PSC REF#:213884

Public Service Commission of Wisconsin
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JOINT APPLICATION OF WISCONSIN ELECTRIC POWER COMPANY AND WISCONSIN GAS LLC TO CONDUCT A BIENNIAL REVIEW OF COSTS AND RATES - TEST YEAR 2015

DOCKET NO. 5-UR-107

1-RENEW-RFP

1-RENEW-RFP-1: Please provide a copy of any PV value analyses performed by or for We Energies or WEPCO in the last ten years.

Objection:

Response: The Company originally objected to this discovery request. RENEW then clarified the request as follows:

In terms of “PV value analyses,” we are interested in any studies, reviews or analyses that evaluate the benefits and avoided costs of PV to We Energies as a customer over the last 10 years.

Subject to the clarification to the request, the Company’s response is as follows:

The Company commissioned an analysis by Clean Power Research in 2009. This report is provided in Response to 1-RENEW-RFP-1 (Clean Power Oct 2009).pdf.

Answered by Eric Rogers

PV VALUE ANALYSIS FOR WE ENERGIES

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October 2009

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EXECUTIVE SUMMARY

INTRODUCTION

We Energies is providing financial incentives to commercial customers under its 2007-2008 "Solar Electric Development" pilot program. The program is expected to stimulate the installation of 1 MW_{AC} of customer-owned photovoltaic (PV) systems.

We Energies contracted with Clean Power Research (CPR) to support this program by performing the following tasks:

- Evaluate ownership scenarios to determine if the systems should be customer-owned, third-party-owned, or utility-owned.[1]
- Design an incentive structure to stimulate the installation of 1 MW_{AC} of PV.
- Provide software services, including PowerClerk®, SolarAnywhere®, and PVSimulator™, to assist in the administration of the Solar Electric Development program.
- Assess the value of PV to We Energies at a specific point in time.

The ownership scenario analysis and incentive structure analysis are documented in separate reports[2] and the software services provide ongoing administrative support to the program.

OBJECTIVE

The objective of this report is to present the results of the value analysis from the perspective of We Energies at a specific point in time. The value of PV to We Energies will change over time. Other utilities that have performed similar studies typically reassess value as economic factors change. It is recommended that We Energies also reassess value as economic factors change.

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[1] The study concluded that systems should be customer-owned. The recent change in the federal investment tax credit becoming available to utilities, however, may alter the optimal system ownership structure.

[2] The two reports are (1) "PV Ownership Scenarios at We Energies: A Comparison of Customer, Third Party, and Utility Ownership", August 26, 2006; and (2) "1 MW Solar Program: PV Incentive Design for We Energies", November 14, 2006. Both reports are prepared by Clean Power Research for We Energies.

The value of PV to We Energies includes the following value components:

- Generation Value
- Environmental Value
- Fuel Price Hedge Value
- Distribution Value
- Transmission Value
- Loss Savings Value

The Executive Summary is divided into three parts. The first part describes the scenarios evaluated. The second part presents the results. The third part discusses the details.

SCENARIOS

Detailed value analyses were performed for all combinations of seven PV system configurations at three locations. Thus, the study summarizes the results of twenty-one scenarios.

PV SYSTEM CONFIGURATIONS

A wide variety of PV system configurations are readily available in the market. PV modules can be fixed (i.e., they remain in the same location throughout the year) or tracking (i.e., they follow the sun). Fixed systems are often oriented to maximize energy production, such as facing south at an angle corresponding to the latitude. Other designs, however, may be used to take into account the building architecture (e.g., modules are aligned with roof slope) or to bias output for energy delivery at a particular time of day. Tracking systems produce more energy than fixed systems by following the sun but are more costly to install and maintain. Both 1-axis and 2-axis tracking systems are used, although 1-axis tracking systems are more common due to their relative simplicity.

The value analysis was performed for seven representative PV system configurations:

- Fixed configurations
  - Horizontal (fixed PV with no tilt)
  - South-30 (south-facing fixed PV tilted at 30^o)
  - SW-30 (southwest-facing fixed PV tilted at 30^o)
  - West-30 (west-facing fixed PV tilted at 30^o)
  - West-45 (west-facing fixed PV tilted at 45^o)
- Tracking configurations
  - 1-Axis (north-south 1-axis tracking PV with no tilt)
  - 1-Axis Tilt (north-south 1-axis tracking PV with 30^o tilt)

Locations

Time- and location-specific hourly solar data from SolarAnywhere were combined with ambient temperature and wind speed data and then processed through PVSimulator to produce hourly PV system output for each of the seven PV system configurations. The data were produced for Appleton, Waukesha, Racine, and Milwaukee.

A screening procedure was used to select three distribution system study areas for a detailed value analysis. The study areas included:

- Merton
- Albers
- Union Grove

RESULTS

Table ES-1 presents the PV value per unit of installed PV capacity ($ per kW_{AC}) broken down by the individual value components for each of the seven PV system configurations at the three study areas. Table ES-2 converts the total PV value from units of installed PV capacity to units of energy ($ per kWh). Figure ES-1 and Figure ES-2 summarize the information from Tables ES-1 and ES-2 graphically. Figure ES-1 presents the total value per unit of installed PV capacity and Figure ES-2 presents the total value per unit of energy.

Figure ES-1 indicates that total value is strongly influenced by PV system orientation but not by location. This raises the question about whether the value is based mainly on the amount of energy produced or on some other factor. Figure ES-2 provides the answer to this question and indicates that PV value is almost linearly related to PV system energy production regardless of system configuration or location.

The conclusion of this analysis is that, for the time period during which the study was conducted, the estimated value of PV for We Energies over the PV system's 30-year lifetime was approximately $0.15 per kWh.

Figure ES-3 presents the results by value component and system configuration for the Merton Substation location. Figure ES-3 indicates that Generation, Environmental, and Fuel Price Hedge Value components comprise the highest portion of total value.

Table ES-1. Value components by PV system configuration and location ($\$/kW_{AC}$).

	1 Axis	*1 Axis Tilt*	*South-30*	*SW-30*	*West-30*	*West-45*	*Horiz*
Generation Value							
Merton	1,522	1,682	1,338	1,273	1,080	1,001	1,134
Albers	1,536	1,691	1,340	1,282	1,095	1,017	1,144
Union Grove	1,536	1,691	1,340	1,282	1,095	1,017	1,144
Environmental Value							
Merton	1,321	1,458	1,134	1,062	891	822	960
Albers	1,343	1,477	1,144	1,075	907	838	973
Union Grove	1,343	1,477	1,144	1,075	907	838	973
Fuel Price Hedge Value							
Merton	680	751	584	547	459	423	494
Albers	692	761	589	554	467	432	501
Union Grove	692	761	589	554	467	432	501
Distribution Value							
Merton	145	143	45	129	149	149	70
Albers	49	49	11	30	39	45	16
Union Grove	147	145	43	92	116	132	56
Transmission Value							
Merton	49	47	25	40	47	48	31
Albers	39	39	18	28	33	36	20
Union Grove	53	51	25	39	46	49	31
Loss Savings Value							
Merton	124	135	103	103	90	85	90
Albers	77	85	65	63	55	51	56
Union Grove	134	146	110	109	96	91	96
Total Value							
Merton	3,842	4,217	3,229	3,154	2,716	2,527	2,778
Albers	3,737	4,101	3,168	3,033	2,595	2,419	2,710
Union Grove	3,905	4,270	3,252	3,152	2,726	2,557	2,801

Table ES-2. Total value per unit of energy by PV system configuration ($/kWh).

	1 Axis	*1 Axis Tilt*	*South-30*	*SW-30*	*West-30*	*West-45*	*Horiz*
Merton	0.1539	0.1531	0.1507	0.1572	0.1614	0.1628	0.1533
Albers	0.1473	0.1470	0.1466	0.1493	0.1515	0.1528	0.1475
Union Grove	0.1539	0.1530	0.1505	0.1552	0.1592	0.1616	0.1524

Figure ES-1. Total value per unit of installed PV capacity by system configuration and location.

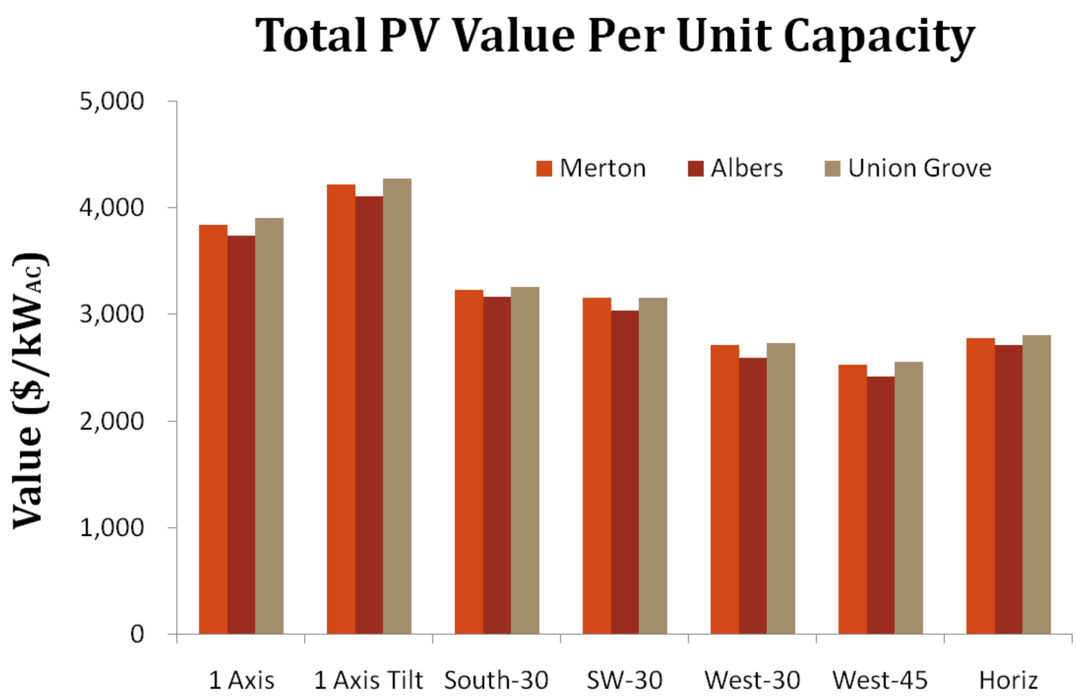


Figure ES-2. Total value per unit of energy by system configuration and location.

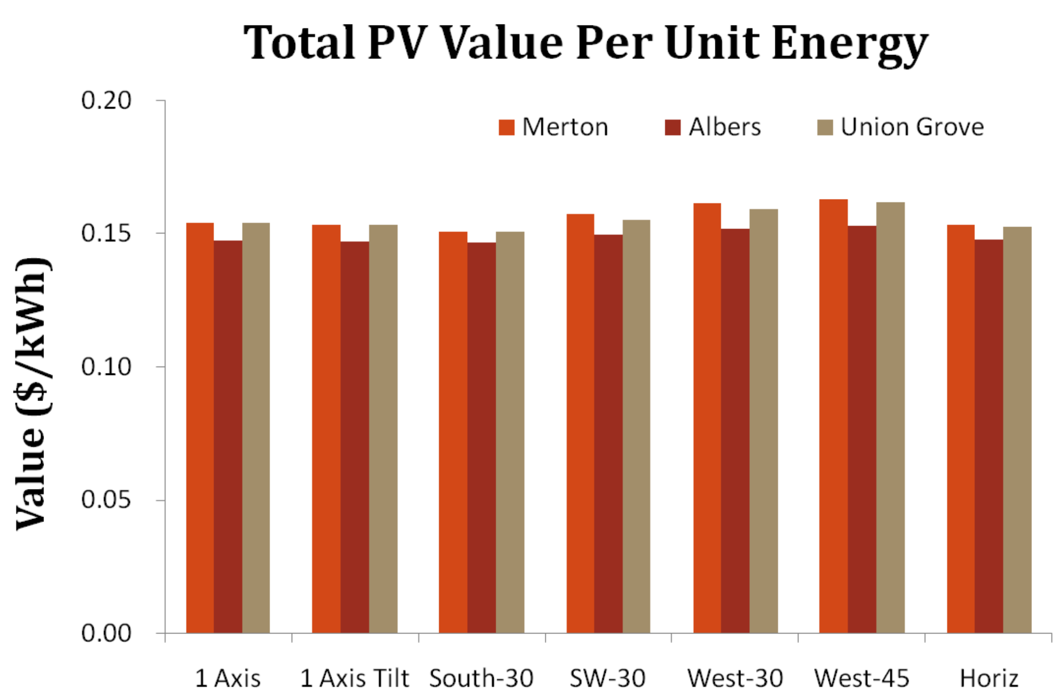
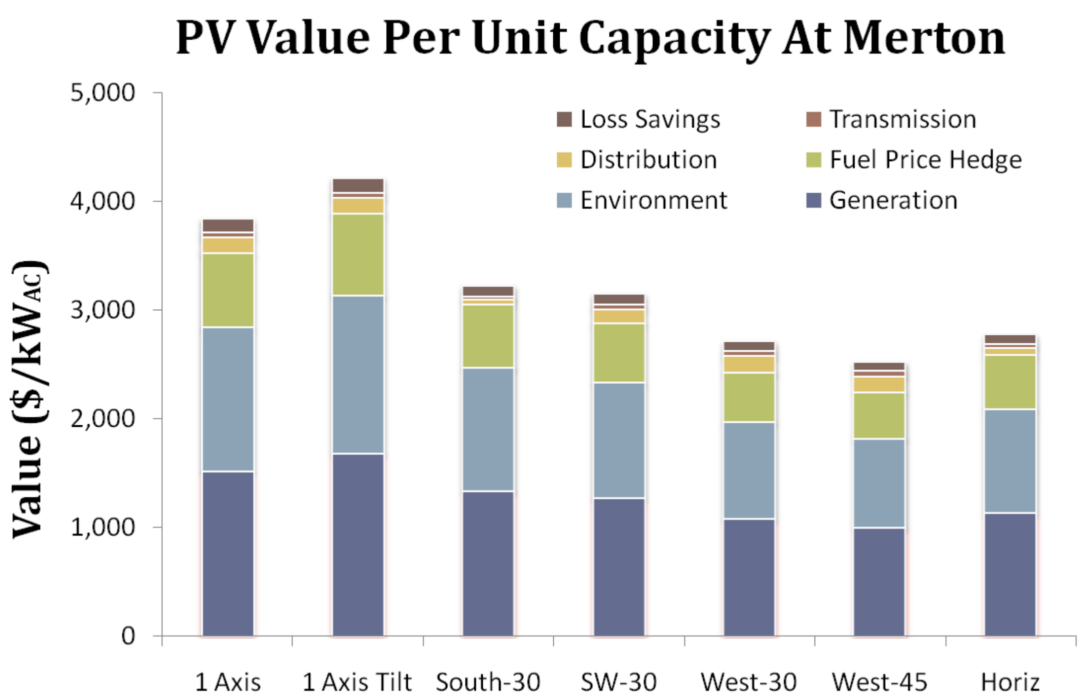


Figure ES-3. Value per unit of installed PV capacity by configuration for Merton Substation.



DISCUSSION

This section describes the value components in more detail.

Generation Value

Generation Value is the benefit that We Energies derives from PV's offset of We Energies' wholesale energy purchases. More specifically, each kWh that PV generates at the customer's site is one less kWh that We Energies needs to purchase or generate. (Note that energy loss savings are accounted for separately in the Loss Savings section.)

The cost savings vary according to the PV system location and the time of the energy production. We Energies participates in the Midwest ISO. Thus, Midwest ISO day-ahead market clearing prices were used for the analysis. The Midwest ISO market employs a Locational Marginal Pricing (LMP) methodology where prices vary by location and hour. LMPs represent the cost of energy generation on a $ per MWh basis. Capacity benefits are considered to be small and were not included in the study even though PV also provides generation capacity benefits.

Historical LMPs from pricing nodes nearby to the locations under consideration were used in combination with modeled PV production in three We Energies distribution areas. The hourly

LMPs were multiplied by the corresponding hourly PV system output. The results were summed for the year and the present worth of the 30-year value stream was calculated using We Energies' discount rate of 8.52 percent.

Environmental Value

PV provides environmental benefits by contributing toward We Energies renewable portfolio standard (RPS) obligations. The utility's requirements for either generating or purchasing renewable energy are reduced when PV systems generate electricity. The environmental benefit for this study is the value of avoided purchases of renewable resource credits (RRCs) to meet the utility's required RPS percentages.

An investigation of established renewable energy credit (REC) markets outside of Wisconsin indicates that current pricing for solar RECs in compliance states[3] with source qualifications similar to Wisconsin's is about $50 per MWh. This value was applied to the annual PV production and the results discounted over the 30-year life.

