The Value of Distributed Photovoltaics to Austin Energy and the City of Austin

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Study to Determine Value of Solar Electric Generation

To Austin Energy

Prepared for:

Austin Energy

Prepared by:

Clean Power Research, L.L.C.

Thomas E. Hoff
Richard Perez
Gerry Braun
Michael Kuhn
Benjamin Norris

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Executive Summary

Introduction

Austin Energy (AE) has a strong commitment to integrating solar electric generation into its power generation and distribution system. This is made clear not only by the introduction of its recent incentive for customer-owned photovoltaic (PV) systems, but even more so by its goal of installing 15 MW of solar generation by the end of 2007 and 100 MW by 2020.

AE wants to ensure that the cost of solar generation is commensurate with its value. As such, AE issued two request for proposals (RFPs) to perform value studies. One RFP was to determine the value of the economic development benefits of solar. The other study was to determine the value of solar generation to AE. Clean Power Research (CPR) was selected for the second RFP.

Objective

There are several alternative approaches to determining the comprehensive value of solar generation. One approach is to perform an in-depth analysis of a single candidate technology. This has the benefit of clearly illustrating evaluation methodologies. Another approach is to perform a less comprehensive analysis for a wide variety of solar technologies. This approach has the benefit of providing results for multiple solar technologies, such as distributed PV, central station PV, central station solar thermal troughs, solar dishes, or customer solar hot water heating to displace electric water heaters.

AE stated in its RFP that the work should provide evaluation methodologies. Thus, in order to maximize the effectiveness of AE's financial investment in this study, the first approach was selected. It performs an in-depth evaluation of a single solar technology that requires a relatively complicated analysis effort (distributed PV) and places special emphasis on documenting evaluation methodologies.

There are two primary objectives of this study:

1. Quantify the comprehensive value of distributed PV to AE in 2006
2. Document evaluation methodologies to assist AE in performing the analysis as conditions change and applying it to other technologies

Scenario Definition

The study assumed that the comprehensive value of distributed PV includes the following benefits:

- Energy production
- Generation capacity
- T&D capacity deferrals
- Reduced transformer and line losses
- Reactive power control
- Environment
- Natural gas price hedge
- Disaster recovery

For each of these benefits, the analysis considers following configurations.

- Fixed configurations
  - Horizontal (fixed PV with no tilt)
  - South-30º (south-facing fixed PV tilted at 30º)
  - SW-30º (southwest-facing fixed PV tilted at 30º)
  - West-30º (west-facing fixed PV tilted at 30º)
  - West-45º (west-facing fixed PV tilted at 45º)

- Tracking configurations
  - 1-Axis (north-south 1-axis tracking PV with no tilt)
  - 1-Axis 30º (north-south 1-axis tracking PV with 30º tilt)

A number of the benefits are a function of the size of the PV system. The analysis is performed for 15 MW of PV unless otherwise specified.

Multiple evaluation methods and input assumptions can be used for almost all of the benefit calculations. Attempting to include all possible combinations of evaluation methodologies and input data sets would result in an excessive number of scenarios.

A variety of evaluation methods and assumptions were considered during preliminary phases of the study. After further consideration, it was decided that a single scenario reflecting the joint opinions of AE and CPR would best serve the purposes of this study. As a result, the results are neither the highest they could be nor the lowest they could be but rather represent a middle ground.

Results

The value for 15 MW of distributed PV to AE is summarized in the top part of Table ES-1. The bottom part of the table presents a factor to adjust for PV size.[1]

15 MW of PV

The value of 15 MW of PV is $2,312 per kW (11.3¢ per kWh) for the best fixed configuration. The best fixed configuration is SW-30º and is only slightly higher that a South-30º configuration. The system with the highest value overall is the 1-Axis 30º tracking system and is worth $2,938 per kW (10.9¢ per kWh). This system has a 27 percent value premium over the best fixed configuration.

100 MW of PV

AE can use these results of this study to determine the value of a larger amount of PV. For example, AE's size adjustment factor for 100 MW is 95 percent as presented in the bottom of Table ES-1. The best fixed and tracking configurations at the 100 MW penetration level are worth $2,196 per kW (10.7¢ per kWh) and $2,791 per kW (10.4¢ per kWh), respectively.

Table ES-1. Value of 15 MW of distributed PV and size adjustment.[2]

Value of 15 MW of PV	Present Value ($/kW)	Levelized ($/kWh)
Fixed Systems		
Horizontal	$2,154	$0.111
South 30º	$2,299	$0.108
SW 30º	$2,312	$0.113
West 30º	$2,127	$0.117
West 45º	$1,983	$0.118
Tracking Systems		
1-Axis	$2,813	$0.110
1-Axis 30º	$2,938	$0.109

	15 MW	25 MW	50 MW	75 MW	100 MW
Size Adjustment	**100%**	**99%**	**98%**	**96%**	**95%**

Breakdown of Value by Component

In addition to total value, it is useful for AE to understand the source of value. The results are presented by benefit component in Figures ES-1 and ES-2. Figure ES-1 presents the results in absolute or capacity terms (present value in $ per kW-AC). Figure ES-2 presents the results in energy terms (levelized value in $ per kWh). As can be seen in the figures, the energy production benefit accounts for two-thirds of the total value.

[1] The reduction in value due to size increase is primarily due to placing a greater weight on AE's 100 MW marginal cost forecast than its 1 MW marginal cost forecast.

[2] While there is some variation in the size adjustment factor based on the system configuration, the variation is small and the size adjustment factor presented in the table is accurate within ½ percent.

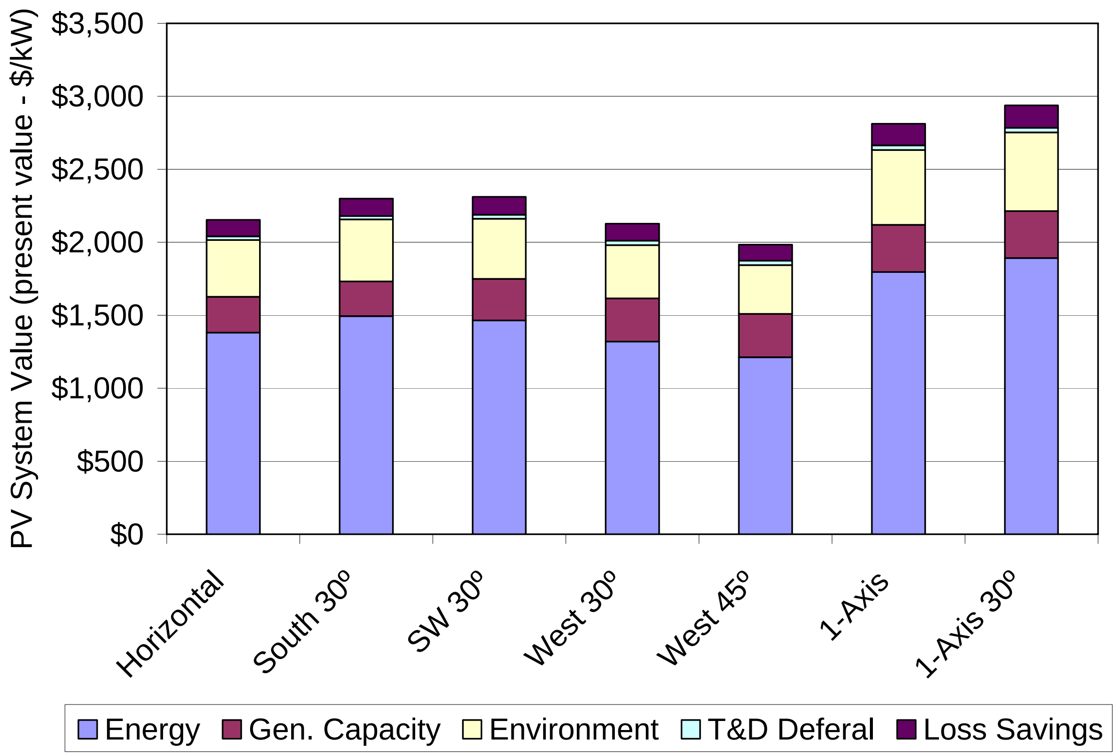

Figure ES-1. Present value for 15 MW of PV by configuration ($/kW-AC).

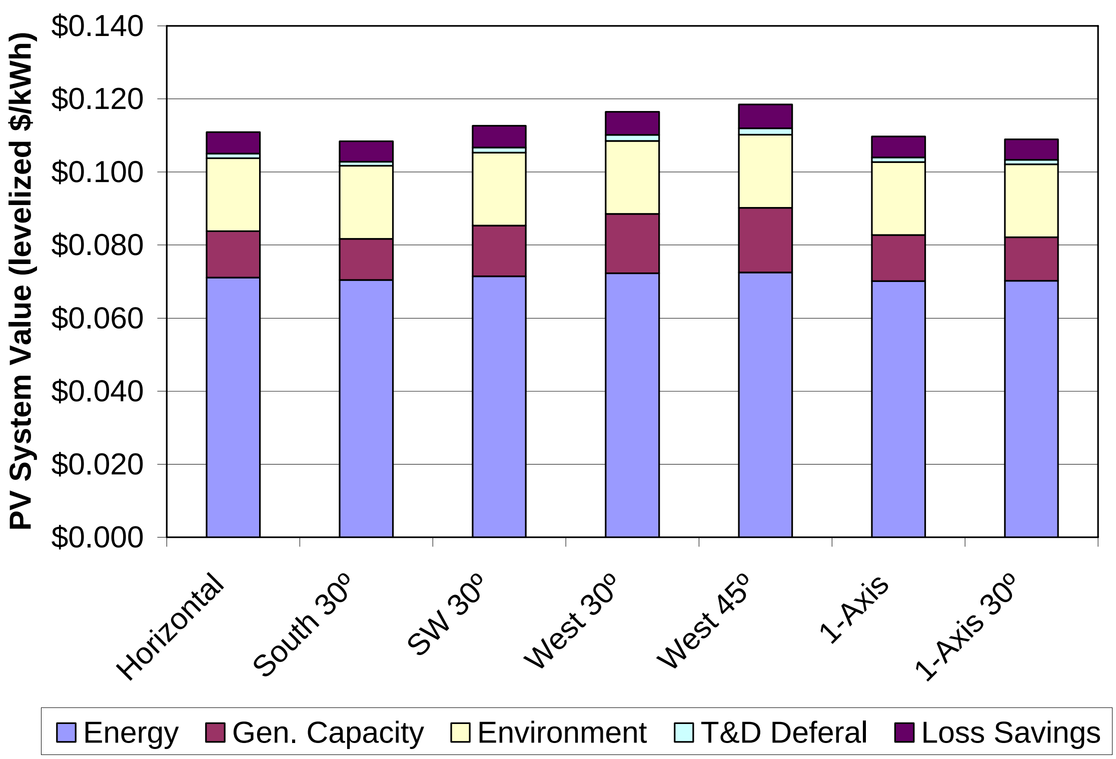

Figure ES-2. Levelized value for 15 MW of PV by configuration ($/kWh).

Discussion

This subsection describes each benefit in more detail.

Energy Production

Distributed PV systems produce electricity at the point of consumption at a stable price over the duration of the life of the system. There are three aspects associated with the value of this energy production.

- PV systems produce electricity. The basic energy production value occurs because the amount of electricity that needs to be generated at other plants is reduced by the amount of PV production, thus decreasing the amount of fuel that is consumed and the O&M costs associated with the electricity-generation equipment.

- PV systems produce energy at the point of consumption. There are reduced losses in the T&D system because the energy produced by PV systems does not have to pass through the transmission and distribution systems to reach the point of use. This is the energy loss savings value.

- PV systems produce electricity at a stable price. PV cost is almost entirely capital related, with nearly negligible O&M costs and no fuel costs. PV energy prices are therefore fixed and known over the life of the system. In contrast, electricity prices from fossil-based generation are subject to potentially large fuel price fluctuations. Just as insurance or certain financial products provide “hedge” value against undesirable outcomes under uncertain future conditions, PV provides a hedge against natural gas price uncertainty. This is the value of the reduction in fuel price uncertainty.

The evaluation methodology includes benefits from AE’s method of marginal cost analysis with a methodology taken from the established risk-free evaluation approach from financial economics to capture both the basic energy value and the value of the natural gas price hedge. The energy loss savings value is included as part of the loss savings benefit.

A critical input into the analysis is the natural gas price forecast. The ideal data set is one in which there is certainty in the natural gas prices over the life of the PV system. While this certainty is obtained for the first 5 years using natural gas futures prices for entities that hedge 100 percent of their gas requirements at the very start of the 5 year timeframe, such a data set was unavailable for the remaining years. The next 25 years of data are based on AE’s consultant’s forecast of natural gas prices.

Generation Capacity

Distributed PV effectively provides generation capacity by reducing demand-side consumption. Generation capacity value is the product of an economic value of an ideal resource (as represented by a natural gas turbine) and a technical adjustment to reflect PV’s actual peak load reduction value to the AE system. The technical adjustment is made using the Effective Load Carrying Capability (ELCC) method. Results indicate that PV is worth between one-half to two-thirds the value of an equivalently sized ideal resource, depending upon system configuration. The generation capacity loss savings value is included in the loss savings section.

Environment

PV systems provide an environmental benefit by eliminating emissions associated with non-renewable resources. While the quantification of reduced emissions is undisputed, their economic value is the subject of ongoing debate. The method used in this analysis is to calculate the value by examining market data that indicate customer willingness to pay premium prices for green power. In addition to the environmental benefits of the energy produced by the PV system, there are benefits associated with the avoided energy losses, and these are covered in the loss savings section.

T&D Capacity

Targeted deployment of PV relieves loads on the utility's transmission, sub-transmission, and distribution systems, effectively increasing available T&D capacity. This relief allows utility T&D planners to defer capital investments in the T&D system. The economic value of these deferrals includes both the time value of money and the reduction in T&D system O&M costs.

The evaluation is performed by first calculating the economic value of an ideal T&D resource and then adjusting this value according to the effective capacity provided by PV. As a key set of inputs, AE provided estimates of deferrable investments by distribution area and year.

Results indicate that the T&D deferral value is relatively uniform throughout the AE service territory. One exception is the downtown area (not shown in Figures ES-1 and ES-2) which potentially has higher value due to slow load growth and expensive underground lines nearing capacity.

The T&D deferral benefit is location-specific. The value of this benefit is included only in cases where AE is able to actually defer T&D capacity investments.

Disaster Recovery

Sixty weather-related disasters over the past 25 years have affected a quarter of a billion U.S. citizens and cost almost a half a trillion dollars. Hurricane Katrina alone has reminded us of the staggering cost of weather-related disasters and how the resulting power outages compound the cost and slow the speed of disaster recovery.

Significant deployment of "solar secure" PV systems (i.e., PV coupled with sufficient electric storage) in the Austin area would change the region's energy security profile. Even the small amount of power produced by these systems could support continuing use of homes, retail businesses, and selected public buildings for extended periods of time. However, deploying solar for this purpose requires that PV systems include energy storage and stand-alone inverter capability, and these come at additional capital cost.

Preliminary analysis suggests that the disaster recovery benefit could increase the value of solar by more than 50 percent. This is first known attempt at quantifying the disaster value benefits. As such, the valuation method requires further refinement.

A discussion about disaster recovery is included in this report, however, due to the uncertainties of quantification, it was decided that the results would not be included in the numerical value calculation. Instead, it is recommended that AE further consider the disaster recovery benefit when combined with battery storage, in particular as it can be jointly implemented with a plug-in hybrid electric vehicle program.

Reactive Power

The reactive power value is the benefit that would accrue if PV inverters were modified to provide voltage regulation support. This benefit is realized by adding a new technical capability to the inverter. Even with such a modification, however, the value was found to be minimal. The value is not included in the final results.

Loss Savings

Loss savings is an indirect benefit because it increases the value of other benefits, including energy production, generation capacity, environmental, and T&D capacity. For example, if the energy production value is $1,000 per kW and the technical loss savings is five percent, the energy production loss savings benefit is $50 per kW.

The two sets of inputs needed to calculate the loss savings value are the benefit-specific loss savings percentage and the corresponding benefit value. The results are based on the marginal system losses rather than the average systems losses (marginal losses are about two times the average losses).

Summary and Recommendations

Study Uses

The first objective of this study is to quantify the comprehensive value of distributed PV to AE in 2006. The preceding paragraphs describe the results of this analysis.

There are several ways that AE might consider how to use these results in advancing its 2020 goals:

- Assist in structuring an RFP for utility-owned systems or power purchase agreements
- Provide input into incentive design for customer-owned systems
- Help to assess the merits of kW-based buydown incentives vs. kWh-based performance incentives for customer-owned systems
- Evaluate other PV applications (e.g., a central station PV could be screened by deleting the distributed benefits – loss savings, and T&D deferral)
- Investigate synergies with other AE programs such as demand management and plug-in hybrid vehicles
- Assist in evaluating opportunities related to AE's new Non-Traditional Energy Business Planning process

Methodology Advances

The second objective of this study is to document evaluation methodologies to assist AE in repeating the analysis as conditions change and/or expand the analysis to include other technologies. These methodologies are documented throughout this report. In the process of the analysis, CPR developed new methodologies and enhanced existing methodologies. More specifically, CPR:

- Applied financial economics' risk-neutral valuation methodology to account for the natural gas price hedge benefit
- Demonstrated that loss savings calculations should be performed on a marginal, rather than an average, basis and then used the results to estimate hourly loss savings
- Developed a preliminary method to quantify the disaster recovery benefit
- Developed a method of capturing technology synergies by converting a non-firm resource into a firm resource by bundling it with load control, thereby capturing additional capacity-related benefits

Study Enhancements

There are a number of ways that this study can be further enhanced.

- This disaster recovery benefit could increase the value of solar by 50 percent. Further investigate the disaster recovery benefit and assess how distributed PV could be incorporated with AE's plug-in hybrid vehicle program and disaster recovery services (City and County) to provide the required storage at a minimal cost; in particular, evaluate implementation on public buildings, such as schools.
- The natural gas price forecast is the most critical assumption in determining energy value in future years. However, only the first 5 years of AE's natural gas forecast reflect certainty in the natural gas price estimates. It would be beneficial to extend the duration over which certainty could be obtain for natural gas prices.
- PV could enable AE to offer a new product: long-term (20 to 30 years) fixed price electricity. Assess the feasibility of using PV to offer a long term, fixed price electricity contract to AE's customers, covering issues such as the customer's willingness to pay and the solar output intermittency risks to AE.
- AE's customers who participate in the GreenChoice® program receive environmental benefits plus fuel price risk protection at a price that is significantly below what other market entities charge for the environmental benefits alone. Confirm that AE is satisfied with its GreenChoice® program pricing.
- The T&D deferral benefit is lower at AE than at other municipal utilities with which CPR has worked (AE's potentially-deferrable T&D investments represent slightly more than ¼ percent of AE's annual revenues). Confirm that the cost of potentially-deferrable T&D capital investments is not artificially low due to AE's budget reporting practices.
- Evaluate how the benefits identified in this study could be applied from perspectives other than AE (e.g., customer-ownership, and local, state, and federal governments)

AE is a leader in its commitment to renewable energy. It is hoped that this study will help to support and expand AE's vision and leadership.

Acknowledgements

The authors acknowledge Austin Energy's Roger Duncan (Deputy General Manager, Distributed Energy Services), John H. Baker Jr., P.E. (Chief Strategy Officer, Strategic Planning and Business Development), Mark Kapner (Senior Strategy Planner, Strategic Planning Group), and Leslie Libby (Project Manager, Commercial Energy Management) for initiating and supporting this study on the Value of Distributed Photovoltaics to Austin Energy and the City of Austin.

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Jerrel Wallace, P.E. (T&D Planning)
Ann Little, CPA (Long Range Planning)
Gordon Alexander (Regulatory Planner)
Bob Breeze, P.E. (Air Program Coordinator)

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Introduction

Austin Energy (AE) has a strong commitment to integrating solar electric generation into its power generation and distribution system. This is made clear not only by the introduction of its recent incentive for customer-owned photovoltaic (PV) systems, but even more so by its goal of installing 100 MW of solar generation by 2020.

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Objective

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AE stated in its RFP that the work should provide evaluation methodologies. Thus, in order to maximize the effectiveness of AE's financial investment in this study, the first approach was selected. It performs an in-depth evaluation of a single solar technology that requires a relatively complicated analysis effort (distributed PV) and places special emphasis on documenting evaluation methodologies. Distributed PV is also selected because it is firmly established in the literature that the value of distributed PV is substantially higher than the value of central station PV.

There are two primary objectives of this study:

1. Quantify the comprehensive value of distributed PV to AE in 2006
2. Document evaluation methodologies to assist AE in performing the analysis as conditions change and applying it to other technologies

Evaluation Frameworks

There is growing interest in customer-owned generation with a particular interest in PV systems. This has resulted in a number of analytical studies aimed at determining the value of PV. Two difficulties that these studies have encountered are the proper selection of evaluation perspective and the determination of which benefits and costs to include in the analysis.

With these difficulties in mind, CPR and the National Renewable Energy Laboratory (NREL) have constructed a framework to evaluate distributed PV [34]. While this current AE study is focused only on the issue of PV value and does not specifically address the ownership issue (i.e., whether the systems should be utility-owned or customer-owned), the NREL framework is relevant to the current study. By way of background, then, the highlights of the framework are presented here.

Energy Conservation Evaluation Framework

Since the 1970s, conservation and load management programs have been promoted by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) as alternatives to power plant construction and gas supply options. In 1983, the evaluation methodology was formalized and documented in the California Standard Practice Manual. This manual has been updated several times; the most recent version is available in [17].

The Standard Practice Manual identifies the cost and benefit components and cost-effectiveness calculation procedures from four major perspectives as summarized in Table 1. Those perspectives include:

1. Participant
2. Ratepayer Impact Measure (RIM)
3. Total Resource Cost (TRC)
4. Program Administrator Cost (PAC)

Table 1. Benefits (+) and costs (-) using Standard Practice tests.

	Total Resource Cost (TRC)		
	Participant		***(PAC)***
		Rate Impact Measure (RIM)	
	Particpant	***All Ratepayers***	***Utility***
Investment			
Equipment	-		
Installation	-		
Sales Tax	-		
O&M Cost	-		
Electric Utility Bill	+	-	
Incentives			
Incentive Payments	+		-
Program Administration			-
Tax Effects			
Tax Credits	+		
Utility Cost Savings			
Energy			+
Capacity			+
T&D System			+
Losses			+

Distributed PV Evaluation Framework

The NREL study [34] identified two limitations of the framework presented in Table 1. First, for the given perspectives that are defined, there are benefits and costs that are not included in the analysis. Second, there are additional perspectives that are not included in the analysis. Table 2 illustrates how the matrix can be expanded for customer-owned distributed PV generation under the current U.S. incentive structure

The blue section titles are the various tests, the headers at the top are the perspectives, and the labels to the left of the matrix are the benefit/cost components. Within the body of the matrix, the boxes have three possible colors: white, yellow, or gray. White indicates that the benefit is currently included in existing Standard Practice tests, yellow indicates that it is not typically included (although some studies may include these components), and gray indicates that the component does not apply from that perspective. A + corresponds to a benefit and a – corresponds to a cost for that particular component and perspective. Note that while a Societal Test is included in the tests described in the Standard Practice Manual, it is treated informally.

Several general observations can be made based on a comparison of Table 1 to Table 2. First, the expanded framework contains many more perspectives and benefits/cost components than Table 2. Second, the industry and government perspectives have many new entries. Third, many of the components have a yellow background and thus are not included in a typical financial analysis even for the existing tests (RIM, TRC, PAC, and Participant). Finally, there are generally more pluses than minuses with the new entries. Including these benefits and costs increase the overall cost-effectiveness of distributed PV systems.

Table 2. Benefits (+) and costs (-) using comprehensive evaluation.

SOCIETAL					
Total Resource Cost (TRC)			Industry	Government	
Participant		(PAC)			
	Rate Impact Measure (RIM)				

	Particpant	All Ratepayers	Utility	Industry	State/Local Gov.	Federal Gov.
Investment						
Equipment	-			+		
Installation	-			+		
Sales Tax	-				+	
O&M Cost	-			+		
Financing	-			+		
Electric Utility Bill	+	-				
Incentives						
Incentive Payments	+		-			
Program Administration			-		+	+
Tax Effects						
Tax Credits	+				-	-
Depreciation	+				-	-
Loan Interest Write-Off	+				-	-
O&M Costs	+				-	-
Utility Bill Savings	-				+	+
Tax on Tax Credits	-					+
Utility Cost Savings						
Energy			+			
Capacity			+			
T&D System			+			
Losses			+			
Technology Synergies			+	+		
Environmental						
Emissions		+				
Water		+				
Health		+				
RECs/Green Tags	+		+			
Job Creation			-	+	+	+
Reliability						
Blackout Prevention		+	+		+	+
Emergency Utility Dispatch	+		+			
Catastrophe Recovery		+			+	+
Backup Power	+				+	+
Risk Factors						
Manage Load Uncertainty			+			
Wholesale Price Hedge			+		+	+
Retail Price Hedge	+				+	+
Retail Price Cap		+	-		+	+
National Energy Security		+			+	+

Framework for Current Study

The expanded benefit-cost framework described above was developed for customer-owned distributed PV systems. AE has not yet determined whether the solar generation in this study will be customer-owned or utility-owned. Consequently, some of the perspectives presented in Table 2 need to be combined. This AE study will examine the benefits that accrue to the perspectives of both “All Ratepayers” and “Utility.”

In particular, this study will examine the following benefits:

- Energy Production
- Generation Capacity
- T&D System (Distribution Deferrals)
- Reduced Transformer and Line Losses
- Environment

- NG Price Hedge (Wholesale Price Hedge)
- Disaster Recovery (Catastrophe Recovery)

The Technology Synergies benefit in Table 2 refers to the situation when the benefit of a bundle of technologies exceeds the sum of the benefits of the technologies evaluated in isolation. The Technology Synergies benefit can be incorporated in the capacity benefits by combining PV with a utility-administered load control program. This combination of technologies may provide firm capacity at a cost that is lower than using either technology in isolation (see [22] for more background information).

Four benefits are listed for the “All Ratepayers” and “Utility” perspectives that are not included in the analysis are: Blackout Prevention, Emergency Utility Dispatch, Manage Load Uncertainty, and Retail Price Cap.

The Blackout Prevention and Emergency Utility Dispatch benefits ([18], [26], [27], and [30]) are the benefits to the utility of having a small amount of battery storage available as part of a PV system to respond to brief emergency situations encountered by the utility. AE decided that battery storage was a separate technology from solar and that these benefits should be excluded from the analysis. Therefore, these benefits are not considered further.

The Managing Load Uncertainty benefit [12] follows from the modularity and short-lead times of distributed generation in the deferral of T&D system investments. This benefit, while real, is excluded from the study because the T&D deferral value was very small for AE and did not justify the effort required to collect the data necessary to implement the methodology.

The Retail Price Cap [23] is the benefit of having PV become a “backstop technology,” i.e., one that allows large or unlimited quantities of a perfect or near perfect substitute to be produced at a given price. It ensures the existence of a “choke price,” the price above which the product which it is replacing will not go. In the case of PV, it can provide long-term electric rate protection to all customers whether or not they purchase the PV. The Retail Price Cap benefit is excluded because it requires the assumption of customer ownership, an assumption which this study does not make.

One benefit not listed above but included is Reactive Power Control. The study evaluates such a benefit. The value is calculated, but it is not included in the final result because inverter control modifications required to capture this benefit would not likely be implemented.

Scenario Specification

There are multiple evaluation methods and input assumptions that could be used for almost all of the benefits listed above. This study would result in an unmanageable number of scenarios if an attempt was made to present all possible combinations of the various evaluation methodologies and input data sets.

A variety of scenarios were developed during preliminary phases of the study. After further consideration, however, it was decided that a single scenario reflecting the joint opinions of AE and Clean Power Research would best serve the purposes of this study. The results are neither the highest they could be nor the lowest they could be but rather represent a middle ground.

A number of the benefits are a function of the size of the PV system. The analysis is performed for 15 MW of PV unless otherwise specified.

PV Performance Estimates

Introduction

Accurately determining the value of distributed PV requires the availability of PV power output data in intervals of one hour or less. Ideally, measured performance data from existing, representative PV installations would be available for this purpose. In practice, however, this type of measured data is extremely difficult to obtain. Often, measured data is not available for the time period of the study, it does not include the range of the configurations of interest, or it does not cover a sufficiently broad geographical area. Such difficulties were encountered in the present study for AE.

The next best alternative to measured PV output data is to simulate PV output using measured global horizontal and direct irradiance data from a geographically diverse set of well-maintained ground stations. Unfortunately, there was not even a single location (much less multiple locations) for which ground-based measurements were available that included both global horizontal and direct irradiance for the time period of this study.

Without measured PV system data or suitable ground based irradiance data, the next best alternative is to use satellite-based measured weather data. This data is available corresponding to the time period of the study, it can be used to simulate a wide variety of PV configurations, and it encompasses a broad geographic area. This is the alternative that was selected to perform the study for AE.

This section describes the PV system conventions used throughout the report, selects the sample PV configurations used in the detailed analysis, describes the satellite-based weather data, and presents the resulting PV output simulations.

As the number of installed PV systems grows in AE's territory, AE should consider collecting 5 or 15-minute data on the electric production from a large number of well-performing PV systems at a variety of locations and orientations in order to be able to repeat the analysis presented in this study using measured PV output data, thereby improving the results of the analysis.

