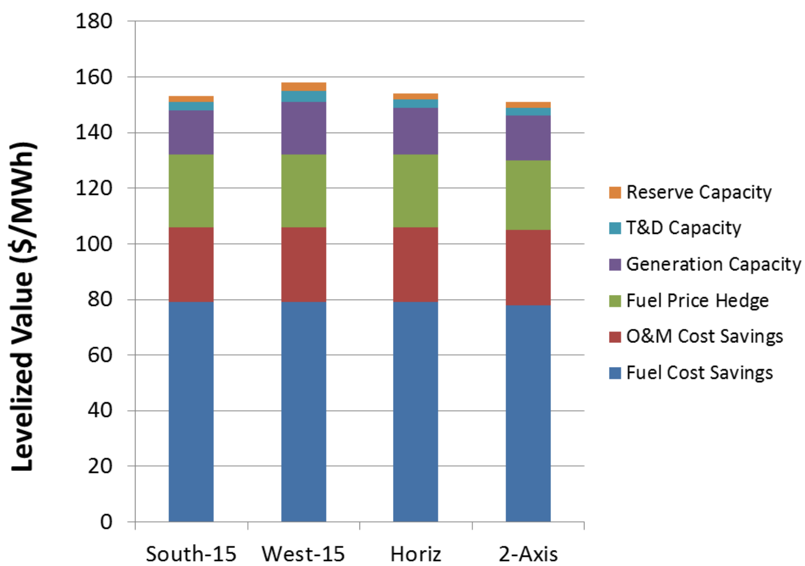
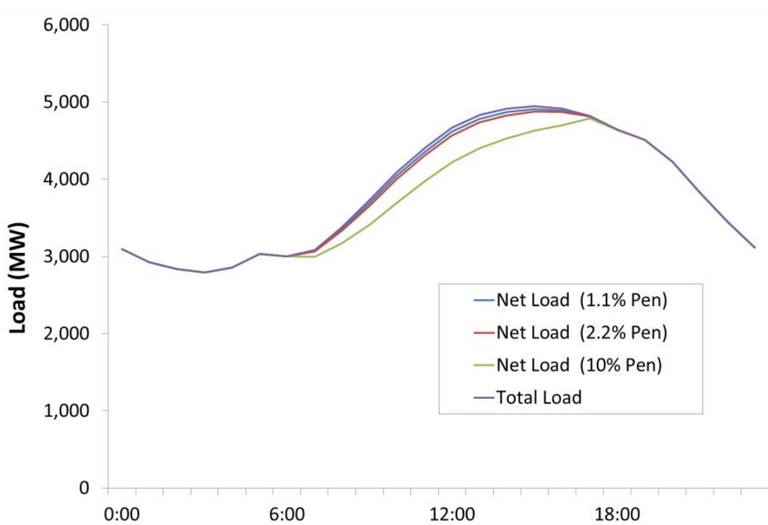



**Figure ES- 2. Peak load day load profile, by penetration level.**



The following observations and conclusions may be made:

- This study was performed entirely through the use of data available to the public (this was not a study sponsored by CPS Energy). Results from this report would be more representative if actual financial and operating data were made available in a more in-depth follow-on study.
- The analysis did not include the cost of accepting solar onto the grid. Such an analysis would require data on individual PV systems. PV variability and its cost impacts may be determined through modeling, but the required input data was not available for this study.
- Additional societal value in the form of economic development and environmental mitigation are also realized by the introduction of PV. However, these values were not included because they do not accrue to the utility.
- The penetration levels considered under this study did not result in significant variations in value. However, further penetration levels beyond 2.2% would result in lower total value amounts. As shown in Figure ES- 2, additional PV capacity would not result in a further reduction of peak load.

# Contents

# Introduction: The Value of PV

This report attempts to quantify the value of distributed solar electricity in San Antonio, Texas. It uses methodologies and analytical tools that have been developed over several years. The framework supposes that PV is located in the distribution system. PV that is located close to the loads provides the highest value per unit of energy to the utility because line losses are avoided, thereby increasing the value of solar relative to centrally-located resources.

The value of PV may be considered the aggregate of several components, each estimated separately, described below. The methods used to calculate value are described in more detail in the Appendices.

| Value Component | Basis |
|---|---|
| Fuel Cost Savings | The cost of natural gas fuel that would have to be purchased for a gas turbine (CCGT) plant operating on the margin to meet electric loads and T&D losses. |
| O&M Cost Savings | The operations and maintenance costs for the CCGT plant. |
| Generation Capacity Value | The cost to build CCGT generation capacity. |
| T&D Capacity Value | The cost of money savings resulting from deferring T&D capacity additions. |
| Avoided Reserve Capacity | The cost to build CCGT capacity to meet reserve margin. |
| Fuel Price Hedge Value | The cost to minimize natural gas fuel price uncertainty. |

## Fuel Cost Savings

Distributed PV generation offsets the cost of power generation. Each kWh generated by PV results in one less unit of energy that the utility needs to purchase or generate. In addition, distributed PV reduces system losses so that the cost of the wholesale generation that would have been lost must also be considered.

Under this study, the value is defined as the cost of natural gas fuel that would otherwise have to be purchased to operate a gas turbine (CCGT) plant and meet electric loads and T&D losses. The study presumes that the energy delivered by PV displaces energy at this plant.

Whether the utility receives the fuel cost savings directly by avoiding fuel purchases, or indirectly by reducing wholesale power purchases, the method of calculating the value is the same.

## O&M Cost Savings

Under the same mechanism described for Fuel Cost Savings, the utility realizes a savings in O&M costs due to decreased use of the CCGT plant. The cost savings are assumed to be proportional to the energy avoided, including loss savings.

## Fuel Price Hedge Value

PV generation is insensitive to the volatility of natural gas or other fuel prices, and therefore provides a hedge against price fluctuation. This is quantified by calculating the cost of a risk mitigation investment that would provide price certainty for future fuel purchases.

## Generation Capacity Value

In addition to the fuel and O&M cost savings, the total cost of power generation includes capital cost. To the extent that PV displaces the need for generation capacity, it would be valued as the capital cost of displaced generation. The key to valuing this component is to determine the effective load carrying capability (ELCC) of the PV fleet, and this is accomplished through an analysis of hourly PV output relative to overall utility load.

## T&D Capacity Value

In addition to capital cost savings for generation, PV potentially provides utilities with capital cost savings on T&D infrastructure. In this case, PV is not assumed to displace capital costs but rather defer the need. This is because local loads continue to grow and eventually necessitate the T&D capital investment. Therefore, the cost savings realized by distributed PV is merely the cost of capital saved in the intervening period between PV installation and the time at which loads again reach the level of effective PV capacity.

# Approach

## Fleet Configurations

Four PV system configurations were included in the study:

- South-15 (south-facing, 15-degree tilt, fixed)
- West-15 (west-facing, 15-degree tilt, fixed)
- Horizontal (fixed)
- 2-Axis (tracking)

These were selected in order to capture possible variations in value due to the different production profiles. For example, west-facing systems are sometimes found to be the best match with utility loads and have the potential to provide more capacity benefits. On the other hand, tracking systems deliver more energy per unit of rated output, so they have the potential to offer more energy benefits (e.g., fuel cost savings).

## Penetration Level

Two PV penetration levels were considered. The current penetration includes 46 MW of utility-owned PV generation and 9 MW of customer-owned PV generation (55 MW total). The peak load is 4,911 MW, so the current level of penetration is about 1.1% of the peak load. All PV capacity is assumed to be behind-the-meter. For example, the peak of 4,911 MW represents the net load with PV while the total load exceeds this amount by the amount of PV production at the peak hour.