Fuel Price Hedge Value

Electricity in Wisconsin is primarily generated from coal, nuclear, natural gas, and petroleum. Electricity prices throughout the state are subject to uncertainty because fuel prices fluctuate over time. The cost of electricity generated from PV, however, is constant and fixed over the 30-year PV system life since it is not dependent upon fuels other than solar energy. Thus, PV provides a "hedge" against future fuel price uncertainty.

The method used to quantify this benefit is loosely based on the Black–Scholes options pricing model. The method is documented more fully in a PV valuation analysis conducted by CPR for Austin Energy in 2006.[4]

The essence of the method is that price volatility from conventional power plants is captured in the futures pricing of fuel commodity markets. Owning a PV system provides "risk-free" electricity and thus is equivalent to holding a futures contract for the purchase of future energy at a known price.

[3] REC pricing is investigated in eight states for this study. Only the closest source classes are used since the definitions of allowable technologies are generally not identical between states.

[4] "The Value of Distributed Photovoltaics to Austin Energy and the City of Austin", Clean Power Research, 2006. This report can be found at www.cleanpower.com.

The analysis focused exclusively on natural gas because PV is assumed to offset natural gas at the margin. Futures prices for NYMEX natural gas were discounted using risk-free yields of Treasury notes having comparable maturity dates. A similar discounting was performed using price forecasts and the standard We Energies discount rate, representing the energy value. The hedge value is the difference between the risk-free energy value and the conventional energy value.

Distribution Value

PV reduces the burden on the distribution system because it is a distributed generation source and less electricity is required from the substation. PV appears as a “negative load” during the daylight hours from the perspective of the distribution operator. PV may be considered as distribution capacity from the perspective of the distribution planner, provided that PV generation occurs at the time of the local distribution peak.

Locating PV capacity in an area of growing loads allows a utility planner to defer capital investments in distribution equipment such as substations and lines. The Distribution Value was determined by calculating the avoided cost of money due to the capital deferral.

The analysis first determined the value of an ideal, perfectly dispatchable generation source by quantifying the cost of future capacity increases needed to meet anticipated load growth. Next, the “effective” PV capacity was calculated by comparing the original annual peak load (without PV) against the annual net peak load (original less PV output). Multiplying the perfect capacity value times the load match factor results in the Distribution Value of PV.

The analysis was performed using detailed technical information and cost estimates for three distribution expansion projects at Merton SS Relief, Albers SS Z3154 Capacity Increase, and Union Grove SS Relief. Results suggest that Distribution Values were relatively low relative to other value components, primarily due to a poor load match.

Transmission Value

We Energies incurs operating costs from its transmission provider based on monthly peak demand at its distribution substations. We Energies realizes cost savings when PV is able to reduce the peak demand. The Transmission Value is the value of these savings.

Monthly demand reduction was estimated using hourly measured feeder/substation loads and PV generation. The difference between the monthly peak load without PV and the monthly peak load with PV is the demand reduction against which the transmission access charge was applied. Monthly savings were summed, and 30-year discounted values were calculated. Transmission Values were low relative to other value components, primarily due to a poor load match.

Loss Savings Value

Distributed generation technologies reduce system losses by generating power at the point of consumption. This reduces transmission and distribution losses that would otherwise be incurred from central generation sources. The analysis treats loss savings as indirect benefits that "magnify" the value of other benefits.

For example, the generation benefit provided by PV represents the avoided cost of generating the electricity that is used by the customer. We Energies saves the cost of generating or purchasing a kWh at the point of production for every kWh produced by PV. We Energies also avoids the need for supplemental energy to account for losses.

Loss savings were calculated on a marginal, not an average, basis.[5] Marginal loss factors were calculated on an hourly basis using historical hourly loads and average loss data. Separate factors were calculated for distribution and transmission since the treatment of losses differs by benefit category (generation, hedge value, etc.). For example, Transmission Value is defined by peak loads occurring at the distribution substation, so only losses saved in the distribution system were relevant in the evaluation of this benefit. There are no loss savings associated with the environmental benefits. Location (central or distributed) does not enter into the analysis because the Environmental Value is based on the number of RECs that the system produces rather than the amount of energy that the system produces.

Hourly values for each benefit were calculated twice: first by assuming no losses and then by assuming calculated losses. The difference between the two results is the Loss Savings Value.

CONCLUSIONS

The following conclusions can be drawn from these results:

- Value per unit of installed PV ***capacity*** ($ per kW_{AC}) was approximately linearly related to energy production for the variations configurations and thus value per unit of ***energy*** ($ per kWh) was relatively independent of location and configuration.
- Value per unit of energy was calculated to be about $0.15 per kWh over the PV system's 30-year lifetime. This value is sensitive to the data (especially the value of energy) that was used at the time of the study and should be interpreted within that context.

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[5] Marginal losses are the losses related to the next marginal increment of load. They are much higher than average losses due to the I^2R nature of losses. For example, if the average losses at 100% load are 10%, the marginal losses might be 20%.

- There was significant variation in value related to system configuration due to the difference in the amount of annual energy production.
- There was minimal variation in value related to system location.
- Generation, Environmental, and Fuel Price Hedge Value components comprised the highest portion of total value.
- Transmission and Distribution Value components were small in comparison to other components.
- Loss Savings Value was small but not insignificant.

NEXT STEPS

- The results of this study are sensitive to the LMPs used. The following table compares some statistics of the LMPs used in the study to the LMP statistics for the period September 2008 through August 2009. A comparison of the two shows that the LMPs have changed significantly. There is a need to rerun this study to obtain a better reflection of the current value of PV as the LMPs change.

	LMPs used in Study			*LMPs year ending Aug. 2009*		
Node	***Max***	***Min***	***Avg***	***Max***	***Min***	***Avg***
GERMANOT1	273.24	4.83	48.72	144.12	-21.69	30.74
PARIS01S1	199.72	5.20	48.36	142.46	-24.51	30.29
PLPRG41	195.59	4.96	45.67	139.39	-38.79	29.10

- The MISO LMPs only reflect energy value and do not include capacity value. The value of generation capacity is very low at this time and is not included in the economic valuation. Future studies should include the generation capacity value of PV.
- We Energies RRC are not currently tradable outside of Wisconsin. This analysis assumes that RECs can be traded across state lines. Further evaluation is required to assess this.
- The Transmission Value depends upon whether PV is claimed as a generation resource or as negative load. This analysis assumed that PV was operating as negative load and that ATC prices are not reallocated as a result of the installation of PV. PV as a generation resource or ATC price reallocation will require a different analysis.

ACKNOWLEDGEMENTS

This report would not have been possible without the support and cooperation of We Energies' personnel across several technical areas and departments. These include Phyllis Dubé (Director, Advocacy and Energy Options, Regulatory Affairs Policy), Jim Prothero (Manager, Electric Reliability and Planning), Paul Schumacher (Manager Planning, Wholesale Energy and Fuels), John Nesbitt (Supervising Engineer, Electric Operations), Steve Pecha (Supervising Engineer, Electric Operations), and Jessica Thibodo-Johnson (Renewable Energy Development Specialist, Regulatory Affairs Policy). Carl Siegrist (Senior Renewable Energy Strategist, Regulatory Affairs Policy) served as the project manager and primary contact at We Energies. Carl provided essential support and assistance by collecting critical technical and economic data, by guiding the project all along the way, and by injecting his enthusiasm for his work throughout all phases of the project.

CONTENTS

FIGURES

TABLES

1. INTRODUCTION

We Energies is providing incentives to commercial customers for approximately 1 MW_{AC}[6] of photovoltaics (PV) in its service territory under its "Solar Electric Development" program. We Energies contracted with Clean Power Research (CPR) to support this program by performing the following tasks:

- Evaluate ownership scenarios to determine if the systems should be customer-owned, third-party-owned, or utility-owned.[7]
- Design an incentive structure to stimulate the installation of 1 MW_{AC} of PV.
- Provide software services, including PowerClerk®, SolarAnywhere®, and PVSimulator™, to assist in the administration of the Solar Electric Development program.
- Assess the value of PV to We Energies at a specific point in time.

CPR has completed the ownership scenario analysis and incentive structure, covered in separate reports[8] and has provided the software services to assist in program administration. The fourth portion of the work, the value analysis, is the subject of this report.

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[6] We Energies uses the following definition for the AC rating of a PV system: the total DC module rating at PVUSA Test Conditions (about 90 percent of standard test conditions) times inverter efficiency (about 95 percent efficiency) times a 90 percent loss factor to account for mismatch, wiring, and other losses. Thus, a nameplate (DC) rating of 1.3 kW_{DC} is approximately equal to 1.0 kW_{AC}. (i.e., 1.3 x 0.9 x 0.95 x 0.9 = 1.0).

[7] The study concluded that systems should be customer-owned. The recent change in the federal investment tax credit becoming available to utilities, however, may alter the optimal system ownership structure.

[8] The two reports are (1) "PV Ownership Scenarios at We Energies: A Comparison of Customer, Third Party, and Utility Ownership", August 26, 2006; and (2) "1 MW Solar Program: PV Incentive Design for We Energies", November 14, 2006. Both reports are prepared by Clean Power Research for We Energies.

The analysis is divided into the following value components:

- Generation Value
- Environmental Value
- Fuel Price Hedge Value
- Distribution Value
- Transmission Value
- Loss Savings Value

PV offers benefits in each of these value categories. The analysis describes and quantifies each in the chapters that follow.

The distribution analysis is presented first because it defines the three study locations used in the remainder of the study. In addition, the selection of solar resource data and ISO pricing node (Chapter 3) is based on the study locations.

The economic assumptions used through the report are presented in Table 1.

Table 1. Economic assumptions.

Discount Rate (nominal)	8.52%
Escalation	2.50%
PV System Life (years)	30

2. DISTRIBUTION VALUE

INTRODUCTION

Utilities need to anticipate when existing local distribution capacity will be exhausted and plan accordingly for new capacity increases in areas of growing electrical load. Capacity might be provided for in a variety of ways including: constructing new substations, replacing older conductors with larger conductors that have higher ampacities, or increasing the operating voltage of distribution circuits. These improvements represent utility capital investments in the form of materials and labor.

Distributed generation (DG) resources, such as PV, have the potential to relieve utility loading constraints by supplying local loads that would otherwise be supplied by the utility grid. DG resources have the potential to reduce peak loads on the substations or distribution feeders, thus delaying the timing of construction projects. DG resources provide cost savings due to the time value of capital investments, even for capital deferrals as short as one year.

Deferral value is calculated using the relation in Equation (1).

$$Value = \underbrace{\left(\frac{X}{L}\right)}_{Average\ Cost} \times \underbrace{\left(\frac{r}{1+r}\right)}_{Value\ of\ Money} \times \underbrace{M}_{Load\ Match} \qquad (1)$$

where Value is expressed in $/kW, X is the present value cost of the distribution expansion plan over the study period ($), L is the annual load growth (kW), r is the real discount rate, and M is a factor that corresponds to the effective peak load reduction provided by the DG system.[9]

Each kW of peak load for a "perfect" DG resource (M=1) is offset by a kW of generation. The load match for a non-dispatchable resource such as PV, however, must be determined by an analysis of time-correlated generation loads relative to distribution loads. Thus, the value is determined by calculating the economic value assuming a perfect load match (M=1) and then by adjusting the result to reflect the actual load match.

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[9] A detailed derivation of this equation is presented in T. E. Hoff, *Identifying Distributed Generation and Demand Side Management Investment Opportunities*, The Energy Journal: 17(4) (September 1996).

Project Descriptions

We Energies provided the following expansion cost estimates for five critically-loaded areas in their distribution system.

Merton SS Relief

Location	Towns of Merton and Lisbon, Waukesha County. Area located north and east of Village of Sussex.
Description	Convert 8.32 kV feeder 35951 to operation at 24.9 kV, bypassing 24.9-8.32 kV Merton SS. Result is reduction of 2.58 MVA for Merton SS, based on 2006 peak of 9.61 MVA for the substation on 8/1/06, hour ending 18:00.
Estimated Project Cost	$2,089,000 (Accounting model - 80% Capital, 12% O&M, 8% Removal)
Peak Capacity	Merton SS - 7.50 MVA (Based on single contingency planning)
Measured Peak	9.61 MVA (9.25 MW, 3.01 MVAR)
Load Growth Rate	4.0%
Capacity Required to Defer Upgrade	Need to reduce Merton SS load to less than 110% of capacity initially, then offset all load growth. This translates to 1800 kW in 2007, then 400 kW per year in 2008, 2009, 2010, and 2011. By 2012, the relief from the planned distribution project will have been exhausted and a new project needed.

Albers SS Z3154 Capacity Increase

Location	City of Kenosha, Town of Somers, Kenosha County.
Description	Reconductor/rebuild 3.3 circuit miles of 24.9 kV overhead construction from 1/0 Cu to 336 ACSR. Result is an increase in Summer Normal rating of Z3154 from 315 Amps to 379 Amps.
Estimated Project Cost	$466,000 (Accounting model - 80% Capital, 12% O&M, 8% Removal)
Peak Capacity	Albers Z3154 - 315 Amps (Summer Normal), 380 Amps (Summer Emergency)
Measured Peak	367 Amps (15.99 MW, 3.59 MVAR at 25.8 kV)
Load Growth Rate	3.0%
Capacity Required to Defer Upgrade	Need to reduce Z3154 load to less than 95% of Summer Normal rating, then offset all load growth. This translates to 3000 kW in 2007, then 480 kW per year in 2008 and 2009. By 2010, the relief from the planned distribution project will have been exhausted and a new project needed.

New Holland SS Feeder

Location	Project in Town of Holland, but affected area is primarily in Town of Lima. Both are in Sheboygan County, southwest of the City of Sheboygan.
Description	Rebuild or reinsulate about 5 miles of existing 8.32 kV feeder to create new Holland 24.9 kV feeder to supply Oostburg SS and a large industrial customer and provide a backup supply for Gibbsville SS. Provides capacity required to supply Gibbsville SS load during an outage for Lyndon SS or Lyndon feeder Z53794.
Estimated Project Cost	$466,000 (Accounting model - 80% Capital, 12% O&M, 8% Removal)
Peak Capacity	Holland Z66471 - 250 Amps (Summer Normal), 300 Amps (Summer Emergency), Lyndon Z53794 - 448 Amps (Summer Normal), 448 Amps (Summer Emergency)
Projected 2006 Peak	316 Amps (14.1 MVA at 25.8 kV) for intact system, 418 Amps (18.7 MVA at 25.6 kV) during outage of Lyndon SS.
Load Growth Rate	3.0%
Capacity Required to Defer Upgrade	Need to reduce feeder Z53794 load in area around Gibbsville SS by about 5000 kW, then offset all load growth (350 kW per year) in future years.

Six Mile SS Relief

Location	Town of Caledonia, Racine County, north of the City of Racine.
Description	Convert portion of 8.32 kV feeders 12752 to operation at 24.9 kV, bypassing 24.9-8.32 kV Six Mile SS. Result is a load reduction of 1.0 MVA for Six Mile SS, based on 2006 peak of 12.79 MVA for the substation on 7/31/06, hour ending 18:00.
Estimated Project Cost	$1,160,000 (Accounting model - 80% Capital, 12% O&M, 8% Removal)
Peak Capacity	8.75 MVA (Based on single contingency planning)
Measured Peak	12.79 MVA (12.02 MW, 4.38 MVAR)
Load Growth Rate	4.0%
Capacity Required to Defer Upgrade	Need to reduce Six Mile SS load to less than 110% of capacity initially, then offset all load growth. This translates to 3000 kW in 2007. Note that planned project only removes 1.0 MVA of load. An additional system project will likely be needed in 2008.

Union Grove SS Relief

Location	Town of Yorkville, Racine County, north of the Village of Union Grove.
Description	Convert majority of 8.32 kV feeder 35451 to operation at 24.9 kV, bypassing 24.9-8.32 kV Union Grove SS. Result is a load reduction of 2.0 MVA for Union Grove SS, based on 2006 peak of 10.49 MVA for the substation on 7/31/06, hour ending 18:00.
Estimated Project Cost	$1,616,000 (Accounting model - 80% Capital, 12% O&M, 8% Removal)
Peak Capacity	Union Grove SS - 8.72 MVA (Based on single contingency planning)
Measured Peak	10.49 MVA (10.16 MW, 2.59 MVAR)
Load Growth Rate	4.0%
Capacity Required to Defer Upgrade	Need to reduce Union Grove SS load to less than 110% of capacity initially, then offset all load growth. This translates to 1000 kW in 2007, then 400 kW per year in 2008, 2009, and 2010. By 2011, the relief from the planned distribution project will have been exhausted and a new project needed.

Project Analysis

Overload Conditions Result in Unfavorable Economics

Each of the projects presented above represent real overload conditions that We Energies must solve in order to ensure reliable system operation. The conventional planning approach is described. We Energies also recognizes that an alternative approach using DG could also suffice, at least as a temporarily measure. We Energies presents the DG capacity requirements for the first year (to meet basic planning constraints) and future years (to meet expected load growth).