Conventions

Rating Convention

It is important to begin with a review of common PV system rating methods. As shown in Table 3, according to the National Renewable Energy Laboratory (NREL), there are eleven factors that influence the amount of energy produced by a PV system.[3] These various "losses" occur at different parts of the system. Some of the losses occur within the PV module, some in the system interconnection, some in the power conversion, and some in the total system.

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[3] NREL lists a variety of derating factors at http://rredc.nrel.gov/solar/calculators/PVWATTS/derate.cgi.

Table 3. PV System derating factors according to NREL.

Component Derate Factors	Range of Acceptable Values
PV module nameplate DC rating	0.80 - 1.05
Inverter and Transformer	0.88 - 0.95
Mismatch	0.97 - 0.995
Diodes and connections	0.99 - 0.997
DC wiring	0.97 - 0.99
AC wiring	0.98 - 0.993
Soiling	0.30 - 0.995
System availability	0.00 - 0.995
Shading	0.00 - 1.00
Sun-tracking	0.95 - 1.00
Age	0.70 - 1.00

As a result, a variety of rating methods have emerged within the PV industry. There are at least five industry rating conventions that are in use:

- Nameplate (DC)
- Nameplate (DC) x Inverter Efficiency
- PTC Module, no Inverter
- AC-PTC (Defined by CEC)
- Delivered AC

A simple example is useful to illustrate the difference between these rating methods. Suppose that a PV system consists of BP Solar 4175 modules and a Xantrex GT 3.0 inverter. According to the California Energy Commission, a BP 4175 module has a nameplate rating of 175 Watts and a PTC module rating (the rating defined at less optimal ambient conditions) of 155.2 Watts. This means that the PTC module rating is 89 percent of the nameplate rating. A Xantrex GT 3.0 inverter has 94 percent efficiency.[4] Assume that there are an additional 5 percent other losses in obtaining the actual AC output. The various rating methods range from 79 to 100 percent of nameplate (DC) for this particular system configuration (see Table 4).

[4] http://www.consumerenergycenter.org/cgi-bin/eligible_pvmodules.cgi and http://www.consumerenergycenter.org/cgi-bin/eligible_inverters.cgi.

Table 4. PV system rating methods at peak weather conditions.

Rating Method	***Losses***			***Rating (% of DC rating)***
	Module	***Inverter***	***Other***[5]	
Nameplate (or DC)				100%
Nameplate x Inverter		94%		94%
PTC Module	89%			89%
AC-PTC	89%	94%		83%
Delivered AC	89%	94%	95%	79%

Throughout this report, PV systems are specified in terms of the Delivered AC rating. This refers to the system's output at 25ºC (77ºF) ambient temperature and 1,000 Watts/square meter plane of array irradiance. That is, the PV rating in this study is the delivered AC rating and is approximately equal to 79 percent of the DC or nameplate rating.

Naming Convention

The PV system naming convention used in this report is that the azimuth orientation is listed first followed by tilt. Thus, a South-30º system refers to a south-facing fixed PV system with a 30º tilt.[6]

Orientation Selection

Two critical factors that affect PV output are sunlight availability (irradiance) and PV system configuration (i.e., the direction and tilt of the system).[7] While it is possible to simulate hourly PV system output data for many conceivable orientations, this study concentrates on a limited number of representative PV configurations. The selection was made by pre-screening the orientations using a simulation model, data for a typical meteorological year (as described by the 30-year National Solar Resource Data Base), and applying some knowledge about the value of PV.

In Austin, TX, a South-30º PV system has the highest annual energy production for a fixed PV system.[8] The configuration with the highest annual energy production, however, does not necessarily have the highest total value. This is because west-facing systems bias PV output toward peak periods and provide corresponding enhanced capacity to support peak utility loads. The additional capacity-related benefits may offset the reduced energy-related benefits.

Figure 1 presents the annual energy production for systems ranging in direction from east to west with a tilt from horizontal (0º) to 60º relative to the annual energy production for a South-30º PV system. In order to provide a representative sample of PV system

[5] Other losses include inverter and transformer, mismatch, diodes and connections, DC wiring, AC wiring, and soiling losses.
[6] PV systems are often installed on sloped roof-tops or angled mounting brackets to point in the direction of the sun's path and capture more energy.
[7] A third factor is shading. It is assumed for this analysis that the PV systems are not shaded.
[8] The 30º optimum tilt angle corresponds to Austin's 30º north latitude.

orientations for the study, based on this pre-screening analysis, the following fixed systems are selected for detailed analysis:

- Horizontal (fixed PV with no tilt)
- South-30º (south-facing fixed PV tilted at 30º)
- SW-30º (southwest-facing fixed PV tilted at 30º)
- West-30º (west-facing fixed PV tilted at 30º)
- West-45º (west-facing fixed PV tilted at 45º)

In addition, single-axis north-south tracking systems for both a horizontal and a 30º tilted system will be included.

- 1-Axis (north-south 1-axis tracking PV with no tilt)
- 1-Axis 30º (north-south 1-axis tracking PV with 30º tilt)

These tracking systems, while more costly and mechanically complex, deliver greater energy to the grid than comparably-sized fixed systems.

Note: while the pre-screening analysis uses the 30-year National Solar Resource Data Base values, the study is based on actual weather data collected for the City of Austin.

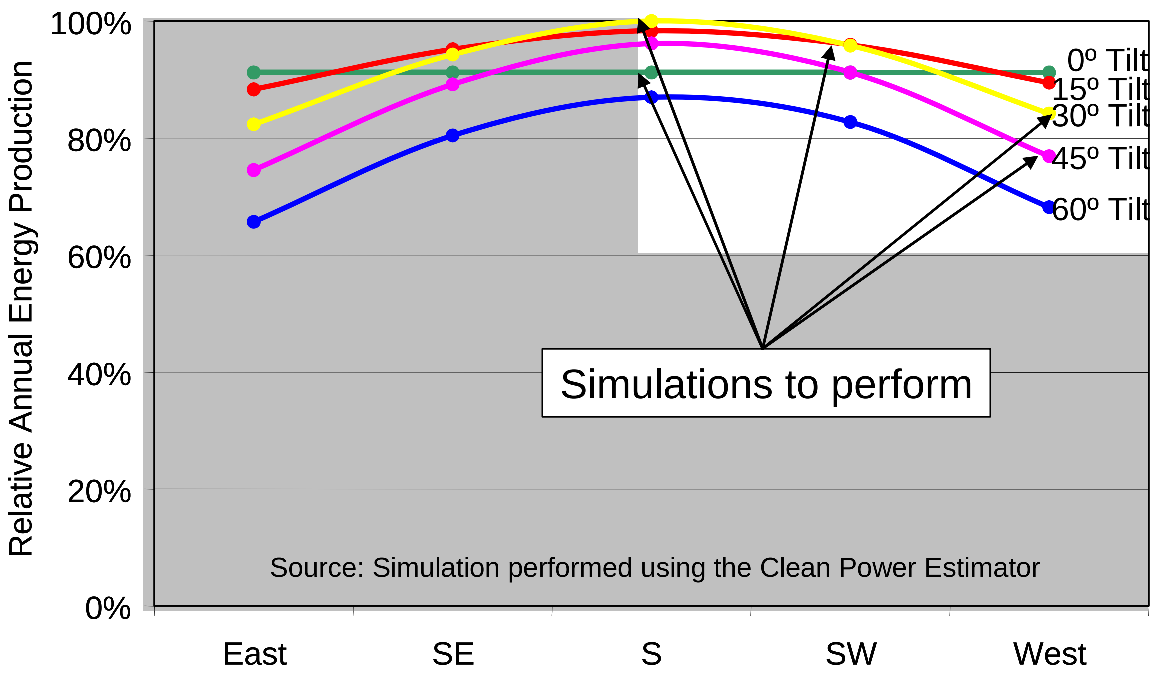


Figure 1. Estimated annual energy production in Austin (Clean Power Estimator).

Output Estimation

Hourly PV output data were simulated for the selected PV configurations based upon solar irradiance data extracted from hourly geostationary satellites ([8], [16], [21], [25], and [28]), and ambient temperatures and wind-speeds extracted from the National Weather Service measurements. Simulations were performed using PVFORM 4.0, the program that powers NREL's PV-Watts PV simulation program.

<u>Precision of Satellite-Derived Estimates</u>

The accuracy of irradiance data from satellite images has been extensively validated using ground data from several climatically distinct locations including Austin, TX [28]. Satellite data are taken as an instantaneous snapshot of the cloud cover once an hour at 27 minutes after the hour. Table 5 summarizes model validations compared to five years of measured data from the University of Texas at Austin.

Table 5. Satellite model validation results (Austin, TX).

	GLOBAL IRRADIANCE	DIRECT IRRADIANCE
Observed Average	494 W/sq.m	405 W/sq.m
Mean Bias Error	13 W/sq.m	-8 W/sq.m
Root Mean Square Error	89 W/sq.m	149 W/sq.m

The Mean Bias Error is a measure of the overall tendency of the satellite-derived irradiances to overestimate or underestimate actual measurements. For Austin, this tendency is +2.5 percent for global irradiance and -1.8 percent for direct irradiance. This suggests that the modeled irradiances used in this study should predict the actual annual value with a bias error not exceeding ± 3 percent. Global irradiance is the total amount of solar energy on a horizontal surface while direct irradiance is the only the direct normal component.

The Root Mean Square Error is a measure of the extent to which any given hourly estimation differs from the ground measurements. It is calculated based on the square root of the sum of the square of the hourly error.

Reference [15] presents detailed results about the effect of measuring data at a single location versus averaging it over an extended area. As discussed in that study [15], the short-term difference as reflected in the Root Mean Square Error is largely the consequence of the fact that the satellite and the ground stations measure different things: the satellite data integrates irradiance over an extended area (e.g., 1 pixel = 10 X 10 km) while the measurement reflects conditions at a pinpoint location. As a result, the short-term scatter is to be expected when comparing satellite and ground measurements as seen in part A of Figure 2. Note, however, that a similar degree of scatter occurs when comparing two nearby pinpoint locations such as the Austin Bergstrom Airport and the Howson Branch library as shown in part B of Figure 2.[9] In both cases, the outlying points represent partly cloudy conditions when one of the sites may be shaded while the

[9] The source for the bottom part of the figure is AE's Internal Draft on PV capacity.

other is not and when the integrated satellite pixel averages the local variations. Therefore, it is arguable that, when investigating the impact of dispersed PV spanning several 100 sq. km on the AE grid, it is preferable to select a spatially integrated signal (9 pixels in the present study) tending to smooth short-term, but highly local, variations, rather than the noisier pinpoint signal. It may be more appropriate to use data from actual PV systems once AE has installed a large number of well-maintained PV systems (with well maintained data collection systems) at a variety of locations and orientations throughout the city of Austin.

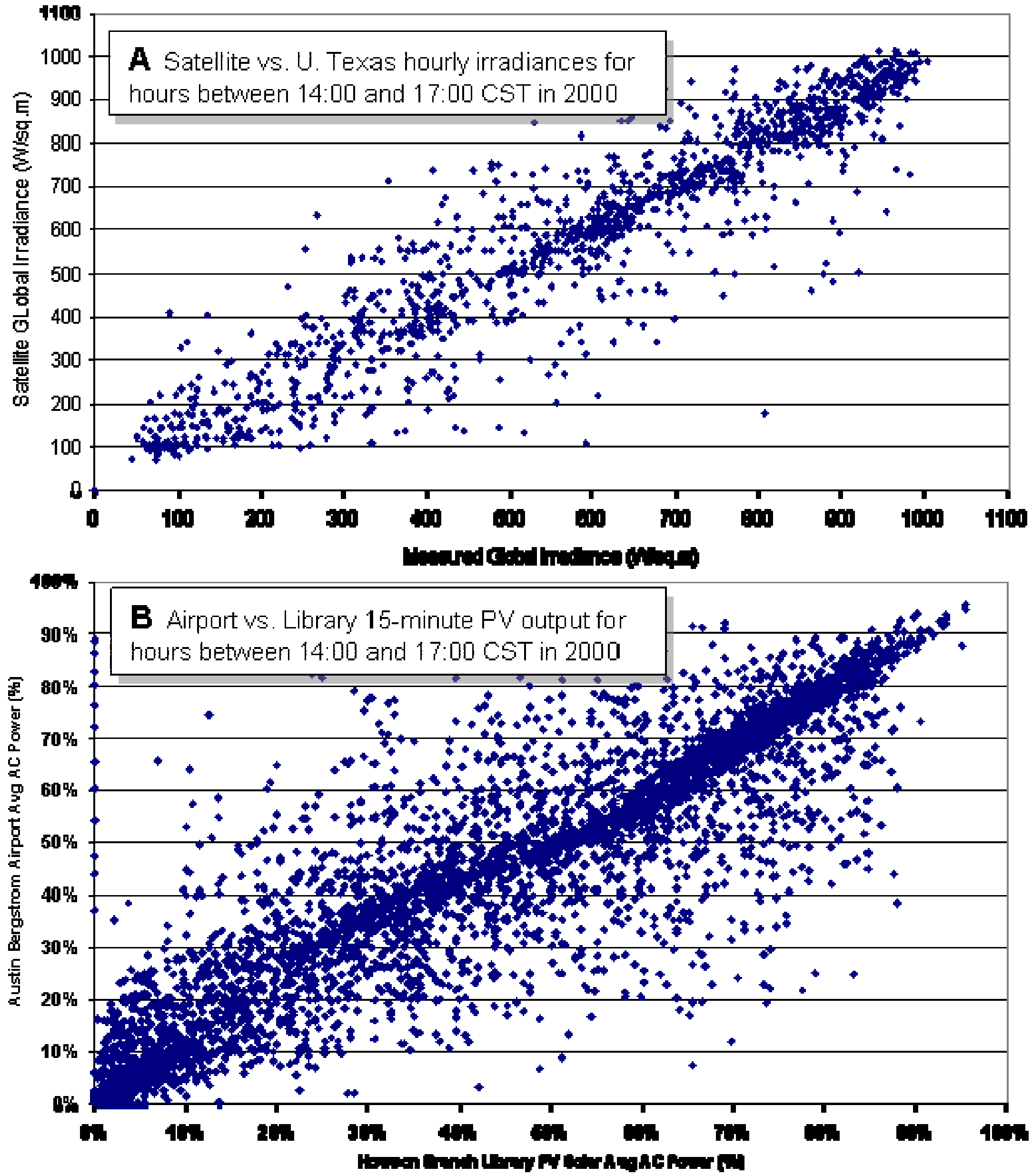


Figure 2. Comparison of satellite-derived to ground measured global irradiance (A) and relative PV output at two locations (B).

Output Simulation

Hourly time step is the highest resolution readily available from satellite sources for arbitrary locations. It may be argued that hourly data do not capture the short-term variability that characterizes the output of a PV system. However, if this is true for any one system at one particular location, it is not critical for the type of PV output of concern to this analysis: the output of PV generation dispersed over several hundred square miles (i.e., throughout AE's service territory). The satellite-derived PV output used here represents the average of 9 satellite pixels, each pixel covering an area of 10X10 km.

PV simulations were performed for each load data year analyzed: 2002, 2003 and 2004. For the first half of 2002, measured PV output data at the Austin Bergstrom Airport were available, coincident to the satellite-based simulations. Table 6 compares the PV capacity factors recorded at the airport installation with the same simulated from satellite data. Results indicate that the system-wide geometry-specific numbers generated for this analysis are comparable and are slightly on the conservative side.

Table 6. Satellite-derived vs. measured PV capacity factors (Bergstrom Airport 2002).

Month	Measured Capacity Factor	Satellite-Derived Capacity Factor
January	15.0%	14.4%
February	19.2%	18.5%
March	18.9%	17.8%
April	21.0%	21.3%
May	24.2%	23.3%
June	24.3%	23.3%
July	24.1%	22.3%
August	24.8%	24.5%
September	missing	19.9%
October	missing	13.2%
November	missing	16.0%
December	missing	13.3%

As an additional check of the validity of satellite-derived PV outputs, Figure 3 compares the peak day output of satellite-derived irradiances and PV outputs with the corresponding recorded data from the Bergstrom Airport and the Howson Branch library in 2002. The year 2002 is selected because it is the only year within the study's 2002-2004 time-frame when data were available from both the satellite-derived PV output and the data measured from the two PV power plants. The figure indicates that irradiance-to-PV simulation accurately captures conversion losses from irradiance to AC output.

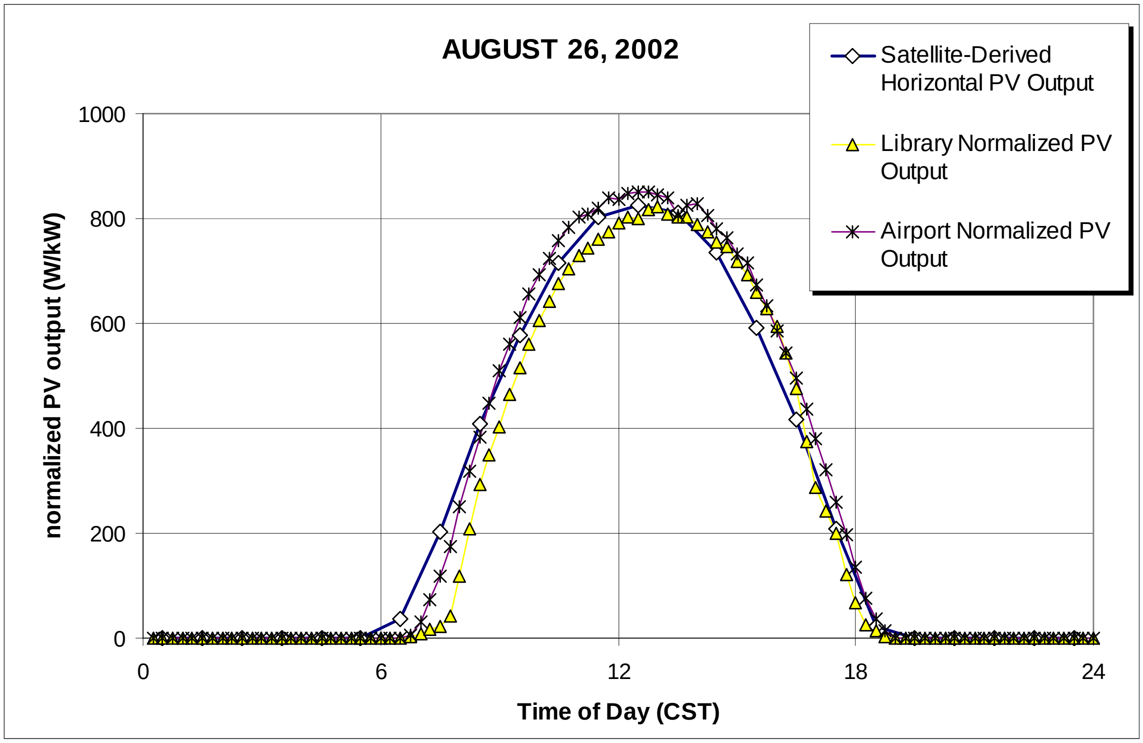


Figure 3. Satellite-simulated compared to measured PV output (2002 peak day).

Figure 4 provides a check on satellite-derived versus ground-based global irradiance for utility peak days in 1999, 2000 and 2001. The figure indicates that satellite-to-irradiance simulation adequately captures peak time conditions (cloudless but hazy in 1999 and with some cloudiness impact in both 2000 and 2001 – note that for the reasons discussed above in Figure 2, the impacts of light clouds are expected not to be perfectly in phase between the pinpoint station and the extended pixel).

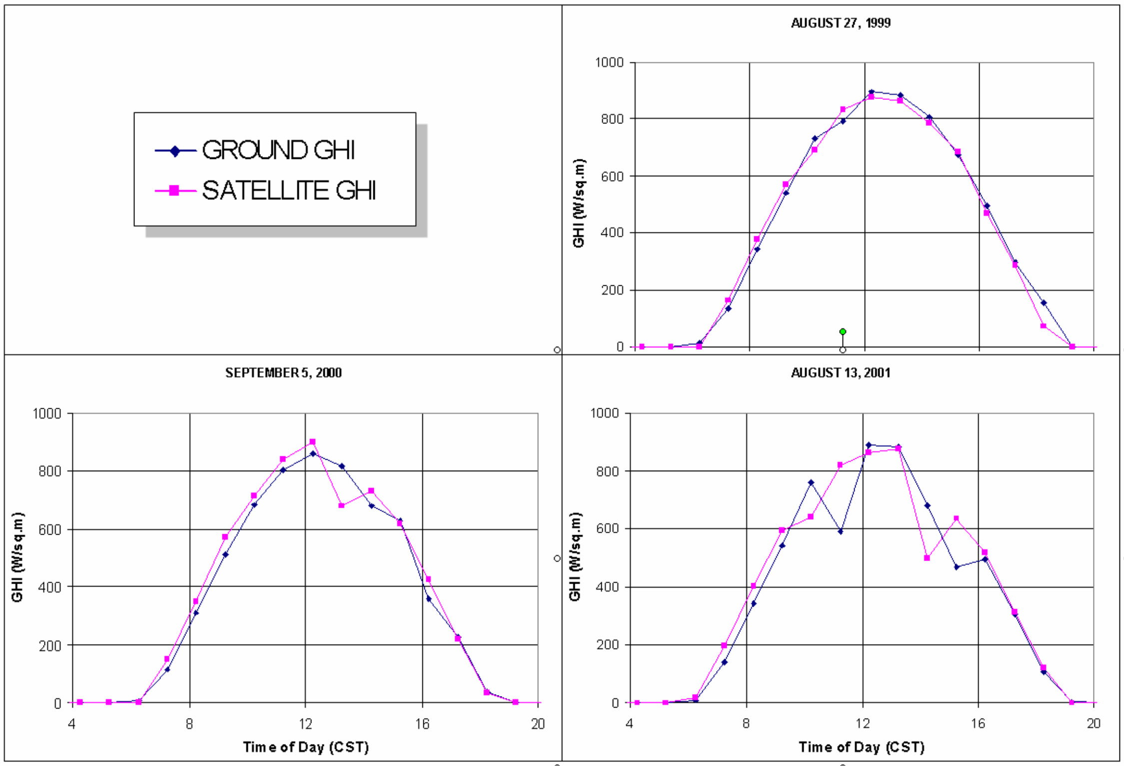


Figure 4. Satellite-derived compared to measured global irradiance on peak days.

Results

Daily PV output profiles for summer and winter averaged over the three-year period are presented in Figure 5. The monthly capacity factors are presented in Figure 6. In order to gauge the consistency of the selected period against long-term standards, Figure 7 compares the 2002-2004 satellite-derived clearness indexes[10] against the 30-year National Solar Resource Data Base values. The comparison shows that the 2002-2004 values are on the conservative side and that July and September are below long-term average.

[10] Defined as the ratio of global irradiance and clear-sky global irradiance

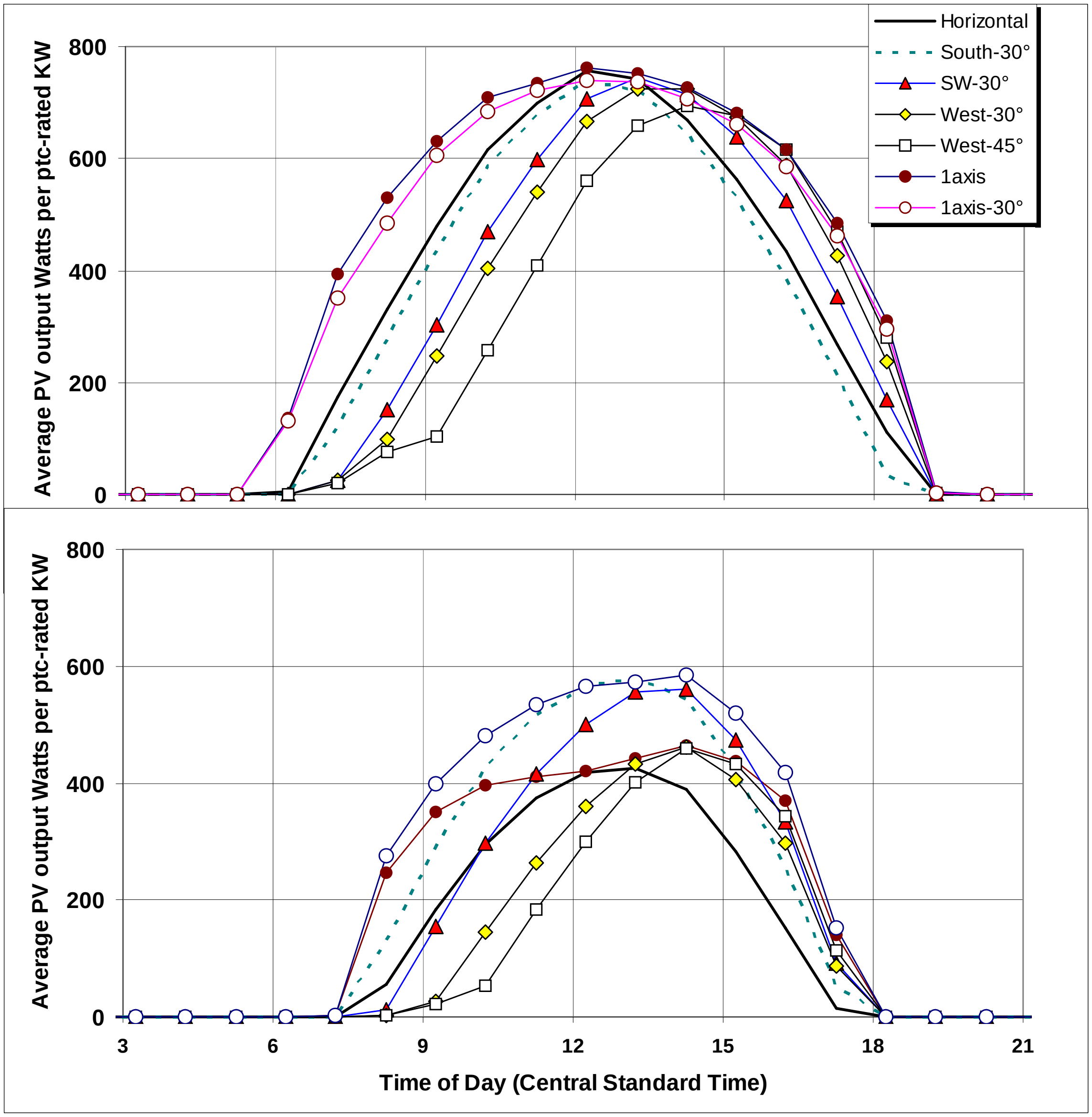


Figure 5. Average summer (top) and winter (bottom) daily PV output.

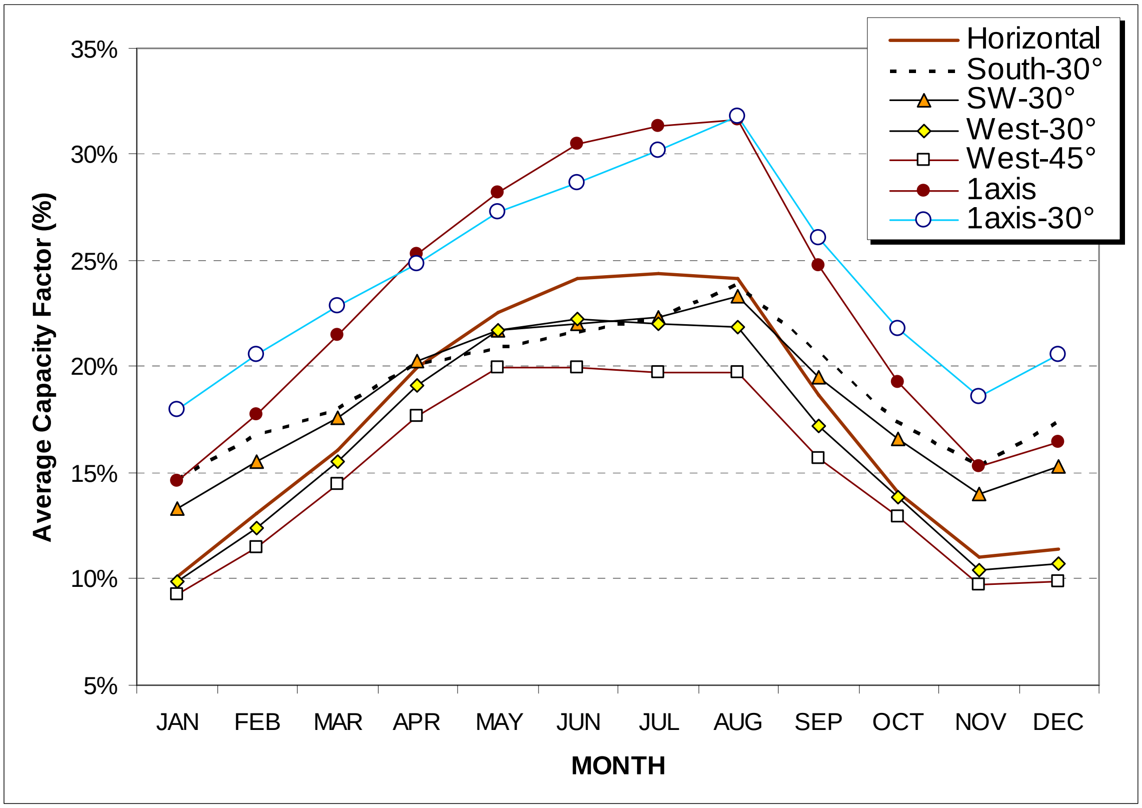


Figure 6. Average monthly PV capacity factors.