A 2.2% penetration level (108 MW) is assumed as a second scenario. This corresponds to the City of San Antonio Vision 2020 goals. This scenario represents a change in the hourly load profile of the utility with a potential change in value.

Data for the fleet of individual PV systems was not available for this study. The 55 MW (1.1% penetration scenario) and 108 MW (2.2% penetration scenario) "baseline" PV capacity is assumed to be in the South-15 orientation. This assumption is made on the basis of the distribution of orientations under the California Solar Initiative (CSI) experience for which data is available. In CSI, the most common tilt angle is 20 degrees, or 54% of the average latitude (average of 32.7 degrees and 41.9 degrees). For

San Antonio, the percentage is assumed to hold true, so the most common tilt by this method would be 54% of the 29.4 degree latitude, or about 15 degrees. Azimuth angle is assumed to be 0 degrees (south).

The baseline capacity is then modeled using the South-15 orientation in order to generate time series data for the loads.

The value of solar per MWh decreases with increasing penetration for several reasons:

- The match between PV output and loads is reduced. As more PV is added to the resource mix, the peak shifts to non-solar hours, thereby limiting the ability of PV to support the peak.
- Line losses are related to the square of the load. Consequently, the greatest marginal savings provided by PV is achieved with small amounts of PV. By adding larger and larger quantities of PV, the loss savings continue to be gained, but at decreasing rates.

## Scenarios and System Modeling

Value was determined for each of the four system configurations. For modeling purposes, systems were located in San Antonio (latitude 29.42390 degrees north and longitude 98.49330 degrees West), a rating of 1 kW-AC rating, a module derate factor (90%), inverter efficiency (95%) and a loss factor (80%).

Fleets were modeled for all hours of 2011 using SolarAnywhere® satellite-derived irradiance data and simulation model with a 10 km x 10 km pixel resolution. [1] Under this procedure, the fleet output for each scenario is location- and time-correlated with hourly ERCOT zonal loads.

## Inputs and Assumptions

Details of inputs and assumptions, including economic assumptions, T&D loss calculations, electric load data, load growth rate, and distribution costs, are presented in Appendix 1.

[1] http://www.solaranywhere.com.

# Study Results

## Technical Results

A summary of technical performance results is presented in Table 1 for the current penetration level (1.1% of peak load). Annual energy production is the modeled output for 2011. Capacity factor is the annual energy production relative to a baseload plant operating at 100% availability with the same rated output. Generation Capacity is Effective Load Carrying Capability (ELCC) expressed as a percentage of rated capacity. T&D Capacity is a measure of the direct annual peak-load reduction provided by the PV system expressed as a percentage of rated capacity.

**Table 1. Technical results, current penetration level.**

| | South-15 | West-15 | Horiz | 2-Axis |
|---|---|---|---|---|
| System Rating (kWac) | 1 | 1 | 1 | 1 |
| Annual Energy Production (MWh) | 2.003 | 1.869 | 1.870 | 2.687 |
| Capacity Factor (%) | 23% | 21% | 21% | 31% |
| Generation Capacity (% of Sys. Rating) | 71% | 82% | 71% | 97% |
| T&D Capacity (% of Sys. Rating) | 82% | 93% | 78% | 108% |

## Value Analysis Results

Figure 1 shows the value results in in dollars per kW installed. Figure 2 shows the value data in levelized dollars per MWh generated. Table 2 and Table 3 shows the same data in tabular form.

The total levelized value ranges from $151 per MWh to $158 per MWh. Of this, the highest value components are the Fuel Cost Savings ($79 per MWh), the O&M Cost Savings ($27 per MWh), and the Fuel Price Hedge ($26 per MWh).

**Figure 1. San Antonio Value of Solar ($ per kW), current penetration level.**

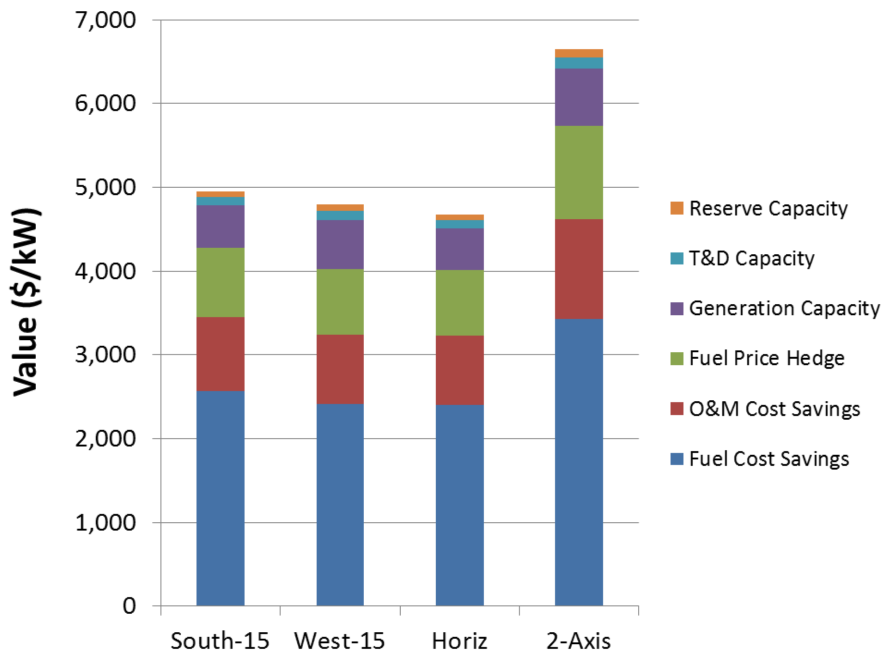



**Figure 2. San Antonio Value of Solar (levelized $ per kWh), current penetration level.**

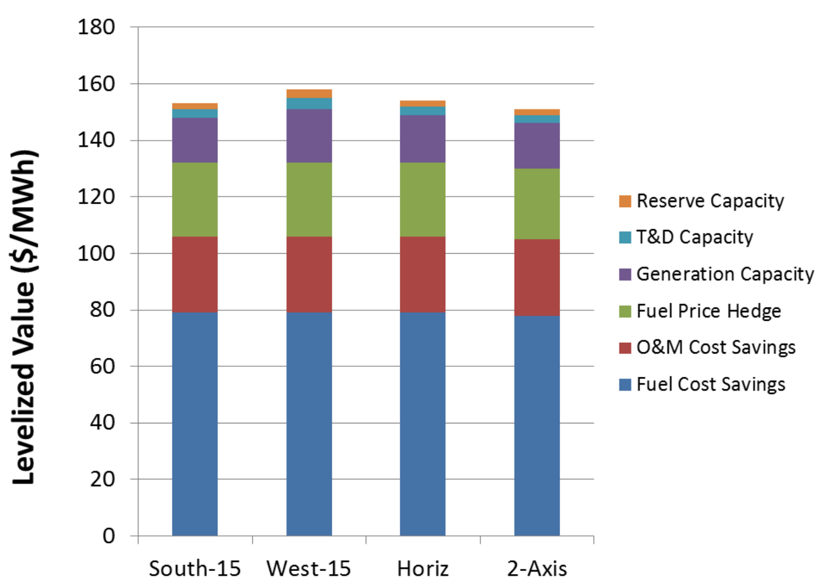


**Table 2. San Antonio Value of Solar ($ per kW), current penetration level.**

| | South-15 | West-15 | Horiz | 2-Axis |
|---|---|---|---|---|
| Fuel Cost Savings | 2,563 | 2,409 | 2,400 | 3,430 |
| O&M Cost Savings | 885 | 832 | 829 | 1,185 |
| Fuel Price Hedge | 831 | 781 | 779 | 1,113 |
| Generation Capacity | 506 | 585 | 504 | 692 |
| T&D Capacity | 99 | 112 | 94 | 130 |
| Reserve Capacity | 70 | 81 | 69 | 95 |
| Total | 4,954 | 4,800 | 4,675 | 6,645 |