The initial 2007 capacity requirements in each of these projects is large due to the fact that overload conditions were already observed in 2006. For example, the measured 9.61 MVA peak loads at Merton Substation have already exceed its 7.50 MVA capacity. We Energies estimates that a minimum of 1800 kW of DG would have to be installed in 2007 in order to ensure reliability equivalent to the voltage conversion project and to defer the project from 2007 to 2008. In addition, 400 kW of additional capacity would be required for subsequent years to meet expected load growth were the project to be delayed for multiple years.

The capacity value of DG under these conditions is small. The Merton SS cost that could be deferred for one year using the We Energies accounting model[10] is $2.089 million x 88% = $1.84 million. Applying Equation (1) with the We Energies 8.52% discount rate, a “load growth” rate of 1800 kW, and M=1 (a “perfect” load match) results in an $80/kW value for an ideal DG resource. The actual value would be less, depending upon the actual load match to be calculated later under the technical analysis.

Capacity Valuation Approach Without Overload Conditions

The low DG capacity value is partly due to the existing overload conditions. Thus, it is natural to pose the question: *What is the value of installing DG in an area that is approaching capacity limits but not yet overloaded?*

The analysis would offer a more realistic valuation if it was broadened to include planning areas not necessarily facing 2007 upgrades because third party DG projects are not generally targeted at planning areas facing current year upgrades. Such an analysis would also more accurately

[10] Under the We Energies accounting model in 2006, 12% of the project cost is considered O&M. Assuming that this cost would be incurred regardless of the decision to proceed with the project, the remaining 88% (including the 8% “removal” costs) are considered capital costs under this analysis. Changes in the cost model for system improvement projects need to be reflected in the valuation model.

reflect the reality that utilities generally do not use anticipated third party DG installations in their load forecasts or rely upon them in their expansion plans.

The present analysis is therefore formulated to quantify the economic value of capacity under the following assumptions:

- We Energies does not rely upon DG in its planning to meet critical loads.
- DG capacity will reduce peak loads. Once installed, DG will impact load measurements and forecasts, and it will defer capital projects, provided that the installed DG capacity is greater than or equal to the rate of load growth.
- DG is installed in areas that have not exceeded capacity limits.
- DG output is perfectly matched to load (this assumption is modified later in technical analysis).

DG Capacity Requirements

Detailed expansion project cost estimates for planning areas that have not yet reached capacity limits may not be available. The approach used in the present analysis is to use the data provided from the five representative projects and to recast the planning scenarios as if the DG alternatives were installed in years prior to the overload.

For example, the *Merton SS Relief* project could have been deferred for one year if 400 kW of DG capacity were added in 2006, 2005, or earlier to the area served by Merton Substation (that is, if the load growth could have been offset for one year): the measured peak loads 9.61 MVA measured in August 2006 would not have been reached until August 2007. The project planning and approval process triggered by the Merton measurements would not have been triggered until a year later.

The 400 kW of DG, while not planned by the utility, would have effectively caused a one-year project deferral. For simplicity, it is assumed that the DG was installed in 2006 and the present value of the deferred cost is the same as the 2007 cost estimate. *The valuation of capacity is therefore calculated as before, except using the load growth rate of 400 kW instead of the 1800 kW necessary for a 2007 DG installation.*

Project Data Summaries

The **Merton SS Relief** project represents a capital cost of $2.089 million. The 12 percent O&M cost is removed from this value. Thus, the potential deferral amount is $2.089 million x 88% = $1.84 million. 400 kW of DG capacity are required to offset annual load growth and defer the project one year.

A similar approach is taken for the **Albers SS Z3154 Capacity Increase** line reconductoring project. DG would be installed on line Z3154 fed by Albers Substation to reduce loading on that feeder and defer the need for reconductoring. The potential capital deferral amount is $466,000 x 88% = $410,000. The annual load growth is 480 kW.

The **New Holland SS Feeder** project presents a difficulty for the analysis. In this case, the new Holland 24.9 kV feeder would serve a dual purpose: supplying local loads (Oostburg SS and an industrial customer) and providing an alternate feed to Gibbsville SS in the event of a loss of supply from Lyndon. DG would not be able to serve as a backup supply. It is concluded that DG is not a true alternative and the deferral benefit is zero.

We Energies does indicate that a large DG installation (5000 kW) would provide relief as a temporary measure (presumably, the existing Gibbsville SS could be alternately fed from another, limited backup source). Additional future DG capacity (350 kW per year), however, would be required due to constraints of the existing backup feed.

This analysis is intended to capture the benefits of all future deferrals by shifting the timeline of capital investments. A single year deferral has very little value, especially for such a large DG capacity requirement (5000 kW) and such a small avoided cost ($460,000). Furthermore, it is not reasonable to expect that DG capacity will be increased each year to further cover the shortfall, especially when We Energies is not in control of DG in its planning process. It is concluded that DG is not a suitable solution for this case.

The **Six Mile SS** project has a potential capital deferral amount of $1,160,000 x 88% = $1,020,000. The annual load growth is 12.02 MW x 4% = 480 kW.

The **Union Grove SS Relief** project has a potential capital deferral amount of $1,616,000 x 88% = $1,420,000. The annual load growth is 400 kW.

These project data are summarized in Table 2.

Table 2. Project cost summary.

Project	***Total Cost***	***Deferrable Cost***	***Required Capacity (kW)***
Merton SS Relief	$2,089,000	$1,838,320	400
Albers SS Z3154 Capacity Increase	$466,000	$410,080	480
New Holland SS Feeder	$466,000	$0	N/A
Six Mile SS	$1,160,000	$1,020,800	480
Union Grove SS Relief	$1,616,000	$1,422,080	400

Recurring Future Upgrades

The impacts of future upgrade requirements are considered next. The load relief provided by the upgrade in the above projects is only temporary. Future upgrades will be required as load continues to grow when the new, higher, capacity limit is reached.

For example, the **Merton SS Relief** project is expected to reduce the substation load from the measured 9.61 MVA by 2.58 MVA to 7.03 MVA. Loads will continue to grow in the area served by the substation at its rate of 4% per year until its rated capacity of 7.50 MVA is reached again, at which time another capacity increase could be required. For conservatism, however (to minimize DG deferral value), it is assumed that the 7.50 MVA threshold is not the one that will trigger the next upgrade. Instead, given that the measured 9.61 MVA load was the 2006 defining event, it is assumed that loads would again have to reach 9.61 MVA again to trigger a future upgrade.

The following relation can be used to estimate the number of years (N) until the substation rating (C_{max}) is reached at a constant rate of growth[11] (g), starting with the load level expected after the upgrade (C_{new}). $C_{\max} = C_{new}(1+g)^N$. Solving for N,

$$N = \frac{\ln(C_{\max} / C_{new})}{\ln(1+g)} \qquad (2)$$

Equation (2) suggests that N = 8 years (rounded up from 7.97 years) using data for the **Merton SS Relief** project with Cmax = 7.50 MVA, Cnew = 7.03 MVA, and g = 4% per year. Thus, once the capital investment is made, another one would be expected in another 8 years.

This method provides a means of estimating the time until the next capacity increase is required. It does not, however, provide an accurate cost estimate. Utilities do not plan eight years into the future, so it is impossible to determine what technical plan might be called for at that time. For simplicity, this analysis assumes that the cost of the future upgrade will be the same as the 2007 upgrade in real terms ($1.84 million). Additional upgrade costs may well be below the original upgrade cost, so future analyses may need to refine this methodology.

In addition, other upgrades would be expected even further into the future as capacity limits are reached. Indeed, it is possible to envision a series of upgrades in the future, each about N years

[11] Actual growth rates may not be constant, but rather “S” shaped. Future analyses may wish to consider this in more detail.

apart, as loads continue to grow. The value of deferring such future upgrades diminishes rapidly, however, due to the time value of money.

All future upgrades over the 30-year PV system life are considered in this analysis. Thus, in the **Merton SS** example, it is assumed that a capacity increase will be required every 8 years and the first such upgrade in the series would occur halfway into this interval at year 4. Note that this is different from the actual We Energies expansion plan (upgrade in 2007) since the purpose is only to use the project cost, rating, and growth rate data as representative of typical locations at We Energies that are not facing overload conditions.

The planned **Albers SS Z3154 Capacity Increase** does not reduce load. Instead, the line ampacity is increased from 315 A (Summer Normal) to 379 A. The actual load would remain at the measure peak of 367 A. Equation (2) is applied (using Amperes instead of MVA) with Cmax = 379 A, Cnew = 367 A, and g = 3%. The result is that a new capacity increase will be required in 2 years.

Other projects are treated similarly and the results are shown in Table 3. This table presents the calculation of the number of years to upgrade, the future expansion scenario (first upgrade is in year N/2) and the corresponding present worth factor (PWF) for the series. Note: this method of accounting for future distribution system capacity costs may overstate costs.

Results

The results are presented in Table 4. This table uses the PWF from Table 3 to calculate the present worth of all future capacity increases, and applies Equation (1) to calculate the deferral value for M=1 (perfect load match).

Values range from $0/kW (the New Holland SS feeder in which DG is not able to serve as a substitute) to $719/kW. The average value is $353/kW which is assumed to be a typical “perfect” distribution capacity value for DG at We Energies.

Table 3. Future upgrades.

Project	Load Growth Rate (%/yr)	Substation or Feeder Capacity (MVA or A)	Substation or Feeder Loading After Upgrade (MVA or A)	Units (MVA or A)	Number of years between equiv. upgrades	Upgrade Year					PWF
Merton SS Relief	4%	9.61	7.03	MVA	8	4	12	20	28		2.822
Albers SS Z3154 Capacity Increase	3%	379	367	A	2	1	3	5	7	9	3.808
New Holland SS Feeder					N/A						0.000
Six Mile SS	4%	12.79	11.79	MVA	3	2	5	8	11	14	3.355
Union Grove SS Relief	4%	10.49	8.49	MVA	6	3	9	15	21	27	2.382

Table 4. Deferral value (perfect load match).

Project	Deferrable Cost ($)	PWF	Present Worth ($)	Load (kW)	[r/(1+r)]	M	Value ($/kW)
Merton SS Relief	$1,838,320	2.822	5,187,218	400	0.0555	1	719
Albers SS Z3154 Capacity Increase	$410,080	3.808	1,561,534	480	0.0555	1	180
New Holland SS Feeder	$0	0.000	0	N/A	0.0555	1	0
Six Mile SS	$1,020,800	3.355	3,425,055	480	0.0555	1	396
Union Grove SS Relief	$1,422,080	2.382	3,386,829	400	0.0555	1	470
Average							353

SOLAR PRODUCTION DATA

Dr. Richard Perez at The State University of New York provided four years (2003, 2004, 2005, and 2006) of hourly PV production data based on satellite imagery and PV system modeling for the four locations as shown in Table 5.

Table 5. Locations of PV production data

Location	***Latitude***	***Longitude***
Appleton	44° 15' N	88° 23' W
Milwaukee (airport)	42° 57' N	87° 54' W
Racine	42° 43' N	87° 51' W
Waukesha	43° 1' N	88° 14' W

Modeled PV system output was performed for seven system orientations for each of the four locations. The configurations include:

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

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

Hourly PV production (8760 hours) was on the basis of kW_{AC} for a 1 MW_{AC} PV system (or, alternatively, W_{AC} for a 1 kW_{AC} PV system). The total number of data sets therefore was: 4 locations x 7 orientations x 4 years = 112 sets, each with 8760 hours of sequential data.

SUBSTATION LOAD

Substation Data

Substation load data was provided by We Energies in spreadsheet format for the five project sites in the date range 9/23/05 to 9/22/06. The format of the data files varied, but generally included phase voltage, phase current, and phase real (kW) and reactive (kVAR) power. For simplicity, only the real power data was retained, and these were combined for phases and feeders as necessary to obtain hourly values of total substation real power.

Times were assumed to be Central Standard Time (CST). No change in time values was observed for CDT.

Each file had some missing or erroneous data as described below.

Merton Substation data was provided for feeders 35951, 35961, and 35962. Bad or missing data was found for 4 hours out of the total 8760 hours, and these were replaced with data from the previous hour. The real power (kW) was combined from all three feeders.

Albers line Z3154 data was processed by We Energies including a calculation of power from the phase voltages and currents. There was no missing data in the set provided.

New Holland data was not used since the T&D benefit is assumed to be zero as described previously.

Six Mile Substation data was rejected due to a significant amount of missing data: 25 percent of the data was missing for feeder 12750 and 17 percent was missing for feeder 12760.

Union Grove Substation data included two feeders. Feeder 35450 had one hour of missing data, and this was replaced with data from the previous hour. Feeder 35460 had 17 hours of contiguous missing data, starting 3/19/06 23:00, and this was replaced with the corresponding hours of the previous day. Also, this feeder had one other hour of missing data that was replaced with data from the previous hour.

Time and Geographical Correlation

It was necessary to time-correlate the substation and PV data sets for the grid analysis work. Only the 2005-2006 PV data were used since the substation data were provided for the year beginning 9/23/05 (day 266).

Hourly PV data were available at the half-hour points in Central Standard Time. Substation data were provided on the hour mark. By inspection, there were no missing hours or repeated hours during the transition between Daylight Savings Time and Standard Time, so Central Standard

Time was assumed for all substation data. The hours were matched so that 00:30 PV data was paired with 01:00 of substation data, 01:30 was paired with 02:00, and so on.

It was then necessary to correlate the geographical locations of the PV and substation data. This was done by proximity as shown in Table 6.

Table 6. Geographic correlation between PV and substation data.

Project	***Location***	***Solar Data Source***
Merton SS Relief	Towns of Merton and Lisbon, Waukesha County	Waukesha
Albers SS Z3154 Capacity Increase	City of Kenosha, Town of Somers, Kenosha County	Racine
Union Grove SS Relief	Town of Yorkville, Racine County	Racine

Only three locations are used for further analysis throughout the remainder of the report. These three locations include Merton, Albers, and Union Grove. Table 7 presents the annual energy produced per unit of installed capacity and Table 8 presents the capacity factors for the three locations and seven system configurations.

Table 7. Annual energy (kWh/kW_{AC}).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	1,789	1,974	1,535	1,438	1,206	1,112	1,299
Albers	1,819	2,000	1,548	1,456	1,228	1,135	1,317
Union Grove	1,819	2,000	1,548	1,456	1,228	1,135	1,317

Table 8. Capacity factor (%).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	20.4%	22.5%	17.5%	16.4%	13.8%	12.7%	14.8%
Albers	20.8%	22.8%	17.7%	16.6%	14.0%	13.0%	15.0%
Union Grove	20.8%	22.8%	17.7%	16.6%	14.0%	13.0%	15.0%

LOAD MATCHING

It is possible to determine the load match using the time- and geographically-correlated substation loads and PV production simulations. This analysis calculates the "effective capacity" of the PV system.

There are several methods described in the literature for determining effective capacity. One common method is the "Effective Load Carrying Capability". This measure captures the relationship between a unit's output and the hourly system load in order to determine the constant load increase that the utility system can carry due to the new resource while maintaining the same level of reliability. The method uses a statistical technique using all hours of the year.

We Energies decided at a project kickoff meeting that the present analysis should evaluate capacity by considering the load relief provided by PV during only the single peak hour of the year. This is the most conservative of all PV capacity methods in use.

Methodology

The following methodology was carried out for each of the three sites where load data were determined to be reliable (Table 6). Loads were time-correlated with simulated PV production data for each hour of the sample year. PV production included the seven configurations assuming a 1 MW_{AC} PV system. Net loads (substation load minus PV production) were then calculated. A 24-hour sample of this data is presented in Table 9 for Merton substation on the peak day (August 1, 2006), although the data included all 8760 hours of the sample year.

Load data were then sorted to determine the peak load for the year. Since the hour of the original peak (without PV) may be different than the "new" peak (with PV), the net load for each configuration was sorted separately, breaking the temporal relationship between the data. The resulting load duration curves (LDCs) are presented in Figure 1, Figure 2, and Figure 3.

Results

The results are presented in Table 10. The peak load for Merton Substation without PV was 9125 kW. The peak load would be reduced to 8923 kW if a 1-Axis tracker rated at 1 MW_{AC} was located in the region served by this substation. This is a net load reduction of 202 kW. Therefore, the effective capacity of the PV system is 202 kW, or 20 percent of the system rating. Similar calculations are performed for the other configurations as shown.

The South-30 orientation produced the lowest results in all configurations considered (6 to 9 percent). The most effective orientations are the single-axis trackers (20 to 31 percent) and the west-facing systems (21 to 28 percent).

Analysis

To better understand these results, consider the PV output curves for the peak day at Merton Substation (August 1, 2006) presented in Figure 4. The south-facing and horizontal system peak in the middle of the day, while the west-facing systems peak toward the end of the day. Tracking systems have a broad output over more hours.