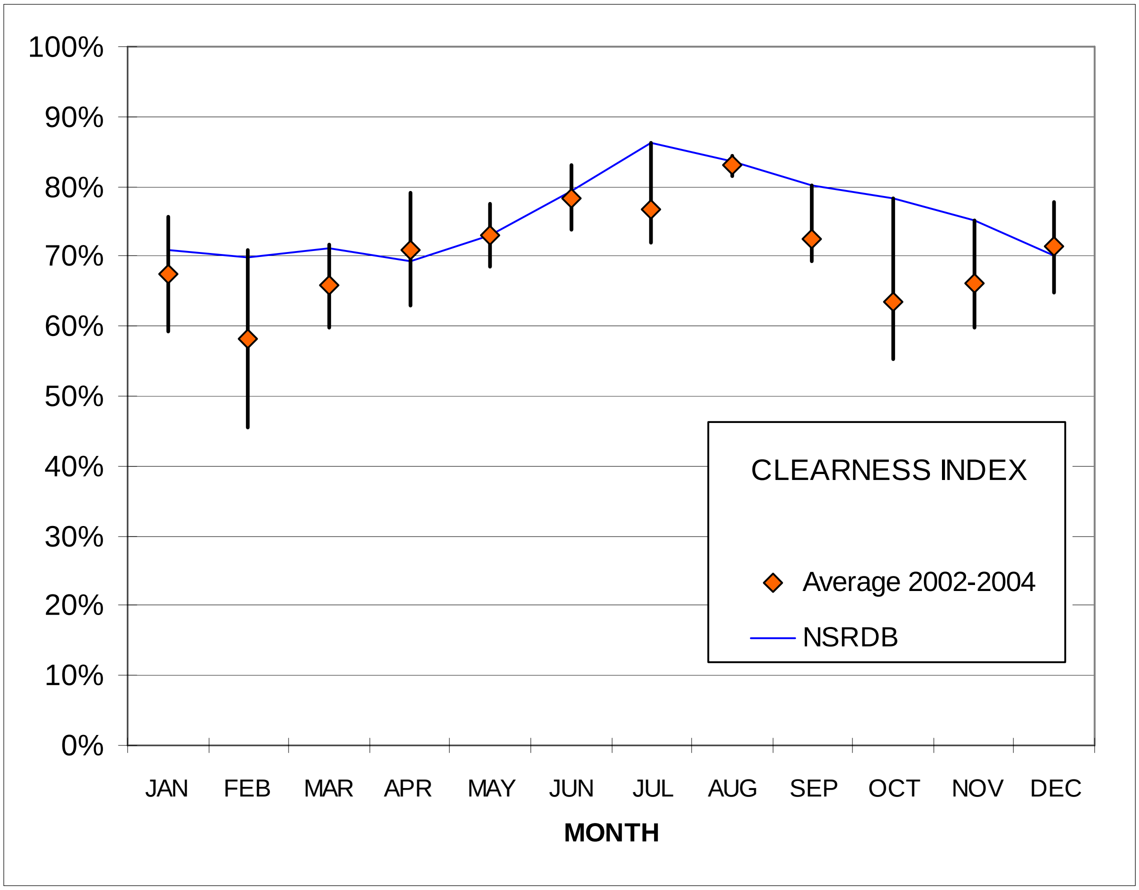


Figure 7. Comparison of seasonal clearness to long-term (2002-2004 vs. NSRDB).

It is assumed that the PV systems will experience ½ percent degradation per year. Table 7 presents the annual PV system output in kWh per kW for each configuration over the 30 year PV system life.

Table 7. Annual PV system output (kWh per kW).

	Horizontal	South 30°	SW 30°	West 30°	West 45°	1-Axis	1-Axis 30°
2006	1,535	1,675	1,621	1,443	1,322	2,025	2,130
2007	1,527	1,667	1,613	1,435	1,316	2,015	2,120
2008	1,521	1,660	1,606	1,429	1,310	2,006	2,110
2009	1,512	1,650	1,597	1,421	1,303	1,995	2,098
2010	1,504	1,642	1,589	1,414	1,296	1,985	2,088
2011	1,497	1,634	1,581	1,407	1,290	1,975	2,077
2012	1,490	1,627	1,574	1,401	1,284	1,966	2,068
2013	1,482	1,618	1,565	1,393	1,277	1,955	2,057
2014	1,474	1,610	1,557	1,386	1,270	1,945	2,046
2015	1,467	1,602	1,550	1,379	1,264	1,936	2,036
2016	1,461	1,595	1,543	1,373	1,259	1,927	2,027
2017	1,452	1,586	1,534	1,365	1,251	1,916	2,016
2018	1,445	1,578	1,526	1,358	1,245	1,907	2,006
2019	1,438	1,570	1,519	1,352	1,239	1,897	1,996
2020	1,432	1,563	1,512	1,346	1,234	1,889	1,987
2021	1,424	1,554	1,504	1,338	1,227	1,878	1,976
2022	1,416	1,546	1,496	1,331	1,220	1,869	1,966
2023	1,409	1,539	1,489	1,325	1,214	1,860	1,956
2024	1,403	1,532	1,482	1,319	1,209	1,851	1,947
2025	1,395	1,523	1,474	1,311	1,202	1,841	1,937
2026	1,388	1,516	1,466	1,305	1,196	1,832	1,927
2027	1,381	1,508	1,459	1,298	1,190	1,823	1,917
2028	1,376	1,502	1,453	1,293	1,185	1,815	1,909
2029	1,368	1,493	1,445	1,285	1,178	1,805	1,898
2030	1,361	1,486	1,437	1,279	1,172	1,796	1,889
2031	1,354	1,478	1,430	1,273	1,167	1,787	1,879
2032	1,348	1,472	1,424	1,267	1,162	1,779	1,871
2033	1,340	1,463	1,416	1,260	1,155	1,769	1,861
2034	1,334	1,456	1,409	1,254	1,149	1,760	1,851
2035	1,327	1,449	1,402	1,247	1,143	1,751	1,842

Future Work

One concern that has been expressed is that the satellite-based PV output estimates might not adequately capture output variations that occur due to clouds on a sub-hourly basis. Based on the experience of the weather expert member of the team (Dr. Richard Perez), this should not be a major issue for AE. This concern, however, can be addressed from a system-wide perspective as follows. One option is to instrument a selected number of PV systems that have been installed under AE's customer-sited PV incentive program. During periods of cloudy weather, AE could determine the instantaneous output of these systems and determine how the average output across all the systems varied compared to what the hourly satellite data alone would have predicted.

Loss Savings

Introduction

Distributed generation technologies reduce system losses by producing power at the point of consumption. Unlike many of the other benefits associated with distributed generation, the economic value of the loss savings benefit is indirect in that it magnifies the value other benefits. Consider a few examples. The energy production benefit provided by PV represents the avoided cost of generating the electricity consumed by the customer. For every kWh produced by PV, AE saves the cost of producing or purchasing a kWh at the point of production. In addition, since PV produces electricity at the point of consumption, AE also does not have to produce the additional, supplemental energy to make up for T&D losses. The loss savings "magnify" the energy production benefit to account for both the direct and supplemental energy benefit. Similarly, loss savings magnify the environmental benefit because emissions are proportional to the quantity of electricity produced – both the direct and supplemental energy. Loss savings also magnify the generation capacity and T&D capacity benefits because the system peak load and T&D system peak loads can be satisfied with less capacity at the point of origin.

Methodology

There are two approaches to account for these types of loss savings into the analysis. One is to credit the PV system output to account for the reduction in losses and then to perform each of the various value calculations using the higher kW and kWh figures. This option implicitly includes the loss savings in the total value but does not provide an explicit number for the loss savings benefit. The second approach is to perform the calculations twice, both with and without the inclusion of loss impacts. The difference between the two is the loss savings benefit. This second approach was selected for this study because, while it requires additional effort, it provides an explicit value for the loss savings benefit. This will enable readers to better understand the difference between distributed and non-distributed applications.

The appropriate loss savings factors need to be determined in order to calculate the loss savings value. A detailed derivation of the appropriate loss savings factors is presented in the Appendix. This section summarizes the key points of the derivation.

First, the loss savings calculations should be performed on a marginal basis rather than an average basis. Performing the analysis using average system losses substantially underestimates the loss savings value. Loss savings have direct and indirect components. The direct loss savings are the loss savings associated with only the output from the PV system. The indirect loss savings are associated with reduced total load (i.e., there is an overall reduction in power throughput in the T&D system and thus there is a reduction in losses). The indirect savings exceed the direct savings and should be included in the analysis for accuracy by performing loss savings on a marginal basis.

Second, both energy-related and capacity-related benefits should be calculated on a marginal basis.

Third, there is a difference between losses and loss savings. Losses are measured relative to the total generating load while loss savings are measured relative to the consumption. For example, if the losses are 10 percent, then the loss savings are 0.1/(1 - 0.1) = 11 percent.

Results

In connection with this study, AE evaluated the marginal losses for the transmission and distribution systems using load flow analysis. The system marginal losses including both transmission and distribution at the time of the seasonal peak demands are shown in Table 8. As shown in the table, the marginal loss savings equal 8.2 percent in the summer of 2005 for the peak period.[11] The marginal losses on the distribution system alone were between 4.3 percent and 5.9 percent. An average of 5.1 percent is used in this study.

This means that the marginal loss savings are 8.2 percent for those benefits that are based on the complete system (both T&D) and 5.4 percent for benefits that are based on the distribution system alone.

Table 8. AE T&D system marginal losses and loss savings

Season	Range of Energy Losses	Average of Marginal Energy Loss Savings
Spring 05	**6.6% to 8.1%**	**7.9%**
Summer 05	**6.8% to 8.3%**	**8.2%**
Fall 05	**6.2% to 7.7%**	**7.5%**
Winter 06	**6.1% to 7.6%**	**7.4%**

The loss savings values are calculated throughout the report. For reference purposes, the results are restated in Table 9.

Table 9. Loss savings value.

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
Energy	$72	$77	$77	$71	$65	$93	$98
Gen. Capacity	$20	$20	$23	$24	$24	$26	$26
Environment	$20	$22	$21	$20	$18	$27	$28
T&D	$1	$1	$2	$2	$2	$2	$2
Total	$114	$119	$123	$116	$109	$148	$154

[11] It is assumed that this occurs at 2300 MW.

Energy Production

Introduction

A primary benefit associated with distributed PV systems is that they produce electricity at the point of consumption at a known future price. There are three aspects associated with the value of this energy production.

1. PV systems produce electricity. The basic energy production value occurs because the amount of electricity that needs to be generated at other plants is reduced by the amount of PV production, thus decreasing the amount of fuel that is consumed and the O&M costs associated with the electricity-generation equipment.

2. PV systems produce energy at the point of consumption. There are reduced losses in the T&D system because the energy produced by PV systems does not have to pass through the transmission and distribution systems to reach the point of use. This is the energy loss savings value.

3. PV systems produce electricity at a stable price. PV cost is almost entirely capital related, with nearly negligible O&M costs and no fuel costs. PV energy prices are therefore fixed and known over the life of the system. In contrast, electricity prices from fossil-based generation are subject to potentially large fuel price fluctuations. Just as insurance or certain financial products provide "hedge" value against undesirable outcomes under uncertain future conditions, PV provides a hedge against natural gas price uncertainty. This is the value of the reduction in fuel price uncertainty.

Methodology

Overview

The basic energy production value can be calculated using two different sets of economic data. The first option is to use the utility's internal marginal production costs. The second option is to use the external market prices. The analysis in this report is based on AE internal marginal costs, costs that are provided by AE.

As mentioned above, there is also a benefit associated with the reduction in uncertainty associated with the PV-generated electricity. Appendix C presents a detailed analysis of this value using the risk-free discount rate and a long-term fixed price natural gas contract over the life of the PV system.

Risk-free discount rate data are available from the U.S. treasury yield curve. Unfortunately, fixed price natural gas contract prices are not available over the long term. Therefore, for purposes of this study, it was decided that futures market price data would be used for the first 5 years of the analysis and AE's best estimate of what it would cost to obtain fixed price natural gas would be used for the remaining 25 years of PV system life. AE’s best estimate for the years 6 through 30 is its current base case natural gas price forecast.

Detailed Steps

The energy value (with loss savings and natural gas price hedge benefit) is calculated as follows. See Appendix D for detailed formulas and calculations.

1. Estimate typical year PV output
   (a) Model PV output using hourly satellite-generated meteorological data for the three year period from 2002 to 2004
   (b) Calculate the hourly Loss Factors for the combined T&D system for the three year period from 2002 to 2004[12]
   (c) Adjust the PV output to account for loss savings by multiplying the hourly PV output times the corresponding hourly Loss Factors
   (d) Create a typical year of PV output by computing the average hourly adjusted PV output

2. Adjust the typical year PV output to reflect ½ percent degradation per year

3. Calculate annual energy value
   (a) Sum the product of hourly PV output (adjusted for degradation and loss savings) and AE's hourly 1 MW marginal cost forecasts (for a specific year)
   (b) Sum the product of hourly PV output (adjusted for degradation and loss savings) and AE's hourly 100 MW marginal cost forecasts (for a specific year)
   (c) Perform a linear interpolation between the results based on 1 MW and 100 MW marginal costs to account for the PV system size

4. Adjust the annual energy value to reflect current natural gas prices
   (a) The adjustment during the first 5 years of the analysis is made using the NYMEX futures price adjusted for basis
   (b) The adjustment during the remaining years of the analysis is made using AE's natural gas price forecast

5. Discount the annual PV value using the risk-free discount rate as reflected by the treasury yield curve to account for the hedge value of PV

6. Repeat for the years 2006 to 2035 over the 30 year life of the PV system

7. Sum the discounted annual energy values

[12] The marginal loss savings at any particular hour equals the marginal loss savings at the peak load times the ratio of the load at that particular hour to the peak load. It is assumed that the marginal loss savings equal 8.2 percent at 2,300 MW. Thus, if the load is 1,400 MW, the loss savings equals 8.2% x 1,400 MW / 2,300 MW = 5.0%. The Loss Factor at this load equals 1.05. AE's hourly generation system load data was required for this analysis.

Results

The energy production loss savings value is calculated independently from the direct energy production value by first performing the calculations with the calculated set of Loss Factors and then with all Loss Factors equal to 1 (no losses). The difference between the two calculations is the energy loss savings value.

Annual Energy Value

This calculation was implemented for each PV system configuration and is presented in detail in Appendix D. This section summarizes some of the key steps of the analysis. The annual energy value for 15 MW of PV is presented Table 10.

Table 10. Energy value (15 MW plant, with loss savings and degradation) - $/kW/yr.

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
2006	$80	$86	$85	$77	$71	$104	$109
2007	$71	$75	$74	$68	$62	$91	$96
2008	$57	$61	$61	$55	$51	$73	$78
2009	$51	$55	$54	$49	$45	$65	$69
2010	$51	$55	$54	$49	$45	$66	$69
2011	$49	$53	$53	$48	$44	$64	$67
2012	$56	$61	$60	$54	$49	$73	$77
2013	$55	$60	$59	$53	$49	$72	$76
2014	$61	$66	$65	$58	$54	$79	$84
2015	$57	$61	$61	$55	$51	$74	$78
2016	$63	$68	$67	$60	$55	$81	$86
2017	$62	$68	$66	$60	$55	$81	$86
2018	$69	$75	$73	$65	$60	$90	$95
2019	$69	$75	$73	$65	$59	$90	$95
2020	$70	$76	$74	$66	$60	$91	$97
2021	$69	$74	$73	$66	$60	$90	$94
2022	$70	$75	$74	$67	$61	$91	$96
2023	$71	$76	$75	$67	$62	$92	$97
2024	$74	$81	$79	$71	$65	$97	$102
2025	$73	$79	$77	$69	$64	$96	$101
2026	$75	$81	$79	$71	$65	$98	$103
2027	$74	$80	$78	$70	$64	$97	$102
2028	$75	$82	$80	$71	$66	$99	$104
2029	$75	$81	$79	$71	$65	$98	$103
2030	$76	$82	$80	$72	$66	$100	$105
2031	$75	$81	$79	$71	$65	$98	$103
2032	$75	$82	$80	$71	$65	$99	$104
2033	$76	$82	$80	$71	$65	$99	$104
2034	$77	$83	$81	$72	$66	$100	$106
2035	$77	$83	$81	$72	$66	$101	$106

Adjustment for Revised Natural Gas Prices

A critical input into the marginal cost projections is AE's 30 year natural gas price forecast. During the course of this study, there was a significant change in the natural gas price forecasts as result of two factors. First, there was a significant change in natural gas prices. Second, there was a change in methodology. The methodology change was to use natural gas futures prices for the first 5 years of the analysis.

Rather than regenerating the full set of marginal costs, it was determined that the annual energy values could be adjusted by multiplying by the ratio of the new natural gas price to the original natural gas price used to generate the marginal costs.

The adjusted annual energy values equal the results from Table 10 multiplied by the corresponding natural gas price adjustment factors for each year. The results are presented in Table 11.

In addition, Table 11 presents the risk-free discount factor based on the Treasury Yield curve on January 9, 2006. The calculation is completed by multiplying the discount factor times the corresponding annual energy value and summing the result to obtain the present value energy value. The result is shown at the bottom of Table 11 and is transferred to the first row of Table 12.

Table 11. Adjusted energy value (15 MW plant, with loss savings) - $/kW/yr.

	Discount Factor	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
2006	1.00	$109	$117	$115	$105	$96	$141	$148
2007	0.96	$110	$117	$115	$105	$97	$142	$148
2008	0.92	$102	$110	$109	$99	$92	$132	$139
2009	0.88	$98	$106	$105	$95	$88	$127	$134
2010	0.84	$92	$99	$98	$89	$82	$119	$125
2011	0.81	$60	$64	$64	$58	$53	$77	$81
2012	0.77	$66	$72	$71	$64	$59	$86	$91
2013	0.74	$66	$72	$71	$64	$59	$86	$91
2014	0.71	$72	$79	$77	$69	$64	$94	$99
2015	0.68	$65	$70	$70	$63	$58	$84	$89
2016	0.65	$58	$63	$62	$56	$52	$76	$80
2017	0.62	$60	$65	$64	$57	$53	$78	$82
2018	0.60	$69	$75	$73	$65	$60	$90	$95
2019	0.57	$72	$79	$76	$68	$62	$95	$100
2020	0.55	$75	$82	$79	$70	$65	$98	$104
2021	0.53	$74	$80	$78	$71	$65	$97	$101
2022	0.50	$77	$83	$81	$73	$67	$101	$106
2023	0.48	$80	$86	$84	$76	$70	$104	$110
2024	0.46	$87	$94	$91	$82	$75	$113	$119
2025	0.42	$88	$95	$92	$83	$76	$114	$120
2026	0.40	$92	$99	$97	$87	$80	$120	$126
2027	0.39	$93	$101	$99	$88	$81	$122	$128
2028	0.37	$98	$106	$103	$92	$85	$128	$134
2029	0.35	$100	$108	$105	$94	$86	$131	$137
2030	0.34	$104	$112	$109	$98	$90	$136	$143
2031	0.32	$104	$113	$110	$99	$91	$137	$144
2032	0.31	$108	$118	$114	$102	$94	$142	$149
2033	0.29	$112	$121	$118	$105	$97	$146	$154
2034	0.28	$116	$126	$123	$110	$101	$152	$160
2035	0.27	$120	$130	$126	$113	$103	$157	$165
Present Value		***$1,454***	***$1,570***	***$1,542***	***$1,390***	***$1,278***	***$1,891***	***$1,990***

Energy and Loss Savings Value

The result of the analysis to this point is the energy value with loss savings. The energy value incorporates the natural gas price hedge value. In order to calculate the loss savings value, the analysis is repeated with the Loss Factors equal to 1. The result is entered in the second row of Table 12. The difference between the two equals the energy loss savings value.

Table 12. Energy value and energy loss savings value ($/kW).

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
Energy Value w/ Loss Savings	$1,454	$1,570	$1,542	$1,390	$1,278	$1,891	$1,990
Energy Value w/o Loss Savings	$1,382	$1,493	$1,465	$1,319	$1,213	$1,797	$1,893
Energy Loss Savings Value	$72	$77	$77	$71	$65	$93	$98
Implied Loss Savings	5.2%	5.1%	5.2%	5.4%	5.4%	5.2%	5.2%

Discussion

One area to improve this analysis is to obtain a single natural gas price forecast that is based on an actual contract that AE could obtain in the market today for a 30-year fixed price contract from an entity with very low default risk rather than using a natural gas price forecast.

Generation Capacity

Introduction

Summer electrical demand is a concern to AE because of peak generation availability, price, environmental quality, and the stress imposed on the system. One solution to these concerns is to deploy distributed PV generation, provided that this is reliably available at peak time. This section quantifies the generation capacity value of PV.

Methodology

Capacity value is the product of an economic input and a technical input. The economic input is the value ($ per kW) of an ideal resource that has a life that is equivalent to the generating resource being evaluated; an ideal resource is one that has no outage probability so that it is always available to satisfy capacity needs. The technical input is the capacity (kW) provided by the resource. The remainder of this section focuses on the determination of these two inputs and the methods by which they are estimated.

Economic Input

The first input that is required to determine the capacity value is the economic value of an ideal resource. AE assumes that the installed capital cost of a natural gas turbine is $515 per kW. It is sometimes assumed that a natural gas turbine (GT) is a proxy for an ideal resource. A GT, however, needs to be adjusted in two ways to represent an ideal resource.

One adjustment needs to reflect the GT's forced outage rate relative to an ideal resource. By definition, an ideal resource has a forced outage rate of 0 percent. If the GT has an 8 percent forced outage rate, then the GT has a capacity value that is 8 percent less than an ideal resource.

Another adjustment needs to reflect the life of the GT relative to the life of the resource being evaluated, which, in this case, is a PV system. AE assumes that the life of a gas turbine is 40 years while the life of a PV system is 30 years.[13] Assume that in year 30, the gas turbine has 10 years of remaining life while the PV system has no remaining life. The GT has a salvage value of 25 percent of its value. At a 7 percent discount rate, the salvage value is 3.3 percent.[14] Thus, the value of gas turbine capacity is 3.3 percent greater than the PV system.

In order to use the GT as an ideal resource, the GT cost needs to be decreased by 8 percent for its forced outage rate and increased by 3.3 percent for its longer life. To be

[13] This may be undervaluing the PV resource because PV system manufacturers have confidence to provide 25 year warranties and the panels are likely to last significantly longer than the warranties. SMUD, for example, states on its website (http://www.smud.org/green/solar/index.html) that the PV system life is expected to be 30 years. The life of a PV system may in fact be longer than that of a GT because the PV system is a solid state device with no moving parts.

[14] The change is calculated as follows: (10 years/40 years) x (1/1.07^25) = 0.033.

conservative, it is assumed that these two factors offset each other and the capacity value of an ideal resource with a 30 year life is $515 per kW.

Technical Input

The second input that is required to determine the capacity value is the effective capacity, or the amount of capacity that the resource actually provides.[15] For a dispatchable resource, the effective capacity is the unit's rating. The answer is more challenging, however, for renewable energy technologies because the output is dependent upon the availability of a variable resource (sun, wind, etc.).

Several evaluation methods have been developed to address this challenge. The methods include the Effective Load Carrying Capability (ELCC) method, the ERCOT Wind method, the Capacity Contribution method, and the Firm with Load Control method. This analysis is based on the ELCC method.

The ELCC is a statistical measure of effective capacity that was developed by Garver in the 1960's [1]. The ELCC of a proposed generating unit in a utility grid is defined as the load increase that the system can carry while maintaining the designated reliability criteria (e.g., constant Loss of Load Probability, LOLP). The ELCC method has been applied extensively throughout the U.S. (e.g., [1], [4], [7], and [13]). The method of calculation is presented in Appendix E.

The ELCC can be expressed as a percentage of PV capacity by dividing the ELCC by the PV Capacity. For example, a 100 kW PV plant with 50 percent ELCC would allow a 50 kW load increase at constant LOLP.

Results

Technical Results

The ELCC was calculated for all the system configurations for the years 2002, 2003, and 2004 for PV system rated capacity (referred to as penetration levels) from 2 percent to 20 percent of peak system load. Figure 8 presents the average ELCC for each orientation as a function of PV penetration. Table 13 suggests that there is strong relationship between peak loading and solar gain results since the results are consistent and stable from year to year.

ELCC is highest overall for the 1-axis tracking geometry. West facing geometries (both low and high-tilt) are the best fixed orientations. The southwest low tilt geometry is within 2 percent of these results. Horizontal collectors do not score nearly as well, but still provide a better match to AE's load than a "classical" south-facing low-tilt orientation.

In every case, even at substantial levels of penetration, the ELCC remains well above the resource's annual capacity factors which are respectively 17, 23, 19, 18, 16, and 15

[15] The effective capacity of a resource of a non-dispatchable resource such as PV is not to be confused with its capacity factor which is its average output relative to installed capacity.

percent for the Horizontal, 1-Axis, 1-Axis 30°, South-30°, SW-30°, West-30°, and West-45° configurations.

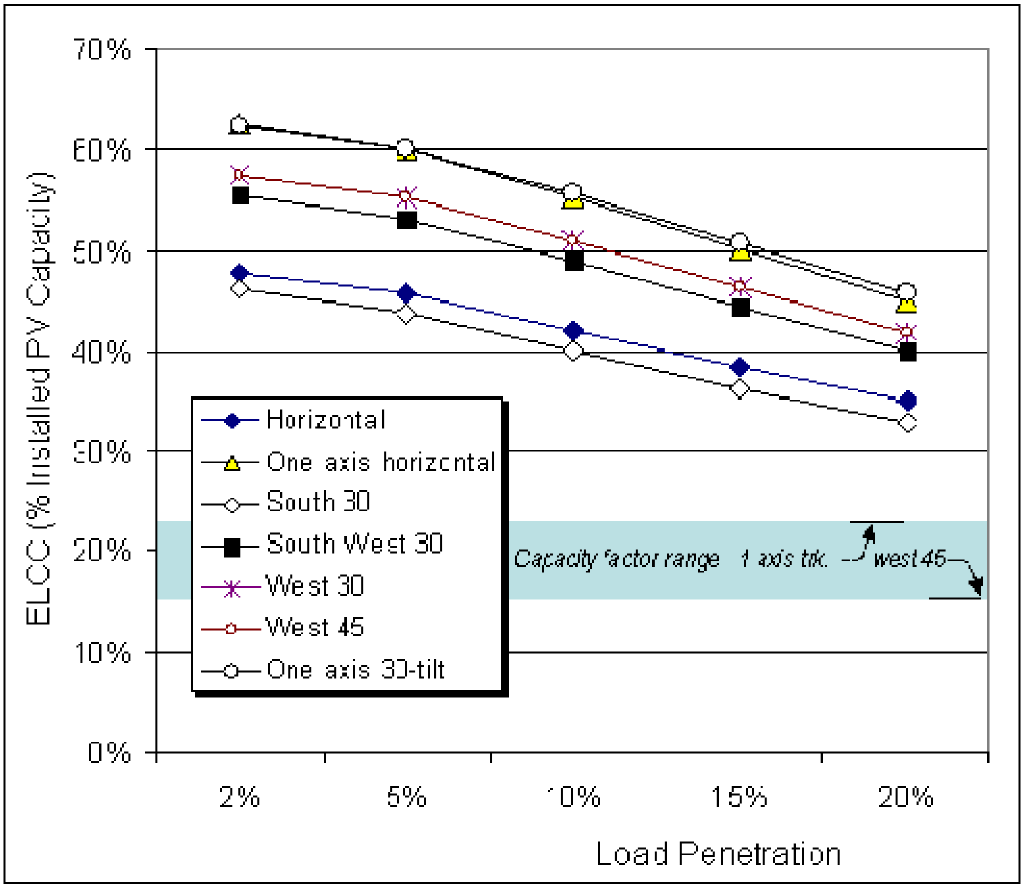


Figure 8. Average 2002-2004 ELCC versus load penetration.

Table 13. Annual and average ELCC versus load penetration.

	Penetration	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
2002	0%	47%	46%	55%	57%	57%	62%	62%
2002	2%	47%	46%	55%	57%	57%	62%	62%
2002	5%	45%	43%	53%	55%	55%	60%	59%
2002	10%	41%	40%	48%	50%	51%	55%	55%
2002	15%	38%	36%	44%	46%	46%	50%	50%
2002	20%	34%	32%	40%	41%	42%	44%	45%
2003	0%	48%	46%	55%	57%	57%	62%	61%
2003	2%	48%	46%	55%	57%	57%	62%	61%
2003	5%	46%	43%	52%	55%	54%	59%	59%
2003	10%	42%	40%	48%	50%	50%	55%	55%
2003	15%	38%	36%	44%	46%	46%	50%	50%
2003	20%	35%	32%	40%	42%	41%	44%	45%
2004	0%	48%	47%	56%	59%	59%	64%	64%
2004	2%	48%	47%	56%	59%	59%	64%	64%
2004	5%	46%	45%	54%	56%	56%	61%	62%
2004	10%	43%	41%	50%	52%	52%	56%	57%
2004	15%	39%	37%	45%	47%	47%	51%	52%
2004	20%	36%	33%	41%	43%	43%	46%	46%
Average	0%	***48%***	***46%***	***55%***	***58%***	***58%***	***63%***	***62%***
Average	2%	***48%***	***46%***	***55%***	***58%***	***58%***	***63%***	***62%***
Average	5%	***46%***	***44%***	***53%***	***55%***	***55%***	***60%***	***60%***
Average	10%	***42%***	***40%***	***49%***	***51%***	***51%***	***55%***	***56%***
Average	15%	***38%***	***36%***	***44%***	***46%***	***46%***	***50%***	***51%***
Average	20%	***35%***	***32%***	***40%***	***42%***	***42%***	***45%***	***45%***

Combined Results

Table 14 summarizes the calculations and results. The generation capacity value equals the economic value of an ideal resource (first row) times the ELCC (second row) and ranges from $239 to $323 per kW (third row). The generation capacity loss savings value equals the generation capacity loss savings (fourth row) times the generation capacity value and ranges from $20 to $26 per kW (fifth row).