**Table 3. San Antonio Value of Solar (levelized $ per MWh), current penetration level.**

| | South-15 | West-15 | Horiz | 2-Axis |
|---|---|---|---|---|
| Fuel Cost Savings | 79 | 79 | 79 | 78 |
| O&M Cost Savings | 27 | 27 | 27 | 27 |
| Fuel Price Hedge | 26 | 26 | 26 | 25 |
| Generation Capacity | 16 | 19 | 17 | 16 |
| T&D Capacity | 3 | 4 | 3 | 3 |
| Reserve Capacity | 2 | 3 | 2 | 2 |
| Total | 153 | 158 | 154 | 151 |

Other observations:

- **Tracking Systems.** The value for the 2-Axis tracking system exceeds the others by nearly $2,000 per kW. However, its value expressed as levelized $ per MWh is close to the other configurations. This is because the tracking system delivers more energy for the same capacity. The tracking system has a 31% capacity factor, much higher than the average 24% capacity factor.
- **Fuel and O&M.** These value components are high compared to similar studies. This can be explained by the high heat rate[2] of 9,750 Btu per kWh. However, this high heat rate is consistent with the "advanced gas turbine" characteristics, whereas most studies use combined cycle technology as the marginal unit. The selected resource has a relatively low capital cost (leading

[2] See Appendix 1 for rationale of input assumptions.

to low capacity value) but a high heat rate and O&M cost. The end result, relative to other studies, is a low capacity value but high fuel and O&M values.

- **Consistency of energy-denominated value**. All of the configurations are shown to be close in value when expressed in levelized value. The average value of all configurations is $155 per MW, and the maximum deviation from this is only 2.7 percent. If CPS energy were to compensate solar generation on the basis of value, it could be done on an energy-denominated basis.

## High Penetration Results

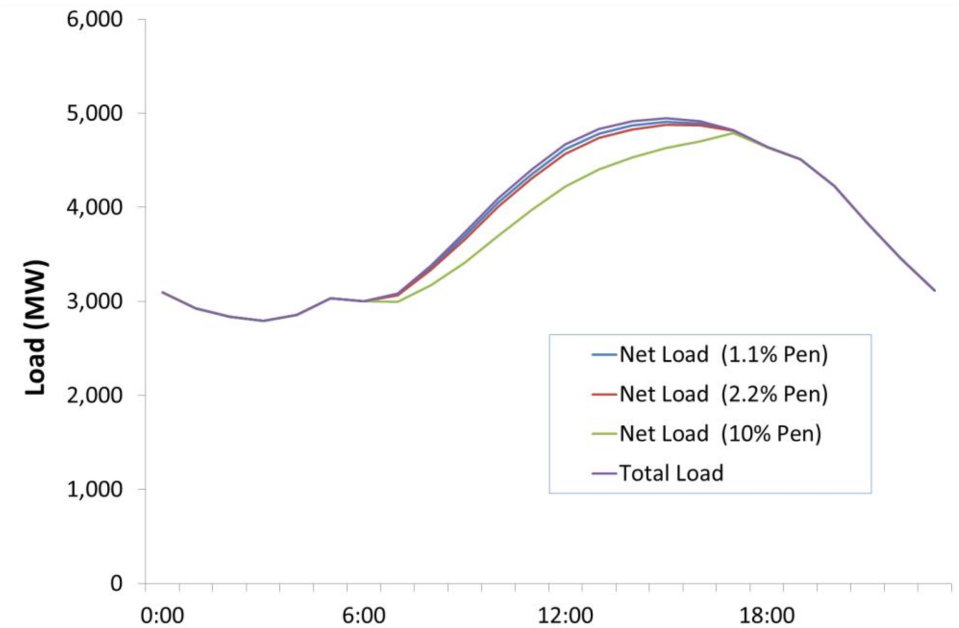
As part of the study, the impact of a "high penetration" scenario was investigated corresponding to the City of San Antonio Vision 2020 goals. The results are shown for the South-15 configuration in Table 4. While the higher penetration level results in lower value, the difference in value is only 0.6%.

**Table 4. Value ($ per kW), by penetration level (South-15).**

| | PENETRATION LEVEL | |
|---|---|---|
| | **1.1%** | **2.2%** |
| Fuel Cost Savings | 2,563 | 2,559 |
| O&M Cost Savings | 885 | 884 |
| Fuel Price Hedge | 831 | 830 |
| Generation Capacity | 506 | 487 |
| T&D Capacity | 99 | 99 |
| Reserve Capacity | 70 | 67 |
| Total | 4,954 | 4,926 |

Figure 3 illustrates how the two scenarios do not significantly change the load shape. This figure is constructed from the time series of load on the peak day, adding the effects of PV capacity. The peak hour decreases somewhat, but any additional increase in PV beyond the 2.2% penetration level will not reduce the peak further. As shown in the 10% penetration curve, the peak does not reduce, even though the total energy required for supplemental generation goes down.

**Figure 3. Impact of penetration level on CPS Energy peak load day.**




## Societal Benefits

This report is based on models designed to quantify utility savings based on deployment of distributed solar. This report does not attempt to include societal savings, such as reducing the likelihood of extreme weather events and other damage attributable to climate instability.

However, PV does provide a number of benefits to society that are not included in the above analysis such as moderating the impacts of climate change, mitigating environmental impacts, and stimulating the local economy. These are covered separately in this section because they do not accrue to the utility and hence do not impact electric rates or utility operations.

### Climate Change Mitigation

PV is a renewable resource that does not generate carbon dioxide or other greenhouse gasses in order to produce electricity. Greenhouse gases are reduced because PV generally offsets fossil fired combustion processes. When PV is generating, less supplemental gas-fired generation is required to meet loads. In addition, since PV is supplying local loads, the losses transmission and distribution system are also avoided, leading to additional greenhouse gas savings.

## Environmental Mitigation

CPS Energy's electrical generation mix[3] is shown in Table 5 along with a range of nominal costs[4] for environmental impact by fuel source. Assuming that PV only displaces natural gas and goal, the the environmental value is shown to be in the range of $40 to $103 per MWh in the CPS Energy electrical service territory.

**Table 5. Environmental Mitigation Value**

| Generation Mix | | Prorated Environmental Cost ($/MWh) | | |
|---|---|---|---|---|
| **37%** | Natural Gas/Oil | 11.4 | to | 22.8 |
| **32%** | Coal | 28.8 | to | 80 |
| **16%** | Nuclear | 0.0 | to | 0.0 |
| **13%** | Purchased Renewables | 0.0 | to | 0.0 |
| **2%** | Other Purchased | 0.0 | to | 0.0 |
| **Environmental value** | | **40.2** | **to** | **102.8** |

## Economic Development Value

A less tangible but nonetheless important component of value derives from the increase in local jobs and the possible tax revenues that follow. PV development in the San Antonio area will expand the jobs base related to installation and construction labor, and there will be indirect job benefits as well.