The loads and net loads with PV are presented in Figure 5 for the Merton Substation. This substation peaks at the end of the day just before the sun sets. This significantly favors the west-facing and tracking systems. Similar results are seen in Figure 6 and Figure 7 for Albers and Union Grove.

Table 9. Merton substation peak load and PV output (August 1, 2006).

		Load	PV Simulated Output							Net Load						
Date	**Time**	**No PV**	**1 Axis**	**1 Axis Tilt**	**South-30**	**SW-30**	**West-30**	**West-45**	**Horiz**	**1 Axis**	**1 Axis Tilt**	**South-30**	**SW-30**	**West-30**	**West-45**	**Horiz**
8/1/2006	1:00	5510	0	0	0	0	0	0	0	5510	5510	5510	5510	5510	5510	5510
8/1/2006	2:00	5082	0	0	0	0	0	0	0	5082	5082	5082	5082	5082	5082	5082
8/1/2006	3:00	4740	0	0	0	0	0	0	0	4740	4740	4740	4740	4740	4740	4740
8/1/2006	4:00	4535	0	0	0	0	0	0	0	4535	4535	4535	4535	4535	4535	4535
8/1/2006	5:00	4465	34	33.5	0	0	0	0	0.25	4431	4432	4465	4465	4465	4465	4465
8/1/2006	6:00	4602	233.5	228.5	29.25	2	2	2	44	4369	4374	4573	4600	4600	4600	4558
8/1/2006	7:00	4962	585.75	571.25	167.25	21.75	8.5	9.5	218.25	4376	4391	4795	4940	4954	4953	4744
8/1/2006	8:00	5403	781	768.5	367.5	117.25	45.5	14.75	393	4622	4635	5036	5286	5358	5388	5010
8/1/2006	9:00	5785	840.25	844.75	565.5	335.25	199.75	49	549.75	4945	4940	5220	5450	5585	5736	5235
8/1/2006	10:00	6187	870	901.5	744	544.25	386.5	193	692.75	5317	5286	5443	5643	5801	5994	5494
8/1/2006	11:00	6814	857.5	918.5	856.25	711	557.25	386.5	781.75	5957	5896	5958	6103	6257	6428	6032
8/1/2006	12:00	7248	852.5	936	924.25	841	705	574	836	6396	6312	6324	6407	6543	6674	6412
8/1/2006	13:00	7717	843.75	926.5	914.75	902.25	800.5	717.75	828.5	6873	6791	6802	6815	6917	6999	6889
8/1/2006	14:00	7940	851.75	911.75	849	906.25	847	812.25	776	7088	7028	7091	7034	7093	7128	7164
8/1/2006	15:00	8177	859.5	891.25	733	857.5	846	855.5	683	7318	7286	7444	7320	7331	7322	7494
8/1/2006	16:00	8502	836.25	840.75	565.5	744.75	781.75	829.5	549.75	7666	7661	7937	7757	7720	7673	7952
8/1/2006	17:00	8910	724	711	353.75	551.5	626.5	695.25	376.5	8186	8199	8556	8359	8284	8215	8534
8/1/2006	18:00	**9125**	472.5	459.25	150.75	294.25	379.75	437.5	187.5	8653	8666	8974	8831	8745	8688	8938
8/1/2006	19:00	8826	105.75	102	2.25	30	84	97.5	9	8720	8724	8824	8796	8742	8729	8817
8/1/2006	20:00	8618	0	0	0	0	0	0	0	8618	8618	8618	8618	8618	8618	8618
8/1/2006	21:00	8151	0	0	0	0	0	0	0	8151	8151	8151	8151	8151	8151	8151
8/1/2006	22:00	7620	0	0	0	0	0	0	0	7620	7620	7620	7620	7620	7620	7620
8/1/2006	23:00	6929	0	0	0	0	0	0	0	6929	6929	6929	6929	6929	6929	6929
8/1/2006	24:00:00	5958	0	0	0	0	0	0	0	5958	5958	5958	5958	5958	5958	5958

Figure 1. Merton Substation load duration curve.

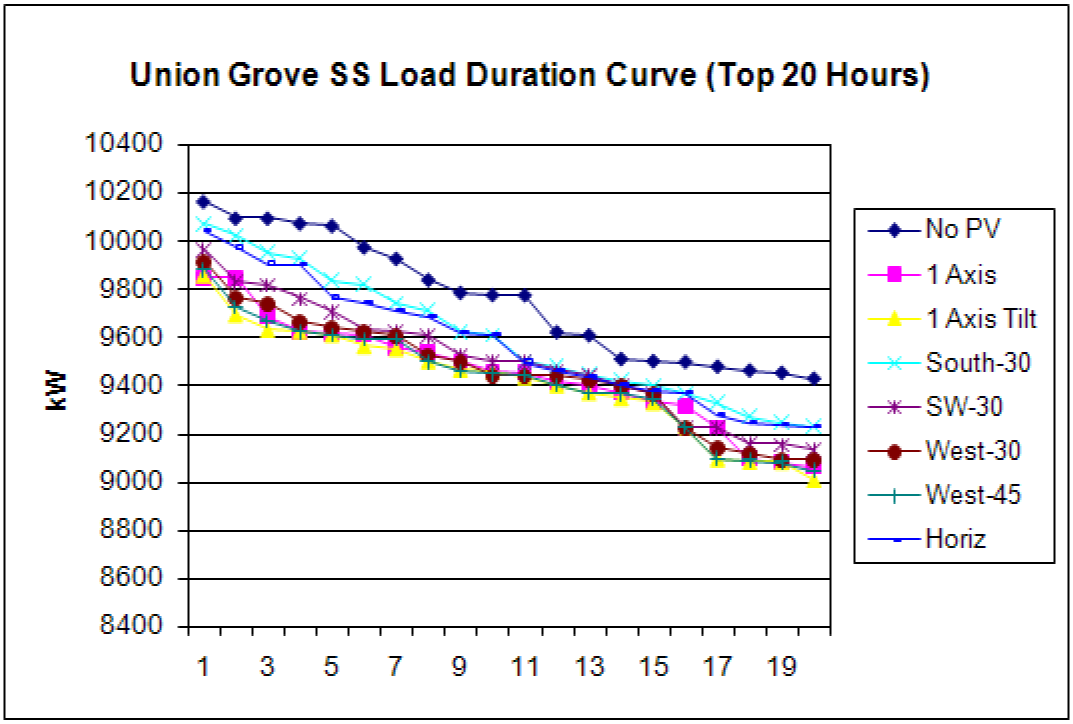


Figure 2. Albers Substation load duration curve.

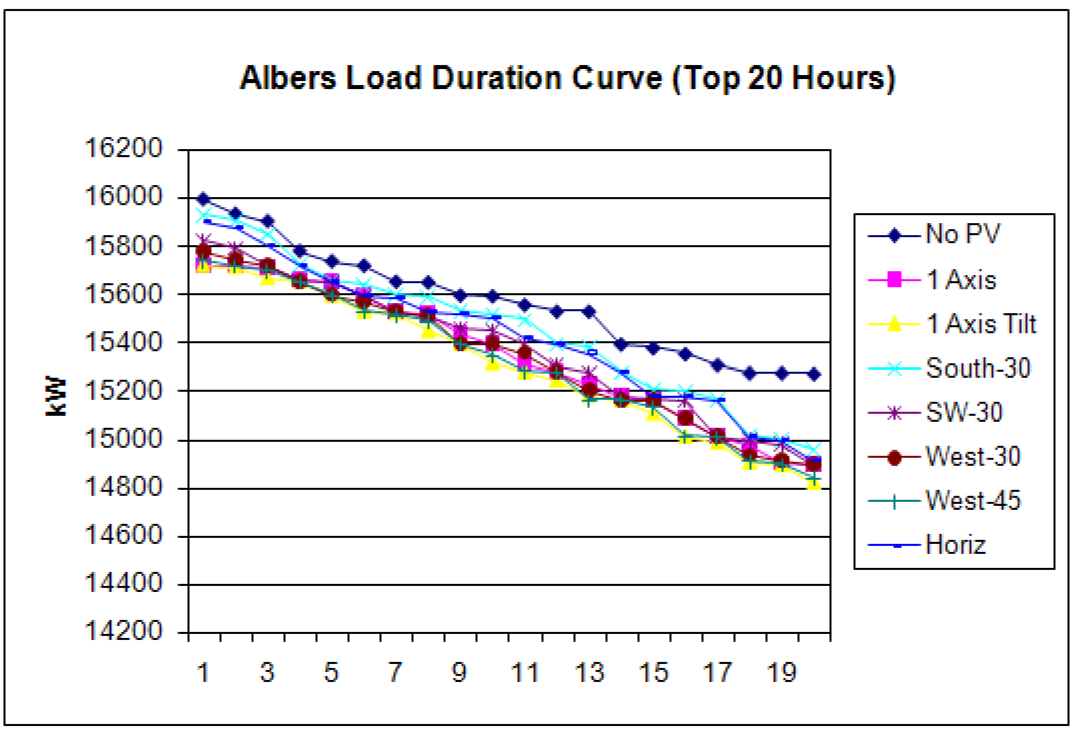


Figure 3. Union Grove Substation load duration curve.

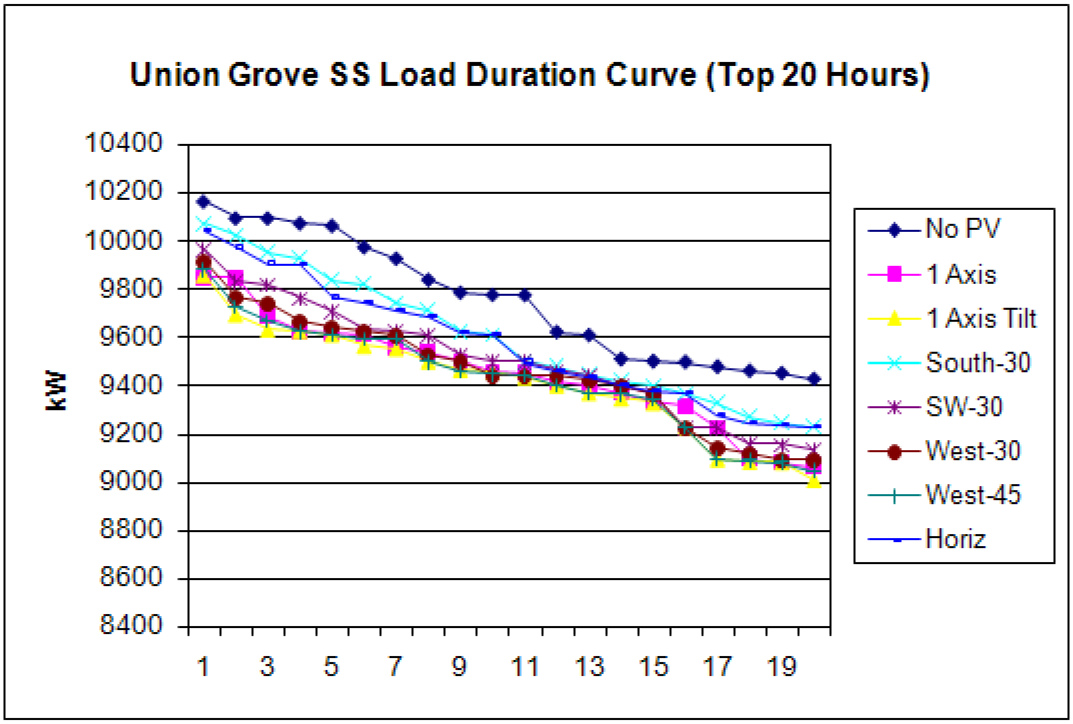


Table 10. Effective capacity calculation.

	No PV	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz
MERTON								
Top LDC hour (kW)	9125	8923	8926	9063	8945	8918	8918	9028
Peak Reduction (kW)		202	199	62	180	207	207	98
Effective Capacity (%)		20%	20%	6%	18%	21%	21%	10%
ALBERS								
Top LDC hour (kW)	15990	15717	15717	15928	15824	15774	15740	15901
Peak Reduction (kW)		273	273	62	167	216	251	89
Effective Capacity (%)		27%	27%	6%	17%	22%	25%	9%
UNION GROVE								
Top LDC hour (kW)	10161	9848	9853	10069	9965	9915	9881	10042
Peak Reduction (kW)		313	308	92	197	246	281	119
Effective Capacity (%)		31%	31%	9%	20%	25%	28%	12%

Figure 4. PV output curves, peak day, Merton Substation.

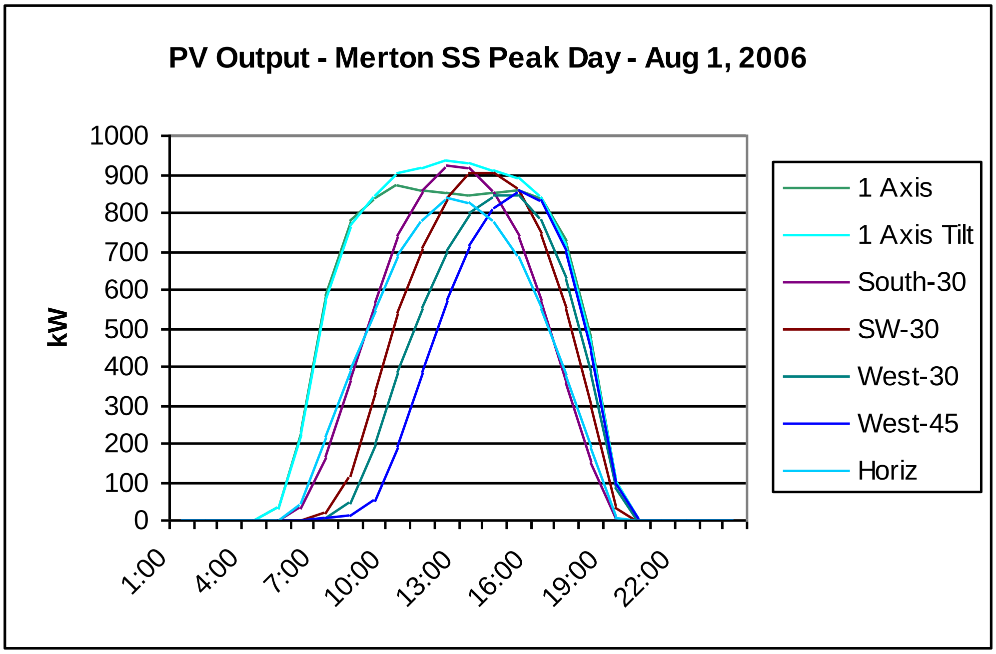


Figure 5. Loads and net loads on Merton peak day (August 1, 2006).

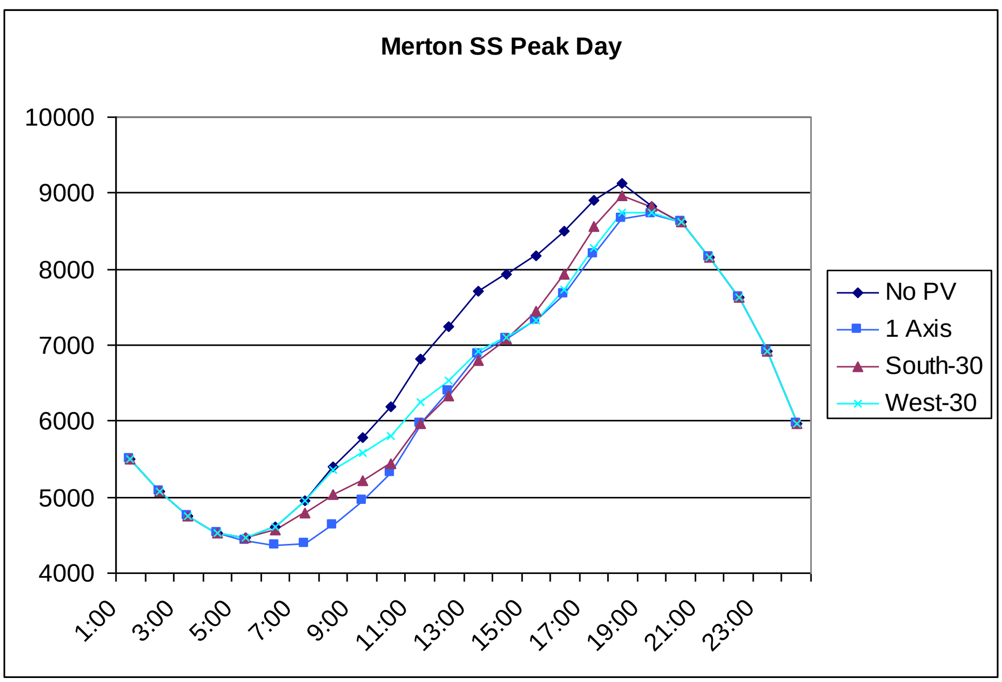


Figure 6. Loads and net loads on Albers peak day (August 1, 2006).