Table 14. Generation capacity value and loss savings value ($/kW).

	Horizontal	*South 30º*	*SW 30º*	*West 30º*	*West 45º*	*1-Axis*	*1-Axis 30º*
Ideal Resource Value	$515	$515	$515	$515	$515	$515	$515
ELCC	48%	46%	55%	58%	58%	63%	62%
Gen. Cap. Value	$245	$239	$285	$297	$297	$323	$321
Loss Savings	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%
Loss Savings Value	$20	$20	$23	$24	$24	$26	$26

Distribution System

Introduction

An appropriately targeted implementation of PV has the potential to relieve capacity constraints on the utility's transmission, sub-transmission, and distribution systems. It accomplishes this by providing power to loads directly, effectively reducing loads on these circuits.

Utilizing the effective PV capacity, planners may be able to defer capital investments and realize cost savings depending on the rate of load growth, the rating of the PV systems, and the temporal match between PV production and peak loading. In order to capture this benefit, investments must actually be deferred.

Deferring T&D capital investments has three financial components. First, there are the direct capital cost deferral savings that result from waiting to invest until a later date. Second, there are indirect financial costs that are incurred when an investment is made and continue as long as the investment exists (e.g., property taxes, insurance, etc.). Third, there are O&M cost savings associated with the investment.

The T&D deferral benefit is site-specific and in cases where there is no benefit, no value should be assigned. The benefit exists when T&D expenditures are deferred by the investment.

Methodology

When there is no load growth uncertainty[16] and the distributed generation service life equals the life of the investment being deferred, the cost-savings equal the fully loaded present value cost of the investment plan that is deferrable divided by the load growth times a term involving the interest rate times the match between the distributed generation resource output and the peak load adjusted for loss savings. When the interest rate is nominal and the deferral period is one year, the finance related savings equals the average investment cost times the time value of money times the load match. The value of T&D investment deferral is as follows:

$$\text{Deferred Capital Cost Value (\$/kW)} = \overset{\text{Avg. Cost}}{[X/L]} \quad \text{x} \quad \overset{\text{Value of Money}}{[(r-i)/(1+r)]} \quad \text{x} \quad \overset{\text{Load Match}}{[M]} \qquad (1)$$

where X is the fully loaded present value cost of the distribution expansion plan over the study period, L is the annual load growth (MW/yr), r is the current nominal discount rate, i is the escalation rate, and M is a factor corresponding to the effective peak load reduction provided by the PV system.[17]

[16] While there is always load growth uncertainty in planning, this analysis assumes that the uncertainty is minimal.
[17] A detailed derivation of this equation is presented in [10]. See also [11].

While this Deferred Capital Cost Value may not represent that actual savings per kW to the utility that can be expected for each kW of PV installed, it can be considered as a typical benefit value and as a measure of the comparative potential value of installed PV.

As a result, the economic evaluation of a distribution system deferral value can be determined in two steps. The first step is to calculate the value of an ideal resource (i.e., one that provides full distribution system capacity reduction). This is the economic calculation. The second step is to calculate the technical impact that a particular resource has on the system. This is the technical evaluation.

Economic Evaluation

Area-Specific Expansion Plan Cost

The first step in performing the distribution deferral analysis is to determine the fully loaded present value cost of the distribution expansion plan (i.e., the load-growth related investments that have the potential to be deferred) on an area-specific basis over the study period. The costs are required over the life of the potential deferral investment, which for this study, is assumed to be 30 years.

AE budgetary estimates of how much is planned to be spent on new load growth related distribution system investments are presented in Table 15. It is assumed that these budgetary estimates include all three of the cost components identified above.

The Distribution and Substations sections of Table 15 are the budgetary estimates broken down by location and by the expenditure category. The Total section is the sum of the Distribution Lines and Distribution Substations expenditures.

AE's budgetary estimates do not specifically identify whether or not the costs are load growth related and have the potential to be deferred. AE personnel estimate that 15 percent of the distribution capacity expansion plans have the potential to be deferred after the first ten years (assuming growth rates remain constant). This means that currently budgeted distribution projects are not deferrable, but addition of PV could possibly defer distribution projects that would start in the 11th year of this study period. The deferrable distribution system capacity expansion plan is presented in the Total Deferrable section in Table 15 and equals 15 percent of the third section.

Table 15. AE distribution budget due to new load growth.

	2006	2007	2008	2009	2010
Budget					
Distribution Lines ($M)					
Central & Downtown	$0.40	$1.74	$0.53	$2.63	$0.98
Northeast	$6.16	$8.33	$2.63	$5.96	$4.93
Northwest	$2.68	$3.29	$1.00	$1.39	$6.23
Southeast	$5.11	$2.61	$9.16	$4.30	$1.64
Southwest	$3.32	$3.42	$6.06	$5.10	$5.60
Substations ($M)					
Central & Downtown	$0.00	$0.00	$0.30	$1.73	$0.00
Northeast	$0.00	$0.01	$0.34	$0.00	$0.00
Northwest	$0.14	$0.37	$0.62	$0.22	$0.15
Southeast	$0.00	$0.60	$1.03	$0.30	$0.00
Southwest	$0.00	$0.01	$0.00	$0.00	$0.00
Total ($M)					
Central & Downtown	$0.40	$1.74	$0.82	$4.36	$0.98
Northeast	$6.16	$8.34	$2.97	$5.96	$4.93
Northwest	$2.82	$3.66	$1.61	$1.61	$6.39
Southeast	$5.12	$3.21	$10.19	$4.59	$1.64
Southwest	$3.32	$3.42	$6.06	$5.10	$5.60
Total Deferrable ($M)					
Central & Downtown	$0.06	$0.26	$0.12	$0.65	$0.15
Northeast	$0.92	$1.25	$0.45	$0.89	$0.74
Northwest	$0.42	$0.55	$0.24	$0.24	$0.96
Southeast	$0.77	$0.48	$1.53	$0.69	$0.25
Southwest	$0.50	$0.51	$0.91	$0.77	$0.84

AE's budget is for the years 2006 and 2010. In order to perform the deferral value analysis, estimated expenditures are required that are equivalent to the life of the PV investment. In order to make this estimate, it is assumed that beginning in 2011, the distribution system expenditures will occur at a constant rate equivalent to the 2006 to 2010 budgeted rate. That is, the analysis needs to determine the area-specific annual distribution upgrade cost starting in 2011 and then escalating at a rate of 2.5 percent per year.[18]

This cost is determined by selecting an "equivalent cost" beginning in 2006 such that when it is escalated at 2.5 percent per year, the present value of the equivalent costs from 2006 to 2010 equals the present value of the budgeted cost. The calculations are

[18] Data was received from AE on 5/19/2005 that reported that the Texas Consumer Price Index is expected to be 137 in 2005 and is expected to be 176 in 2015. This suggests that the annual escalation rate is about 2.5 percent (i.e., 137 x 1.025 ^ 10 = 175).

presented in Table 16. As can be seen in the table, the 5-year present value of the two cost streams (budgeted versus equivalent cost) is the same for the corresponding areas.

Table 16. Total distribution cost due to new growth (budgeted and equivalent cost).

	2006	2007	2008	2009	2010	5-year Present Value
Budget						
Total Deferrable ($M)						
Central & Downtown	$0.06	$0.26	$0.12	$0.65	$0.15	$1.06
Northeast	$0.92	$1.25	$0.45	$0.89	$0.74	$3.78
Northwest	$0.42	$0.55	$0.24	$0.24	$0.96	$2.08
Southeast	$0.77	$0.48	$1.53	$0.69	$0.25	$3.30
Southwest	$0.50	$0.51	$0.91	$0.77	$0.84	$3.04
Equivalent Cost ($M)						
Central & Downtown	$0.23	$0.24	$0.24	$0.25	$0.25	$1.06
Northeast	$0.82	$0.84	$0.86	$0.88	$0.91	$3.78
Northwest	$0.45	$0.46	$0.47	$0.49	$0.50	$2.08
Southeast	$0.72	$0.74	$0.75	$0.77	$0.79	$3.30
Southwest	$0.66	$0.68	$0.69	$0.71	$0.73	$3.04
Discount Factor	1.000	0.935	0.873	0.816	0.763	

The budgetary estimates for 2006 through 2010 can now be combined with the projected costs beginning in 2011. The first five years of the distribution system capacity expansion plan are based on the budgetary estimates provided by AE. The remaining 25 years are based on the equivalent cost results developed above. The annual results are presented in Figure 9 and Table 17 and the bottom of table includes present value capacity expansion plan cost by area.

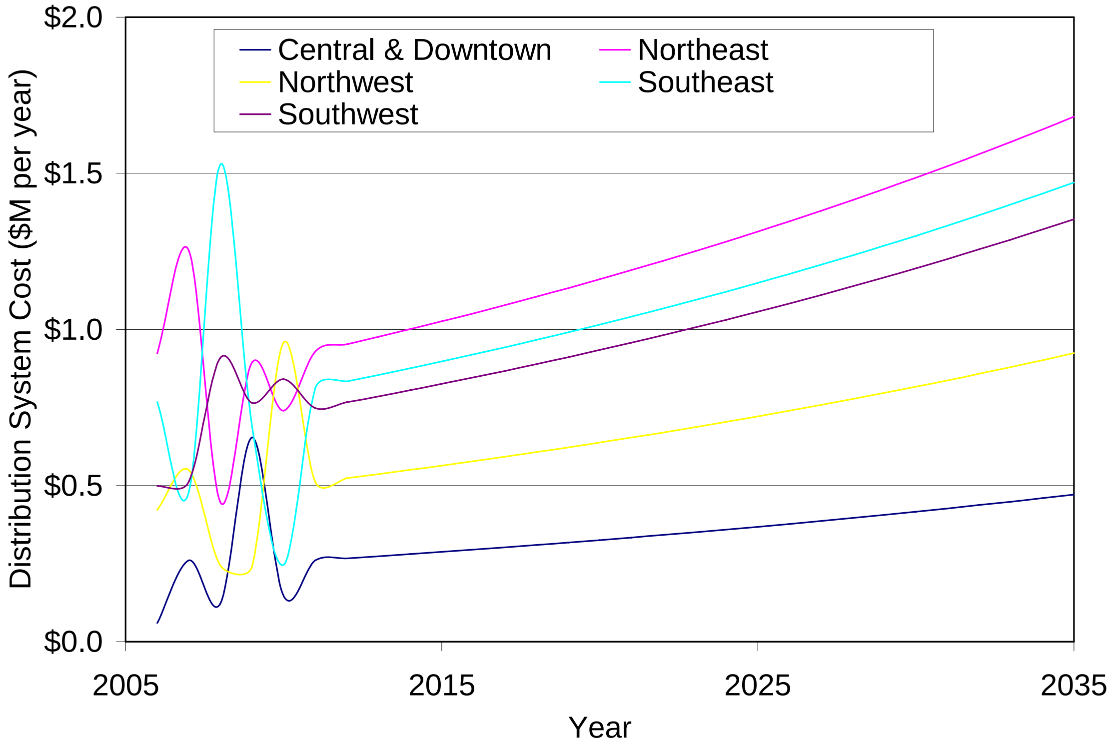


Figure 9. Distribution capacity expansion plan costs by area and year.

Table 17. Distribution capacity expansion plan costs by area and year ($M).

	Discount Factor	Central & Downtown	Northeast	Northwest	Southeast	Southwest	All Areas
2006	1.0000	$0.1	$0.9	$0.4	$0.8	$0.5	$2.7
2007	0.9346	$0.3	$1.3	$0.5	$0.5	$0.5	$3.1
2008	0.8734	$0.1	$0.4	$0.2	$1.5	$0.9	$3.2
2009	0.8163	$0.7	$0.9	$0.2	$0.7	$0.8	$3.2
2010	0.7629	$0.1	$0.7	$1.0	$0.2	$0.8	$2.9
2011	0.7130	$0.3	$0.9	$0.5	$0.8	$0.7	$3.3
2012	0.6663	$0.3	$1.0	$0.5	$0.8	$0.8	$3.3
2013	0.6227	$0.3	$1.0	$0.5	$0.9	$0.8	$3.4
2014	0.5820	$0.3	$1.0	$0.6	$0.9	$0.8	$3.5
2015	0.5439	$0.3	$1.0	$0.6	$0.9	$0.8	$3.6
2016	0.5083	$0.3	$1.1	$0.6	$0.9	$0.8	$3.7
2017	0.4751	$0.3	$1.1	$0.6	$0.9	$0.9	$3.8
2018	0.4440	$0.3	$1.1	$0.6	$1.0	$0.9	$3.9
2019	0.4150	$0.3	$1.1	$0.6	$1.0	$0.9	$4.0
2020	0.3878	$0.3	$1.2	$0.6	$1.0	$0.9	$4.1
2021	0.3624	$0.3	$1.2	$0.7	$1.0	$1.0	$4.2
2022	0.3387	$0.3	$1.2	$0.7	$1.1	$1.0	$4.3
2023	0.3166	$0.4	$1.2	$0.7	$1.1	$1.0	$4.4
2024	0.2959	$0.4	$1.3	$0.7	$1.1	$1.0	$4.5
2025	0.2765	$0.4	$1.3	$0.7	$1.1	$1.1	$4.6
2026	0.2584	$0.4	$1.3	$0.7	$1.2	$1.1	$4.7
2027	0.2415	$0.4	$1.4	$0.8	$1.2	$1.1	$4.8
2028	0.2257	$0.4	$1.4	$0.8	$1.2	$1.1	$5.0
2029	0.2109	$0.4	$1.4	$0.8	$1.3	$1.2	$5.1
2030	0.1971	$0.4	$1.5	$0.8	$1.3	$1.2	$5.2
2031	0.1842	$0.4	$1.5	$0.8	$1.3	$1.2	$5.3
2032	0.1722	$0.4	$1.6	$0.9	$1.4	$1.3	$5.5
2033	0.1609	$0.4	$1.6	$0.9	$1.4	$1.3	$5.6
2034	0.1504	$0.5	$1.6	$0.9	$1.4	$1.3	$5.8
2035	0.1406	$0.5	$1.7	$0.9	$1.5	$1.4	$5.9
Present Value		$3.97	$14.15	$7.78	$12.38	$11.39	$49.66

Annual Load Growth

In addition to determining the fully loaded present value capacity expansion plan cost, the annual load growth needs to be determined. AE indicated that the annual load growth should be determined by taking the 2012 projected peak load, subtracting from it the 2004 actual load, and dividing it by 8 years. The result is presented in Table 18

Table 18. T&D area-specific annual load growth.

	2004 Actual Load	2012 Projected Load	Annual Load Growth (MW/year)
Central & Downtown	407	410	0.4
Northeast	358	451	11.6
Northwest	600	658	7.3
Southeast	302	377	9.4
Southwest	503	601	12.3

Deferral Value

Having obtained the present value distribution system capacity expansion plan cost and annual load growth, the deferral value can be determined. The results are presented in Table 19 based on Equation (1) assuming a 7 percent discount rate and 2.5 percent escalation rate. As shown in the table, the value for areas that account for most of the load growth averaged $51 per kW. The one exception to this is the Central & Downtown areas. The value is $445 per kW in this area due to the fact that the load growth is slow and there are a number of underground lines in the area.

Table 19. Deferral value for ideal resource.

	(1)	(2)	(3)	(4) = (1) x (3) / (2)
	Expansion Plan Cost (Present Value in $M)	Load Growth for 1 year (MW)	Value of Money	Ideal Value ($/kW)
Central & Downtown	$3.97	0.4	4.2%	$445
Northeast	$14.15	11.6	4.2%	$51
Northwest	$7.78	7.3	4.2%	$45
Southeast	$12.38	9.4	4.2%	$56
Southwest	$11.39	12.3	4.2%	$39
All Areas	$49.66	40.9	4.2%	$51

Technical Evaluation

In previous studies, CPR has performed extensive technical evaluations about the impact that PV would have on distribution circuits. The analyses have been performed by examining the detailed hourly match between PV system output and the distribution system load over multi-year periods. In addition, some studies have incorporated risk and uncertainty into the analysis [37].

Such a detailed technical analysis is not performed in the present study for two reasons. First and foremost, the effective PV generation capacity determined above is representative of the effective PV distribution capacity.

Second, while the load for a particular distribution system may not perfectly match AE's system load, the increase in accuracy of results from a detailed technical analysis does not justify the effort it will require AE to provide the necessary data. As a result, a detailed technical analysis would be very unlikely to have any substantial change in the deferral value results. It is assumed that the technical match as calculated by the ELCC method for the generation system (see Table 13) will apply at the T&D level.

Results

The results are presented Table 20. The values range from about $24 to $32 per kW.

Table 20. T&D deferral value and loss savings results ($/kW).

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
Ideal T&D Value	$51	$51	$51	$51	$51	$51	$51
Load Match	48%	46%	55%	58%	58%	63%	62%
T&D Value	$24	$24	$28	$29	$29	$32	$32
T&D Loss Savings	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%
T&D Loss Savings Value	$1	$1	$2	$2	$2	$2	$2

(All areas except Central & Downtown).

Discussion

One item to confirm is that the cost of potentially-deferrable T&D capital investments is not artificially low due to AE's budget reporting practices. AE revenues are currently approximately $800 Million per year. The maximum amount that can be deferred for all distribution areas is currently about $3 Million per year. This means that about ¼ percent of AE's annual revenues is spent on distribution system investments that have the potential to be deferred. This number appears to be low relative to other municipal utilities.

Reactive Power Control

Introduction

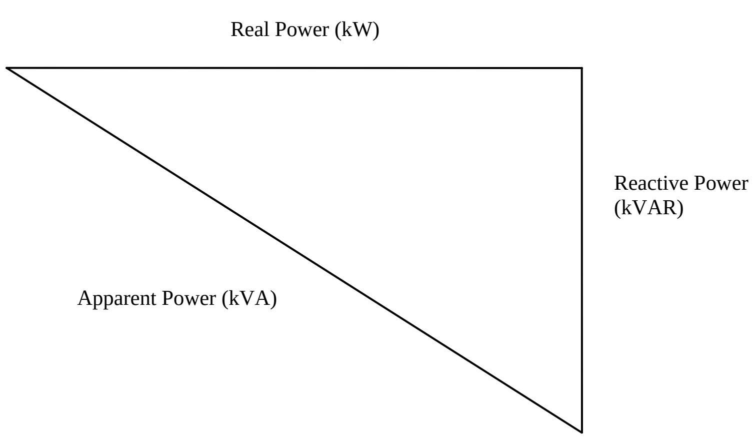
The power electronic switching components employed in PV inverters are limited in their rated throughput current, resulting in kVA design constraints. Generally, grid-connected inverters are designed to operate at unity power factor,[19] however, with minimal changes to the switching control software, these same inverters could as easily be operated at any desired power factor, whether fixed or variable. Such a PV system could be operated to control voltage on the distribution system. This section evaluates the voltage regulation benefit that would accrue to AE if it allowed such modified inverters on its distribution grid.

There are three possible control strategies for implementing PV with reactive power capabilities. First, the inverters could be designed with a fixed power factor, say, 0.85 leading, such that the inverter looks like a fixed capacitive load to the utility. Second, the inverter could vary power factor by time of day or utility voltage in order to deliver reactive power when utility voltage was low and to consume reactive power when voltage was high. Third, the inverter could be integrated into the utility's SCADA system to optimize power factor directly by the operators. This third scheme is more complicated than the other two since it would require communications capabilities and add cost to the PV system. Also, since the utility would effectively control the inverter output, there would be further ownership and tariff issues to consider.

Methodology

Power Factor

Regardless of control scheme, the inverter would be capable of generating real power (kW) and sourcing and sinking reactive power (kVAR). Given the total kVA rating of the inverter, the availability of reactive power at any given time would depend upon the amount of real power delivered (and vice versa) according to the power triangle:



[19] Interconnection standards (e.g., IEEE P1547) discourage manufacturers from providing voltage regulation. However, utilities are not bound by these standards.

The power factor (pf) equals the real power (kW) divided by the apparent power (kVA).

Availability of Reactive Power

Assuming that real power has a higher value than reactive power, the PV inverter would be operated to maximize real power, and the remaining reactive capacity would vary accordingly as an intermittent resource. For example, if the rated kVA of the inverter (the maximum apparent power) were 1000 kVA and the solar conditions at the time provided generation of 750 kW, then the maximum reactive power available would be $SQRT(1000^2 – 750^2)$ = 660 kVAR. In the extreme case, if the inverter was delivering 1000 kW, there would be no reactive power available at all.

The valuation of reactive power, therefore, depends upon the treatment of availability, and it is possible to propose three scenarios shown in Table 21.

Table 21. Scenarios for reactive power availability.

	Low	Medium	High
Assumption	The PV system cannot be depended upon for voltage support 100% of the time. The utility does not use the reactive power capability of the PV system.	The PV system is rarely delivering its peak real power output, so availability is calculated according to average system delivery.	The PV system can be controlled to zero real power at any time, so reactive power is available at the full kVA rating.
Availability	0%	With an annual average daytime[20] real output of 40%, the remaining reactive power is, on average, 92% of rated output.	100%

Results

Three scenarios for the reactive power benefit can be calculated by combining the technical kVAR benefit presented in Table 21 with the economic benefit. Since the kVAR rating of the (modified) inverter would equal to the kW rating, the value in $/kW

[20] This neglects the fact that 100% reactive power is available at night because there is no solar output and the full capability of the inverter is available for reactive power. The system could be controlled to act as an inductive load during the night, helping to prevent system over-voltage on lightly loaded distribution circuits. 92% = (1 – 0.4^2) ^ 0.5.

of inverter rating is equal to the product of the $/kVAR value (assumed to be $20 per kVAR)[21] and the availability, as shown in Table 22.

Table 22. Reactive power benefit.

	(1)	(2)	(3) = (1) x (2)
	kVAR Availability (kVAR/kW)	Value ($/kVAR)	Benefit ($/kW)
Low	0.00	$20	$0
Medium	0.92	$20	$18
High	1.00	$20	$20

Summary

As shown in Table 22, the reactive power benefit ranges from $0 to $20 per kW. The fundamental assumption, however, is that this benefit is realized by adding a new technical capability to the inverter. Thus, without this modification, the benefit does not currently exist. Thus it is assumed that the benefit is $0. In addition, if this is the only benefit that comes from being able to control the inverter, the value is low and does not seem to justify adding this feature to the inverter.

[21] Voltage regulation is provided through a variety of methods, including adjustments of power factor at large synchronous generators and the use of switched capacitors on the distribution system. The cost to provide these services is borne by the distribution utility and the system operator, and includes the capital cost of equipment, maintenance, and operating costs (for example, the labor required for field personnel to operate remote switches). These costs are not well established, but are assumed to be around $20/kVAR.

Environment

Introduction

PV systems provide an environment benefit by reducing emissions associated with non-renewable resources. While the reduced emissions are undisputed, there are differing opinions on how to calculate economic value.

Most valuation methodologies can be grouped in one of two categories: direct cost savings and human health benefits. The direct cost savings approach is to calculate the reduction in emissions (e.g., lbs of CO_2, NO_x, etc.) and then to assign an economic value to the savings based on the direct costs, such as imposed penalties or costs to meet regulated power plant emissions standards. In some cases, there are no direct cost savings (e.g., many locations have no direct costs associated with CO_2 emissions at the current time) even though there may be substantial liabilities associated with future emissions.

The human health benefits method assigns economic value based on emissions-related health costs/shortened life times. The deficiencies associated with this approach are that the recipients do not pay for the benefits and that the connection between pollution and health effects is not well established.

To avoid the difficulties of these two methods, the present study is founded upon the existing market-based Renewable Energy Credit (REC) – also called Green Tag - price. This market is expected to continue its growth in the coming years through the Renewable Portfolio Standards (RPS) – the compliance market – and through customer choice.

Methodology

<u>Renewable Portfolio Standards</u>

Many states in the U.S. have implemented Renewable Portfolio Standards (RPS). These standards are typically established by legislative mandates, public utility commissions, or the self-imposed policies of the utilities themselves.

An RPS requires electric service providers to obtain a certain percentage of their electricity supply from renewable energy sources. Electric service providers can satisfy the RPS requirement by either building/acquiring renewable-generated electricity or by purchasing RECs from others who have invested in renewable energy sources.

New Jersey Solar Renewable Energy Credit (SREC)

Some states have created RPS requirements that specify that a fixed percentage of generation from solar. One example of this is the New Jersey Clean Energy program which institutes the "Solar Renewable Energy Credit (SREC). The program currently pays $0.17 per kWh for a multi-year contract with prices even higher for shorter-term contracts.[22] To emphasize the magnitude of this value, a 10-year SREC contract for a South-30º PV system in New Jersey has a present value of more than $2,000 per kW.[23]

Customer Choice Programs

Over the past several years, a growing number of residential and commercial customers have become interested in purchasing the environmental attributes associated with renewable energy projects.

AE Green Choice Program

AE has such a customer choice program available for its customers, the voluntary GreenChoice® program.[24] For the third year in a row, AE's green power program has been the top selling green power program in the nation.

Under this program, the GreenChoice® rate replaces a customer's standard fuel charge with a green power charge. This program includes both green power and protection against unknown future fuel price increases, it is priced at cost rather than at market value, and it is oversold. As a result, it cannot be used to establish the environmental benefit.

Market-Based Green Power Prices in Texas

In addition to the AE program, similar products are available to electric customers in Texas. The Center for Resource Solutions established the Green-e Renewable Electricity Certification Program to help build consumer confidence in "green" electricity, and they provide a list of companies that have products that are Green-e certified on their website.[25]

Table 23 lists nine Green-e certified products in Texas, listed in order of price. There are several things to notice in the table. First, the highest price product costs $0.035 per kWh and contains 100 percent solar. Second, most of the products cost $0.020 per kWh and contain almost all wind. These programs also differ from AE's GreenChoice® program in that they do not include any fuel price protection.

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[22] http://www.njcep.com/srec/trading-statistics.php
[23] 1-year of RECs is worth $0.17 x 1,500 kWh/kW = $255 per kW. The 10-year present value of a stream of payments of $255 per year at a 7% discount rate equals approximately $2,000 per kW.
[24] http://www.austinenergy.com/Energy%20Efficiency/Programs/Green%20Choice/programDetails.htm

[25] http://www.green-e.org/your_e_choices/tx_home.html

Table 23. Green-e certified products in Texas.

	Solar	Wind	Bio.	Price
PVUSA Solar Green Certificates (PVUSA) www.pvusasolar.com	100%			$0.035/kWh
New Wind Energy (Community Energy) www.newwindenergy.com		100%		$0.025/kWh
WindCurrent (Chesapeak) windcurrent.com		100%		$0.025/kWh
Green Tags (Bonneville Environmental Foundation) www.greentagsusa.org/GreenTags/index.cfm	<1%	>99%	<1%	$0.020/kWh
Renewable Energy Choice www.renewablechoice.com		100%		$0.020/kWh
3 Phases Energy Services www.3phases.com		100%		$0.020/kWh
Sky Energy www.sky-energy.com		100%		$0.020/kWh
Climate Save[26] www.climatesave.com	5%	95%		$0.0175/kWh
Green America (Sterling Planet) www.sterlingplanet.com	5%	45%	50%	$0.016/kWh

Results

At the current time, AE does not have an RPS mandate calling for a specific percentage of solar electric generation. As such, the appropriate values to use in the calculation are the values from the customer choice programs. Given the experience of the AE program and the others shown above, a conservative estimate of the value for this study is the typical market-based green power program of $0.020/kWh. It will be assumed that this value will exist over the life of the PV system with no escalation (declining in real terms).

The environmental value for each configuration equals the product of the per unit environmental value ($/kWh) times the discount factor times the corresponding annual energy output (kWh/kW) for the particular configuration summed for all years. The environmental loss savings value equals the loss savings factors calculated for the energy value times the environmental value. The calculations and results are presented in the bottom of Table 24. For example, the environmental value for a horizontal system equals $30.70/kW[27] in 2006, $30.54/kW in 2007, etc. When each annual value is discounted and then summed, the present value equals $388/kW.

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[26] Includes renewable generators that first started operating after January 1st, 1999.
[27] $0.02/kWh x 1,535 kWh/kW = $30.70/kW.

Table 24. Environmental value.