Only direct economic activity created as a measure of PV-related economic development is considered. Lost jobs from conventional generation are netted. However, the analysis is simplified considerably by ignoring secondary impacts such as:

- Lost jobs from other industries (solar jobs are assumed to be "created," lowering the unemployment level, rather than transferred to the solar industry from other industries)
- Reductions in unemployment payments and the subsequent economic effects

[3] Resource mix taken from: http://www.cpsenergy.com/About_CPS_Energy/Who_We_Are/Environmental_Stewardship/Sustainability_Environmental_2012_Update.asp

[4] R. Perez, et. al., "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania," October 2012.

- Increased secondary local economic activity due to spending from solar workers
- Higher costs that result from new solar worker demand for secondary goods and services
- Reduced consumption of electricity in response to higher prices and resulting job loss
- Secondary non-energy job losses resulting from higher energy costs, e.g., caused by lower demand associated with higher manufacturing costs

With these caveats, the new direct economic benefit of solar capacity installed in the CPS Energy service territory would be about $3,750 per kW, estimated as follows:

- Assume that turnkey PV costs $6,000 per kW vs. $712 per kW for conventional generation (Appendix 1), and that PV is composed of 1/3 power hardware (modules and inverters) and 2/3 structure, installation and soft costs. Assume further that 20% of PV power hardware costs and 90% of the other costs are traceable to domestic jobs, while 50% of conventional generation cost is assumed to be domestic jobs.
- Noting that PV has an effective capacity (South-15) of 71% of rated AC capacity as shown in Table 1, the domestic jobs-traceable amount spent on PV is equal to:

$$\$6{,}000\ per\ kWpv \times \left[\left(\frac{1}{3}\right) \times 20\% + \left(\frac{2}{3}\right) \times 90\%\right] = \$4{,}000\ per\ kWpv$$

- The domestic jobs-traceable amount spent on CCGT is:

$$\$712\ per\ kW\ \times \left(\frac{0.71\ kW}{kWpv}\right) \times 50\% = \$250\ per\ kWpv$$

- The net jobs-traceable amount is therefore about:

$$\$4000\ - \$250 = \$3{,}750\ per\ kWpv$$

## Solar Integration Costs

In addition to benefits, CPS Energy would have to take measures to accept the variable solar generation onto its grid. The costs of integrating solar are not quantified here because of lack of data on individual systems. These costs could be quantified through known methods using the geographical placement of systems across the service territory, from which aggregate fleet variability and regulation costs may be calculated.

While integration costs were not evaluated here, a recent study for New Jersey and Pennsylvania estimated these costs to be in the range of $10-20 per MWh[5]

As an alternative to conventional regulation, energy storage could be used to manage variability. Storage could be situated as scattered small systems associated with the PV resources directly, community-level or substation based storage, or even large systems connected to transmission.

Depending upon design, these systems could be operated either in response to PV output, local voltage, or system frequency. Local storage could, for example, be tied behind the meter to the inverters, absorbing the fluctuating power during times of high variability. If sufficient storage capacity were available, it could also be used by the customer to help manage peak demand. Community or substation storage might be operated based on local line voltage readings, dispatch center inputs, or a combination of the two. Large central systems might participate in the regional ancillary service market and operate based on an AGC or similar signal in real time.

A novel use of storage would be to take advantage of batteries on-board electric vehicles. For example, during the daylight hours when commuter vehicles are recharging, these grid-connected resources could be used for regulating solar variability. Some vehicles may be charged routinely from solar resources, so these would easily be able to provide a regulation function. In other cases, vehicles could provide a wide range of energy, capacity, and ancillary services depending upon price signals and tariff design.

[5] R. Perez, et. al., "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania," October 2012.

# Conclusions and Recommendations

- This study was performed entirely through the use of data available to the public. None of the data was provided by, or reviewed by, CPS Energy. Load data, cost data, and PV system data were all estimated through the use of data from EIA, ERCOT, BLS, and other sources. The results from this report would be more representative if actual financial and operating data were made available in a more in-depth follow-on study.
- The analysis did not include the cost of accepting solar onto the grid. Such an analysis would require data on individual PV systems. Only through knowledge of the physical spread of capacity across the system can the impacts of solar variability be determined, and this data is only known to the utility.
- Additional societal value in the form of economic development and environmental mitigation are also realized by the introduction of PV. However, these values were not included because they do not accrue to the utility.

# Appendix 1. Inputs and Assumptions

## Economic Assumptions

The utility discount rate is taken as 4.4% based on the CPS Energy Audited financial statement for the year ending January 31, 2012. The value is based on the weighted average of long term bond interest rates.

Escalation is assumed to be 3.38% (seven year PPI escalation for turbine and power equipment) for everything except T&D escalation which is assumed to be 3.89% (seven year PPI escalation for electric distribution).

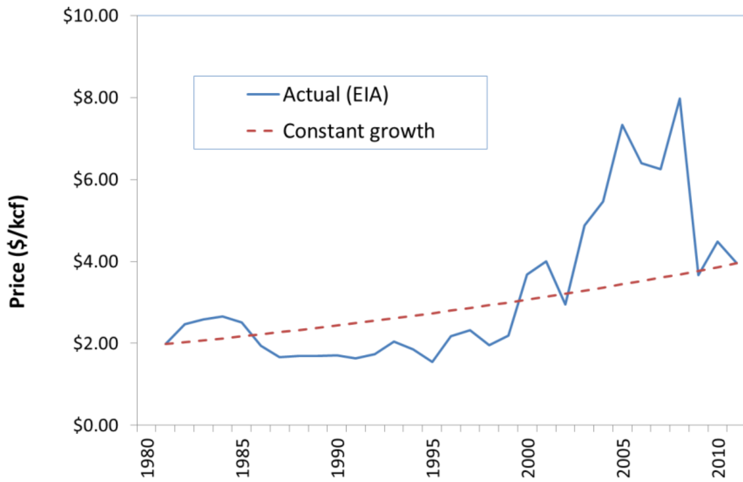
Generation costs are based on the "advanced combustion turbine" in the EIA *2012 Annual Energy Outlook,*[6] corresponding to the practice of the Texas PUC for energy efficiency capacity evaluations.[7] Total overnight capital cost is $712 per kW. Fixed and variable O&M costs are combined for a total of $14.64 per MWh, assuming a 20% capacity factor. The heat rate is 9,750 Btu per kWh.

Reserve capacity costs are based on the ERCOT target margin of 13.75%. Using the same overnight capital cost, the avoided reserve capacity cost is $712 x 13.75 = $98 per kW.

Natural gas prices are taken from NYMEX gas futures for the first 12 years. For the remaining years, NYMEX prices are not available. Therefore prices are assumed to escalate at 2.33% per year based on the equivalent constant rate 30-year escalation of wellhead natural gas prices (EIA).

[6] http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf. All costs are escalated to 2012 dollars.

[7] P.U.C. SUBST. R. 25.181), available at http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.181/25.181.pdf. The upfront capital cost is used rather than the equivalent amortized value of $80 per kW-year because it represents utility-owned capacity rather than capacity procured in the market.




## T&D Losses

T&D Losses were not available from CPS Energy. Therefore losses for AEP Texas Central as reported to ERCOT[8] are taken as a proxy.

| | |
|---|---|
| Energy at generation | 1.09779 |
| Energy at dist substation | 1.06939 |
| Energy at customer | 1.00000 |
| | |
| Avg T&D Losses | 8.91% |
| Avg D Losses | 6.49% |

## Hourly Electric Load Data

Load data was not available from CPS Energy. Therefore, hourly loads for the ERCOT South Central Zone (including Bexar County) were used as a proxy, scaled to correspond to the 2011 CPS Energy peak load[9] of 4,911 MW. In the resulting data set, this peak is observed on August 29, 2011 at HE 16:00 CST.