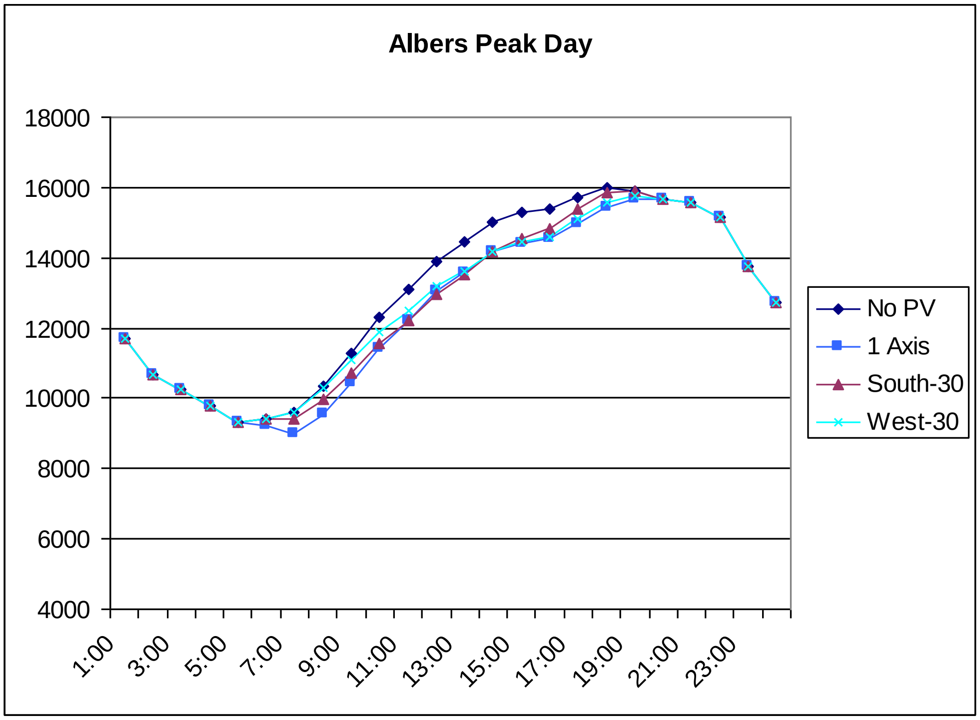
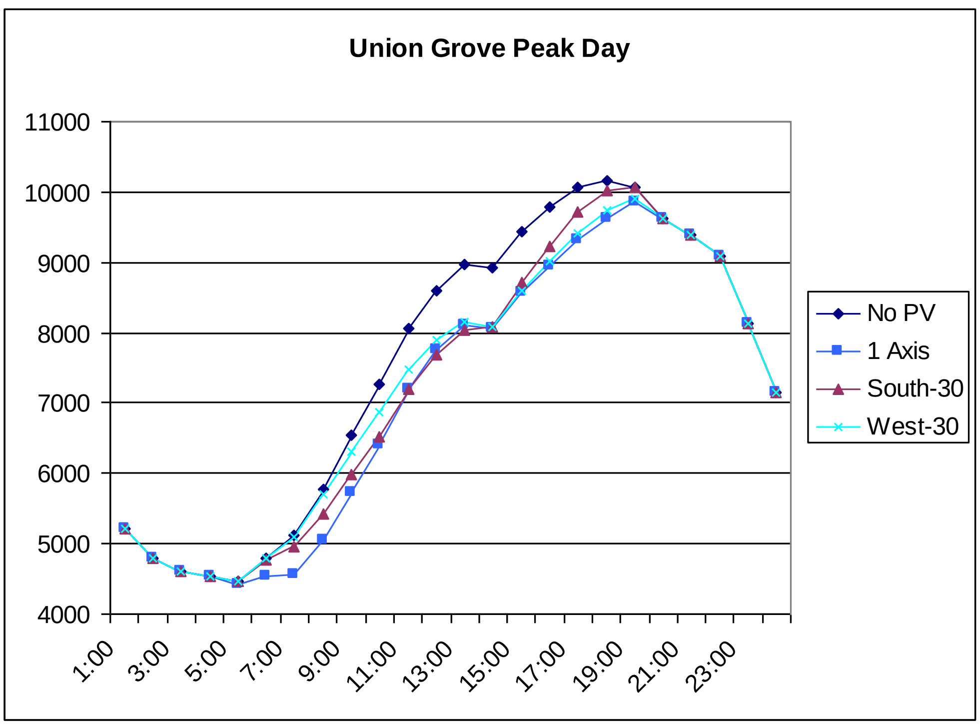


Figure 7. Loads and net loads on Union Grove peak day (July 31, 2006).



Load Shifting

It is possible that the effective capacity could be improved if some form of load shifting were available. This might be accomplished with rate design, efficiency, or storage. The analysis considered the impact of a 5 percent peak reduction to explore the effects of load shifting. The calculations for the peak day at Merton Substation are presented in Table 11.

The peak load in this case occurs at hour 18:00 and is 9125 kW. A 5 percent reduction (456 kW) is assumed, and the new peak of 8669 kW is taken as the new peak load. Adjacent hours are adjusted to retain the 8669 kW peak, and a corresponding mid-day increase is added such that the total energy of the load shifting is zero.

The new (shifted) load, and the new net loads (shifted with PV) are shown for selected configurations in Figure 8. Load shifting, however, does not produce a corresponding increase in effective PV capacity since the peak still occurs at the end of the day. Similar results are presented in Figure 9 and Figure 10 for Albers and Union Grove, respectively. Numeric values are presented in Table 12.

The main issue is that peak loads are occurring at the end of the day. By "flattening" these peaks through some form of load shifting, the peak-shifting benefit is achieved (in this example, a 5 percent peak load reduction). PV, however, is not able to provide additional peak load reduction on the net loads. This is because, for these locations of study, the output of PV does not correspond well with the peak. The peak – and shifted peak – is during hours of low or no PV output.

Table 11. Load Shifting – Merton Substation.

Date	Time	No PV	Load Shift	New Load
8/1/2006	1:00	5510		5510
8/1/2006	2:00	5082		5082
8/1/2006	3:00	4740		4740
8/1/2006	4:00	4535		4535
8/1/2006	5:00	4465		4465
8/1/2006	6:00	4602		4602
8/1/2006	7:00	4962		4962
8/1/2006	8:00	5403		5403
8/1/2006	9:00	5785		5785
8/1/2006	10:00	6187		6187
8/1/2006	11:00	6814	-241	7055
8/1/2006	12:00	7248	-456	7704
8/1/2006	13:00	7717	-157	7874
8/1/2006	14:00	7940		7940
8/1/2006	15:00	8177		8177
8/1/2006	16:00	8502		8502
8/1/2006	17:00	8910	241	8669
8/1/2006	18:00	**9125**	456	**8669**
8/1/2006	19:00	8826	157	8669
8/1/2006	20:00	8618		8618
8/1/2006	21:00	8151		8151
8/1/2006	22:00	7620		7620
8/1/2006	23:00	6929		6929
8/1/2006	24:00:00	5958		5958

Table 12. Effective PV capacity with load shifting.

	No PV	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz
MERTON								
Top LDC hour (kW)	8669	8618	8618	8667	8639	8618	8618	8660
Peak Reduction (kW)		51	51	2	30	51	51	9
Effective Capacity (%)		5%	5%	0%	3%	5%	5%	1%
ALBERS								
Top LDC hour (kW)	15191	15191	15191	15191	15191	15191	15191	15191
Peak Reduction (kW)		0	0	0	0	0	0	0
Effective Capacity (%)		0%	0%	0%	0%	0%	0%	0%
UNION GROVE								
Top LDC hour (kW)	9653	9621	9621	9651	9621	9621	9621	9624
Peak Reduction (kW)		32	32	2	32	32	32	29
Effective Capacity (%)		3%	3%	0%	3%	3%	3%	3%

Figure 8. Load shifting for Merton Substation.

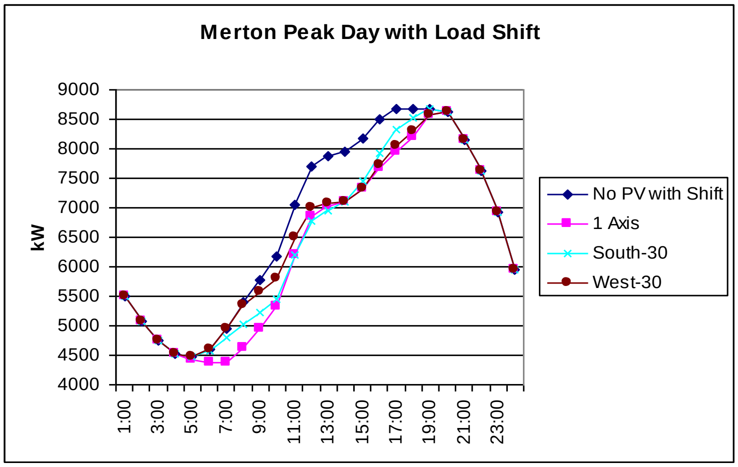


Figure 9. Load shifting for Albers.

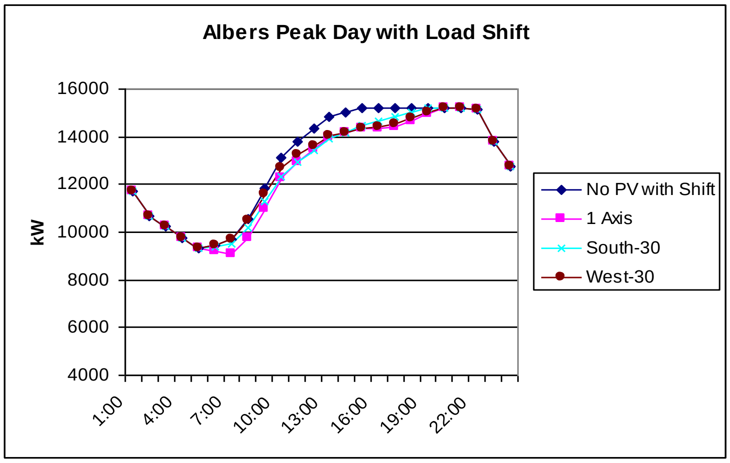
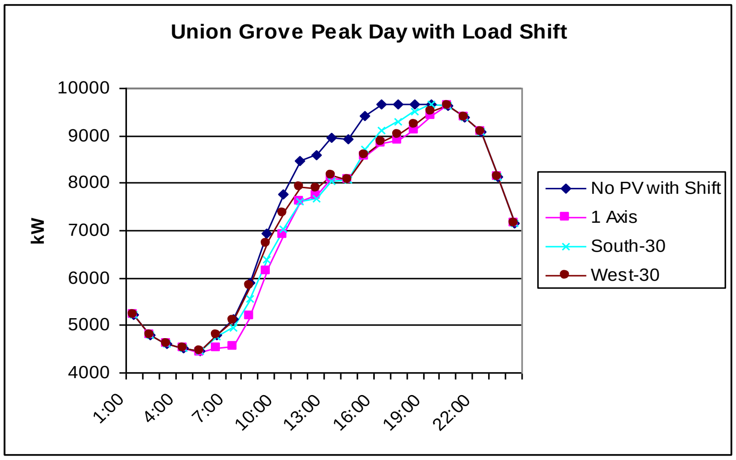


Figure 10. Load shifting for Union Grove Substation.



Load Control with PV

Another way to manage peak loads is through remote utility load control (LC). This practice has been proposed as a complementary technology to PV, since the "hybrid" PV with LC system would perform better than each technology in isolation.

Table 13 illustrates how 1 MW of LC could be used (without PV) for the area served by the Merton Substation. The peak load of 9125 kW is reduced to 8125 kW, and this level is maintained through selective LC in adjacent hours. In this case, 7 hours of LC are needed to cap the peak at 8125 kW.

Table 13. Load control at Merton Substation (1 MW).

Date	Time	No PV no LC	LC	Net Load (w/o PV)
38930	1:00	5510		5510
38930	2:00	5082		5082
38930	3:00	4740		4740
38930	4:00	4535		4535
38930	5:00	4465		4465
38930	6:00	4602		4602
38930	7:00	4962		4962
38930	8:00	5403		5403
38930	9:00	5785		5785
38930	10:00	6187		6187
38930	11:00	6814		6814
38930	12:00	7248		7248
38930	13:00	7717		7717
38930	14:00	7940		7940
38930	15:00	8177	52	8125
38930	16:00	8502	377	8125
38930	17:00	8910	785	8125
38930	18:00	9125	1000	8125
38930	19:00	8826	701	8125
38930	20:00	8618	493	8125
38930	21:00	8151	26	8125
38930	22:00	7620		7620
38930	23:00	6929		6929
38930	24:00:00	5958		5958

However, with PV in the area, some of this energy is displaced by the PV, reducing the LC requirements imposed by the utility. Table 14 shows the amount of LC (in kWh) required to reduce the peak load by 1 MW. For example, 3434 kWh of LC energy would be required at Merton Substation to reduce the peak load by 1 MW. With a 1-axis tracker, the amount is only 1703 kW, a reduction of 50 percent. The amount of reduction depends upon the power generation characteristics of the PV configuration and the shape of the load curve.

The PV system can be combined with LC as a hybrid system to be considered as a “firm” source of power. In this case, for example, 1 MW of power would always be available, regardless of the solar resource in any hour. The cost of the LC project implementation would have to be considered and this would reduce the benefit.

Table 14. Load control requirements to achieve 1 MW peak load reduction.

	No PV	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz
MERTON								
Required Load Control (kW)	3434	1703	1733	2498	2129	1915	1775	2432
% Reduction in LC		50%	50%	27%	38%	44%	48%	29%
ALBERS								
Required Load Control (kW)	4797	2552	2570	3596	3085	2854	2663	3503
% Reduction in LC		47%	46%	25%	36%	41%	44%	27%
UNION GROVE								
Required Load Control (kW)	4399	1991	2023	3080	2511	2288	2107	2992
% Reduction in LC		55%	54%	30%	43%	48%	52%	32%

Distribution Capacity Value with Load Match

Table 4 presented the value of capacity when there is a perfect load match (M=1). These results are repeated in the first row for each location in Table 15. The value of capacity of a perfect resource can now be adjusted to reflect the effect of the actual load match. Table 15 presents the calculations in which the perfect match values are scaled by the actual match. These results are based on effective capacity using only the single peak hour for each location and do not reflect load shifting or load control methodologies.

Table 15. Distribution capacity value per unit of installed PV capacity ($/kW$_{AC}$).

	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz
MERTON							
Perfect Value, M=1 ($/kW)	719	719	719	719	719	719	719
Effective Capacity (%)	20%	20%	6%	18%	21%	21%	10%
Effective Value ($/kW)	145	143	45	129	149	149	70
ALBERS							
Perfect Value, M=1 ($/kW)	180	180	180	180	180	180	180
Effective Capacity (%)	27%	27%	6%	17%	22%	25%	9%
Effective Value ($/kW)	49	49	11	30	39	45	16
UNION GROVE							
Perfect Value, M=1 ($/kW)	470	470	470	470	470	470	470
Effective Capacity (%)	31%	31%	9%	20%	25%	28%	12%
Effective Value ($/kW)	147	145	43	92	116	132	56

CONCLUSIONS

The area expansion plan costs were used in this study as an indicator of expected future upgrade costs as loads approach capacity limits. The effective distribution capacity values were calculated for three areas using actual load data and simulated PV system output: Merton, Albers, and Union Grove.

Capacity values range from $11/kW to $149/kW, depending on location and PV system configuration. These values are driven by the following factors:

- The Albers location is a line reconductoring project with a low capital cost ($466,000).
- In all cases, the peak falls very late in the day when the PV output is declining. This is especially true for south-facing systems that have a low effective capacity for all three sites.
- The values assume a PV-only solution. Other methods, such as combining systems with load control or storage, were not considered in the results.

3. GENERATION VALUE

INTRODUCTION

Generation Value is the benefit that We Energies derives from PV's offset of We Energies' wholesale energy purchases: each kWh that PV generates at the customer's site is one less kWh that We Energies needs to purchase. The value of PV in providing generation capacity and energy derives from its ability to offset wholesale MISO energy purchases by We Energies.

Generation Energy Value

The cost savings of power generation is among the key benefits provided by distributed PV to utilities. Each unit of energy produced by PV allows the utility to avoid corresponding generation or power purchases.

Most PV valuation studies in the past have quantified this benefit by determining the value of generation capacity and energy separately, and most use the utility's own generation fleet as the basis of valuation. In this study, the value is based on the avoided cost of power purchases from the wholesale market, the Midwest ISO. The avoided cost of power purchases represents the cost of energy. Capacity benefits are considered to be small and are not included in the study even though PV also provides generation capacity benefits.