	Environmental Value ($/kWh)	Discount Factor	Energy Production (kWh) Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
2006	$0.020	1.00	1,535	1,675	1,621	1,443	1,322	2,025	2,130
2007	$0.020	0.93	1,527	1,667	1,613	1,435	1,316	2,015	2,120
2008	$0.020	0.87	1,521	1,660	1,606	1,429	1,310	2,006	2,110
2009	$0.020	0.82	1,512	1,650	1,597	1,421	1,303	1,995	2,098
2010	$0.020	0.76	1,504	1,642	1,589	1,414	1,296	1,985	2,088
2011	$0.020	0.71	1,497	1,634	1,581	1,407	1,290	1,975	2,077
2012	$0.020	0.67	1,490	1,627	1,574	1,401	1,284	1,966	2,068
2013	$0.020	0.62	1,482	1,618	1,565	1,393	1,277	1,955	2,057
2014	$0.020	0.58	1,474	1,610	1,557	1,386	1,270	1,945	2,046
2015	$0.020	0.54	1,467	1,602	1,550	1,379	1,264	1,936	2,036
2016	$0.020	0.51	1,461	1,595	1,543	1,373	1,259	1,927	2,027
2017	$0.020	0.48	1,452	1,586	1,534	1,365	1,251	1,916	2,016
2018	$0.020	0.44	1,445	1,578	1,526	1,358	1,245	1,907	2,006
2019	$0.020	0.41	1,438	1,570	1,519	1,352	1,239	1,897	1,996
2020	$0.020	0.39	1,432	1,563	1,512	1,346	1,234	1,889	1,987
2021	$0.020	0.36	1,424	1,554	1,504	1,338	1,227	1,878	1,976
2022	$0.020	0.34	1,416	1,546	1,496	1,331	1,220	1,869	1,966
2023	$0.020	0.32	1,409	1,539	1,489	1,325	1,214	1,860	1,956
2024	$0.020	0.30	1,403	1,532	1,482	1,319	1,209	1,851	1,947
2025	$0.020	0.28	1,395	1,523	1,474	1,311	1,202	1,841	1,937
2026	$0.020	0.26	1,388	1,516	1,466	1,305	1,196	1,832	1,927
2027	$0.020	0.24	1,381	1,508	1,459	1,298	1,190	1,823	1,917
2028	$0.020	0.23	1,376	1,502	1,453	1,293	1,185	1,815	1,909
2029	$0.020	0.21	1,368	1,493	1,445	1,285	1,178	1,805	1,898
2030	$0.020	0.20	1,361	1,486	1,437	1,279	1,172	1,796	1,889
2031	$0.020	0.18	1,354	1,478	1,430	1,273	1,167	1,787	1,879
2032	$0.020	0.17	1,348	1,472	1,424	1,267	1,162	1,779	1,871
2033	$0.020	0.16	1,340	1,463	1,416	1,260	1,155	1,769	1,861
2034	$0.020	0.15	1,334	1,456	1,409	1,254	1,149	1,760	1,851
2035	$0.020	0.14	1,327	1,449	1,402	1,247	1,143	1,751	1,842
Environmental Value ($/kW)			***$388***	***$424***	***$410***	***$365***	***$335***	***$513***	***$539***
Energy Loss Savings (%)			5.2%	5.1%	5.2%	5.4%	5.4%	5.2%	5.2%
Environmental Loss Savings Value ($/kW)			***$20***	***$22***	***$21***	***$20***	***$18***	***$27***	***$28***

Disaster Recovery[28]

> The captain assigned a sergeant to get cheap battery-powered walkie-talkies from Wal-Mart – the kind you use for hunting or skiing and have a range of a few hundred yards – because with the power out, the police radios were going to be useless. A lieutenant was ordered to come up with a simple system of hand communication that the officers could learn in a few minutes. Despite all their preparations, the Kenner Police Department was headed back to the Stone Age. The situation at the New Orleans Police Department was even worse...[29]
>
> As floodwaters rose around Charity Hospital, the rescuers needed their own rescuing. Charity's backup generator was running out of diesel fuel. Nurses hand-pumped ventilators for patients who couldn't breathe. Doctors canoed supplies in from three nearby hospitals. '"It's like being in a Third World country. We're trying to work without power. Everyone knows we're all in this together. We're just trying to stay alive," said Mitch Handrich, a registered nurse manager at the state's biggest public hospital...[30]

In the past, there have been mega-disasters for which preparations and response have been demonstrably inadequate. This experience has led to significant adjustments in emergency planning and infrastructure hardening. Such adjustments are likely in the years following Hurricane Katrina. No attempt is made here to anticipate what these changes may be. The Katrina disaster serves as a reminder, however, of the staggering cost of weather-related disasters and the fact that resulting power outages compound the cost of disaster recovery, prevent timely damage mitigation and extend the time required for the afflicted region to recover economically.

Introduction

This section addresses the disaster recovery value of solar. The section presents background information, develops the value model, and describes deployment scenarios.

The City of Austin's Vulnerability

More than sixty weather-related disasters over the past 25 years have affected a quarter of a billion U.S. citizens and cost almost a half a trillion dollars. Such disasters are enormously costly and are being declared with an increasing frequency (see Figure 10).

Figure 11 suggests that a southern band ranging from central Texas to North Carolina is more vulnerable to weather-related disasters than other areas of the U.S. This pattern is confirmed by an analysis of global disasters (Figure 13) that identifies southeastern Texas as subject to combined drought and hydrological events having high aggregate economic

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[28] The analysis in this section was performed primarily by Gerry Braun, [24].
[29] Source: Philipp Meyer, "Katrina Through the Eyes of an EMT", Home Section, Austin Chronicle, September 2, 2005, http://www.austinchronicle.com/issues/dispatch/2005-09-02/pols_feature2.html
[30] Source: Source: http://news.yahoo.com/s/ap/20050831/ap_on_re_us/katrina_medical

impact. It is thus likely that Austin's 800,000 inhabitants will be directly affected by a weather-related disaster during the coming 25 year period.[31]

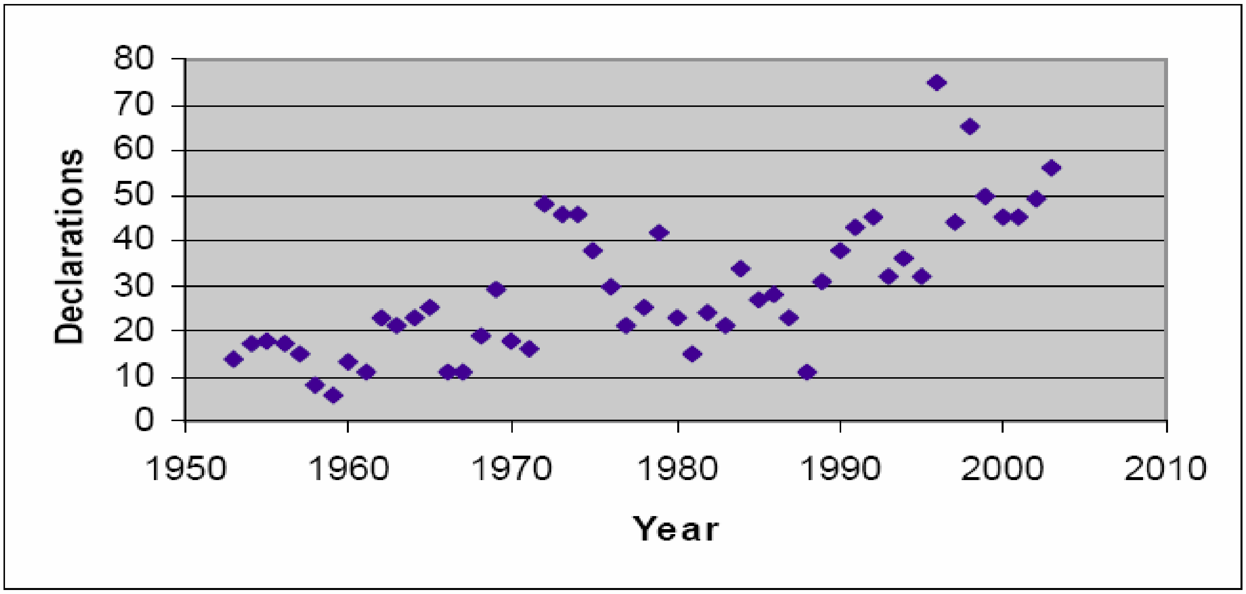

Figure 10. U. S. Disaster Declarations[32, 33]

[31] For example, Austin area city and county emergency managers interviewed for this report indicated their worst case weather related disaster would be a Category 4 or 5 hurricane making landfall and sweeping inland as in the recent case of Katrina. Based on historical experience, another scenario would involve a heat wave over-stressing both local populations and the electric power infrastructure on which they rely for space cooling. A recent New York Times article (Gregory S. McNeal, "The Terrorist and the Grid, New York Times, August 12, 2005) discusses the threat of terrorism that could target switching critical computers and relays, resulting in outages lasting weeks as customized equipment is replaced or repaired.

[32] Source: Federal Emergency Management Administration, http://www.fema.gov/library/dis_graph.shtm

[33] Local and State governments share the responsibility for protecting their citizens from disasters, and for helping them to recover when a disaster strikes. In some cases, a disaster is beyond the capabilities of the State and local government to respond. The Robert T. Stafford *Disaster Relief and Emergency Assistance Act,* Public Law 93-288, as amended (the Stafford Act) was enacted to support State and local governments and their citizens when disasters overwhelm them. This law establishes a process for requesting and obtaining a Presidential disaster declaration, defines the type and scope of assistance available under the Stafford Act, and sets the conditions for obtaining that assistance.

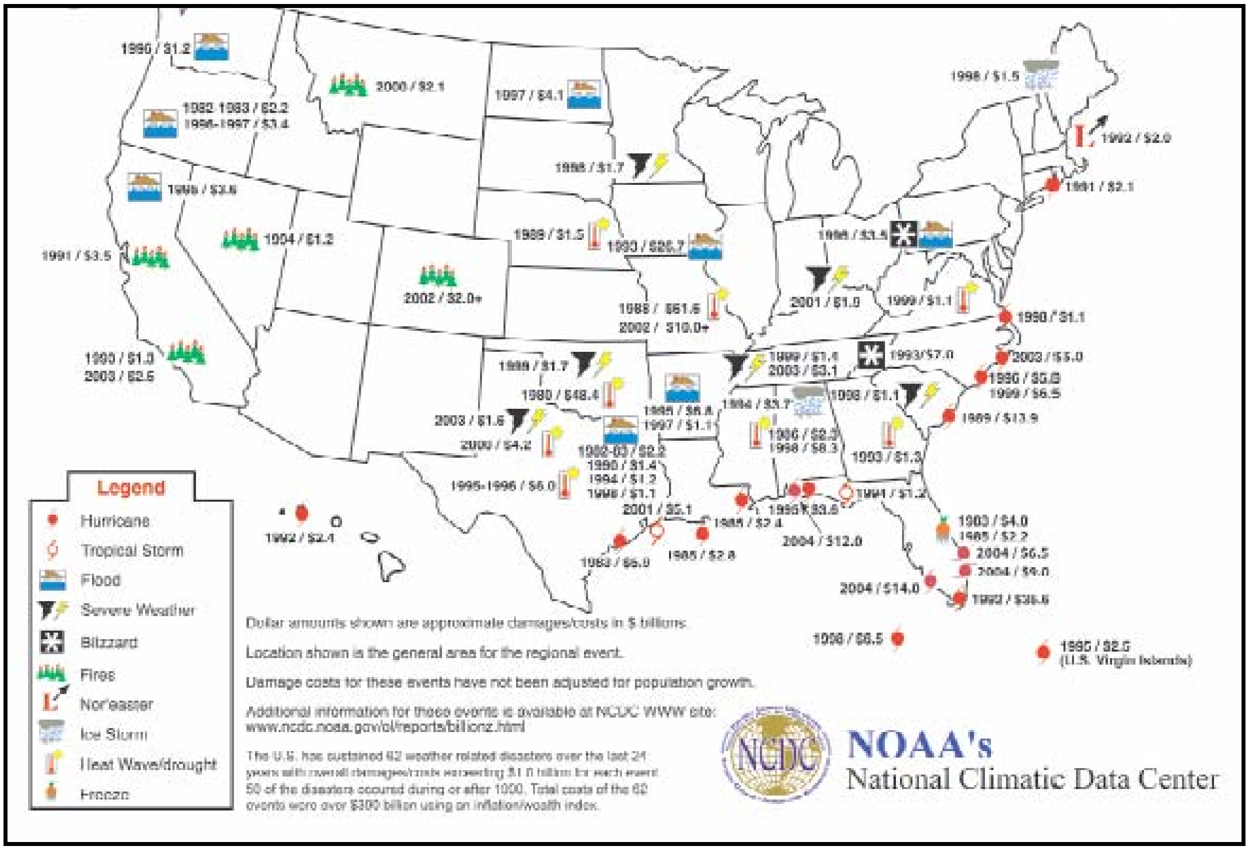

Figure 11. Billion Dollar Weather Disasters 1980-2004[34]

[34] Source: US National Climatic Data Center

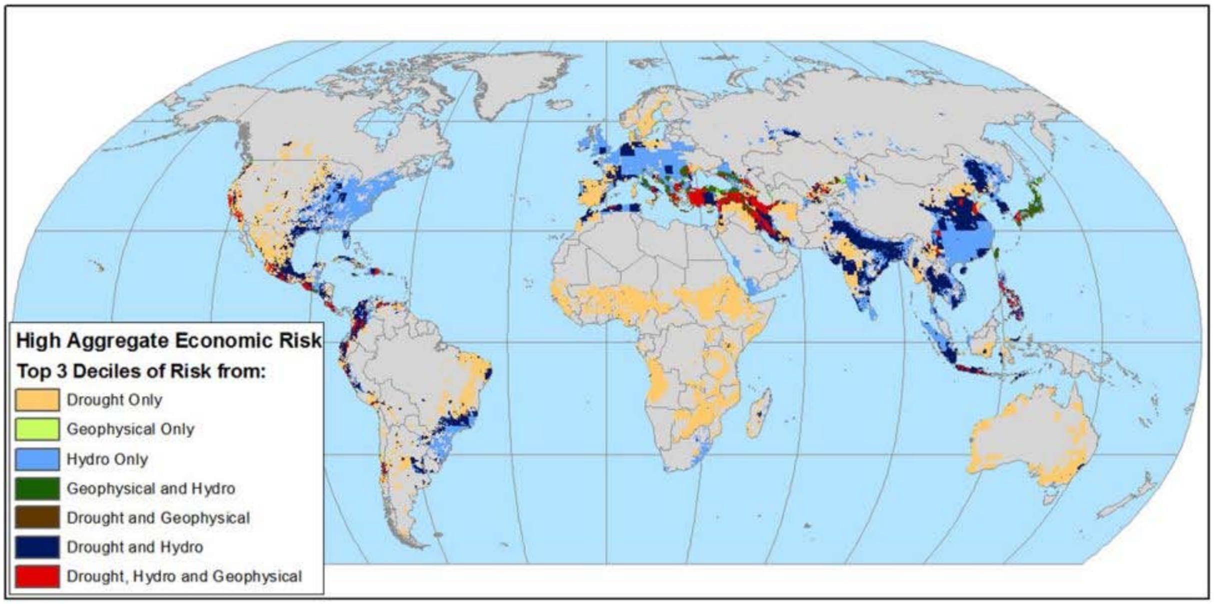

Figure 12. Disaster Risk Hotspots[35]

Disaster Recovery Value Model

Assuming such a disaster does strike the Austin area, is it possible to estimate the value of solar power in disaster response and recovery efforts? Can "avoided disaster recovery costs" be attributed to the solar power infrastructure embedded in a disaster-stricken community?

A spreadsheet model has been developed for use in estimating disaster recovery value of a targeted Austin area solar deployment. This model represents one of the first known attempts to economically quantify the value of disaster recovery. As such, there are certain to be refinements in the model as it is developed over time.

Primary inputs to the model include:

- The expected value of disaster recovery costs and economic impacts for the Austin area over the next twenty-five years.
- Austin area solar deployment targets over the same 25 years
- Results of interviews with relevant Austin area public agencies that were arranged by AE

These inputs will be discussed before describing the model and presenting base case results. Exercise of the model requires consideration of market and technology realities of solar power and "solar secure power", i.e. the use of solar energy in conjunction with energy storage. Appendix F summarizes the details of the input assumptions, the model, and solar deployment considerations.

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[35] Source: *LiveScience* web posting by Michael Schirber, "Global Disaster Hotspots: Who Gets Pummeled"

General Inputs

Forecasting the timing and cost of any future disasters in the Austin area is impossible. What can be done, however, is to make nominal assumptions based on general experience and use considerations of disaster vulnerability to suggest a range around the nominal value.

Disaster Cost

The literature divides the many types of disasters into two main categories: weather-related and technological. The technological category includes airline crashes, urban fires, chemical spills, etc. Weather-related disasters are on the average more costly and more frequent than comparably costly technological disasters. For simplicity, only vulnerabilities and cost data for weather-related disasters are considered in this analysis.

There is data relating to the economic impacts of disasters that can be used to generate nominal disaster costs for a multi-year planning period. Specifically, The United States sustained 62 weather-related disasters in the 25 years 1980 to 2004 in which overall damages and costs were $1 billion or more at the time of the event. The total cost of these disasters (mostly) in 2002 dollars and deaths has been estimated at $390 billion and 490 respectively.[36] Taking, for convenience, a disaster planning horizon for the Austin area of 25 years starting in 2005 and supposing, conservatively, that the total cost of disasters across the US will be the same over the next 25 years as it was over the preceding 25 years, then a city having a growing population of roughly 1 million, i.e. one three hundredth of the current US population, could expect its proportional share of major US disaster costs over the next 25 years to be in the neighborhood of at least $1.3 billion, or $1,300 per person.

Disaster Propensity

An important question: Is Austin's cost is likely to be proportional? The literature contains analysis that can help identify whether Austin and surrounding areas are more or less vulnerable to weather-related disasters than other areas of the US. Based on the above discussion of vulnerability, Austin is in a geographic band that appears to be disaster-prone. Furthermore, Figure 10 suggests a significant upward trend in the frequency of the declaration of major disaster in the U.S.

While an extremely conservative analysis might ignore disaster propensity and assume the proportional cost of $1,300 per person, a worst-case analysis might assume a cost several times this figure. There is no known analytical basis to assume other than the proportional cost. The present analysis will assume a range of (twenty-five year) costs between $1,500 per person and $3,000 per person.

The proposed range of disaster cost is unlikely to cause over-estimation of the disaster recovery value of solar deployment.[37]

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[36] http://www.livescience.com/forcesofnature/disaster_chronology_1980_2004.html#list

[37] It will be useful to revisit the issue of the degree to which Austin is prone to disasters relative to other parts of the country in future work, since Austin does not have earthquakes, hurricanes, or blizzards.

Base Case Disaster Scale and Timing

As a base case, a single disaster costing $2,000 per person will be assumed to occur with equal annual probability during the 25 year period 2006 through 2030.

Solar Specific Inputs

Emergency Power

The prospect and economic consequences of grid outages are the primary motivation for installation of emergency power supplies. The size of available emergency power supplies ranges from battery-based portable power supplies found in small laptop computers capable of delivering a few Watts to multi-MW fuel-based generators coupled with dedicated long-term fuel storage. Technology options for emergency power have proliferated in the years since computer use began to mushroom, but all of the options in current widespread use, *except one*, involve either or both: 1) storing electricity from the grid, or 2) on-site power generation using stored or pipeline fuel.

Solar Emergency Power

This option stores electricity from PV arrays rather than from the grid. This option has been used commercially for decades where relatively small amounts of highly reliable continuous power are needed and the power grid is not cost-effectively accessible. A small percentage of grid-tied PV systems do include battery storage (for purposes of enhanced power reliability), but most do not, primarily because most are purchased under incentive programs premised on using the grid to back up the grid-tied PV system rather than vice versa.

AE recognizes that the value of grid-tied PV resources may exceed the value of comparably rated conventional resources and intends to deploy PV to the extent its cost can be justified by its economic value to AE. The City of Austin goals (as stated in the Austin Energy Strategic Plan) are 15 MW by 2007, 30 MW by 2010, 50 MW by 2014, and 100 MW by 2020. A rebate program is underway that shares the cost of customer-purchased PV systems to the extent of $4/Watt for residential applications up to a maximum of $13,500 per home (or 80% of project cost) and $4/Watt for commercial applications up to a maximum of $100,000 (or 80% of project cost) per project.

AE also offers its customers a “green electricity” purchase option based on wind energy feeding into the Austin area from West Texas. Customers pay a premium rate based on wind energy costs. The rate is capped for a period of years, making it attractive to customers who expect the cost of non-renewable power sources to continue to escalate.

AE’s capital improvement plans for PV, the terms of AE’s rebate program, along with customer concerns about future grid electricity price escalation and reliability degradation, will determine the pace of Austin area PV deployment. Interview results suggest that such customer concerns are minimal at this time. Interview results also suggest that the PV rebate level will be determined by the avoided cost value of the installed PV to AE, a value that can change based on changes in operating costs of other AE generation resources. An assumption consistent with AE fuel price forecasts would be that such operating costs and the retail electricity prices they influence will not increase significantly from their current levels over the next fifteen years.

A conservative assumption regarding PV system cost is that installed PV system costs will continue to trend downward at about 2-3 percent per year in constant 2005 dollars. Such an assumption is consistent with historical rates of PV cost reduction over the past two decades.

AE anticipates technology and market breakthroughs during the coming fifteen years that would accelerate this trend later in the fifteen year period, but this effect is ignored in the present analysis for the sake of conservatism. Absent the competing "green electricity" offering by AE, a gradual acceleration of PV deployment might be expected during the fifteen year period, but it is reasonable to assume that wind energy costs will also trend downward along with PV costs. Thus, for the sake of a first-order forecast, a steady rate of deployment of 10 MW per year between 2006 and 2020 can be assumed.

To a first approximation, PV has no disaster recovery value unless it is coupled energy storage; therefore, assumptions have to be made about the extent of coupled energy storage. For purposes of developing and testing the disaster recovery value model, the base case assumes that all installed solar is coupled with energy storage sufficient to provide limited operational continuity during disaster response. This 100 percent solar secure base case is one extreme outcome – the other extreme, i.e. PV deployed without coupled energy storage, delivers essentially no disaster recovery value. The model will allow evaluation of intermediate cases as well as the 100 percent solar secure case. Further discussion of solar secure deployment considerations can be found in Appendix F.

Emergency Management Considerations

Greater Austin and Travis County

Postulating a representative disaster scenario for Austin requires local knowledge, especially regarding emergency management plans and experience, facilities used during disaster recovery, and plans for PV deployment. Accordingly, to acquire this information, interviews were conducted with representatives of the following local organizations:

- AE
- American Red Cross of Central Texas
- City of Austin Emergency Management
- Travis County Office of Emergency Management
- Austin Independent School District

Emergency Management Plans and Experience

Austin is subject to heat waves as well as localized flooding and high winds, e.g. tornados spun off from category 4 and 5 hurricanes. Severe weather events are not rare. Five population shelters had to be opened November 2004, and serious localized flooding occurred a week prior to the interviews performed for this study. Austin area emergency planning, in addition to dealing with the safety of local residents, addresses the need to handle evacuation overflow from the Houston area when hurricanes threaten to make landfall there.

Emergency management priorities include radio and central telecom sites as well as hospitals. Emergency generators at critical facilities require significant maintenance and in some cases are vulnerable to being disabled by localized flooding. In periods between major disasters, their readiness tends to degrade, resulting in high failure rates and fuel shortages when they are operated under emergency conditions.

The Austin Independent School District has favorable experience with grid reliability and so does not make provision for emergency power at its facilities. This could be a problem waiting to happen. However, AISD and AE both point out that power outages are typically of short duration and that conditions leading to extended outages, e.g. ice storms, also result in conditions that do not favor school operation, e.g. in the wake of ice storms that cause power outages, roads are also icy, temporarily compromising the safety of transportation to and from school.

Facilities

Austin area emergency managers are involved in planning to determine emergency operations facility expansion needs in 5, 10 and 20 years. For example, the Austin area emergency operations center needs a new parking structure on which a solar array might serve the multiple purposes of emergency power, protection from weather, and shading. The local American Red Cross chapter house and the United Way call center are also critical to emergency operations.

Austin/Travis County plans for mass care of its own evacuees as well as displaced populations from coastal areas and has 30 designated shelters for this purpose, including schools, churches and recreations centers. Some are designated as special needs shelters serving evacuees under medical care or requiring medical attention. The list is being expanded to 70 designated shelters by adding all local area middle and high schools. Greater Austin is a major sheltering area for refugees and evacuees from other areas, with planned capacity to handle up to 45,000 people evacuating from coastal areas struck by a hurricane or tropical storm. Local field houses and recreation centers, some of which have large emergency generators, are used to serve evacuees from coastal areas.

Value Analysis

A spreadsheet model has been developed which allocates disaster value, up to a specified amount per person, determined based on relevant experience, according to the relative extent, timing and application focus of solar secure power deployment.

The valuation model hinges on the link between electricity consumption and economic productivity, a well correlated relationship under normal conditions. Obviously, some economic effects of disasters are simply costs of replacement and repair of damaged or destroyed assets. Other effects relate to the loss of economic productivity. An implied premise of the value analysis is that if some, rather than no, electricity supply is available throughout the stricken area, both asset and economic productivity loss will be mitigated in proportion to the amount of the non-grid electricity supply still available and operating.

The effect is assumed to be segment-specific, i.e. some segments are more economically critical during disaster recovery. It is also assumed to be non-linear, i.e. essential economic activity, loss prevention and acceleration of recovery times can be supported with limited electricity supply, provided it is widely accessible.

Disaster recovery value can be estimated for each year in the solar deployment period using a spreadsheet model that enables local knowledge to drive key assumptions. The flow chart in Figure 13 summarizes key inputs and calculations. Steps A through K of the model are described as follows in more detail:

A. Organize electric load data for the planning area according to sector, i.e. residential, commercial, industrial and public
B. Forecast solar capacity deployment in terms of deployment rate (MW/year) and sector (% allocation) in order to project cumulative capacity for each sector over the planning period, i.e. for year 1 through n.
C. Calculate the percentage of sector load met by solar secure capacity for each year of the analysis.[38]
D. Determine disaster value capture in each sector as a function of percent sector load met (see Table 16).[39]
E. Determine sector value percentages by applying judgment and experience.
F. Estimate the percentage of total disaster recovery value for each sector in each year as the product of the disaster recovery value percentage times the sector value percentage
G. Set the total potential disaster recovery value by multiplying the assumed disaster cost per person (discussed above) times the affected population.
H. Determine the value if the event occurs in a given year by summing the sector percentages in F and multiplying the result by the total disaster value.

[38] This can be done two ways, i.e. by calculating the solar percentage based on peak capacity or based on energy delivery. Solar capacity factors are typically much less than grid system load factors, so the energy basis results in more conservative values.

[39] Solar secure power will not be cost-effective for on-site industrial power in most cases, i.e. plants that run more than one shift. Further, industrial load would be minimal until after significant recovery in other sectors, since industry depends on local labor and infrastructure. Accordingly, the model assigns no value to solar secure power at industrial sites and also assumes no deployment in this sector. Residential and commercial sectors are given equal weight in general, since they are generally inter-dependent. People need food, shelter, and public services, or they'll evacuate if they can. Unless the public sector can at least provide for public safety and relief operations, residential and commercial power is devalued for lack of people to use it. Likewise, if people cannot get food either from markets or retail food services, they may evacuate. Accordingly, serving small percentages of public sector critical load is highly valuable and more valuable than serving small percentages of commercial load, which is more valuable than serving small percentages of residential load. Serving critical food services and retail building supply loads of the commercial sector has higher value than serving the remainder, e.g. shopping malls, which relies on discretionary spending.

I. Determine the probability of occurrence for each year by assuming the disaster occurs during the planning period and its probability of occurrence is the same each year.

J. Determine the expected value for the year by multiplying disaster recovery value (H) by the probability of occurrence (I).

K. Discount the yearly expected values to determine total present value.

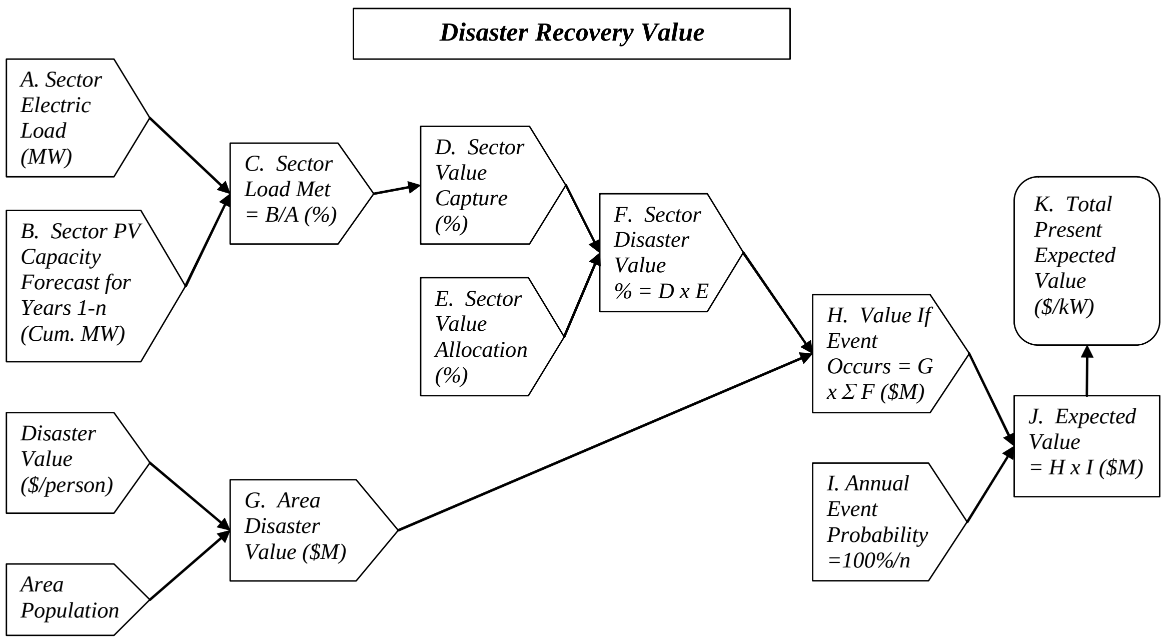

Figure 13. Disaster recovery value flow chart.