## Peak Load Growth Rate

The growth rate of the peak load at CPS Energy is assumed to grow at the same rate as that of the ERCOT South Central Zone. These loads were available from April 2003 (when zonal definitions were

[8] Available at http://www.ercot.com, "Summary of SILF equation coefficients – 2010").
[9] "The Future is Here," 2011/2012 CPS Energy Annual Report.

changed from a previous convention), so the 2003 peak was included in this calculation. By comparing the 2003 peak to the 2011 peak, the resulting growth rate of 2.32% per year is determined.

# Distribution Costs

CPS Energy distribution costs were not available. IOUs in ERCOT region were considered as proxies for CPS Energy, but none were found to report both peak loads and the electric energy account to FERC (required for the analysis). Therefore El Paso Electric was selected as a proxy as it is a comparably-sized utility for which data was available.

To evaluate the T&D benefits of PV, only costs that are potentially deferrable by PV are included as shown in Table 6. Other capital costs would be required. For example, line transformers are assumed to be required with the same rating as before in order to serve load when PV is not available.

**Table 6. 2010 distribution costs at El Paso Electric.**

| Line | Account | Account Name | Additions [A] | Retirements [R] | Deferrable ? | Deferable Amount = [A] - [R] |
|---|---|---|---|---|---|---|
| 59 | 4. | **DISTRIBUTION PLANT** | | | | |
| 60 | (360) | Land and Land Rights | 1,050,668 | | ✓ | 1,050,668 |
| 61 | (361) | Structures and Improvements | 117,566 | | ✓ | 117,566 |
| 62 | (362) | Station Equipment | 9,600,537 | | ✓ | 9,600,537 |
| 63 | (363) | Storage Battery Equipment | | | | |
| 64 | (364) | Poles, Towers, and Fixtures | 8,228,430 | 129,103 | | |
| 65 | (365) | Overhead Conductors and Devices | 5,248,949 | 9,204 | | |
| 66 | (366) | Underground Conduit | 4,958,433 | 461 | | |
| 67 | (367) | Underground Conductors and Devices | 5,886,469 | 33,251 | | |
| 68 | (368) | Line Transformers | 16,317,159 | 395,518 | | |
| 69 | (369) | Services | 1,087,490 | | | |
| 70 | (370) | Meters | 2,148,148 | 279,746 | | |
| 71 | (371) | Installations on Customer Premises | 605,782 | 1,341 | | |
| 72 | (372) | Leased Property on Customer Premises | | | | |
| 73 | (373) | Street Lighting and Signal Systems | 134,439 | 9,323 | | |
| 74 | (374) | Asset Retirement Costs for Distribution Plant | | | | |
| 75 | TOTAL | **Distribution Plant (Enter Total of lines 60 thru 74)** | 55,384,070 | 857,947 | | **10,768,771** |

Costs were obtained for each year in 2006-11, the average capital investment per unit growth rate was obtained using methods developed previously for NYSERDA,[10] and the 30-year NPV was taken for the potentially deferrable investment.  The final step was to scale the NPV by peak load a CPS Energy relative to El Paso Electric.

[10] Norris and Hoff, "PV Valuation Tool," Final Report (DRAFT), NYSERDA, May 2012.

# Appendix 1: Detailed Assumptions

The full set of input assumptions are shown in Table 7.

**Table 7. Input assumptions and units common to all scenarios.**

| Input Name | Value | | Unit |
|---|---|---|---|
| | 1.1 % Pen | 2.2% Pen | |
| **PV Assumptions** | | | |
| PV Degradation | 0.50% | | per year |
| PV System Life | 30 | | years |
| **Economic Factors** | | | |
| Discount Rate | 4.40% | | per year |
| **Generation Factors** | | | |
| Gen Capacity Cost | $712 | | per kW ELCC |
| Gen Heat Rate (First Year) | 9750 | | BTU/kWh |
| Gen Plant Degradation | 0.00% | | per year |
| Gen O&M Cost (First Year) | $14.64 | | per MWh |
| Gen O&M Cost Escalation | 3.38% | | per year |
| **NG Wholesale Market Factors** | | | |
| End of Term NG Futures Price Escalation | 2.33% | | per year |
| **Utility System** | | | |
| Load Loss Condition | 2,979 | 2,964 | MW |
| Avg. Losses (at Condition) | 8.91% | 8.91% | % |
| Garver M Characteristic | 252 | 250 | MW |
| Electric Load Data (Series Name) | San Antonio Syst 1.1 Pct | San Antonio Syst 2.2 Pct | |
| **Distribution** | | | |
| Distribution Expansion Cost | $2,808,957,009 | $2,808,957,009 | $ |
| Distribution Expansion Cost Escalation | 3.89% | 3.89% | per year |
| Distribution Load Growth | 114 | 114 | MW per year |
| Load Loss Condition | 2,902 | 2,887 | MW |
| Avg. Losses (at Condition) | 6.49% | 6.49% | % |
| Latitude | 29.4239 | 29.4239 | |
| Longitude | -98.4933 | -98.4933 | |
| Electric Load Data (Series Name) | San Antonio Dist 1.1 Pct | San Antonio Dist 2.2 Pct | |
| **Custom Components** | | | |
| Avoided Reserve Capacity | 98 | | $/kW ELCC |

PV degradation is assumed to be 0.50% per year indicating that the output of the system will degrade over time. This is a conservative assumption (PV degradation is likely to be less than 0.5% per year). Studies often ignore degradation altogether because the effect is small, but it is included here for completeness.

The study period is taken as 30 years, corresponding to typical PV lifetime assumptions.

PV is assumed to displace power generated from peaking plants fueled by natural gas. Gas turbine capital, O&M, heat rate, and escalation values are taken from the EIA.[11] Plant degradation is assumed to be zero.

Costs for generation O&M are assumed to escalate at 3.38%, calculated from the change in Producer Price Index (PPI) for the "Turbine and power transmission equipment manufacturing" industry[12] over the period 2004 to 2011.

Natural gas prices used in the fuel price savings value calculation are obtained from the NYMEX futures prices. These prices, however, are only available for the first 12 years. Ideally, one would have 30 years of futures prices. As a proxy for this value, it is assumed that escalation after year 12 is constant based on historically long term prices to cover the entire 30 years of the PV service life (years 13 to 30). The EIA published natural gas wellhead prices from 1922 to the present.[13] It is assumed that the price of the NG futures escalates at the same rate as the wellhead prices.[14] A 30-year time horizon is selected with 1981 gas prices at $1.98 per thousand cubic feet and 2011 prices at $3.95. This results in a natural gas escalation rate of 2.33%.

---

[11] Updated Capital Cost Estimates for Electricity Generation Plants, U.S. Energy Information Administration, November 2010, available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf. Taken from Table 1, page 7. Costs are escalated to 2012 dollars.

[12] PPI data is downloadable from the Bureau industry index selected was taken as the most representative of power generation O&M. BLS does publish an index for "Electric power generation" but this is assumed.

[13] US Natural Gas Prices (Annual), EIA, release date 2/29/2012, available at http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

[14] The exact number could be determined by obtaining over-the-counter NG forward prices.

# Appendix 2: Methodologies

## Overview

The methodologies used in the present project drew upon studies performed by CPR for other states and utilities. In these studies, the key value components provided by PV were determined by CPR, using utility-provided data and other economic data.

The ability to determine value on a site-specific basis is essential to these studies. For example, the T&D Capacity Value component depends upon the ability of PV to reduce peak loads on the circuits. An analysis of this value, then, requires:

Hour by hour loads on distribution circuits of interest.