Power Markets

The Midwest ISO operates both a day-ahead market and a real-time energy market to facilitate scheduling and unit dispatching. The markets are based on centralized dispatch, using a Locational Marginal Pricing (LMP) methodology to optimize power flows. There is also a financial transmission rights (FTR) market that provides participants with an opportunity to hedge against day-ahead congestion costs. These three markets operate independently.

Clearing prices from the day-ahead market were used to value solar energy production for purposes of this study. The PV output may be considered a relatively reliable source of energy in the sense that it impacts the utility's load forecasts each day in a regular and predictable manner. Forecasts are made using daily load profiles, or more accurately "net" loads, that include the beneficial impacts of PV. Therefore, the scheduled power demanded in the day-ahead market with PV in the distribution system is reduced according to the amount of PV on the system. The FTR market was not relevant to this study.

The Midwest ISO day-ahead market is a forward market where hourly clearing prices are calculated for each hour of the next operating day based on the concept of LMPs. The market is cleared using computer programs[12] to satisfy various energy demand bid requirements and supply requirements. The results of the market clearing include hourly LMP values and hourly demand and supply quantities.

Locational Marginal Pricing (LMP)

The Federal Energy Regulatory Commission (FERC) has endorsed an LMP model of wholesale electricity pricing[13], and this model is employed by the Midwest ISO. Historical hourly LMP clearing prices from the Midwest ISO were used in the present study as the basis of energy value from PV.

LMPs vary by time and location due to physical limitations, congestion, and loss factors[14] and can be separated into three pricing components: the Marginal Energy Cost (MEC), the Marginal Congestion Component (MCC) and the Marginal Loss Component (MLC). Historical values for each of these three components are available from the Midwest ISO. Only the total value (LMPs), however, are of interest in this study.

LMP AND PV PRODUCTION DATA

LMP Data

LMP data were downloaded from the Midwest ISO website.[15] Historical data are available from April 2005 to the present in separate files for each day of the year. For the study period of 9/23/05 through 9/22/06, 365 csv data files were downloaded. Each daily file contains about 4500 sets of 24-hour pricing data including LMP, MCC, and MLC from about 1500 pricing nodes. The pricing data are in units of U.S. dollars per MWh.

A real-time pricing contour (updated every 5 minutes) such as the one shown in Figure 11, is provided on the Midwest ISO website. This map, accessed through an Adobe SVG plug-in viewer,

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[12] Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED).

[13] An excellent overview of locational marginal pricing is available from the National Regulatory Research Institute at http://www.nrri.ohio-state.edu/Electric/LMP-Primer.

[14] Market Concepts Study Guide, Version 3.0, December 2005, Midwest ISO.

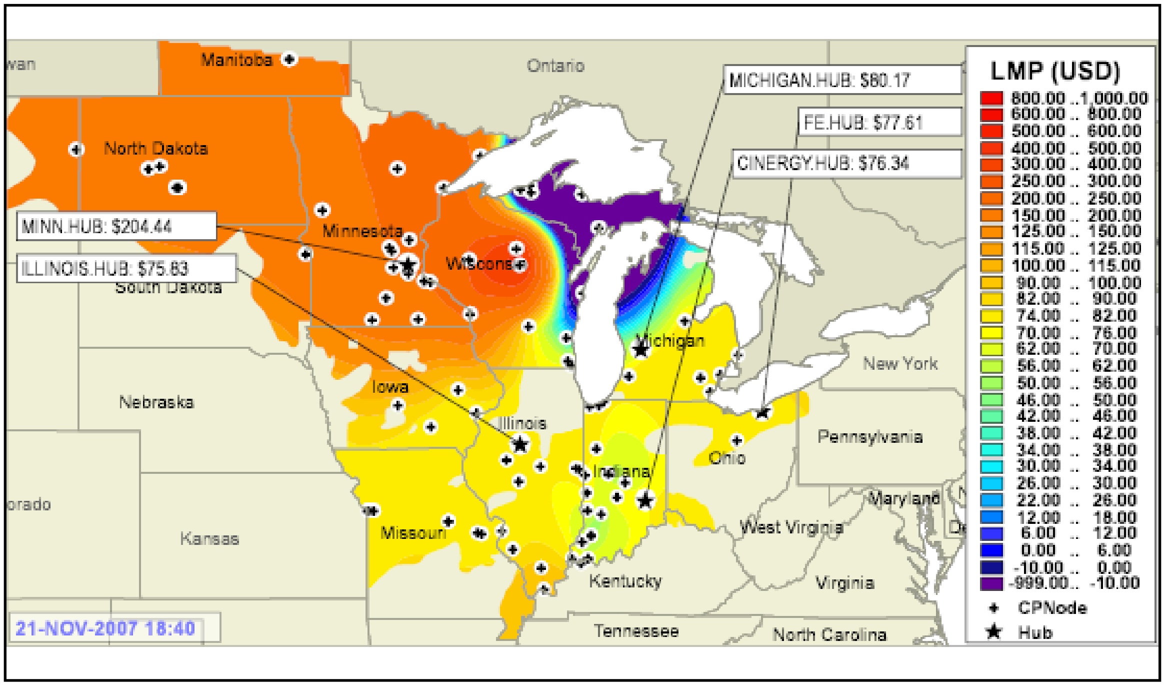
[15] www.midwestiso.org.

allows the user to highlight selected nodes to see the pricing components during the current interval. Three nodes were identified from this map in the study area of interest:

- GERMANOT1
- PARIS01S1
- PLPRG41

These nodes correspond approximately to Waukesha, Racine, and Kenosha counties, respectively.

Figure 11. Midwest ISO pricing contours.



A Microsoft Excel Visual Basic program was written to open these data files, search for the three nodes of interest, and transpose the hourly data to a separate data file of 8760 LMPs for each node.

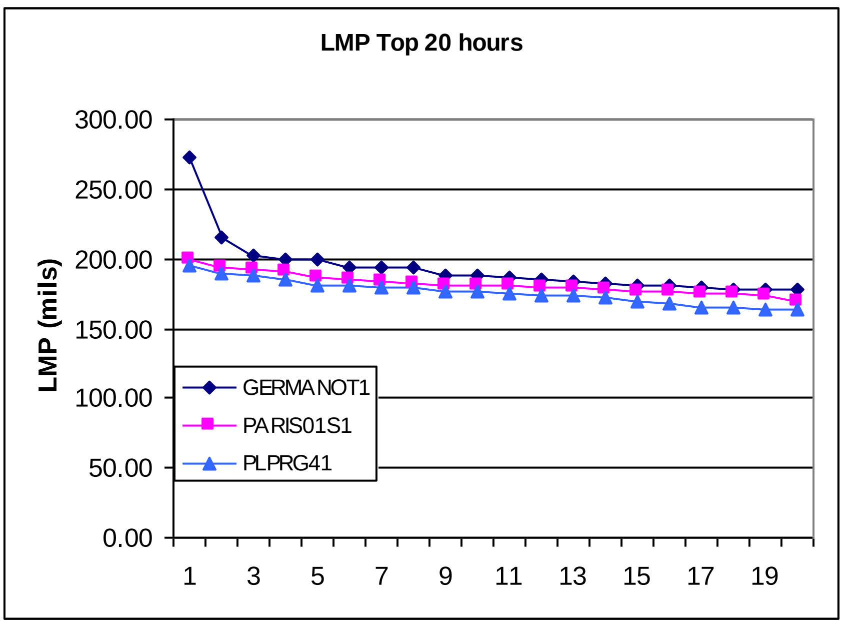
RESULTS

LMP Pricing

The top 100 hours of pricing over the one-year period are presented for each respective node in Figure 12. The prices appear to track reasonably closely with the exception of the top two hours for GERMANOT1. The minimum, maximum and average prices for the three nodes are presented in Table 16.

The valuation could be performed for each of the three pricing nodes separately. The PARIS01S1 node, however, was selected as a representative pricing node for all locations.[16] This simplifying assumption was made because the PARIS01S1 node: tracks the other two nodes; eliminates the two high priced hours of GERMANOT1; has an average price in the middle of the other two; and pricing variation is not significant overall.

Figure 12. LMP Top 100 Hours.



[16] PARIS01S1 is not necessarily representative of what We Energies would use to design a tariff. WEC-South is more representative of what We Energies pays MISO for purchase of energy to serve load.

Table 16. LMP pricing statistics for three nodes ($/MWh).[17]

Node	***Max***	***Min***	***Avg***
GERMANOT1	273.24	4.83	48.72
PARIS01S1	**199.72**	**5.20**	**48.36**
PLPRG41	195.59	4.96	45.67

The LMP pricing has changed significantly since the analysis was performed. The new values are presented in Table 17 for completeness. An analysis using current values would change the Generation Value of PV.

Table 17. Updated LMP pricing statistics ($/MWh, year ending August 2009).

Node	***Max***	***Min***	***Avg***
GERMANOT1	144.12	-21.69	30.74
PARIS01S1	**142.46**	**-24.51**	**30.29**
PLPRG41	139.39	-38.79	29.10

Generation Energy Value

The objective of this chapter is to determine the generation energy value from PV systems located in the distribution area of the three project sites. Table 6 presents the sources of solar data used for the three locations. All three locations use pricing data from the PARIS01S1 node. For example, a PV system in the area of the Albers project is assumed to perform as a PV system at Racine and the value of offset wholesale energy purchases is based on pricing at PARIS01S1.

The value of the first year's energy produced by a PV system in any given hour is the product of the system's output (MWh) and the value of energy at the Midwest ISO pricing node ($/MWh). These values are summed for each hour of the year:

$$Value(\$/yr) = \sum_{Hour=1}^{8760} Energy_{Hour}(MWh) x LMP_{Hour}(\$/MWh)$$

[17] The LMPs are dependent upon when the study is performed.

This equation was applied using the PV production data and LMP pricing data as described above for nominal 1 kW_{AC} PV systems oriented in the seven configurations. The results are presented in Table 18.

Table 18. First-year Generation Value ($/kW-yr).

	1 Axis	*1 Axis Tilt*	*South-30*	*SW-30*	*West-30*	*West-45*	*Horiz*
Merton	103	114	91	86	73	68	77
Albers	104	114	91	87	74	69	77
Union Grove	104	114	91	87	74	69	77

The economic assumptions in Table 1 were then used to escalate the prices over the life of the system and discount them using the We Energies discount rate. The resulting Generation Values in $/$kW_{AC}$ are presented in Table 19.

Table 19. Generation Value per unit of installed PV capacity ($/$kW_{AC}$).

	1 Axis	*1 Axis Tilt*	*South-30*	*SW-30*	*West-30*	*West-45*	*Horiz*
Merton	1,522	1,682	1,338	1,273	1,080	1,001	1,134
Albers	1,536	1,691	1,340	1,282	1,095	1,017	1,144
Union Grove	1,536	1,691	1,340	1,282	1,095	1,017	1,144

ANALYSIS

The generation energy value provided by PV at We Energies ranged from about $1,000 per kW_{AC} to about $1,700 per kW_{AC}. The highest values, as expected, came from tracking systems because they produce the highest energy. Value provided at Albers and Union Grove are identical because both are calculated using the same PV production and LMP data sources. On an energy basis, the variation in $/kWh value is very small among all cases, suggesting that the energy value is driven primarily by the quantity of energy production.

Match Between PV Output and Pricing

The values appear lower relative to comparable studies performed elsewhere. To better understand why, the match between PV output and pricing was examined. First, the idealized case of a perfect match between PV output and price was considered. For example, a 1-axis tracking system at Merton produces 1,789 kWh annually per kW of installed capacity (see Table 7). Suppose that this energy was produced at exactly the optimal pricing hours. The PV system would deliver energy at its maximum rated output during the highest LMP hours only. In this example, a 1 kW PV system would produce 1 kW for the 1789 highest price hours.

LMPs at the PARIS01S1 pricing node were sorted by value and the "maximum price match" Generation Values were calculated by assuming all energy was produced during the highest price hours. The results are presented in Table 20. Another calculation can be made to show the value if all the energy were spread equally over all 8760 hours. This is presented in Table 21. Finally a calculation of the "minimum price match" using the lowest LMP hours is presented in Table 22.

Table 20. Generation Value - maximum price match ($\$/kW_{AC}$).

	1 Axis	*1 Axis Tilt*	*South-30*	*SW-30*	*West-30*	*West-45*	*Horiz*
Merton	2,392	2,570	2,137	2,034	1,781	1,676	1,885
Albers	2,421	2,595	2,150	2,053	1,806	1,701	1,904
Union Grove	2,421	2,595	2,150	2,053	1,806	1,701	1,904

Table 21. Generation Value - baseload match ($\$/kW_{AC}$).

	1 Axis	*1 Axis Tilt*	*South-30*	*SW-30*	*West-30*	*West-45*	*Horiz*
Merton	1,278	1,410	1,097	1,027	861	795	928
Albers	1,299	1,429	1,106	1,040	877	810	941
Union Grove	1,299	1,429	1,106	1,040	877	810	941

Table 22. Generation Value – minimum price match ($\$/kW_{AC}$).

	1 Axis	*1 Axis Tilt*	*South-30*	*SW-30*	*West-30*	*West-45*	*Horiz*
Merton	560	635	464	427	345	313	378
Albers	572	645	468	434	352	320	384
Union Grove	572	645	468	434	352	320	384

An examination of these results suggests that the match between PV output and pricing is highly significant. The Generation Value for a 1-axis tracker at Merton in the maximum case is 4.3 times the Generation Value of the minimum case. Similar results are seen for the other configurations and locations.

Seasonal Price Match

The analysis above suggests that the timing of PV output relative to LMPs is critical. The hourly match was considered for four sample days by season at Merton to better understand the price/output relationship (LPM node PARIS01S1, PV data source Waukesha).

Figure 13 presents the daily LMP profiles at node PARIS01S1 on March 21, June 21, September 21, and December 21, representing four seasons. There is a significant price peak in the late evening hours for each non-summer season. The summer price peak occurs at the end of the day. Autumn pricing, the lowest price season, is relatively flat. Winter offers the highest pricing by a significant amount.

By comparison, energy output of a South-30 PV system at Waukesha is shown for the same days in Figure 13. PV output drops to zero in every season except summer before the pricing peak. The highest seasonal prices in December are met with the lowest PV output. PV output in spring and autumn are the highest, but the prices are the lowest during these seasons. June provides a reasonably good match between LMPs and solar output, but the magnitude of PV output is small. The value of PV in offsetting wholesale power purchases is limited for these reasons.

Table 23 quantifies this result beyond the four sample days by showing the best and worst possible price/output correlations for a 30-South PV system at Merton. The best theoretical case would be if all of the PV system energy (1,535 kWh per year per kW) was generated during the highest price hours of the year. If PV output were perfectly matched to price, it would deliver its full rated power output during the 1,535 hours of highest LMP. Conversely, the theoretically worst case would be if all the energy were generated during the 1,535 hours of lowest price.

Figure 13. Seasonal pricing at PARIS01S1.

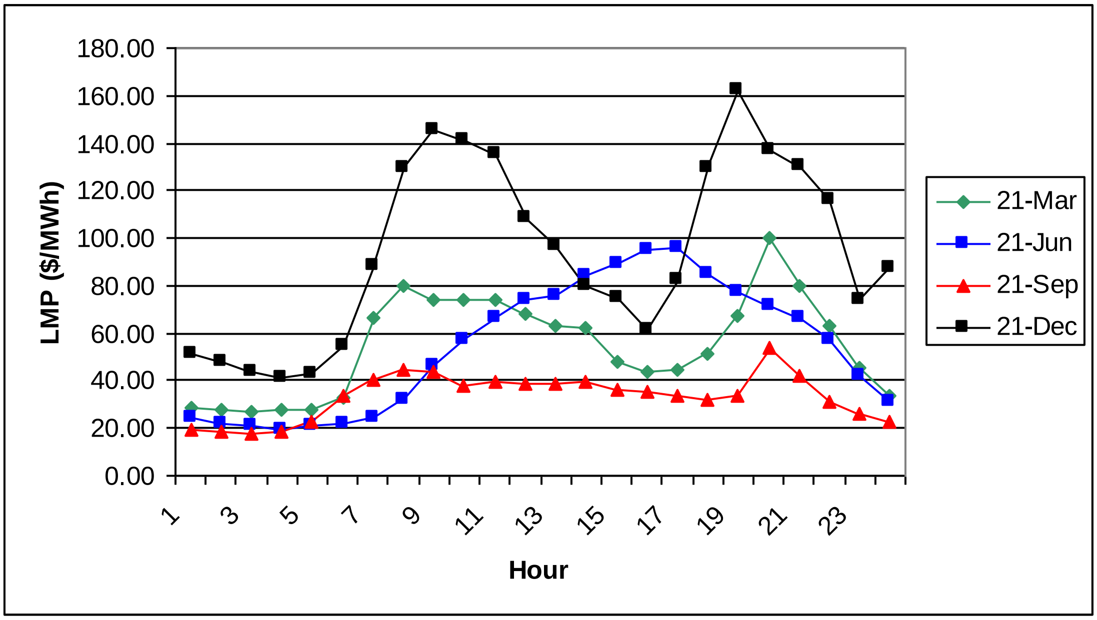


Figure 14. Seasonal output at Waukesha.