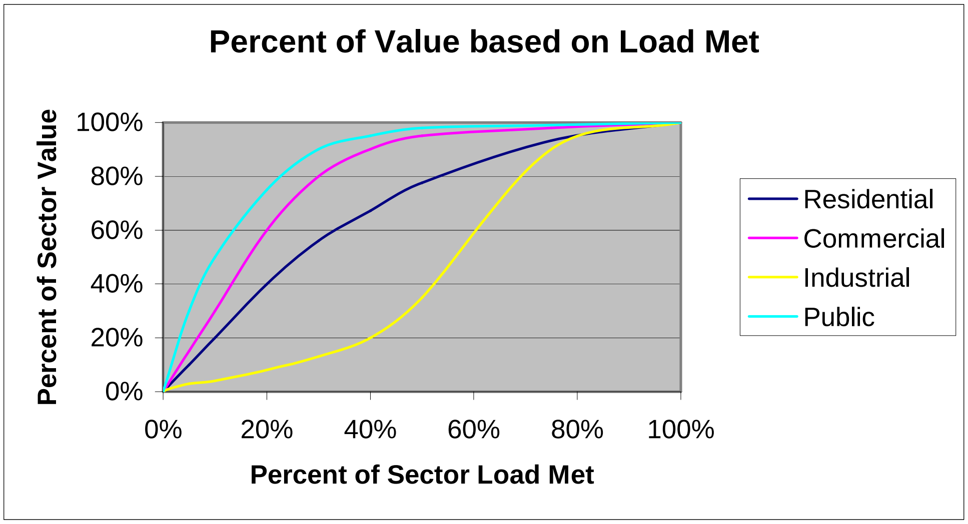

Figure 14. Relationship between load met and disaster recovery value.

Results

Results based on the energy method and the capacity method[38] are presented in Table 25. As can be seen by the table, the results for the energy basis calculations are lower than then capacity basis calculations.

Table 25. Disaster recovery value results on energy and capacity basis ($/kW).

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
Energy Basis	$1,232	$1,334	$1,290	$1,182	$1,121	$1,547	$1,578
Capacity Basis	$2,701	$2,701	$2,701	$2,701	$2,701	$2,701	$2,701

This is first known attempt at quantifying the disaster value benefits. As such, the valuation method requires further refinement. In particular, the following areas require further examination:

- Provide a more detailed examination of how much disaster costs are related to asset losses as compared to lost business opportunities; solar power backup will not prevent asset losses
- Have a better assessment of what fraction of electric power may be lost if a disaster occurs
- Assess the speed at which utility crews are likely to restore power to critical locations
- Include the cost of battery storage in the analysis

Due to the uncertainty associated with the results, it was decided that this benefit should not be included in the results at this time. Instead, it is recommended that AE further consider the disaster recovery benefit when combined with battery storage, in particular as it can be jointly implemented with a hybrid electric vehicle program.

Conclusions and Recommendations

Results support the general conclusion that solar can have a significant value related to avoiding and mitigating economic costs of disasters and speeding disaster recovery. The value can be economically significant, i.e. in excess of $1,000/kW, in cases where solar is deployed in conjunction with appropriate amounts of energy storage. Obviously, the valuation methodology is inexact.[40] Calculations based on energy production result in a lower value, i.e. around $1,300/kW, and calculations based on peak capacity result in a higher value, i.e. around $2,600/kW. There is probably a threshold level of solar deployment that must be achieved before the value becomes proportional to installed solar capacity (as assumed).

The present analysis did not consider the potential load shifting and peak shaving value of PV-coupled energy storage either to AE or to AE customers. Likewise, the analysis did not consider the reliability enhancement value of a PV-coupled UPS capability in carrying through typical or extended non-disaster related grid outages. These values are primarily attributable to energy storage, not solar, but should be considered in setting deployment targets and designing incentive programs.

Future Work

The results suggest the interesting possibility of optimizing solar disaster recovery value by intentionally locating at least some of the targeted Austin area PV installations at facilities designed and/or designated for use in emergency operations. For example, emergency operations centers are likely to be equipped with adequate back-up power capability, but facilities used opportunistically for mass care and special medical care of refugees and evacuees may not be. Schools, for example, especially in the Austin area, have not yet been subjected to the effects of extended grid outages and so are not investing in back-up power capabilities. Meanwhile, all Austin middle schools and high schools are being added to the list of designated evacuation shelters, and over time, their reliance on information technology will increase, making them more vulnerable to the effects of grid outages that lead commercial enterprises to invest in back-up power. Their favorable recent grid reliability experience may be encouraging under-investment in backing up critical loads and in anticipation of extended grid outages and in preparation for crisis operations.

One dimension of optimization still to be addressed is the relationship of value to cost. Storage costs vary with storage capacity, and other studies have suggested that capacities necessary to provide some level of extended operational continuity would be significantly greater than those needed to carry loads over for two or three hours. On the other hand, in most cases, sizing criteria for stand-alone PV/battery hybrid systems would be excessive, i.e. economically inappropriate. Recent studies have suggested that storage

[40] More exact methods are available for specific solar secure applications, esp. schools. In this case it is possible to use per pupil costs and school downtime assumptions to calculate economic value. Appendix E provides a reference to related work, which incidentally supports value estimates in the same range as the method used here.

capacity consistent with disaster recovery needs would add about 25 percent to the cost of the basic solar power system in most cases. As opportunities emerge to couple the storage capacity of plug-in hybrid vehicles to basic solar power systems, the incremental cost of solar secure capabilities would be much less than 25 percent, probably in the 5 percent range. Additional cases should be analyzed to quantify scenario effects and cost/value trade-offs.

Subsequent work should use the model to evaluate alternative deployment scenarios by weighing the incremental value of solar in disaster recovery against the incremental cost[41] of capturing this value under different assumptions regarding deployment strategy. It is also recommended that model assumptions be reviewed in the light of actual disaster experience and on-going disaster recovery planning. For example, base case results assume a recovery scenario that would assign more value to solar deployment at commercial sites than residential sites. More thorough and detailed scenario definition is recommended as solar deployment proceeds.

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[41] To have non-zero disaster recovery value, a solar electricity system must include provisions for energy storage, and these provisions add cost.

Conclusions

AE has a strong commitment to integrating solar electric generation into its utility system. As part of this commitment, AE issued a request for proposals to determine the value of solar generation to the AE electric system. CPR was selected to perform the study.

There are two primary objectives of this study:

1. Quantify the comprehensive value of distributed PV to AE in 2006
2. Document evaluation methodologies to assist AE in performing the analysis as conditions change and applying it to other technologies

This section summarizes the results of the study. It discusses how the results might be used and makes recommendations as to how to improve the analysis in the future.

Value of PV to AE in 2006

A primary objective of this study is to quantify the comprehensive value of distributed PV to AE in 2006. This section summarizes the results from the individual sections.

Figure 15, Figure 16, and Table 26 present the value of 15 MW of PV to AE. Figure 15 presents the results in absolute or capacity terms (present value in $ per kW-AC). Figure 16 presents the results in energy terms (levelized value in $ per kWh). Table 26 summarizes the results numerically.

The value of 15 MW of PV is $2,312 per kW (11.3¢ per kWh) for the best fixed configuration. The best fixed configuration is SW-30º and is only slightly higher than a South-30º configuration. The highest overall system is the 1-Axis 30º tracking system worth $2,938 per kW (10.9¢ per kWh). This system has a 27 percent value premium over the SW-30º configuration. As can be seen in the figures, energy production accounts for two-thirds of the total value.

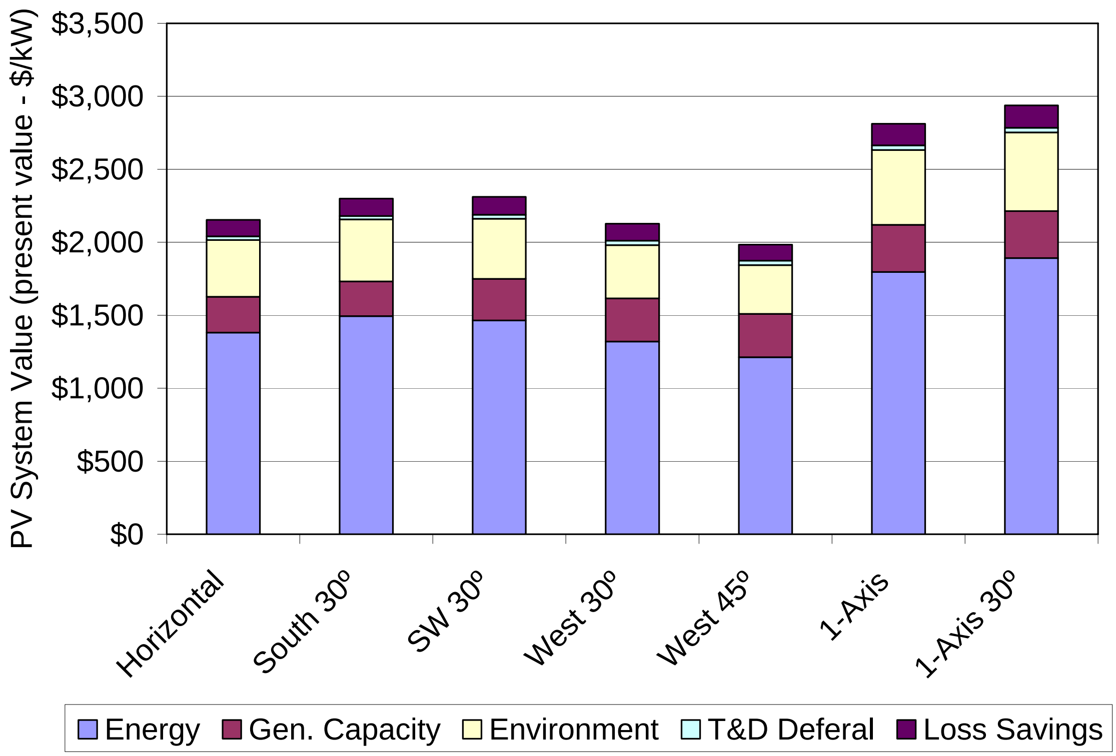

Figure 15. Total value by PV configuration ($/kW).

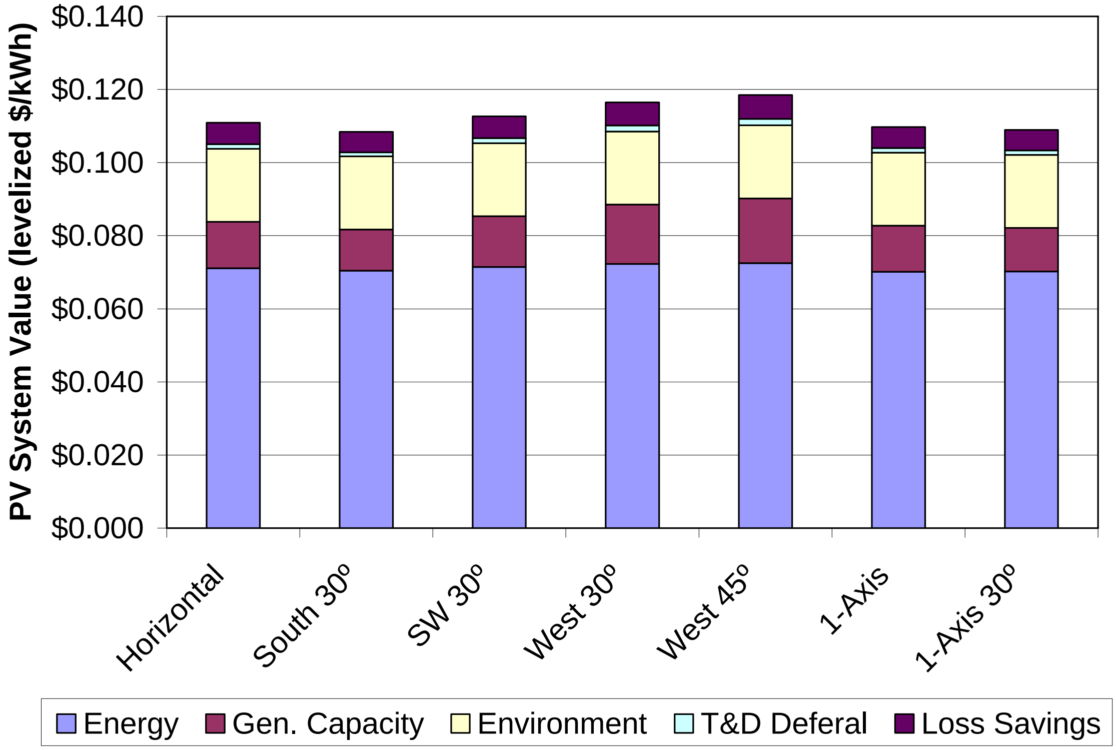

Figure 16. Levelized value by PV configuration ($/kWh).

Table 26. Breakdown by benefit component ($/kW and $/kWh).

Value ($ per kW)

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
Energy	$1,382	$1,493	$1,465	$1,319	$1,213	$1,797	$1,893
Gen. Capacity	$245	$239	$285	$297	$297	$323	$321
Environment	$388	$424	$410	$365	$335	$513	$539
T&D Deferal	$24	$24	$28	$29	$29	$32	$32
Loss Savings	$114	$119	$123	$116	$109	$148	$154
Disaster Recovery	$0	$0	$0	$0	$0	$0	$0
Total	***$2,154***	***$2,299***	***$2,312***	***$2,127***	***$1,983***	***$2,813***	***$2,938***

Factors to convert from $ per kW to $ per kWh

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
Discount Factor (Sum)	13.28	13.28	13.28	13.28	13.28	13.28	13.28
Annual Energy (Levelized)	1,463	1,597	1,545	1,375	1,260	1,930	2,030
Levelization Factor	19,424	21,205	20,517	18,257	16,736	25,629	26,959

Levelized Value ($ per kWh)

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
Energy	$0.071	$0.070	$0.071	$0.072	$0.072	$0.070	$0.070
Gen. Capacity	$0.013	$0.011	$0.014	$0.016	$0.018	$0.013	$0.012
Environment	$0.020	$0.020	$0.020	$0.020	$0.020	$0.020	$0.020
T&D Deferal	$0.001	$0.001	$0.001	$0.002	$0.002	$0.001	$0.001
Loss Savings	$0.006	$0.006	$0.006	$0.006	$0.007	$0.006	$0.006
Disaster Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Total	***$0.111***	***$0.108***	***$0.113***	***$0.117***	***$0.118***	***$0.110***	***$0.109***

Results Represent a Middle Ground Scenario

A range of methods and sets of assumptions were given consideration throughout the study. As a result, during early phases of the work, consideration was given to having several scenarios. AE ultimately decided that a single scenario reflecting the joint opinions of AE and CPR would best serve the purposes of this study.

Summary and Recommendations

Study Uses

The first objective of this study is to quantify the comprehensive value of distributed PV to AE in 2006. The preceding paragraphs describe the results of this analysis.

It is also useful to consider how AE might use these results in advancing its 2020 goals:

- Assist in structuring an RFP for utility-owned systems or power purchase agreements
- Provide input into incentive design for customer-owned systems
- Help to assess the merits of kW-based buydown incentives vs. kWh-based performance incentives for customer-owned systems

- Evaluate other PV applications (e.g., a central station PV could be screened by deleting the distributed benefits – loss savings and T&D deferral)
- Investigate synergies with other AE programs such as demand management and plug-in hybrid vehicles
- Assist in evaluating opportunities related to AE's new Non-Traditional Energy Business Planning process

Methodology Advances

The second objective of this study is to document evaluation methodologies to assist AE in repeating the analysis as conditions and apply them to other technologies. These methodologies are documented throughout this report. In the process of the analysis, CPR developed new methodologies and enhanced existing methodologies. More specifically, CPR:

- Applied financial economics' risk-neutral valuation methodology to account for the natural gas price hedge benefit
- Demonstrated that loss savings calculations should be performed on a marginal, rather than an average, basis and then used the results to estimate hourly loss savings
- Developed a preliminary method to quantify the disaster recovery benefit
- Developed a method of how to capture the benefit of converting a non-firm resource into a firm resource by bundling it with load control

Study Enhancements

There are a number of ways that this study can be improved.

- This disaster recovery benefit has the potential to increase the value of solar by a significant amount. Further investigate the disaster recovery benefit and assess how distributed PV could be incorporated with AE's plug-in hybrid vehicle program to provide the required storage at a minimal cost; in particular, evaluate implementation on public buildings, such as schools.
- The natural gas price forecast is a critical assumption. Due to the limitations in the availability of data, only the first 5 years of the natural gas forecast reflect certainty in the natural gas price estimates. It would be beneficial to extend the duration over which certainty could be obtain for natural gas prices.
- PV could enable AE to offer a new product: long-term (20 to 30 years) fixed price electricity. Assess how much customers would be willing to pay for electricity from an on-site AE solar utility that provides a long-term fixed rate as well as the option for on-site storage.
- AE's customers who participate in the GreenChoice® program receive environmental benefits plus fuel price risk protection at a price that is significantly below what other market entities charge for the environmental benefits alone. Confirm that AE is satisfied with its GreenChoice® program pricing.
- The T&D deferral benefit is lower at AE than at other municipal utilities with which CPR has worked (AE's potentially-deferrable T&D investments represent

slightly more than ¼ percent of AE’s annual revenues). Confirm that the cost of potentially-deferrable T&D capital investments is not artificially low due to AE’s budget reporting practices.

- Evaluate how the benefits identified in this study could be applied from perspectives other than AE (e.g., customer-ownership, and local, state, and federal governments)

AE is a leader in its commitment to renewable energy. It is hoped that this study will help to support and expand AE’s vision and leadership.

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Appendix B. Marginal Loss Savings

Abstract

Locational Marginal Pricing (LMP) has been useful in facilitating competitive electricity generation markets. LMP includes location-specific marginal energy prices, marginal losses, and congestion costs. This paper demonstrates how marginal loss calculations also apply to the economic evaluation of customer-sited distributed generation facilities. It presents a method to calculate marginal losses assuming that all losses occur at a single point. It then extends the method to account for the fact that losses occur along the length of a wire in order to avoid calculation errors that occur with the single point solution. The method states that the marginal loss factor equals the square of the inverse of 1 minus average losses at any given point in time, where average losses are based on the mix of resources that will change when there is output from distributed generation. The paper applies the method to calculate the annual energy value of a distributed PV system using hourly data.

Introduction

Competitive Electricity Markets

There has been a move in the U.S during the past several years toward a competitive electricity generation market. To facilitate this move, these markets are gradually adopting nodal pricing, or Locational Marginal Pricing (LMP), to communicate pricing to all market participants.

There are two important aspects of LMP. First, LMP is composed of energy, losses, and congestion price components. Second, the energy and loss price components are based on marginal, not average, values [31], [29], and [19].

In order to calculate the effect of marginal losses on the energy price, the LMP has a Penalty Factor. The Penalty Factor associated with any bus on the transmission system is defined as the increase required in injection at that bus to supply an increase in withdraw at the system reference bus with all other bus net injections held constant. More specifically, it equals:

$$Penalty\ Factor = \frac{1}{1 - \frac{\partial P^{Loss}}{\partial P^{i}}} \qquad (2)$$

where P^i is the net power at bus i, P^{Loss} is the power loss.

While there is not full agreement as to how the marginal loss calculation should be performed, the observation should be made that the Penalty Factor incorporates marginal losses into the price.

Utility Marginal Costs

Within another context, there was an emphasis starting more than 15 years ago on calculating an electric utility's marginal costs [9] In a paper devoted to loss analysis and marginal costs, Parmesano presented a method to calculate losses for electric utilities [5]. The loss factor for any given point in time t equals:

$$\text{factor} = \frac{1}{1 - \frac{dM_t}{dL_t}} \tag{3}$$

Where *M* are the losses, *L* are the loads, P is the peak hour, and the change in losses with a change in loads equals $\frac{dM_t}{dL_t} = 2\frac{L_t}{L_P}\frac{M_P}{L_P}$. This change can be interpreted as 2 times the average losses at time t. This factor is consistent with the Penalty Factor used in LMP.

Objective

This paper focuses on the issue of how to account for losses when evaluating customer-sited distributed resources. In particular, the paper determines what level of generation resource savings corresponds to a reduction in load at the secondary level (i.e., on the customer's premises). First, the paper demonstrates how to perform the simple calculation assuming that all losses occur at a single point. Second, it describes why this loss calculation is valid for both energy and capacity savings. Third, it presents a slightly modified formula that captures the fact that energy losses occur along a physical distance (i.e., a wire) and not at a single point. Finally, it demonstrates how to use the method to calculate the energy value of a distributed PV system.

Analysis

Instantaneous Point Losses

Problem Formulation

If it is assumed that all losses occur at a single point, the amount of power that needs to be generated to satisfy a given level of consumption equals the power generated minus the losses associated with the delivery of that generation. That is, at any given point in time, *t*,

$$\underbrace{P_t^0}_{\text{Generation}} - \underbrace{L_t}_{\text{Losses}} = \underbrace{P_t^1}_{\text{Consumption}} \tag{4}$$

Note: Throughout this paper, the subscripts refer to time and the superscripts refer to the location in the system.

Average losses expressed as a percent of generation can be calculated by solving this equation and dividing by generation.

$$Average\ Percent\ Losses_t = \frac{L_t}{P_t^0} = \frac{P_t^0 - P_t^1}{P_t^0} \quad (5)$$

Losses can also be calculated using engineering principles. Since losses are proportional to the square of the current and current is proportional to generation, losses equal some constant times the square of the generation. If it is assumed that voltage is constant,

$$Losses_t = \alpha \left(P_t^0\right)^2 \quad (6)$$

Furthermore, if the constant α is defined to be equal to be η_T divided by generation at some fixed time T (P_T^0) then

$$Losses_t = \left(\frac{\eta_T}{P_T^0}\right)\left(P_t^0\right)^2 \quad (7)$$

Losses expressed as a percent of generation are calculated by dividing by generation.

$$Average\ Percent\ Losses_t = \frac{\left(\frac{\eta_T}{P_T^0}\right)\left(P_t^0\right)^2}{P_t^0} = \eta_T \left(\frac{P_t^0}{P_T^0}\right) \quad (8)$$

Setting equations (5) and (8)equal to each other and then letting t equal a fixed time T results in

$$\eta_T = \frac{P_T^0 - P_T^1}{P_T^0} \quad (9)$$

That is, η_T is interpreted as the percent losses at some fixed level of generation that occurred at time T.

The final formulation is obtained by substituting equation (7) into (4) and simplifying.

$$P_t^0\left(1 - \eta_T \frac{P_t^0}{P_T^0}\right) = P_t^1 \quad (10)$$

That is, consumption at any time t is based on generation at time t and a pair of average losses/generation values at some other time T.

Change in Losses

In order to determine the effect of a change in generation with a change in consumption, take the derivative of both sides of equation (10) and solve. The result is that the change in generation with a change in consumption equals 2 times the average percent losses at the time T multiplied by the ratio of generation at time t to generation at time T.

$$\frac{dP_t^0}{dP_t^1} = \frac{1}{1 - 2\eta_T \left(\frac{P_t^0}{P_T^0} \right)} \tag{11}$$

Discussion

Equation (11) has several important implications. First, this result is consistent with what has been presented in the literature if marginal losses equal 2 times average losses. Second, the marginal losses that occur at any generation level for a fixed system can be calculated based on three numbers: the pair of numbers of average losses and generation level at any given time and the generation at the given point in time of interest. For example, a common choice for the pair of numbers could be the average system losses at the time of the system peak. Then for any other time of the year, one only needs to know the load at that exact time to calculate the time-specific marginal losses.

Numerical Example

This section provides a simple numerical example to verify equation (11).

Suppose that a system has a load of 2,500 MW and that average losses are 10 percent at that given load level. As presented in equation (7), this implies that losses = (0.1/2500) x Load^2.

Equation (11) predicts that an average loss of 10 percent will translate to a 25 percent[42] marginal loss savings associated with a small change in consumption. An Excel spreadsheet was constructed to calculate the loss savings associated with a distributed PV system. Table 27 and Table 28 present the loss savings for 10 MW and 100 MW PV systems. The 10 MW PV system has 24.9 percent loss savings and the 100 MW PV system has 24.2 percent loss savings. This is consistent with the predicted loss savings.

[42] 1/(1 – 2 x 0.1) = 1.25.

Table 27. Hypothetical example: 10 MW PV has 24.9 percent loss savings.

	Current System		System With PV		Savings
Generation	2,500.0		2,487.5		
Minus Losses	250.0		247.5		2.5
Delivered Generation		2,250.0		2,240.0	
Consumption	2,250.0		2,250.0		
Minus PV Output	-		10.0		10.0
Net Consumption		2,250.0		2,240.0	
Avg. Losses	10.0%		10.0%		
PV Loss Savings					**24.9%**

Table 28. Hypothetical example: 100 MW PV has 24.2 percent loss savings.

	Current System		System With PV		Savings
Generation	2,500.0		2,375.8		
Minus Losses	250.0		225.8		24.2
Delivered Generation		2,250.0		2,150.0	
Consumption	2,250.0		2,250.0		
Minus PV Output	-		100.0		100.0
Net Consumption		2,250.0		2,150.0	
Avg. Losses	10.0%		9.5%		
PV Loss Savings					**24.2%**

Loss Definition

Before proceeding, it is useful to clarify what is referred to by the term average losses.

First, the preceding problem formulation presented the relationship between average losses and marginal losses.

Technical and Non-Technical Losses

Losses can be divided into two main categories: technical losses and non-technical losses [32]. Non-technical losses include unread/improperly read/inaccurate meters as well as stolen energy. Technical losses include no-load and load losses. No-load losses include transformer core and other such losses and are independent of the amount of load on a system. Load losses are based on the fact that load losses are proportional to the square of the current flowing through the wire.

The preceding analysis demonstrated that losses should be calculated on a marginal basis. As such, the only change in losses that occurs when the load changes is with is the technical load-related losses. Thus, the use of the term "losses" in this paper refers to technical load- related losses.

Capacity versus Energy Losses

One issue that arises is to which portions of the system that the marginal loss savings calculations apply. In particular, it needs to be determined if the marginal loss calculations apply to only the energy portions of the system or do they apply to the capacity portions as well.

The methodology presented by Paresano [5] differentiates between capacity-related and energy-related losses. "The difference between capacity-related losses and energy-related losses is that the former are based on an expanding system and the latter are based on the concept of additional energy from a fixed system" [5, p. 2]. She claimed that capacity-related losses should be based on the ***average*** losses at the time of system peak demand while energy-related losses should be based on the ***marginal*** losses.

Parmesano's justification for differentiating between capacity- and energy-related losses was that capacity losses assume an expanding system while energy losses assume a fixed system. Consider how this justification should apply when evaluating a distributed resource. The very basis for deploying a distributed resource is to avoid "expanding the system" through central station generation and T&D investments. That is, the goal of deploying distributed resources is to maintain a fixed system. Thus, while Parmesano's distinction may have been useful for traditional utility planning, this author sees no reason to differentiate between capacity-related and energy-related losses when evaluating distributed resources.

In order to strengthen this point, we will slightly modify the previous example to determine the marginal costs associated with a generation capacity expansion. Assume that the current system is generating 2,375.8 MW, that system losses equal 225.8 MW, and that 100 MW of new customer loads are expected to come online. How much additional generation capacity is needed?

As shown in Table 29, 100 MW of new customer loads will require 124 MW of additional generation capacity. Since 100 MW of new customer loads can be met directly with 100 MW of distributed generation, the generation capacity loss savings should be performed on a marginal basis in the same way that the energy calculations should be performed on a marginal basis.

When evaluated a distributed resource, both capacity and energy loss calculations should be performed on a marginal (not average) basis.

Table 29. 100 MW of new customer loads requires 124.2 MW of generation capacity.

	Current System		System w/ Growth		Added Losses
Generation	2,375.8		2,500.0		
Minus Losses	225.8		250.0		24.2
Delivered Generation		2,150.0		2,250.0	
Consumption	2,150.0		2,150.0		
Load Growth	-		100.0		100.0
Net Consumption		2,150.0		2,250.0	
Avg. Losses	9.5%		10.0%		
PV Loss Savings					**24.2%**

Instantaneous Line Losses

The previous sections demonstrate two important points. First, loss savings calculations should be based on marginal, not average, losses. Second, there should be no distinction between the loss savings factors that are applied to capacity calculations as are applied to energy calculations.

This section addresses one limitation associated equation (11). The limitation is that it leads to counterintuitive results in extreme cases. Equation (11) results in a negative marginal loss value when average losses exceed 50 percent. This means that **decreasing** the load **increases** system losses when average losses exceed 50 percent. Furthermore, when average losses equal 50 percent, marginal losses are undefined.

This result is due to the failure of correctly modeling the behavior of losses on a real T&D system. A T&D system is composed of miles and miles of wires. As a result, losses do not occur at a single point in the system but rather are distributed across the system. Thus, rather than assuming that the losses occur at a single point, a more accurate model is to divide the system into a large number of subsystems (i.e., sections of wire) and then calculate the losses on each subsystem.