- Hourly expected PV outputs corresponding to the location of these circuits and expected PV system designs.
- Local distribution expansion plan costs and load growth projections.

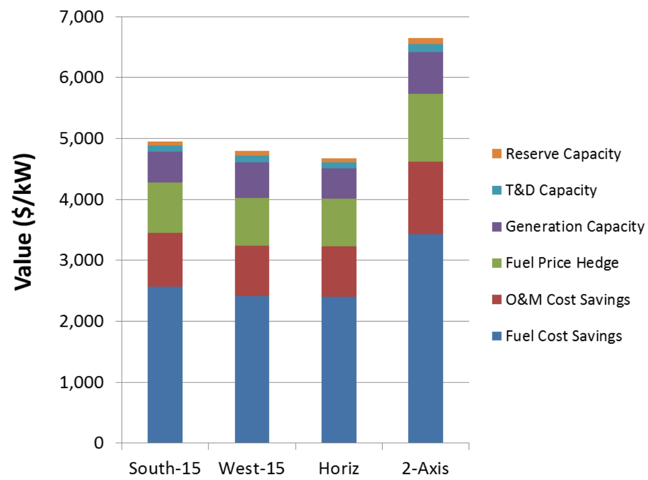
## Units of Results

The discounting convention assumed throughout the report is that energy-related values occur at the end of each year and that capacity-related values occur immediately (i.e., no discounting is required).[15]

The Present Value results are converted to per unit value (Present Value $/kW) by dividing by the size of the PV system (kW). An example of this conversion is illustrated in Figure 4 for results from a previous study. The y-axis presents the per unit value and the x-axis presents seven different PV system configurations. The figure illustrates how value components can be significantly affected by PV system configuration. For example, the tracking systems, by virtue of their enhanced energy production capability, provide greater generation benefits.

[15] The effect of this will be most apparent in that the summations of cash flows start with the year equal to 1 rather than 0.

**Figure 4. Sample results.**




The present value results per unit of capacity ($/kW) are converted to levelized value results per unit of energy ($/MWh) by dividing present value results by the total annual energy produced by the PV system and then multiplying by an economic factor.

## PV Production and Loss Savings

### PV System Output

An accurate PV value analysis begins with a detailed estimate of PV system output. Some of the energy-based value components may only require the total amount of energy produced per year. Other value components, however, such as the energy loss savings and the capacity-based value components, require hourly PV system output in order to determine the technical match between PV system output and the load. As a result, the PV value analysis requires time-, location-, and configuration-specific PV system output data.

For example, suppose that a utility wants to determine the value of a 1 MW fixed PV system oriented at a 30° tilt facing in the southwest direction located at distribution feeder "A". Detailed PV output data that is time- and location-specific is required over some historical period, such as from Jan. 1, 2001 to Dec. 31, 2010.

### Methodology

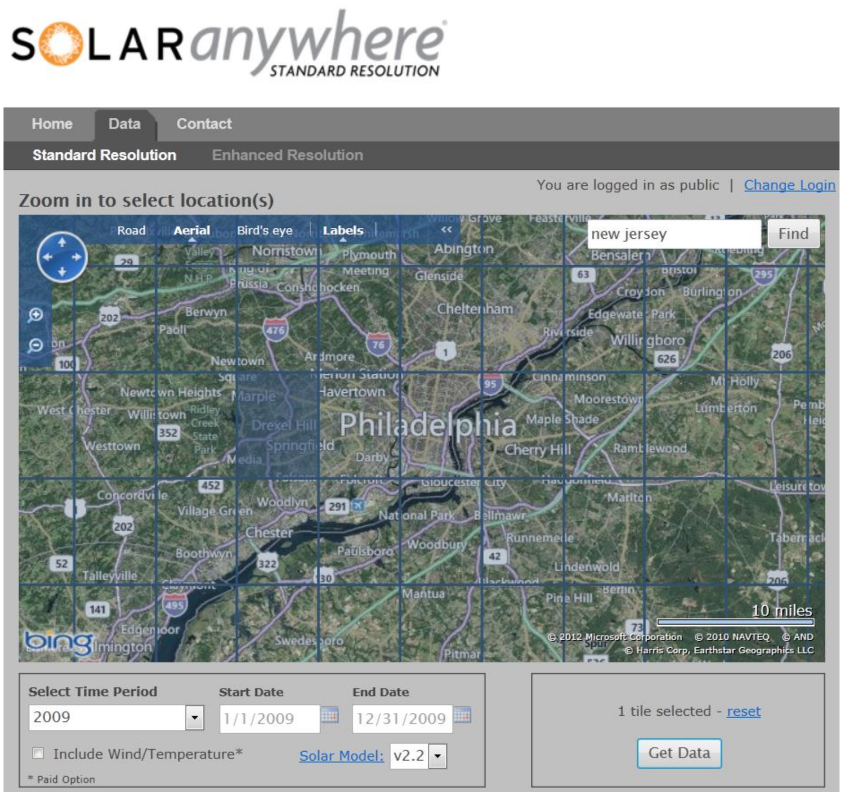
It would be tempting to use a representative year data source such as NREL's Typical Meteorological Year (TMY) data for purposes of performing a PV value analysis. While these data may be representative of long-term conditions, they are, by definition, not time-correlated with actual distribution line loading on an hourly basis and are therefore not usable in hourly side-by-side comparisons of PV and load. Peak substation loads measured, say, during a mid-August five-day heat wave must be analyzed alongside PV data that reflect the same five-day conditions. Consequently, a technical analysis based on anything other than time- and location-correlated solar data may give incorrect results.

CPR's SolarAnywhere® and PVSimulator™ software services will be employed under this project to create time-correlated PV output data. SolarAnywhere is a solar resource database containing almost 14 years of time- and location-specific, hourly insolation data throughout the continental U.S. and Hawaii. PVSimulator, available in the SolarAnywhere Toolkit, is a PV system modeling service that uses this hourly resource data and user-defined physical system attributes in order to simulate configuration-specific PV system output.

The SolarAnywhere data grid web interface is available at www.SolarAnywhere.com (Figure 5). The structure of the data allows the user to perform a detailed technical assessment of the match between PV system output and load data (even down to a specific feeder). Together, these two tools enable the evaluation of the technical match between PV system output and loads for any PV system size and orientation.

Previous PV value analyses were generally limited to a small number of possible PV system configurations due to the difficulty in obtaining time- and location-specific solar resource data. This new value analysis software service, however, will integrate seamlessly with SolarAnywhere and PVSimulator. This will allow users to readily select any PV system configuration. This will allow for the evaluation of a comprehensive set of scenarios with essentially no additional study cost.

**Figure 5. SolarAnywhere data selection map.**




## Loss Savings

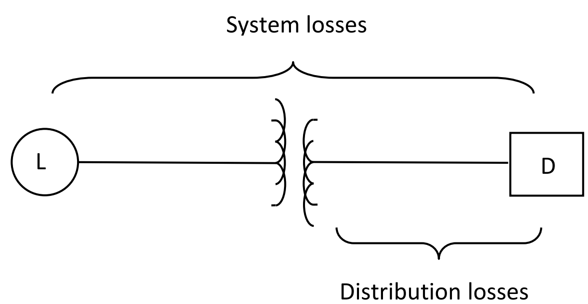
### Introduction

Distributed resources reduce system losses because they produce power in the same location that the power is consumed, bypassing the T&D system and avoiding the associated losses.