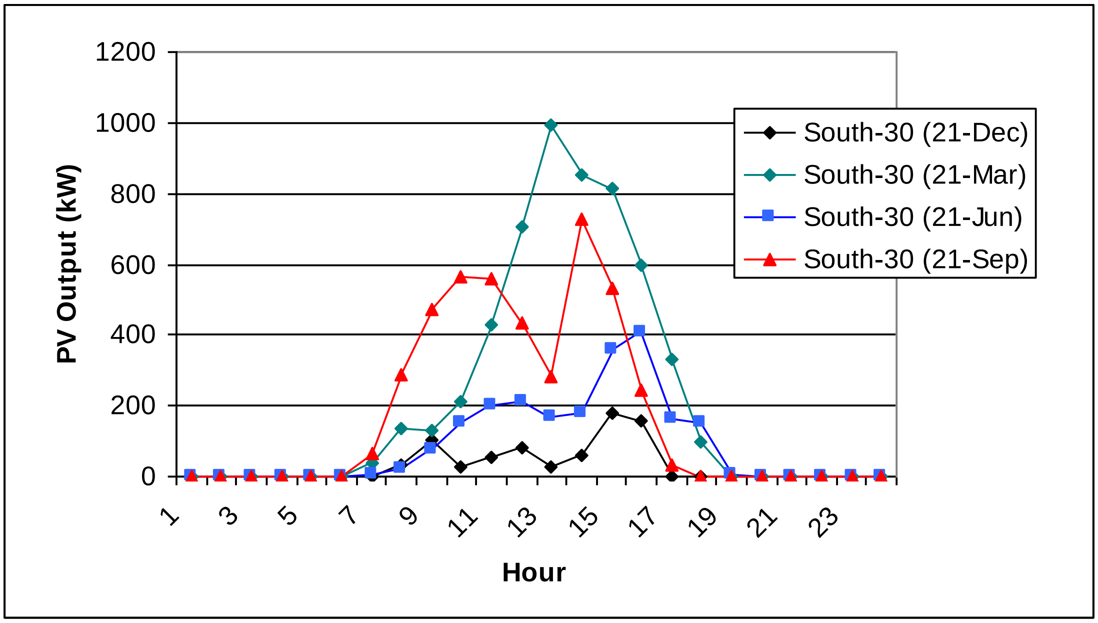


Table 23 highlights these two extremes of “high range” and “low range” by sorting LMP from highest price hour to lowest price hour for the year. The high range represents the 1,535 hours of highest price. LMP varies in this range from $70.05 to $199.72 per MWh, and the average price is $94.22. So, the theoretical maximum value would be $94.22/MWh x 1535 h / 1000 = $2,137/kW. This would be the value of a perfectly dispatchable generator with perfect foreknowledge of the pricing, dispatched to give the same capacity factor as PV. A similar calculation can be done to derive the theoretical worst case of $463.

The actual value of PV ($1,338/kW) is therefore 63 percent of the theoretically maximum possible value. PV provides 63 percent of the energy value as compared to a fully dispatchable generator with the same capacity factor.

Table 23. Highest and lowest value match at Merton.

	High Range			Low Range		
	Upper Limit	Lower Limit	Range Average	Upper Limit	Lower Limit	Range Average
LMP Sort Rank	1	1535		7225	8760	
LMP ($/MWh)	199.72	70.05	94.22	25.17	5.20	20.43
Generation Value ($/kW)			2,137			463

Conclusions

The Generation Value analysis leads to several observations and conclusions:

- The Generation Value at We Energies for the locations of interest ranged from about $1,000/kW$_{AC}$ to $1,700/kW$_{AC}$, depending upon system configuration.
- Value at Albers and Union grove were identical because they are close geographically. The analysis used the same solar resource and pricing node. Results for Merton were similar.
- LMPs for the three pricing nodes considered in this analysis were very close, and only one node was used in order to simplify the analysis.

4. ENVIRONMENTAL VALUE

INTRODUCTION

Several approaches could be taken to quantify the Environmental Value of PV. The value could be defined as the premium customers are willing to pay for renewable energy as compared to conventional sources. Alternatively, the value could be derived by estimating the health care cost savings from reduced air pollution. While such approaches would be attempts to quantify the true value, they would be subject to numerous complications, and it is likely that the models and numeric assumptions would not have been broadly accepted.

Furthermore, such approaches focus on the value to society, outside the obligations of the utility in providing electric power. The financial impact to We Energies would not, for example, be directly affected by such health care savings. For these reasons, the societal approaches are not used.

We Energies does, however, have direct financial impacts related to its state-mandated renewable portfolio standards (RPS) obligations. PV provides direct cost savings to the utility by contributing toward these obligations. Therefore, for the purposes of this study, the value of PV in providing environmental benefits is defined as its ability to contribute towards the We Energies RPS.

Wisconsin Renewable Portfolio Standard

Wisconsin has passed several laws over the past decade related to a statewide renewable portfolio standard (RPS) to ensure integration of renewable resources in its energy portfolio.[18] The current law, passed in March 2006, establishes the requirement that 10 percent of electricity sold in the state be derived from eligible sources. Table 24 is a summary of the requirements by year.

Compliance by individual electric providers is based on a Renewable Resources Credit (RRC) tracking and trading program verified and administered by the Midwest Renewable Energy Tracking System (M-RETS). [19]

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[18] Refer to http://www.ucsusa.org/assets/documents/clean_energy/Wisconsin.pdf for a summary of the Wisconsin RPS by the Union of Concerned Scientists.

[19] APX was selected by the PSC to provide the system for tracking RRCs. M-RETS is located at http://www.m-rets.com. In addition to this responsibility, M-RETS tracks RECs for other Midwestern states and provinces.

Table 24. Wisconsin RPS schedule.

Year	Renewable Generation Requirement
2006 – 2009	Each electric provider may not decrease its renewable energy percentage below the electric provider's baseline renewable percentage (average of renewable percentage during the period 2001-03).
2010	Each electric provider shall increase its renewable energy percentage so that it is at least 2 percentage points above the electric provider's baseline renewable percentage.
2011 – 2014	Each electric provider may not decrease its renewable energy percentage below the electric provider's renewable energy percentage required in 2010.
2015, and thereafter	Each electric provider shall increase its renewable energy percentage so that it is at least 6 percentage points above the electric provider's baseline renewable percentage. By 12/31/15, Wisconsin must achieve the goal of having 10 percent of all electric energy consumed in the state being renewable energy.

RRC PRICING

The value analysis centers on the value of the Wisconsin RRC because We Energies is able to save the cost of purchasing RRCs from other parties to the extent that PV generates renewable energy and We Energies can own the RRC.

RRC/REC Pricing Comparisons

Published pricing sources for similar products in other states may be used to estimate pricing for Wisconsin RRCs. REC products (and prices) vary considerably making it important to understand the definitions of the products under comparison.

The impact of REC definitions is apparent in considering the three REC classes defined by the New Jersey RPS. "Class I" renewable energy is defined as electricity derived from solar energy, wind energy, wave or tidal action, geothermal energy, landfill gas, anaerobic digestion, fuel cells using renewable fuels, and some sustainable biomass. "Class II" renewable energy is defined as electricity generated by hydropower facilities no greater than 30 megawatts (MW), and resource-recovery facilities. Solar RECs (SRECs) are also defined in a separate class. The RPS defines required percentages of each class by year through 2021. Table 25 presents current pricing[20] for these three types of RECs. The SREC is by far the most expensive. This may be explained by the higher technology cost, the lack of supply, or the high demand among energy providers striving to meet their RPS solar requirement.

Table 25. New Jersey REC prices ($/MWh).

	Bid	*Offer*	*Last*	*Date*
Solar (SREC)	$250.00	$275.00	$265.00	6/12/08
Class I	$3.50	$9.00	$7.75	6/27/08
Class II	No Bid	$1.00	$0.60	6/20/08

It is important, therefore, to recognize the sensitivity of price to REC technology definitions in estimating the prices of the Wisconsin RRCs. There is also a differentiation between "voluntary" RECs (that may be used, for example, to meet voluntary utility or corporate clean energy goals) and "compliance" RECs (that must be obtained to meet state laws, and are typically more expensive). Compliance RECs are used in this analysis because the Wisconsin RRCs are used to comply with the state RPS.

REC Prices

Table 26 presents a set of current prices for RECs comparable to the Wisconsin RRC. These are compliance (non-voluntary) products exchanged through various brokers and trading systems. Monitoring and tracking is performed through state agencies, similar to M-RETS.

The pricing comparison is intended to be indicative of prices under the RRC definition even though the definitions of qualifying sources are not identical. For reference, Table 27 describes the qualifying sources[21] for the Wisconsin RRC and the other RECs in the price comparison.

[20] Pricing data is taken from the "REC Markets" June 2008 Monthly Market Update from Evolution Markets, http://www.evomarkets.com.

[21] Data taken from the DSIRE database, http://www.dsireusa.org.

Table 26. Compliance RECS ($ per MWh).

REC	*Bid*	*Offer*	*Last*	*Date*
CT Class I Certificate (2008)	$40.00	$46.50	$45.00	6/26/08
MA Class I Certificate (2008)	$46.00	$52.50	$51.75	5/19/08
TX (2008)	$4.00	$5.25	$5.75	3/12/08
NJ Class I (2008/09)	$17.50	$22.00	$20.00	6/23/08
DE (2007)	$10.00	$15.00	$13.75	6/27/08
RI (2008)	$40.00	$50.00	$48.00	7/28/07
MD Tier I (2008)	$0.90	$1.75	$1.10	04/22/08
DC Tier 1 (2008)	$0.50	$1.75	$1.15	02/19/08

Table 27. Comparison of qualifying sources by REC.

	Solar PV	**Solar Thermal Electric**	**Wind**	**Tidal/Wave**	**Ocean Thermal**	**Fuel Cells (Renewable Fuels)**	**Fuel Cells (Non-renewable Fuels)**	**Hydro**	**Biomass**	**Geothermal**
Wisconsin	•	•	•	•		•		•	•	•
Connecticut Class I	•	•	•	•	•	•	•	•	•	
Massachusetts Class I	•	•	•	•	•	•		•	•	•
Texas	•	•	•	•				•	•	•
New Jersey Class I	•	•	•	•		•			•	•
Delaware	•	•	•	•		•		•	•	
Rhode Island	•	•	•	•	•			•	•	•
Maryland Tier I	•	•	•	•	•	•		•	•	•
District of Columbia Tier I	•	•	•	•	•	•			•	•

Prices vary over a wide range, from $1 to $52 per MWh. The range could be due to a number of factors, such as:

- Demand varies depending upon the aggressiveness of the current year state RPS targets. States with high demand may have higher prices.
- Demand varies based on installed capacity. States with historically supportive policies may have more installed renewable resources.
- Renewable resource varies by region. This would especially be true in the case of wind power. States with favorable wind conditions (such as Texas) have more installed renewable capacity and higher capacity factors, both of which would drive down prices.
- Differences between qualifying renewable source definitions.

RESULTS

This section determines the Environmental Value from PV systems located in the distribution area at the three project sites. The REC value is assumed to be $50 per MWh. This is the highest comparable REC value in Table 26. The highest value is taken because, even though it is out-of-state, it drives the price in Wisconsin. Suppliers of Wisconsin RRCs (PV system owners) can choose to supply out-of-state markets instead, shrinking local supply until prices are comparable. In addition, We Energies could sell its title to renewable attributes out-of-state rather than use them for local RPS requirements.[22] The value is defined by this out-of-state market price in either case.

The value of the first year's energy produced by a PV system in any given hour is the product of the REC value ($/MWh) and the system output (MWh). These values are summed for each hour of the year:

$$Value(\$/yr) = REC(\$/MWh)\sum_{Hour=1}^{8760} Energy_{Hour}(MWh)$$

This equation was applied using the assumed REC value and PV production data as described above for nominal 1 kW_{AC} PV systems. The results are presented in Table 28.

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[22] Most states grant out-of-state generators eligibility in meeting RPS goals with the provision that the energy is also sold in-state. For example, Massachusetts, Rhode Island, and Connecticut use NEPOOL-GIS certificates to document RPS compliance. While rules provide for external generators outside the NE-ISO to participate, they require that the energy be delivered into the control area. This analysis presumes such requirements are met.

Table 28. First-year Environmental Value ($/kW-yr).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	89	99	77	72	60	56	65
Albers	91	100	77	73	61	57	66
Union Grove	91	100	77	73	61	57	66

The economic assumptions shown in Table 1 were then used to escalate the prices over the life of the system and discount them using the We Energies discount rate. The resulting Environmental Values are presented in Table 29.

Table 29. Environmental Value per unit of installed PV capacity ($/kW$_{AC}$).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	1,321	1,458	1,134	1,062	891	822	960
Albers	1,343	1,477	1,144	1,075	907	838	973
Union Grove	1,343	1,477	1,144	1,075	907	838	973

CONCLUSIONS

The Environmental Value analysis yielded several observations and conclusions:

- The value of the environmental benefit was derived from the ability to offset purchases of renewable resource credits (RRCs) to meet the utility RPS percentages.
- Out-of-state markets provided a wide range of REC value, from about $1 to $52 per MWh for compliance RECs having source qualifications roughly comparable to the Wisconsin RRC. There are a number of possible reasons for this variation, and the price-setting maximum of $50 per MWh was assumed for this analysis.
- The environmental benefit to We Energies (based on estimated solar performance at Waukesha and Racine TMY sites) ranged from $822/kW$_{AC}$ for a fixed West-45 based system to $1,477/kW$_{AC}$ for a tilted 1-axis tracking system.

5. FUEL PRICE HEDGE VALUE

INTRODUCTION

Electricity in the state of Wisconsin is primarily generated from coal, nuclear, natural gas, and petroleum. The electricity prices throughout the state are subject to uncertainty because the prices of these fuels fluctuate over time. The cost of electricity generated from PV, however, is constant and fixed over the 30-year system life since it is not dependent upon fuels other than solar energy. PV provides a "hedge" against future fuel price uncertainty.

APPROACH

Introduction

PV offsets current and future electric power generation needs and helps to stabilize future generation costs when it is a component of a utility's resource mix. Generation from PV is not dependent upon coal, oil, natural gas, or other fuels that may be subject to future price volatility whether owned by the utility or directly by the end-use customer. Therefore, PV displaces ongoing energy commodity purchases and reduces the price uncertainty of those purchases.

PV provides a "hedge" against future fuel price uncertainty. The method used to quantify this benefit is loosely based on the Black–Scholes options pricing model and is documented more fully in a PV valuation analysis conducted by CPR for Austin Energy in 2006.[23]

The essence of this method is that fuel price volatility is captured in commodities futures pricing. Energy from PV systems offsets conventional power plant generation. In this sense, PV provides "risk-free" energy over its useful service life, and its ongoing energy production is equivalent to holding futures contracts for purchase of energy. The valuation methodology segregates the energy value from the purely financial risk avoidance benefit, the Fuel Price Hedge Value.

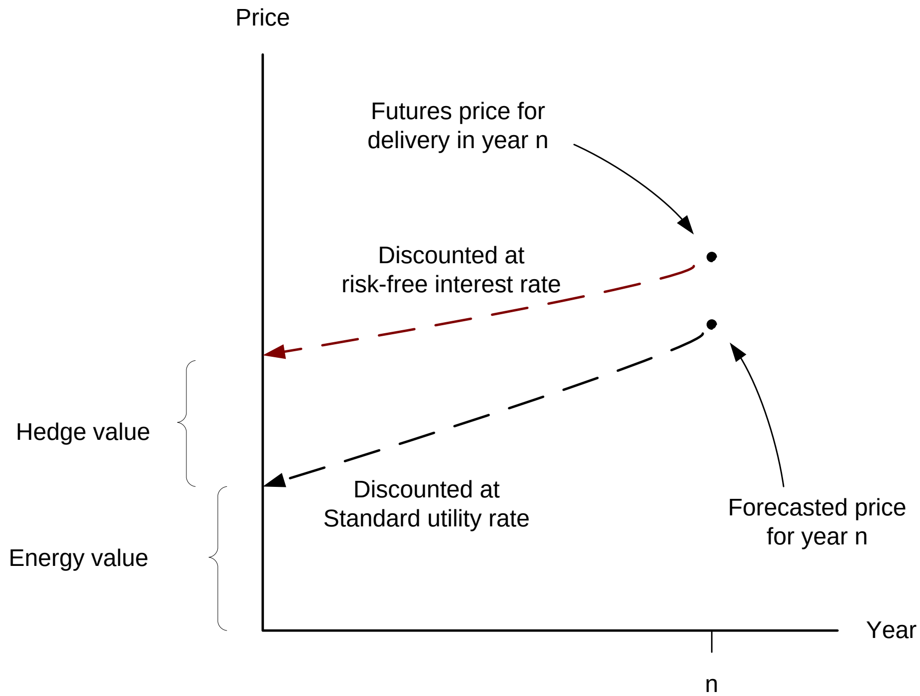
Figure 15 illustrates the calculation of hedge value for a commodity fuel such as natural gas. The risk-free value of the fuel can be determined by discounting the futures price at the risk-free interest rate, such as the yield of a Treasury note. The risk-free rate is used because the fuel could be guaranteed for a specified delivery date using the vehicle of the futures contract. The

[23] "The Value of Distributed Photovoltaics to Austin Energy and the City of Austin", Clean Power Research, 2006. This report can be found at www.cleanpower.com.

conventional energy value (subject to price uncertainty) is determined separately by discounting the forecasted price using the standard utility discount rate.