If the system is divided into *n* sections, the load can be expressed as follows. The load begins on section 0 and ends at section n, the point of consumption. The load at the start of section 0 minus the losses on section 0 equals the net load at the start of section 1. The load at the start of section 1 minus the losses on section 1 equals the net load at the start of section 2. Etc. That is, at any given time t, using the formulation presented in equations (4) and (6), the load is defined by the following set of equations.

$$
\begin{aligned}
P_t^0\left(1-\alpha^0 P_t^0\right) &= P_t^1 \\
P_t^1\left(1-\alpha^1 P_t^1\right) &= P_t^2 \\
&\ldots \\
P_t^{n-1}\left(1-\alpha^{n-1} P_t^{n-1}\right) &= P_t^n
\end{aligned}
\tag{12}
$$

If the system is divided such that each section has the same average loss as all other sections (i.e., $\alpha^i P_t^i = A_t / n$), then Equation (12) can be written as:

$$
\begin{aligned}
P_t^0\left(1-A_t / n\right) &= P_t^1 \\
P_t^1\left(1-A_t / n\right) &= P_t^2 \\
&\ldots \\
P_t^{n-1}\left(1-A_t / n\right) &= P_t^n
\end{aligned}
\tag{13}
$$

The solution to the set of equations presented in (13) implies that

$$
A_t = n\left(1-\sqrt[n]{\frac{P_t^n}{P_t^0}}\right) \tag{14}
$$

When *n* is large,

$$
A_t = \ln\left(\frac{1}{1-\frac{P_t^0 - P_t^n}{P_t^0}}\right) \tag{15}
$$

Next, consider the change in load. The change in load in the previous section due to a change in load in the current section is calculated by taking the derivative of both sides of equation (12) and solving.

$$
\begin{aligned}
\frac{dP_t^0}{dP_t^1} &= \frac{1}{1-2\alpha^0 P_t^0} = \frac{1}{1-2A_t / n} \\
\frac{dP_t^1}{dP_t^2} &= \frac{1}{1-2\alpha^1 P_t^1} = \frac{1}{1-2A_t / n} \\
&\ldots \\
\frac{dP_t^{n-1}}{dP_t^n} &= \frac{1}{1-2\alpha^{n-1} P_t^{n-1}} = \frac{1}{1-2A_t / n}
\end{aligned}
\tag{16}
$$

The set of equations in (16) can be multiplied together to determine the change in load at point 0 due to a change in load at point n. The result is

$$\frac{dP_t^0}{dP_t^1}\frac{dP_t^1}{dP_t^2}\cdots\frac{dP_t^{n-1}}{dP_t^n}=\frac{dP_t^0}{\cancel{dP_t^1}}\frac{\cancel{dP_t^1}}{\cancel{dP_t^2}}\cdots\frac{\cancel{dP_t^{n-1}}}{dP_t^n}=\frac{dP_t^0}{dP_t^n}=\left(\frac{1}{1-2A_t/n}\right)^n \tag{17}$$

As n becomes large,

$$\frac{dP_t^0}{dP_t^n}=\left[\exp(A_t)\right]^2 \tag{18}$$

Substitute Equation (15) into Equation (18) to eliminate A and the result is:

$$\frac{dP_t^0}{dP_t^n}=\left(\frac{1}{1-\dfrac{P_t^0-P_t^n}{P_t^0}}\right)^2 \tag{19}$$

In order to extend this result to any time of the year, substitute equation (9).

$$\frac{dP_t^0}{dP_t^n}=\left(\frac{1}{1-\eta_T\,\dfrac{P_t^0}{P_T^0}}\right)^2 \tag{20}$$

Discussion

The result presented in equation (20) is similar to equation (11) in most ways. As before, the marginal losses that occur at any level of generation for a fixed system can be calculated based on three numbers: a pair of numbers (average losses and the generation level at the time the loss is measured) and the generation at time of interest. The results differ in that rather than multiplying the average losses by 2, the entire term is squared. The immediate benefit of this is that equation (20) eliminates the problems associated with the extreme cases (i.e., average losses greater than 50 percent).

Figure 17 presents the marginal losses versus the average losses that were calculated using the two methods. The black line is the method that accounts for the losses along the system. The red line is the method that treats all losses as occurring at a single point. The top part of the figure presents results when average losses vary from 0 to 10 percent As can be seen from the figure, the two methods have similar marginal losses when the average loss is less than 10 percent. The bottom part of the figure presents results for average losses than range up to 20 percent. While average losses of 20 percent would be very high for a utility system, the results between these two methods begin to diverge. Thus, while such high average losses are not typically observed by a utility, the point method should be used to avoid mathematical errors that can occur when there are high average losses.

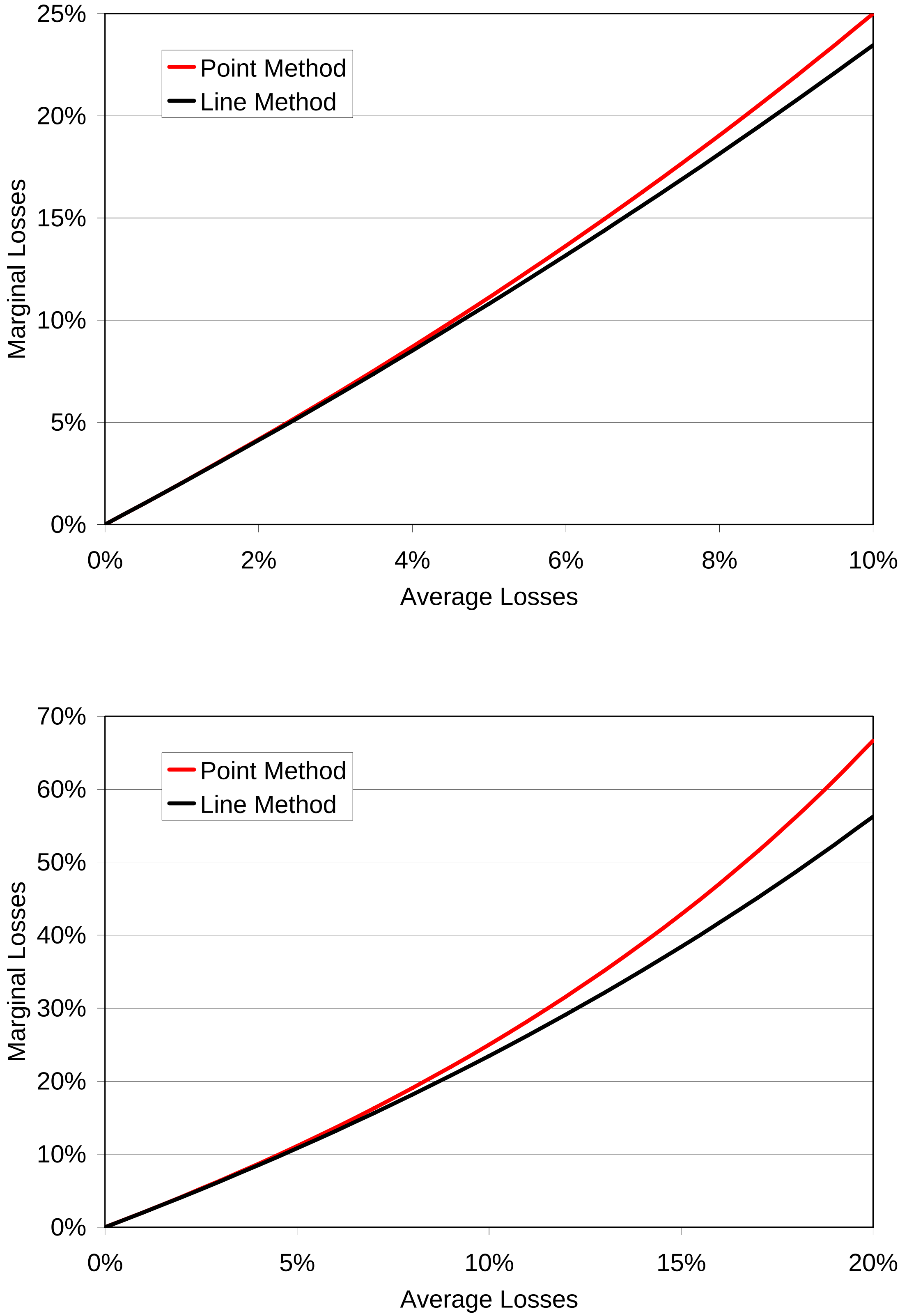

Figure 17. Hypothetical results for two methods to calculate marginal losses.

Preliminary Verification

It is useful to verify the calculations using publicly available data. Sacramento Utility District (SMUD) performed a PV Value analysis study [20]. The loss savings calculations in that report were based on marginal loss analysis developed by SMUD. As can be calculated based on the PV output with and without the loss adjusted presented in Table 23 on page 65 of [8], the energy production credited to the PV system was 12.5 percent greater than direct PV system output.[43] A complete verification of these results requires the annual losses and the hourly generation data. Unfortunately, these data are not publicly available in the above mentioned report. As an alternative, SMUD's annual energy losses were reported to the U.S. Department of Energy's Energy Information Administration on Form EIA-861 [33].[44] The losses were 5.3 percent in 2000. If it is assumed that the same loss factors applied throughout the year, the marginal loss factor would equal 11.5 percent.

AE Verification

AE performed an evaluation of the Generation and Transmission system[45] and determined that, during the peak time, the generation losses equal 2.5 percent and the transmission losses equal 0.65 percent, for a total loss of 3.13 percent. Results from this paper suggest that the marginal losses equal 6.26 percent. AE Then ran its simulation models and determined that the actual marginal losses were 2.9 percent, a number that is significantly lower than what is predicted.

In order to verify the reason for this discrepancy, AE examined the marginal losses for each power plant and then took the weighted average losses based on the amount of energy produced during on-peak conditions. AE then took the weighted average of the marginal losses. The result, which is presented in Table 30, is that the weighted average marginal losses equal 6.26 percent, thus, verifying the predicted number.

Thus, the explanation why the marginal losses do not equal approximately 2 times average losses is because a distributed PV system will only reduce output from Decker, Holly & Sand Hill. Even though Fayette, STP, and Sweetwater have much higher marginal losses than Decker, Holly & Sand Hill, the output from them will not be reduced because they are baseload or non-dispatchable renewable resources whose capacity does not impact marginal costs.

---

[43] 1,576.6 kWh per kW of PV and PV output adjusted for losses was 1,774.4 kWh per kW of PV

[44] There are inconsistencies in this data source from year to year.

[45] Confidential draft of report prepared by Steven Havemann, June 2005.

Table 30. On-peak marginal losses.

Power Plant Name	**Plant Type**	**2004 energy (%)**	**Marginal G&T losses (%) At Summer Peak Demand**
Decker, Holly & Sand Hill	Natural Gas	31%	2.60%
Fayette	Coal	36%	6.96%
STP	Nuclear	31%	8.96%
Sweetwater II , King Wind, Texas Wind	Wind	2%	8.5%
2004 Energy Weighted Marginal losses			**6.26%**

Methodology Implementation

Having derived a formula to determine hourly marginal loss factors, the formula can now be used to calculate annual energy value. First, it is discussed how to obtain the required data. Next, it is demonstrated how to calculate the value.

Parameter Determination

There are several ways to obtain the required parameters to implement equation (20). One alternative is to obtain η_T for a specific generation level using a system model. Another alternative, if the total load-based annual energy losses is available, is to use equation (7) to solve for the efficiency/generation pair as follows.

$$Annual\ Losses = \sum_{t=1}^{8,760} \left(\frac{\eta_T}{P_T^0} \right) \left(P_t^0 \right)^2 \Rightarrow \frac{\eta_T}{P_T^0} = \frac{Annual\ Losses}{\sum_{t=1}^{8,760} \left(P_t^0 \right)^2} \qquad (21)$$

Annual Energy Value

In addition to the average efficiency load pair, the other data that are required are hourly load data, hourly prices, and hourly PV system output. Once the required data are obtained, the energy value is calculated as follows.

$$Annual\ Energy\ Value = \sum_{t=1}^{8,760} \left(Price_t \right) \left(\frac{1}{1 - \eta_T \frac{P_t^0}{P_T^0}} \right)^2 \left(PV_t \right) \qquad (22)$$

Note: it can be shown that if the utility system is divided into two parts (e.g., one part is up to the substation transformer and the other part is from the substation transformer to the customer), then the energy value can be calculated as follows.

$$Annual\ Energy\ Value = \sum_{t=1}^{8,760} \left(Price_t\right) \left(\frac{1}{1 - \eta_T^{Gen.} \frac{P_t^{Gen.}}{P_T^{Gen.}}} \right)^2 \left(\frac{1}{1 - \eta_T^{Dist.} \frac{P_t^{Dist.}}{P_T^{Dist.}}} \right)^2 \left(PV_t\right) \qquad (23)$$

Conclusions and Future Work

This paper demonstrated how marginal loss calculations should be used in the economic evaluation of customer-sited distributed generation facilities. It presented a method to calculate marginal losses assuming that all losses occur at a single point. It then extended the method to account for the fact that losses occur along the length of a wire to avoid calculation errors that occur with the single point solution. The result was that the marginal loss factor equals the square of the inverse of 1 minus average losses. The paper applied the method to calculate the annual energy value of a distributed PV system using hourly data.

There are several areas of future work. First, it would be useful to extend the fundamental analysis presented in this paper to calculate the marginal loss savings given that feeder loads are decreasing as a result of consumption prior to the location where the distributed facility is located.

Second, it is the author's hunch that the general practice in evaluating demand side management/distributed generation investments is to base the analysis on average losses rather than marginal losses. If this is correct, these analyses are underestimating (and thus under investing in) the value. This hunch should be confirmed and the economic implications should be quantified.

Appendix C: Natural Gas Price Uncertainty

Introduction

While non-renewable sources are subject to potentially large fuel price variations and planning uncertainties, solar, wind, and other renewable technologies provide stable, predictable energy prices because the fuel is free [35].

It has always been recognized that natural gas prices have the potential to be volatile. The fact of this volatility, however, has been solidified in recent months with the occurrence of natural disasters (e.g., Hurricane Katrina in August 2005, Rita in September 2005) as well as changes in market conditions.

This Appendix discusses natural gas price uncertainty and how to calculate the value of eliminating this uncertainty using a risk-neutral evaluation approach.

Methodology

Scenario Analysis

One way to understand the effect of natural gas price uncertainty is to perform a scenario analysis using low, base case, and high natural gas price forecasts. There are two limitations with this approach. First, it is unclear as to how wide of a range of natural gas price forecasts is required to capture the potential levels of uncertainty. Second, it is unclear on how to establish the probability that the various scenarios will occur.

In order to illustrate the difficulty of developing a sufficiently wide range of natural gas price forecasts, it is valuable to take a history lesson and examine some data from California. Every two years, the California Energy Commission (CEC) conducts a comprehensive analysis of the California natural gas market. As part of this analysis, it develops a 20-year forecast of market trends, prices and supply availability.

Consider the results from the CEC's natural gas price forecast made in 1997 [14]. While the study predicted that "natural gas supplies will remain plentiful for the next several decades," and "prices will remain low," actual experience has turned out to be quite different. Figure 18 presents historical and forecast natural gas prices from the CEC study (red lines) and actual prices from Henry Hub (blue lines). The solid red line is the historical price of natural gas for electricity generation for PG&E and the dashed lines are the low, medium, and high price forecasts as of 1997. The blue lines are the actual annual average Henry Hub natural gas price.

As the figure shows, the actual prices exceeded the high price forecast within three years and actual prices are almost triple the high price forecast eight years later (2005). The point is that, while a scenario analysis could be very useful, it is difficult to construct scenarios that represent a sufficiently wide range (low and high) of natural gas prices that could occur in the future.

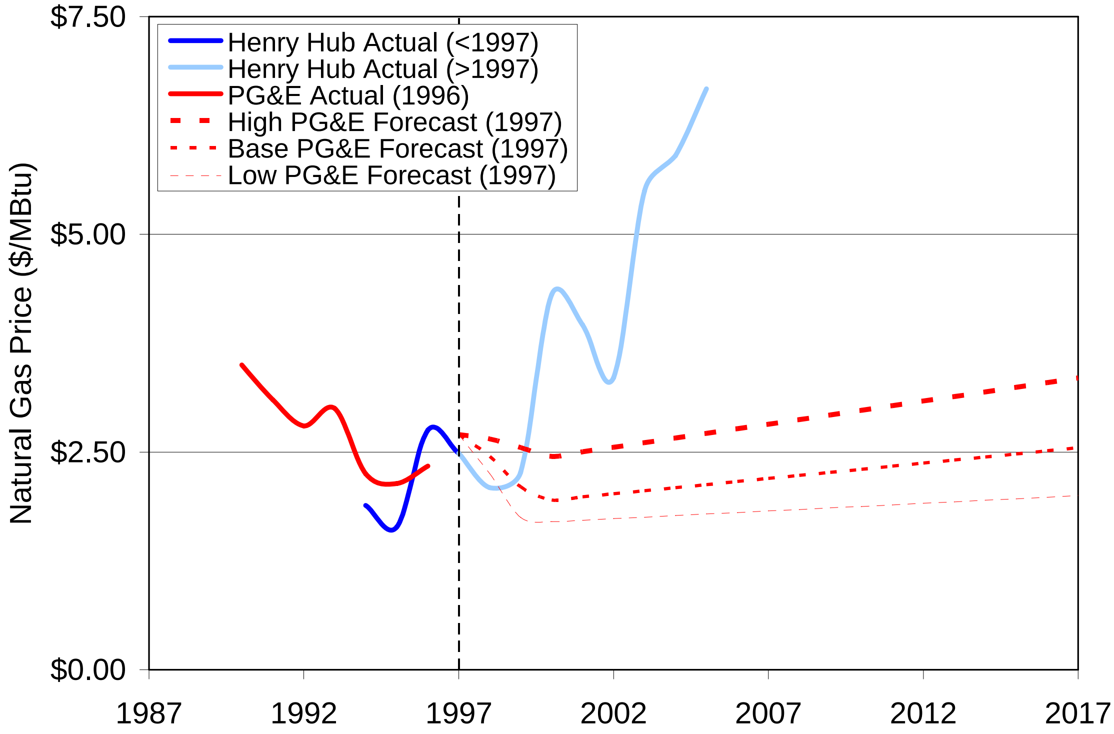

Figure 18. Historical and forecast natural gas prices for PG&E and Henry Hub.

Risk-Neutral Valuation

Fortunately, an alternative approach exists that will yield more accurate results. This approach is taken from financial economics. Resources are available that discuss the financial economics approach at an introductory level [6] as well as at a graduate level [36].

For years, the problem that the financial community encountered when assessing the value of an investment was how to select the correct discount rate. The problem was intensified when the investment had asymmetrical payoffs, such as an option on a stock.

The breakthrough in this field occurred when Fisher Black and Myron Scholes [2] and Robert Merton [3] developed what has become known as the Black-Scholes (or Black-Scholes-Merton) model.

The essence of the Black-Scholes model is that it creates a portfolio that consists of the fundamental investment and the derivative investment in proportions such that there is no uncertainty in what the future portfolio payoff will be. Since the payoff is certain and there is no risk, in order to avoid arbitrage opportunities, the payoff is discounted at the risk-free discount rate.[46] This eliminates the problem of how to select the correct discount rate.

[46] See p. 101 of [36] to see a discussion of the conditions for the analysis.

Forward Contract Example

Consider a simple example of how this applies to the valuation of forward contract[47] to purchase a non-dividend paying stock in 1 year ([36], p 102). The current stock price is $50.00 and the 1-year risk-free interest rate is 5 percent.

First suppose that the forward price is relatively high at $55.00. An arbitrageur could borrow $50.00 at the risk-free rate of 5 percent, buy one share of stock, and short (sell) the forward contract (i.e., be required to sell one share of stock in 1 year). After 1 year, the arbitrageur delivers the share, receives $55.00, and repays $52.50 to cover the loan plus interest. The arbitrageur locks in a risk-free profit of $2.50.

Next suppose that the forward price is relatively low at $50.00. An arbitrageur could short (sell) one share, invest the proceeds at 5 percent interest, and take a long position (buy) the forward contract. After 1 year, the arbitrageur receives $52.50 from the investment, pays $50.00 to take delivery of the share, and uses the share to close out the short position. The arbitrageur locks in a risk-free profit of $2.50.

The only forward price that does not result in an arbitrage opportunity is $52.50, i.e., the current stock price times 1 plus the risk-free interest rate.

Futures Market Characteristics

Futures and other derivative securities have become popular tools that companies use to manage risk. Consider some facts and characteristics about the market for these financial instruments:

1. Both the exchange-traded and over-the-counter markets for derivative securities are very large: the total principal amounts underlying transactions equals the world gross domestic product in the exchange-traded market and five times the world gross domestic product in the over-the-counter market [36], p. 3.
2. Futures contracts are typically settled financially rather than delivered physically when used for risk management purposes. For example, if a firm initially enters into a long futures position, it will typically close out its position prior to delivery by entering into a corresponding short futures position.
3. A market participant does not need to own the underlying asset in order to sell a future on the asset; the market has developed various mechanisms (e.g., margin accounts) to minimize default risk.

Application to PV Value

The risk-neutral valuation approach can be applied to a PV investment. There are two ways that the analysis can be framed. One option is to assume that AE wants to retain the generation portfolio risk reduction benefits associated with a PV investment. The other option is to assume that AE does not want to alter the risk associated with its existing generation portfolio but still wants to invest in PV. Both alternatives result in the same value. In essence, the two perspectives ask the following questions: What is the cost to

[47] Forward contracts and futures contracts can be treated in a similar manner.

purchase an equivalent amount of risk protection as provided by PV? How much could you sell the risk protection associated with the PV?

AE Retains NG Price Risk Hedge Benefits

One approach to the problem is to determine how much it would cost to guarantee that a portion of AE's electric supply costs are fixed. This could be accomplished by signing a guaranteed fixed price natural gas contract with an entity that has essentially no risk of defaulting on their obligation.

For example, suppose that AE wants to guarantee that 17 GWh of its electricity supply in 2006 is produced at a fixed cost. AE could accomplish this by purchasing a sufficient amount of natural gas futures contracts that will allow it to generate 17 GWh of electricity. Since there is no uncertainty as to what the fuel price will be, AE should discount the cost of the futures contracts at the risk-free discount rate. This is then repeated over the life of the PV system.

AE could obtain the same guarantee by installing 10 MW of South-30º PV that will produce 17 GWh of electricity.[48]

Two investments that have the same payoffs have the same value. As a result, the value equals the cost of the natural gas futures discounted at the risk-free discount rate.

AE Sells NG Price Risk Hedge Benefits

Another approach to the problem is to sell the risk reduction benefits provided by PV while retaining the energy production and other benefits. A PV investment reduces AE's generation portfolio risk because there is a reduction in the purchase of natural gas. The generation portfolio could be returned to the same risk it had without PV by selling the risk benefits associated with the PV. AE could accomplish this by selling natural gas futures (or other contracts) in proportion to the natural gas savings due to the PV. As a result, the PV investment alters the physical generation mix but does not alter the portfolio's financial risk.

Suppose that AE determines that it will reduce natural gas consumption by 136,000 MBtu per year by installing 10 MW of PV. AE would sell the corresponding risk reduction attribute of PV as follows. It would immediately short (sell) 136,000 MBtu of natural gas futures or over-the-counter contracts that are due in 1 year. Immediately prior to the required delivery date of the contract, AE would go long (buy) a futures contract for the same delivery date as the short futures contract; this futures contract will have a price that is very close to the spot market because of the very short duration of the futures contract. This closes out AE's position so it does not have to physically purchase and deliver the natural gas. From a financial perspective, however, it is as if AE continued to purchase the same amount of natural gas it would have needed without the PV system.[49]

[48] This assumes that the timing of the electricity production from PV is the same as the timing of the production from natural gas; this assumption would be true because the marginal cost analysis performed in the Energy Production section has accounted for this match.
[49] This "risk-free" discussion references a hypothetical reduction in gas volume by the PV.

There is no risk associated with selling a futures contract because the contract price is known with certainty at the date of sale. As a result, the revenue to be obtained from the sale of the futures contract is discounted at the risk-free discount rate. When this is repeated for each year of the life of the PV system, the result is the total value of risk-free natural gas savings. Since the result includes both the energy production benefit and the natural gas price hedge benefit, the natural gas price hedge benefit is determined by subtracting out the energy production benefit from the total value.

Required Inputs

Two inputs are required to perform the analysis:

1. Natural gas price over life of PV system
2. Risk-free discount rate associated with each year of the analysis

Natural Gas Price

The source for the future natural gas price needs to come from an entity that offers the contract price and has no default risk. The NYMEX natural gas futures market fits this description well. It is limited, however, in that it only contains futures contracts through December 2010. For the remaining life of the PV system, it is assumed that AE's natural gas forecast are the prices that AE would pay for a natural gas forward contract with an entity that has essentially no default risk.

Risk-Free Discount Rate

The second input required to perform the analysis is the risk-free discount rate. For each cash flow, there needs to be a corresponding risk-free discount rate. Cash flows are discounted at this rate.

The yield of a financial instrument is the amount of money to be made per year by investing in that instrument. The yield curve is the plot of yields versus time. The yield curve is also known as the term structure of interest rates or the zero curve [36].

The typical choice for the risk-free interest rate when evaluating derivative securities is the London Interbank Offer Rate (LIBOR). The LIBOR rates, however, are short-term when compared with the life of a PV system. An alternative is the U.S. Treasury Bills or Treasury Bonds. The advantage of these rates is that they are long-term and cover the life of this study.

Several sources[50] are available that present the treasury yield curve[51] rates. The treasury yield curve obtained from the Treasury Department for January 9, 2006 is presented in Figure 19.

---

[50] Historical daily yield curve data are available at http://www.treas.gov/offices/domestic-finance/debt-management/interest-rate/yield.html and today's data are available at http://www.bloomberg.com/markets/rates/. Since the natural gas futures data are based on the prices on January 9, 2006, the corresponding yield curve is selected for this analysis.

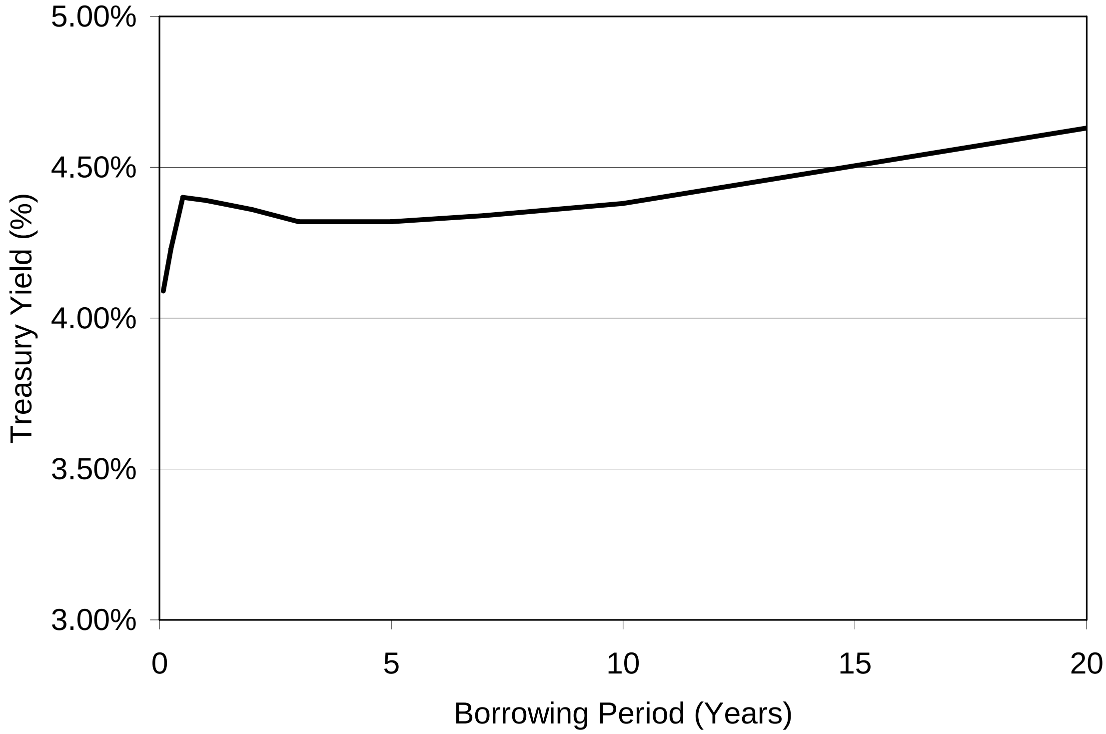

Figure 19. Treasury yield curve (January 9, 2006).

[51] See http://en.wikipedia.org/wiki/Yield_curve for a good summary of the yield curve. See [36] p. 82 for a good discussion on how to construct the yield curve based on market data.

Appendix D: Energy Value

This Appendix describes how to calculate the energy value. It presents the mathematical specification of how to perform the calculation and then applies the formula to the energy value with and without loss savings.