Loss savings are not treated as a stand-alone benefit under the convention used in this methodology. Rather, the effect of loss savings is included separately for each value component. For example, in the section that covers the calculation of Energy Value, the quantity of energy saved by the utility includes both the energy produced by PV and the amount that would have been lost due to heating in the wires if the load were served from a remote source. The total energy that would have been procured by the utility equals the PV energy plus avoided line losses. Loss savings can be considered a sort of “adder” for each benefit component.

This section describes the methodology for calculating loss savings for each hour. The results of these calculations are then used in subsequent sections. As illustrated in Figure 6, it will be important to note that, while the methodology describes the calculation of an hourly loss result, there are actually two different loss calculations that must be performed: "system" losses, representing the losses incurred on both the transmission and distribution systems (between generation load, L, and end-use demand, D), and "distribution" losses, representing losses specific to distribution system alone.

**Figure 6. System losses versus distribution losses.**




The two losses are calculated using the same equation, but they are each applicable in different situations. For example, "Energy Value" represents a benefit originating at the point of central generation, so that the total system losses should be included. On the other hand, "T&D Capacity Value" represents a benefit as measured at a distribution substation. Therefore, only the losses saved on the distribution system should be considered.

The selection of "system" versus "distribution" losses is discussed separately for each subsequent benefit section.

## Methodology

One approach analysts have used to incorporate losses is to adjust energy- and capacity-related benefits based on the *average* system losses. This approach has been shown to be deficient because it fails to capture the true reduction in losses on a marginal basis. In particular, the approach underestimates the reduction in losses due to a peaking resource like PV. Results from earlier studies demonstrated that loss savings calculations may be off by more than a factor of two if not performed correctly [6].

For this reason, the present methodology will incorporate a calculation of loss savings on a marginal basis, taking into account the status of the utility grid when the losses occur. Clean Power Research has previously developed methodologies based on the assumption that the distributed PV resource is small relative to the load (e.g., [6], [9]). CPR has recently completed new research that expands this methodology so that loss savings can now be determined for any level of PV penetration.

## Fuel Cost Savings and O&M Cost Savings

### Introduction

Fuel Cost Savings and O&M Cost Savings are the benefits that utility participants derive from using distributed PV generation to offset wholesale energy purchases or reduce generation costs. Each kWh generated by PV results in one less unit of energy that the utility needs to purchase or generate. In addition, distributed PV reduces system losses so that the cost of the wholesale generation that would have been lost must also be considered. The capacity value of generation is treated in a separate section.

### Methodology

These values can be calculated by multiplying PV system output times the cost of the generation on the margin for each hour, summing for all hours over the year, and then discounting the results for each year over the life of the PV system.

There are two approaches to obtaining the marginal cost data. One approach is to obtain the marginal costs based on historical or projected market prices. The second approach is to obtain the marginal costs based on the cost of operating a representative generator that is on the margin.

Initially, it may be appealing to take the approach of using market prices. There are, however, several difficulties with this approach. One difficulty is that these tend to be hourly prices and thus require hourly PV system output data in order to calculate the economic value. This difficulty can be addressed by using historical prices and historical PV system output to evaluate what results would have been in the past and then escalating the results for future projections. A more serious difficulty is that, while hourly market prices could be projected for a few years into the future, the analysis needs to be performed over a much longer time period (typically 30 years). It is difficult to accurately project hourly market prices 30 years into the future.

A more robust approach is to explicitly specify the marginal generator and then to calculate the cost of the generation from this unit. This is often a Combined Cycle Gas Turbine (CCGT) powered using natural gas (e.g., [6]). This approach includes the assumption that PV output always displaces energy from the same marginal unit. Given the uncertainties and complications in market price projections, the second approach is taken.

Fuel Cost Savings and O&M Cost Savings equals the sum of the discounted fuel cost savings and the discounted O&M cost savings.

## Fuel Price Hedge Value

### Introduction

Solar-based generation is insensitive to the volatility of fuel prices while fossil-based generation is directly tied to fuel prices. Solar generation, therefore, offers a "hedge" against fuel price volatility. One way this has been accounted for is to quantify the value of PV's hedge against fluctuating natural gas prices [6].

### Methodology

The key to calculating the Fuel Price Hedge Value is to effectively convert the fossil-based generation investment from one that has substantial fuel price uncertainty to one that has no fuel price uncertainty. This can be accomplished by entering into a binding commitment to purchase a lifetime's worth of fuel to be delivered as needed. The utility could set aside the entire fuel cost obligation up front, investing it in risk-fee securities to be drawn from each year as required to meet the obligation. The approach uses two financial instruments: risk-free, zero-coupon bonds[16] and a set of natural gas futures contracts.

Consider how this might work. Suppose that the CCGT operator wants to lock in a fixed price contract for a sufficient quantity of natural gas to operate the plant for one month, one year in the future. First, the operator would determine how much natural gas will be needed. If *E* units of electricity are to be generated and the heat rate of the plant is *H*, *E * H* BTUs of natural gas will be needed. Second, if the

[16] A zero coupon bond does not make any periodic interest payments.

corresponding futures price of this natural gas is $P^{NG\ Futures}$ (in $ per BTU), then the operator will need $E * H * P^{NG\ Futures}$ dollars to purchase the natural gas one year from now. Third, the operator needs to set the money aside in a risk-free investment, typically a risk-free bond (rate-of-return of $r^{risk\text{-}free}$ percent) to guarantee that the money will be available when it is needed one year from now. Therefore, the operator would immediately enter into a futures contract and purchase $E * H * P^{NG\ Futures} / (1+ r^{risk\text{-}free})$ dollars worth of risk-free, zero-coupon bonds in order to guarantee with certainty that the financial commitment (to purchase the fuel at the contract price at the specified time) will be satisfied.[17]

This calculation is repeated over the life of the plant to calculate the Fuel Price Hedge value.

## Generation Capacity Value

### Introduction

Generation Capacity Value is the benefit from added capacity provided to the generation system by distributed PV. Two different approaches can be taken to evaluating the Generation Capacity Value component. One approach is to obtain the marginal costs based on market prices. The second approach is to estimate the marginal costs based on the cost of operating a representative generator that is on the margin, typically a Combined Cycle Gas Turbine (CCGT) powered by natural gas.

### Methodology

The second approach is taken here for purposes of simplicity. Future version of the software service may add a market price option.

Once the cost data for the fully-dispatchable CCGT are obtained, the match between PV system output and utility loads needs to be determined in order to determine the effective value of the non-dispatchable PV resource. CPR developed a methodology to calculate the effective capacity of a PV system to the utility generation system (see [10] and [11]) and Perez advanced this method and called it the Effective Load Carrying Capability (ELCC) [12]. The ELCC method has been identified by the utility industry as one of the preferable methods to evaluate PV capacity [13] and has been applied to a variety of places, including New York City [14].

The ELCC is a statistical measure of effective capacity. The ELCC of a generating unit in a utility grid is defined as the load increase (MW) that the system can carry while maintaining the designated reliability

[17] $[E * H * P^{NG\ Futures} / (1+ r^{risk\text{-}free})] * (1+ r^{risk\text{-}free}) = E * H * P^{NG\ Futures}$

criteria (e.g., constant loss of load probability). The ELCC is obtained by analyzing a statistically significant time series of the unit's output and of the utility's power requirements.

Generation Capacity Value equals the capital cost ($/MW) of the displaced generation unit times the effective capacity provided by the PV.

## T&D Capacity Value

### Introduction

The benefit that can be most affected by the PV system's location is the T&D Capacity Value. The T&D Capacity Value depends on the existence of location-specific projected expansion plan costs to ensure reliability over the coming years as the loads grow. Capacity-constrained areas where loads are expected to reach critical limits present more favorable locations for PV to the extent that PV will relieve the constraints, providing more value to the utility than those areas where capacity is not constrained.

Distributed PV generation reduces the burden on the distribution system. It appears as a "negative load" during the daylight hours from the perspective of the distribution operator. Distributed PV may be considered equivalent to distribution capacity from the perspective of the distribution planner, provided that PV generation occurs at the time of the local distribution peak.

Distributed PV capacity located in an area of growing loads allows a utility planner to defer capital investments in distribution equipment such as substations and lines. The value is determined by the avoided cost of money due to the capital deferral.

### Methodology

It has been demonstrated that the T&D Capacity Value can be quantified in a two-step process. The first step is to perform an economic screening of all areas to determine the expansion plan costs and load growth rates for each planning area. The second step is to perform a technical load-matching analysis for the most promising locations [18].

## Methodology References

[1]. Hoff, T. E., Wenger, H. J., and Farmer, B. K. "Distributed Generation: An Alternative to Electric Utility Investments in System Capacity", Energy Policy 24(2):137-147, 1996.

[2]. Hoff, T. E. Final Results Report with a Determination of Stacked Benefits of Both Utility-Owned and Customer-Owned PV Systems: Deliverable 1.3.5.2, SMUD Report, 2002.

[3]. Hoff, T. E., and Margolis, R. *Distributed Photovoltaics in New Jersey*, NREL Report, 2003. www.cleanpower.com/research/distributedgeneration/DistributedPVInNewJersey.pdf.

[4]. Hoff, T. E., Norris, B. L., and Wayne, G. *Potential Economic Benefits of Distributed Photovoltaics to the Nevada Power Company*. Report, 2003. www.cleanpower.com/Content/Documents/research/distributedgeneration/NevadaPower2003.pdf

[5]. Hoff, T. E. and Margolis, R. M. *Moving Towards a More Comprehensive Framework to Evaluate Distributed Photovoltaics*. Report, 2005. www.cleanpower.com/Content/Documents/research/customerPV/EvaluationFramework.pdf

[6]. Hoff, T.E., Perez, R., Braun, G., Kuhn, M., and Norris, B. *The Value of Distributed Photovoltaics to Austin Energy and the City of Austin*, 2006. www.cleanpower.com/Content/Documents/research/distributedgeneration/AE_PV_ValueReport.pdf.

[7]. Norris, B. L., Hoff, T. E., Perez, R. *PV Value Analysis for We Energies*, 2009.

[8]. Perez, R. Zweibel, K., and Hoff, T. E. "Solar Power Generation in the US: Too expensive, or a bargain?" Submitted to Energy Policy. 2011.

[9]. Hoff, T. and Shugar, D. S., "The Value of Grid-Support Photovoltaics In Reducing Distribution System Losses", IEEE Transactions on Energy Conversion, 10(9): 569-576.,1995.

[10]. Garver, L. L. "Effective Load Carrying Capability of Generating Units. IEEE Transactions, Power Apparatus and Systems." Vol. Pas-85, no. 8, 1966.

[11]. Hoff, T. "Calculating Photovoltaics' Value: A Utility Perspective," IEEE Transactions on Energy Conversion 3: 491-495, 1988.

[12]. Perez, R., Seals, R., and Stewart, R. “Assessing the Load Matching Capability of Photovoltaics for US Utilities Based Upon Satellite-Derived Insolation Data”, IEEE Transactions, pp. 1146-1149 (23d. PV Specialists, Louisville, KY), 1993.

[13]. Hoff, T., Perez, R. Ross, JP, and Taylor, M. *Photovoltaic Capacity Valuation Methods*, Solar Electric Power Association Report #02-08, 2008.

[14]. Hoff, T. E. and Perez, R. *Shining on the Big Apple: Satisfying New York City’s Peak Electrical Needs with PV*. Report, 2008.
www.cleanpower.com/Content/Documents/research/distributedgeneration/PVForNewYorkCity.pdf.

[15]. Fthenakis, V., Kim, H.C., Alsema, E., “Emissions from Photovoltaic Life Cycles”. Environmental Science and Technology, 42(6): p. 2168-2174, 2008.

[16]. Devezeaux J. G. “Environmental Impacts of Electricity Generation”. 25th Uranium Institute Annual Symposium. London, UK, 2000.

[17]. Epstein, P. “Full cost accounting for the life cycle of coal”. Annals of the New York Academy of Sciences, 2011.

[18]. Hoff, T. E. “Identifying Distributed Generation and Demand Side Management Investment Opportunities”, The Energy Journal: 17(4), 1996.

[19]. Fthenakis, V., Kim, H.C., Alsema, E., 2008. Emissions from Photovoltaic Life Cycles. Environmental Science and Technology, 42(6): p. 2168-2174

[20]. Devezeaux J. G., 2000. Environmental Impacts of Electricity Generation. 25th Uranium Institute Annual Symposium. London, UK (September, 2000).

[21]. Epstein, P. 2011. Full cost accounting for the life cycle of coal. Annals of the New York Academy of Sciences. February, 2011.

[22]. Louw, B., J.E. Worren and T. Wohlgemut, 2010. Economic Impacts of Solar Energy in Ontario. CLearSky Advisors Report (www.clearskyadvisors.com).

[23]. Ban-Weiss G. et al., 2010 “Solar Energy Job Creation in California”, University of California at Berkeley.

[24]. Perez, R., K. Zweibel and T.E. Hoff, (2011): Solar Power Generation in the US: Too Expensive, or a Bargain? Journal of Energy Policy, 39 (2011), 7290-7297.

[25]. Tol R.S.J., J. Guo, C.J. Hepburn, and D. Anthoff 2006. Discounting and the Social Cost of Carbon: a Closer Look at Uncertainty, Environmental Science & Policy, 9, 205-216, 207.

[26]. Perez, R., R. Margolis, M. Kmiecik, M. Schwab and M. Perez, (2006): Update: Effective Load Carrying Capability of Photovoltaics in the United States. Proc. ASES Annual Conference, Denver, CO

[27]. Perez, R., R. Seals, H. Wenger, T. Hoff and C. Herig, 1997. PV as a Long-Term Solution to Power Outages. Case Study: The Great 1996 WSCC Power Outage. Proc. ASES Annual Conference, Washington, DC.

[28]. Perez R., B. Collins, R. Margolis, T. Hoff, C. Herig J. Williams and S. Letendre, 2005. Solution to the Summer Blackouts – How dispersed solar power generating systems can help prevent the next major outage. Solar Today 19,4, July/August 2005 Issue, pp. 32-35.

[29]. Letendre S. and R. Perez, 2006. Understanding the Benefits of Dispersed Grid-Connected Photovoltaics: From Avoiding the Next Major Outage to Taming Wholesale Power Markets. The Electricity Journal, 19, 6, 64-72.

[30]. Perez R., B. Collins, R. Margolis, T. Hoff, C. Herig J. Williams and S. Letendre, (2005) Solution to the Summer Blackouts – How dispersed solar power generating systems can help prevent the next major outage. Solar Today 19,4, July/August 2005 Issue, pp. 32-35.

[31]. Perez, R., T. Hoff and M. Perez, (2010): Quantifying the Cost of High PV Penetration. Proc. of ASES National Conference, Phoenix, AZ.

[32]. Felder, F. A., "Examining Electricity Price Suppression Due to Renewable Resources and Other Grid Investments," The Electricity Journal, Vol. 24, Issue 4, May 2011.