Specification

Mathematically, the energy value can be calculated as follows:[52]

$$\begin{matrix} Energy \\ Value \end{matrix} = \sum_{year=0}^{PV\ Life-1} \frac{\overbrace{NGAdjust_{year}}^{Gas\ Price\ Adjustment} \times \overbrace{\sum_{hour=1}^{8,760} \left(PV_{year,hour}\right)\left(Marg.Cost_{year,hour}\right)}^{Annual\ energy\ value}}{(1+r)^{year}}$$

where

$$NGAdjust_{year} = \begin{cases} \dfrac{NGFutures\ Price_{year}}{NG\ Price\ in\ MCForecast_{year}} & year <= 2010 \\ \dfrac{AE\ NG\ Price\ Forecast_{year}}{NG\ Price\ in\ MCForecast_{year}} & year\ > 2010 \end{cases} \tag{24}$$

$$PV_{year,hour} = (1-degradation)^{year-1}\left(Typical\ PV_{hour}\right)$$

$$Typical\ PV_{hour} = \left(\sum_{year=2002}^{2004} PV_{year,hour} LossFactor_{year,hour}\right)\left(\frac{1}{3}\right)$$

$$LossFactor_{year,hour} = Peak\ Loss\ Savings \times \frac{Load_{year,hour}}{Peak\ Load}$$

[52] The additional performing a linear interpolation based on the PV system size and the two sets of marginal costs is not reflected in the equation.

Energy Value With Loss Savings

Calculate Value Using 1 MW Marginal Costs

The annual energy value is calculated using (24) based on AE's hourly marginal costs for a 1 MW resource. The results are presented in Table 31.

Table 31. Energy value (1 MW marginal costs, with loss savings) - $/kW/yr.

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
2006	$81	$87	$86	$78	$71	$105	$110
2007	$72	$76	$76	$69	$63	$93	$97
2008	$58	$62	$62	$56	$52	$74	$79
2009	$51	$55	$55	$50	$46	$66	$70
2010	$52	$55	$55	$50	$46	$67	$70
2011	$50	$54	$54	$48	$45	$65	$68
2012	$57	$62	$61	$55	$50	$74	$78
2013	$56	$61	$60	$54	$50	$73	$77
2014	$62	$67	$66	$59	$54	$80	$85
2015	$58	$63	$62	$56	$52	$75	$79
2016	$64	$69	$68	$61	$56	$83	$87
2017	$63	$69	$67	$61	$56	$83	$87
2018	$70	$76	$74	$66	$61	$91	$96
2019	$70	$76	$74	$66	$60	$91	$96
2020	$70	$77	$75	$67	$61	$93	$98
2021	$70	$75	$74	$67	$61	$91	$96
2022	$71	$76	$75	$67	$62	$92	$97
2023	$72	$77	$75	$68	$62	$93	$98
2024	$75	$81	$79	$71	$65	$98	$103
2025	$74	$80	$78	$70	$64	$97	$102
2026	$76	$82	$80	$72	$66	$99	$104
2027	$75	$81	$79	$71	$65	$98	$103
2028	$76	$82	$80	$72	$66	$100	$105
2029	$76	$82	$80	$72	$66	$99	$104
2030	$77	$83	$81	$72	$66	$100	$105
2031	$75	$82	$79	$71	$65	$98	$103
2032	$76	$82	$80	$72	$66	$99	$105
2033	$76	$83	$80	$72	$66	$100	$105
2034	$77	$84	$81	$73	$67	$101	$106
2035	$77	$84	$81	$73	$67	$101	$106

Calculate Value Using 100 MW Marginal Costs

The annual energy value is calculated using (24) based on AE's hourly marginal costs for a 100 MW resource. The results are presented in Table 32.

Table 32. Energy value (100 MW marginal costs, with loss savings) - $/kW/yr.

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
2006	$73	$78	$77	$71	$65	$95	$99
2007	$65	$68	$68	$62	$57	$83	$87
2008	$52	$56	$56	$51	$47	$67	$71
2009	$45	$49	$49	$44	$41	$59	$62
2010	$47	$50	$50	$46	$42	$61	$64
2011	$45	$48	$48	$44	$40	$58	$61
2012	$51	$55	$55	$49	$45	$66	$70
2013	$50	$54	$54	$49	$45	$65	$69
2014	$56	$61	$60	$54	$50	$73	$77
2015	$51	$55	$55	$50	$46	$66	$69
2016	$56	$61	$60	$54	$50	$73	$77
2017	$56	$61	$60	$54	$50	$73	$77
2018	$62	$68	$66	$59	$55	$82	$86
2019	$63	$68	$67	$60	$55	$82	$87
2020	$64	$70	$68	$60	$56	$84	$89
2021	$64	$69	$68	$61	$56	$83	$87
2022	$65	$70	$69	$62	$57	$84	$89
2023	$66	$71	$70	$63	$58	$86	$90
2024	$70	$76	$74	$66	$61	$91	$96
2025	$69	$74	$73	$65	$60	$90	$94
2026	$70	$76	$74	$67	$61	$92	$97
2027	$70	$76	$74	$67	$61	$92	$96
2028	$72	$78	$76	$68	$63	$94	$99
2029	$71	$77	$75	$68	$62	$93	$98
2030	$73	$79	$77	$69	$64	$96	$100
2031	$71	$77	$75	$68	$62	$93	$98
2032	$72	$78	$76	$68	$63	$95	$99
2033	$72	$78	$77	$69	$63	$95	$100
2034	$74	$80	$78	$70	$64	$97	$102
2035	$74	$81	$79	$71	$65	$97	$102

Interpolate Between 1 MW and 100 MW Marginal Costs

The results are then interpolated using Table 31 and Table 32 for each year and PV system configuration to reflect a 15 MW PV plant as shown in Table 33. This completes the annual energy value calculation.

Table 33. Energy value (15 MW plant, with loss savings) - $/kW/yr.

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
2006	$80	$86	$85	$77	$71	$104	$109
2007	$71	$75	$74	$68	$62	$91	$96
2008	$57	$61	$61	$55	$51	$73	$78
2009	$51	$55	$54	$49	$45	$65	$69
2010	$51	$55	$54	$49	$45	$66	$69
2011	$49	$53	$53	$48	$44	$64	$67
2012	$56	$61	$60	$54	$49	$73	$77
2013	$55	$60	$59	$53	$49	$72	$76
2014	$61	$66	$65	$58	$54	$79	$84
2015	$57	$61	$61	$55	$51	$74	$78
2016	$63	$68	$67	$60	$55	$81	$86
2017	$62	$68	$66	$60	$55	$81	$86
2018	$69	$75	$73	$65	$60	$90	$95
2019	$69	$75	$73	$65	$59	$90	$95
2020	$70	$76	$74	$66	$60	$91	$97
2021	$69	$74	$73	$66	$60	$90	$94
2022	$70	$75	$74	$67	$61	$91	$96
2023	$71	$76	$75	$67	$62	$92	$97
2024	$74	$81	$79	$71	$65	$97	$102
2025	$73	$79	$77	$69	$64	$96	$101
2026	$75	$81	$79	$71	$65	$98	$103
2027	$74	$80	$78	$70	$64	$97	$102
2028	$75	$82	$80	$71	$66	$99	$104
2029	$75	$81	$79	$71	$65	$98	$103
2030	$76	$82	$80	$72	$66	$100	$105
2031	$75	$81	$79	$71	$65	$98	$103
2032	$75	$82	$80	$71	$65	$99	$104
2033	$76	$82	$80	$71	$65	$99	$104
2034	$77	$83	$81	$72	$66	$100	$106
2035	$77	$83	$81	$72	$66	$101	$106

Adjust Value Based on Natural Gas Prices And Calculate Result

The next step of the calculation is to adjust the annual energy values to reflect updated natural gas prices. The result is presented in Table 34. The final step is to calculate the discounted value by multiplying the discount factor times the adjusted annual energy value. The result is presented in the bottom of Table 34 and is the energy value with loss savings.

Table 34. Adjusted energy value (15 MW plant, with loss savings) - $/kW/yr.

	Discount Factor	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
2006	1.00	$109	$117	$115	$105	$96	$141	$148
2007	0.96	$110	$117	$115	$105	$97	$142	$148
2008	0.92	$102	$110	$109	$99	$92	$132	$139
2009	0.88	$98	$106	$105	$95	$88	$127	$134
2010	0.84	$92	$99	$98	$89	$82	$119	$125
2011	0.81	$60	$64	$64	$58	$53	$77	$81
2012	0.77	$66	$72	$71	$64	$59	$86	$91
2013	0.74	$66	$72	$71	$64	$59	$86	$91
2014	0.71	$72	$79	$77	$69	$64	$94	$99
2015	0.68	$65	$70	$70	$63	$58	$84	$89
2016	0.65	$58	$63	$62	$56	$52	$76	$80
2017	0.62	$60	$65	$64	$57	$53	$78	$82
2018	0.60	$69	$75	$73	$65	$60	$90	$95
2019	0.57	$72	$79	$76	$68	$62	$95	$100
2020	0.55	$75	$82	$79	$70	$65	$98	$104
2021	0.53	$74	$80	$78	$71	$65	$97	$101
2022	0.50	$77	$83	$81	$73	$67	$101	$106
2023	0.48	$80	$86	$84	$76	$70	$104	$110
2024	0.46	$87	$94	$91	$82	$75	$113	$119
2025	0.42	$88	$95	$92	$83	$76	$114	$120
2026	0.40	$92	$99	$97	$87	$80	$120	$126
2027	0.39	$93	$101	$99	$88	$81	$122	$128
2028	0.37	$98	$106	$103	$92	$85	$128	$134
2029	0.35	$100	$108	$105	$94	$86	$131	$137
2030	0.34	$104	$112	$109	$98	$90	$136	$143
2031	0.32	$104	$113	$110	$99	$91	$137	$144
2032	0.31	$108	$118	$114	$102	$94	$142	$149
2033	0.29	$112	$121	$118	$105	$97	$146	$154
2034	0.28	$116	$126	$123	$110	$101	$152	$160
2035	0.27	$120	$130	$126	$113	$103	$157	$165
Present Value		***$1,454***	***$1,570***	***$1,542***	***$1,390***	***$1,278***	***$1,891***	***$1,990***

Energy Value without Loss Savings

Next, the energy value without loss savings is calculated.

Calculate Value Using 1 MW Marginal Costs

Table 35. Energy value (1 MW marginal costs, without loss savings) - $/kW/yr.

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
2006	$77	$83	$81	$74	$68	$100	$105
2007	$68	$73	$72	$65	$60	$88	$92
2008	$55	$59	$59	$53	$49	$71	$75
2009	$49	$53	$52	$47	$44	$63	$67
2010	$49	$53	$52	$47	$44	$63	$67
2011	$48	$51	$51	$46	$42	$62	$65
2012	$54	$59	$58	$52	$48	$70	$74
2013	$53	$58	$57	$51	$47	$69	$73
2014	$59	$64	$63	$56	$52	$76	$81
2015	$55	$60	$59	$53	$49	$71	$75
2016	$60	$66	$64	$58	$53	$78	$83
2017	$60	$65	$64	$57	$53	$78	$83
2018	$66	$72	$70	$63	$58	$87	$92
2019	$66	$72	$70	$62	$57	$87	$92
2020	$67	$74	$71	$63	$58	$88	$93
2021	$67	$72	$70	$63	$58	$87	$91
2022	$67	$73	$71	$64	$59	$88	$92
2023	$68	$73	$72	$64	$59	$89	$93
2024	$71	$77	$75	$68	$62	$93	$98
2025	$70	$76	$74	$67	$61	$92	$97
2026	$72	$78	$76	$68	$62	$94	$99
2027	$71	$77	$75	$67	$62	$93	$98
2028	$72	$78	$76	$68	$63	$95	$100
2029	$72	$78	$76	$68	$62	$94	$99
2030	$73	$79	$77	$69	$63	$95	$100
2031	$71	$78	$75	$67	$62	$94	$98
2032	$72	$78	$76	$68	$62	$95	$100
2033	$72	$79	$76	$68	$63	$95	$100
2034	$73	$80	$77	$69	$63	$96	$101
2035	$73	$80	$77	$69	$63	$96	$101

Calculate Value Using 100 MW Marginal Costs

Table 36. Energy value (100 MW marginal costs, without loss savings) - $/kW/yr.

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
2006	$70	$74	$73	$67	$62	$90	$94
2007	$61	$65	$64	$59	$54	$79	$82
2008	$49	$53	$53	$48	$45	$64	$67
2009	$43	$46	$46	$42	$39	$56	$59
2010	$45	$48	$48	$44	$40	$58	$61
2011	$43	$46	$45	$41	$38	$55	$58
2012	$49	$52	$52	$47	$43	$63	$66
2013	$48	$52	$51	$46	$43	$62	$65
2014	$54	$58	$57	$52	$48	$70	$74
2015	$48	$52	$52	$47	$44	$63	$66
2016	$54	$58	$57	$51	$47	$69	$73
2017	$53	$58	$57	$51	$47	$69	$73
2018	$59	$65	$63	$56	$52	$78	$82
2019	$60	$65	$63	$57	$52	$78	$83
2020	$61	$67	$65	$57	$53	$80	$84
2021	$61	$65	$64	$58	$53	$79	$83
2022	$62	$66	$65	$59	$54	$80	$84
2023	$63	$67	$66	$60	$55	$82	$86
2024	$66	$72	$70	$63	$58	$87	$91
2025	$65	$71	$69	$62	$57	$85	$90
2026	$67	$72	$71	$64	$58	$87	$92
2027	$67	$72	$70	$63	$58	$87	$91
2028	$68	$74	$72	$65	$59	$89	$94
2029	$68	$73	$72	$64	$59	$89	$93
2030	$69	$75	$73	$66	$60	$91	$95
2031	$68	$73	$72	$64	$59	$89	$93
2032	$69	$74	$73	$65	$60	$90	$94
2033	$69	$75	$73	$65	$60	$90	$95
2034	$70	$76	$74	$67	$61	$92	$97
2035	$71	$77	$75	$67	$61	$93	$97

Interpolate Between 1 MW and 100 MW Marginal Costs

Table 37. Energy value (15 MW plant, without loss savings) - $/kW/yr.

	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
2006	$76	$81	$80	$73	$67	$98	$103
2007	$67	$72	$71	$64	$59	$87	$91
2008	$54	$58	$58	$52	$48	$70	$74
2009	$48	$52	$51	$47	$43	$62	$66
2010	$48	$52	$52	$47	$43	$62	$66
2011	$47	$51	$50	$45	$42	$61	$64
2012	$53	$58	$57	$51	$47	$69	$73
2013	$53	$57	$56	$51	$46	$68	$72
2014	$58	$63	$62	$55	$51	$75	$80
2015	$54	$58	$58	$52	$48	$70	$74
2016	$59	$65	$63	$57	$52	$77	$82
2017	$59	$64	$63	$57	$52	$77	$81
2018	$65	$71	$69	$62	$57	$86	$90
2019	$65	$71	$69	$62	$57	$86	$90
2020	$66	$73	$70	$62	$57	$87	$92
2021	$66	$71	$69	$62	$57	$86	$90
2022	$67	$72	$70	$63	$58	$87	$91
2023	$67	$72	$71	$64	$58	$88	$92
2024	$71	$77	$75	$67	$61	$92	$97
2025	$70	$75	$74	$66	$61	$91	$96
2026	$71	$77	$75	$67	$62	$93	$98
2027	$70	$76	$74	$67	$61	$92	$97
2028	$72	$78	$76	$68	$62	$94	$99
2029	$71	$77	$75	$67	$62	$93	$98
2030	$72	$78	$76	$68	$63	$95	$100
2031	$71	$77	$75	$67	$61	$93	$98
2032	$72	$78	$76	$68	$62	$94	$99
2033	$72	$78	$76	$68	$62	$94	$99
2034	$73	$79	$77	$69	$63	$96	$101
2035	$73	$79	$77	$69	$63	$96	$101

Adjust Value Based on Natural Gas Prices And Calculate Result

Table 38. Adjusted energy value (15 MW plant, without loss savings) - $/kW/yr.

	Discount Factor	Horizontal	South 30º	SW 30º	West 30º	West 45º	1-Axis	1-Axis 30º
2006	1.00	$104	$111	$110	$99	$91	$134	$141
2007	0.96	$104	$111	$110	$100	$92	$135	$141
2008	0.92	$97	$105	$104	$94	$87	$125	$132
2009	0.88	$93	$101	$100	$90	$83	$120	$127
2010	0.84	$88	$94	$93	$85	$78	$113	$119
2011	0.81	$57	$61	$60	$55	$50	$73	$77
2012	0.77	$63	$69	$67	$61	$56	$82	$87
2013	0.74	$63	$68	$67	$61	$56	$82	$86
2014	0.71	$69	$75	$73	$66	$61	$89	$94
2015	0.68	$62	$67	$66	$60	$55	$80	$85
2016	0.65	$56	$60	$59	$53	$49	$72	$76
2017	0.62	$57	$62	$60	$54	$50	$74	$78
2018	0.60	$65	$71	$69	$62	$57	$85	$90
2019	0.57	$69	$75	$73	$65	$59	$90	$95
2020	0.55	$71	$78	$75	$67	$61	$93	$99
2021	0.53	$71	$76	$74	$67	$62	$92	$96
2022	0.50	$73	$79	$77	$70	$64	$96	$100
2023	0.48	$76	$82	$80	$72	$66	$99	$104
2024	0.46	$82	$89	$87	$78	$71	$108	$113
2025	0.42	$83	$90	$88	$79	$72	$109	$114
2026	0.40	$87	$94	$92	$83	$76	$114	$120
2027	0.39	$89	$96	$94	$84	$77	$116	$122
2028	0.37	$93	$101	$98	$88	$80	$122	$128
2029	0.35	$95	$103	$100	$90	$82	$124	$130
2030	0.34	$99	$107	$104	$93	$85	$129	$136
2031	0.32	$99	$108	$105	$94	$86	$130	$137
2032	0.31	$103	$112	$109	$97	$89	$135	$142
2033	0.29	$106	$115	$112	$100	$92	$139	$146
2034	0.28	$110	$120	$117	$104	$95	$145	$152
2035	0.27	$114	$124	$120	$107	$98	$149	$157
Present Value		***$1,382***	***$1,493***	***$1,465***	***$1,319***	***$1,213***	***$1,797***	***$1,893***

Appendix E: Effective Load Carrying Capability

This appendix presents the mathematical formulas that can be used to calculate the Effective Load Carrying Capability (ELCC) of a non-dispatchable resource.

The Loss of Load Probability (LOLP) using hourly data for a one year period can be approximated as follows:

$$LOLP \approx \left[\frac{LOLP_{Peak}}{8{,}760}\right]\sum_{hour=1}^{8{,}760} \exp\left\{-\frac{\left[Peak\ Load - Load_{hour}\right]}{m}\right\} \tag{25}$$

where *m* is the Garver capacity factor. This factor represents the slope of a utility risk curve relating the utility's loss of load probability (LOLP) and the utility's reserve margin when plotted on a semi-logarithmic diagram. As such, this factor is equal to the growth in demand that would result in an LOLP increase equal to "e" (= 2.718....). The factor can be derived from the utility's risk-reserve margin curve if known. If not, an alternate method is to estimate *m* based on the sum of a utility's power plants' capacities times their forced outage rate. AE used this approach and estimated that *m* should be 5 percent of AE's peak load.

The approach of determining PV's ELCC is to find a resource with a constant output of ELCC such that the LOLP for the utility system is the same as it would be for the utility system with PV.

The LOLP when PV is added to the system equals:

$$LOLP_{PV} \approx \left[\frac{LOLP_{Peak}}{8{,}760}\right]\sum_{hour=1}^{8{,}760} \exp\left\{-\frac{\left[Peak\ Load - \left(Load_{hour} - PV\ Output_{hour}\right)\right]}{m}\right\} \tag{26}$$

The LOLP when a resource with a fixed output of *ELCC* is added to the system equals:

$$LOLP_{ELCC} \approx = \left[\frac{LOLP_{Peak}}{8{,}760}\right]\sum_{hour=1}^{8{,}760} \exp\left\{-\frac{\left[Peak\ Load - \left(Load_{hour} - ELCC\right)\right]}{m}\right\} \tag{27}$$

The equivalent constant capacity that PV provides to the system occurs when these two equations are equal so that the $LOLP_{PV}$ equals the $LOLP_{ELCC}$. The solution occurs when:

$$ELCC = m \ln\left\{\frac{\sum_{hour=1}^{8{,}760} \exp\left[-\frac{\left(Peak\ Load - Load_{hour}\right)}{m}\right]}{\sum_{hour=1}^{8{,}760} \exp\left[-\frac{\left(Peak\ Load - Load_{hour} + PV_{hour}\right)}{m}\right]}\right\} \tag{28}$$

Appendix F: Disaster Recovery

Solar Deployment Considerations

Determining the "avoided costs" that can be attributed to the availability of solar power infrastructure in a disaster-stricken community requires some general understanding of the interplay of grid and solar power supply systems and emergency management resources and processes.[53] Key points guiding the present analysis include:

- Disasters that threaten populations and disrupt economic activity in many cases also damage or disable the local power grid.
- Extended power grid outages during or in the wake of disasters compound the difficulty, risks and costs of disaster recovery.
- Some regions of the US are more prone to specific weather-related or human-induced disasters than others, but even within a given region, each disaster is unique in terms of impact, geographic extent and duration.[54]
- There is little or no documented experience with use of economically significant local solar power resources in disaster recovery.[55]
- AE's current solar incentive programs would result in PV systems averaging around 5kW (average is 3 kW for residential and 15 kW for commercial). An equal number of kW in each category at these sizes would result in an average size of 5kW.

Initial "Solar Secure" Deployment

Grid-tied PV systems without energy storage capability have little or no disaster recovery value. Typically, they have no value at all if the grid to which they are connected becomes disabled because most grid-tied inverters require a signal from the grid to operate. So, it is important to envision the rate and extent to which grid-tied PV systems will either be installed with storage included or later upgraded to couple with on-site energy storage. It is also important to envision technology options that may lower the cost and remove other barriers to deployment of on-site PV-compatible energy storage.

Stationary batteries represent the current commercially available option, and their costs are well known. Including sufficient battery storage and related power control and

[53] Hurricane Hugo which hit the coast of South Carolina in 1989 provides an illustration. Hugo' major impact on lifelines was the failure of the local electric supply system, which collapsed in winds of only 70mph. Only 23 percent of residents in the Charleston area had power eight days after the hurricane. Source: Disasters by Design: A Reassessment of Natural Hazards in the United States, by Dennis Mileti, Joseph Henry Press, 1999

[54] Mitigation and recovery is typically an exercise in crisis management and opportunistic use of volunteer, donated and often portable resources, not fixed resources dedicated to the purpose (other than emergency management operations centers).

[55] The reasons are worth mentioning, i.e.: 1) the grid-tied solar electricity market is still concentrated in a few countries and regions, 2) typical grid-tied PV inverters are rendered inoperable by grid outages, and 3) typical PV incentive programs apply only to generating solar power and not to storing it.

conditioning capability to provide emergency power during an extended grid outage would add about 25 percent to the cost of the basic PV system, more or less independent of system size.[56] The large and profitable UPS industry is now starting to introduce "PV-compatible" products, and alternative products having comparable functionality are also in development.

Future "Solar Secure" Deployment

Importantly, AE and other major utilities and energy experts across the US envision a scenario involving "plug-in hybrid" vehicles, i.e. hybrid vehicles with expanded battery capacity, allowing their use as electric-only commuter and fleet vehicles. The technology barriers to this scenario are minimal, and the economic drivers (gasoline-equivalent "fuel" costs under $1/gallon) are compelling. It is beyond the current scope to envision how, where and how rapidly the plug-in hybrid scenario will be realized, but once it is established, it will provide a much more cost effective option for "solar secure" deployment than a "business as usual" scenario involving stationary batteries configured in PV-compatible UPS products.

By 2020, there will likely be enough plug-in hybrid vehicles on the road in the Austin area to allow any installed or planned residential PV system there to be made "solar secure" at an additional cost in a range starting around $1000, or an additional 5 percent (vs. the current 25 percent) above the basic PV system cost. It may be assumed that in the first 10 years of Austin area PV deployment, 2005-2015, conventional UPS configurations will predominate and, over the following decade, 2015-2025, solar coupled UPS systems will recede in favor of using the imbedded and portable energy storage capacity inherent in plug-in hybrid vehicles. It is reasonable to assume that by 2020 all or nearly all new PV systems will have provisions to couple to plug-in hybrids, thus avoiding the current 25 percent cost penalty incurred using stationary batteries.

PV Deployment Pattern

If PV deployment is primarily an outcome of an incentive program of the current design, then it is reasonable to expect a fairly even geographic distribution of residential and commercial systems in the 2kW to 25kW size range. This deployment pattern has value in disaster recovery and but steps can be taken to direct solar deployment toward loads that are critical to disaster recovery. Further analysis should consider targeting schools and other facilities that play a critical role during disaster recovery.

Disaster Recovery Model

Table 39 presents the inputs used to calculate the disaster recovery value and Table 40 presents the calculations.

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[56] See G. Braun, P. Varadi, and J. Thornton, "Energy Secure Schools: Technology, Economic and Policy Considerations", Solar 2005 Proceedings. Additional detail is available in a soon to be published NREL report entitled "Solar Secure Schools"

Table 39. Disaster recovery model inputs.

INPUTS	PV Investment Allocation	Total Load Consumption	Disaster Value Distribution
Residential	25%	30%	25%
Commercial	25%	30%	25%
Industrial	0%	30%	0%
Public	50%	10%	50%
Total (must equal 100%)	***100%***	***100%***	***100%***

PV Investment (MW/year)	10
PV Capacity Factor	19.1%
AE Peak Load (MW)	2,300
AE Energy (GWh/yr)	11,000
Meet Load (MW) or Energy (GWh)	Annual Energy
Value of Having 100% Power ($/Person/Event)	$2,000
Number of People	1,000,000
Frequency of Occurrence (years)	25
Discount Rate	7%

Percent of Sector Load Met	***Percent of maximum available sector value***			
	Residential	Commercial	Industrial	Public
0%	0%	0%	0%	0%
1%	2%	3%	1%	6%
5%	10%	15%	3%	30%
10%	20%	30%	4%	50%
20%	40%	60%	8%	75%
30%	56%	80%	13%	90%
40%	67%	90%	20%	95%
50%	78%	95%	35%	98%
75%	93%	98%	90%	99%
100%	100%	100%	100%	100%

Table 40. Disaster recovery model calculations.

CALCULATIONS									
Total Value ($/Event)	$2,000,000,000								
	2007	2008	2009	2010	2011	2012	2017	2022	2026
PV Investment (MW)									
Incremental Investment	10	10	10	10	10	10	10	10	10
Cumulative PV Investment	10	20	30	40	50	60	110	160	200
Cumulative PV Investment (MW)									
Residential	2.5	5	7.5	10	12.5	15	27.5	40	50
Commercial	2.5	5	7.5	10	12.5	15	27.5	40	50
Industrial	0	0	0	0	0	0	0	0	0
Public	5	10	15	20	25	30	55	80	100
PV Output (GWh)									
Residential	4.1829	8.3658	12.5487	16.7316	20.9145	25.0974	46.0119	66.9264	83.658
Commercial	4.1829	8.3658	12.5487	16.7316	20.9145	25.0974	46.0119	66.9264	83.658
Industrial	0	0	0	0	0	0	0	0	0
Public	8.3658	16.7316	25.0974	33.4632	41.829	50.1948	92.0238	133.8528	167.316
Load by Sector (MW)									
Residential	690	690	690	690	690	690	690	690	690
Commercial	690	690	690	690	690	690	690	690	690
Industrial	690	690	690	690	690	690	690	690	690
Public	230	230	230	230	230	230	230	230	230
Total	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
Energy by Sector (GWh)									
Residential	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Commercial	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Industrial	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Public	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Total	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
Percent of Sector Load or Energy Met by PV									
Residential	0.1%	0.3%	0.4%	0.5%	0.6%	0.8%	1.4%	2.0%	2.5%
Commercial	0.1%	0.3%	0.4%	0.5%	0.6%	0.8%	1.4%	2.0%	2.5%
Industrial	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Public	0.8%	1.5%	2.3%	3.0%	3.8%	4.6%	8.4%	12.2%	15.2%
Percent of Sector Load Met by PV (Cap)									
Residential	0.1%	0.3%	0.4%	0.5%	0.6%	0.8%	1.4%	2.0%	2.5%
Commercial	0.1%	0.3%	0.4%	0.5%	0.6%	0.8%	1.4%	2.0%	2.5%
Industrial	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Public	0.8%	1.5%	2.3%	3.0%	3.8%	4.6%	8.4%	12.2%	15.2%
Percent of Sector Value (based on Lookup table)									
Residential	0.1%	0.2%	0.3%	0.5%	0.6%	0.7%	1.2%	2.0%	2.5%
Commercial	0.3%	0.6%	0.9%	1.5%	1.8%	2.1%	3.6%	6.0%	7.5%
Industrial	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Public	4.2%	8.4%	12.0%	18.0%	21.0%	27.0%	42.0%	55.0%	62.5%
Maximum Percent of Total Value By Sector									
Residential	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
Commercial	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
Industrial	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Public	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
Estimated Percent of Total Disaster Value									
Residential	0.0%	0.1%	0.1%	0.1%	0.2%	0.2%	0.3%	0.5%	0.6%
Commercial	0.1%	0.2%	0.2%	0.4%	0.5%	0.5%	0.9%	1.5%	1.9%
Industrial	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Public	2.1%	4.2%	6.0%	9.0%	10.5%	13.5%	21.0%	27.5%	31.3%
Total	2.2%	4.4%	6.3%	9.5%	11.1%	14.2%	22.2%	29.5%	33.8%
Disaster Value if Event Occurs ($M)	$44	$88	$126	$190	$222	$284	$444	$590	$675
Probability of Occurrence	4%	4%	4%	4%	4%	4%	4%	4%	4%
Expected Value ($M)	$2	$4	$5	$8	$9	$11	$18	$24	$27
Discount Factor	100%	93%	87%	82%	76%	71%	51%	36%	28%