The difference between the risk-free value and the conventional energy value is the hedge value. It can be thought of as a "price premium" over the energy commodity itself.

Figure 15. Hedge valuation concept.



Wisconsin Energy Sources

Table 30 shows the primary energy sources for power generation in Wisconsin. Coal, petroleum, natural gas, and nuclear fuels are all subject to future price uncertainty and could be modeled using the method described above. In particular, most of the state's electricity is from coal (65 percent) and nuclear (19.8 percent), so that the benefit of offsetting these fuels is potentially high.

PV systems would not offset the generation from coal and nuclear plants because they are generally used for baseload generation while PV is used for peaking resources.

Electricity from petroleum is a relatively small contribution in Wisconsin (1.4 percent). The only petroleum plants in the state are Units 3 and 4 at French Island Generating Plant in Lacrosse,[24] each burning No. 2 fuel oil. Petroleum futures prices could be used for this analysis based on NYMEX heating oil (trading symbol HO) which is identical to No. 2 distillate. Settlement prices, however, are only available covering delivery dates up to three years into the future, limiting the accuracy of results. Therefore, petroleum is also excluded from the analysis.

Futures prices for natural gas are available for delivery dates as far as 12 years into the future. The analysis assumed that PV would offset electricity from natural gas plants.

Futures Prices

Figure 16 presents natural gas futures prices (trading symbol NG) from the New York Mercantile Exchange (NYMEX).[25] Settlement prices are in dollars per mmBTU and represent future deliveries to Henry Hub. These prices were used to quantify the natural gas price hedge offered by PV. NG futures prices show a strong seasonal variation. Annual average prices were used for simplicity.

[24]See http://en.wikipedia.org/wiki/List_of_power_stations_in_Wisconsin. The two units are each 100 MW simple cycle combustion turbines (Westinghouse Model 501B2) built in 1974.

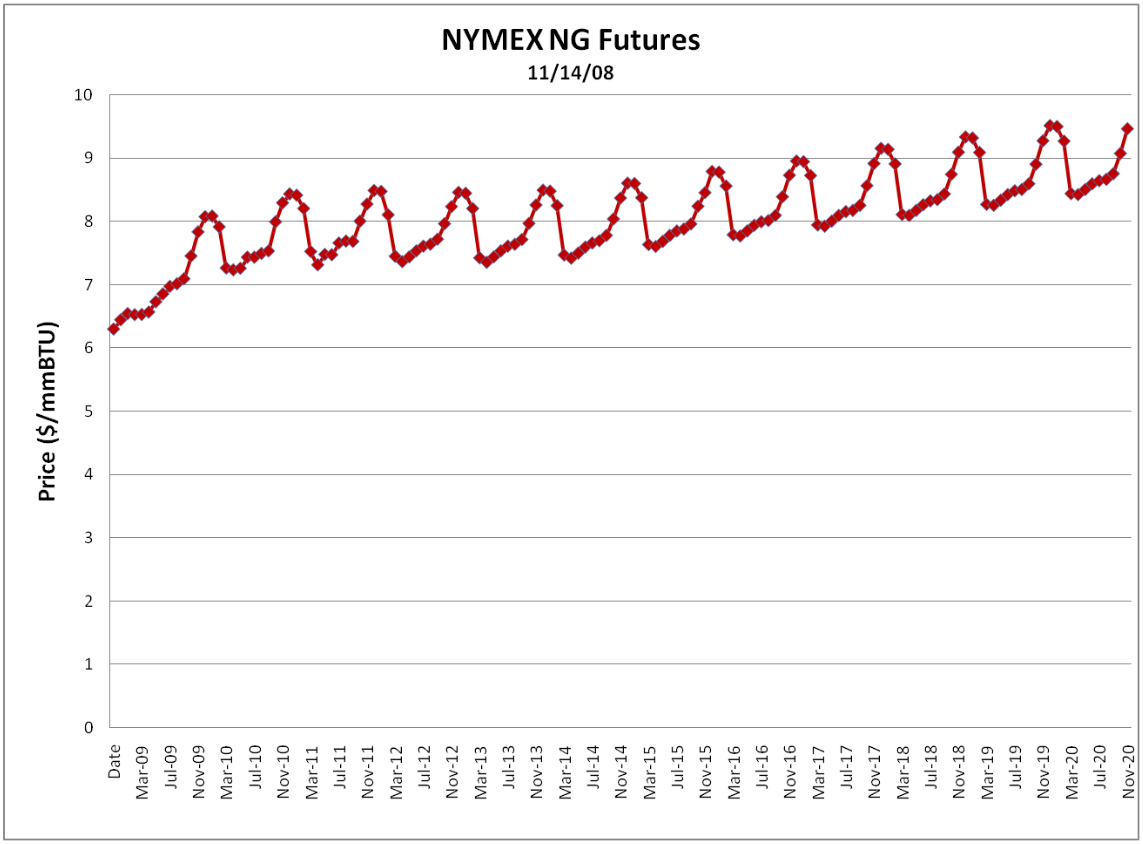
[25] Futures data taken from the Wall Street Journal, online edition, http://online.wsj.com, 11/1/4/06.

Table 30. State of Wisconsin electric generation by primary energy source.[26]

Energy Source	MWh	(%)
Electric Utilities	51,914,755	84.2
Coal	38,866,178	63.1
Petroleum	591,486	1.0
Natural Gas	2,114,624	3.4
Nuclear	8,560,416	13.9
Hydroelectric	1,446,192	2.3
Other Renewables	259,408	0.4
Pumped Storage	-	-
Other	76,451	0.1
IPPs and CHP	9,725,088	15.8
Coal	1,176,558	1.9
Petroleum	275,343	0.4
Natural Gas	3,244,886	5.3
Nuclear	3,673,099	6.0
Hydroelectric	232,406	0.4
Other Renewables	1,089,301	1.8
Other	33,495	0.1
Total Electric Industry	61,639,843	100.0
Coal	40,042,736	65.0
Petroleum	866,829	1.4
Natural Gas	5,359,510	8.7
Nuclear	12,233,515	19.8
Hydroelectric	1,678,598	2.7
Other Renewables	1,348,709	2.2
Pumped Storage	-	-
Other	109,946	0.2

[26] Source (2006): http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept05wi.xls

Figure 16. NYMEX natural gas futures prices.



RESULTS

Heat Rate

Wisconsin statewide average heat rates for natural gas plants was determined using the data in Table 31 for 2007. There were 43,977 million cubic feet of natural gas consumed in 2007 to produce 5,359,510 MWh. The average heat rate was calculated as 8435 BTU/kWh assuming a natural gas energy content of 1028 BTU per cubic foot.[27]

[27] http://en.wikipedia.org/wiki/Natural_gas.

Table 31. State of Wisconsin natural gas consumption by end use.[28]

	MMcf
Pipeline & Distribution Use	3,109
Volumes Delivered to Consumers	369,283
Residential	120,567
Commercial	86,342
Industrial	118,396
Vehicle Fuel	65
Electric Power	43,977
Total Consumption	372,457

Hedge Value – Yearly Basis

Table 32 presents the hedge value for each year of the 30-year life of PV. The annual average prices for the 12 years of available NYMEX NG futures are in column (2) and wholesale electricity prices at the point of generation (corresponding to the average heat rate) are in column (3). These electricity prices represent the fuel cost component of electricity only – not the capacity or O&M cost components.

Risk-free discount rates were based on U.S. Treasury notes of varying maturation dates, corresponding to the yields of column (4). Discount factors were calculated in column (5) using these yields, and the discounted risk-free value is shown in column (6).

A similar set of calculations are shown using EIA forecasted prices in column (7) and the We Energies discount rate in column (9). These calculations show the discounted energy value.

[28] Source (2006): http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SWI_a.htm

Table 32. Hedge value by year.

Treasury Security	Year	(1) Heat Rate (BTU/kWh)	(2) Futures Price ($/mmBtu)	(3) = (2) x (1) Electricity Price ($/kWh)	(4) Discount Rate (Risk-free)	(5) Discount Factor	(6) = (3) x (5) Discounted Value ($/kWh)	(7) Forecast Price ($/mmBTU)	(8) = (7) x (1) Electricity Price ($/kWh)	(9) Discount Rate (Standard)	(10) Discount Factor	(11) = (8) x (10) Discounted Value ($/kWh)
	2008	8435	6.295	0.053	0.0%	100.0%	0.053	7.231	0.061	0.00%	100.0%	0.061
2-year Note	2009	8435	6.877	0.058	1.2%	98.8%	0.057	7.348	0.062	8.52%	92.1%	0.057
2-year Note	2010	8435	7.664	0.065	1.2%	97.6%	0.063	6.902	0.058	8.52%	84.9%	0.049
2-year Note	2011	8435	7.842	0.066	1.2%	96.4%	0.064	6.561	0.055	8.52%	78.2%	0.043
5-year Note	2012	8435	7.831	0.066	2.3%	91.2%	0.060	6.369	0.054	8.52%	72.1%	0.039
5-year Note	2013	8435	7.833	0.066	2.3%	89.2%	0.059	6.160	0.052	8.52%	66.4%	0.035
5-year Note	2014	8435	7.891	0.067	2.3%	87.1%	0.058	5.987	0.051	8.52%	61.2%	0.031
5-year Note	2015	8435	8.051	0.068	2.3%	85.2%	0.058	5.865	0.049	8.52%	56.4%	0.028
10-year Note	2016	8435	8.220	0.069	3.7%	74.6%	0.052	5.820	0.049	8.52%	52.0%	0.026
10-year Note	2017	8435	8.383	0.071	3.7%	71.9%	0.051	5.892	0.050	8.52%	47.9%	0.024
10-year Note	2018	8435	8.561	0.072	3.7%	69.3%	0.050	5.972	0.050	8.52%	44.1%	0.022
10-year Note	2019	8435	8.728	0.074	3.7%	66.8%	0.049	6.055	0.051	8.52%	40.7%	0.021
10-year Note	2020	8435	8.900	0.075	3.7%	64.4%	0.048	5.948	0.050	8.52%	37.5%	0.019
	2021	8435						5.817	0.049	8.52%	34.5%	0.017
	2022	8435						5.951	0.050	8.52%	31.8%	0.016
	2023	8435						6.083	0.051	8.52%	29.3%	0.015
	2024	8435						6.250	0.053	8.52%	27.0%	0.014
	2025	8435						6.391	0.054	8.52%	24.9%	0.013
	2026	8435						6.558	0.055	8.52%	23.0%	0.013
	2027	8435						6.605	0.056	8.52%	21.2%	0.012
	2028	8435						6.864	0.058	8.52%	19.5%	0.011
	2029	8435						7.058	0.060	8.52%	18.0%	0.011
	2030	8435						7.220	0.061	8.52%	16.5%	0.010
	2031	8435						7.242	0.061	8.52%	15.3%	0.009
	2032	8435						7.263	0.061	8.52%	14.1%	0.009
	2033	8435						7.285	0.061	8.52%	12.9%	0.008
	2034	8435						7.307	0.062	8.52%	11.9%	0.007
	2035	8435						7.329	0.062	8.52%	11.0%	0.007
	2036	8435						7.351	0.062	8.52%	10.1%	0.006
	2037	8435						7.373	0.062	8.52%	9.3%	0.006
	2038	8435						7.395	0.062	8.52%	8.6%	0.005

Hedge Value – 30 Years

The 30-year hedge premium is presented in Table 33. The discounted values were summed over the 12-year period for which the risk-free data were available for both the risk-free and conventional cases. The hedge premium was calculated to be 59 percent of the energy value. This percentage was assumed to be valid across the 30-year PV system life.

Table 33. Hedge premium.

	12 years	30 years
Risk Free	0.722	
Standard	0.454	0.644
Hedge Premium	59%	59%

The Fuel Price Hedge Value was calculated in Table 34 by multiplying the hedge premium percentage by the 30-year energy value and the annual energy production (Table 7).

Table 34. Fuel Price Hedge Value per unit of installed PV capacity ($\$/kW_{AC}$).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	680	751	584	547	459	423	494
Albers	692	761	589	554	467	432	501
Union Grove	692	761	589	554	467	432	501

CONCLUSIONS

The hedge value analysis resulted in several observations and conclusions:

- Hedge Value represents the "price premium" associated with the risk-avoidance benefit offered by PV.
- The Hedge Value ranged from \$423 to \$761 per installed kW_{AC} of PV. The range is dependent on PV orientation and location because of the varying energy outputs.

6. TRANSMISSION VALUE

INTRODUCTION

We Energies incurs operating costs from its transmission provider based on monthly peak demand at its distribution substations. We Energies realizes cost savings when PV is able to reduce the peak demand. The Transmission Value is the value of these savings.

APPROACH

Avoided Transmission Costs

American Transmission Company (ATC) is a transmission-only utility that serves the Upper Peninsula of Michigan, the eastern half of Wisconsin, and portions of Illinois. ATC plans, constructs, operates, and maintains its transmission assets to serve electricity producers and distribution companies.

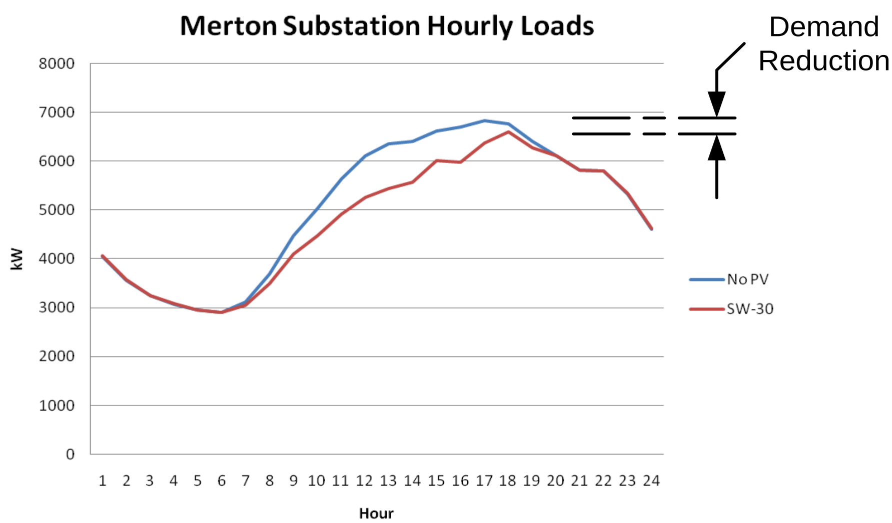
We Energies pays monthly transmission access fees[29] to ATC of about $3.155 per kW of peak monthly demand. PV located in the distribution system may lower overall costs to We Energies by reducing peak demands.

Calculating Demand Reduction

Figure 17 presents hourly loads at Merton Substation for two scenarios: (1) without PV; and (2) with a 1 MW_{AC} PV facility oriented southwest with a 30° tilt angle. The data without PV were measured on June 17, 2007, the day having the highest peak hourly load for the month. The data with PV represent the "net" load that would have been measured, had such a facility been available in the load area served by that substation.

[29] Paul Schumacher, Nov. 2008.

Figure 17. Merton Substation (June 17).



The PV system produced power during the peak hour. Thus, it also would have saved transmission costs by reducing the peak monthly load at Merton. The PV system would have shifted the monthly peak from 17:00 to 18:00. Depending on load shapes and PV output, the new peak hour could occur on a different day entirely. The demand reduction is defined by the difference between peak monthly load, with and without PV regardless of when the new peak occurs.

PV provides the greatest reductions in demand when its output coincides with loads. There is little or no demand reduction at all when the peak occurs at the end of the day or at night.

The transmission savings was calculated by applying the charge ($/kW) to the demand reduction (kW). The overall value for the year was found by summing up the value for each month separately:

$$Value(\$/yr) = \sum_{Month=1}^{12} TransmissionCharge(\$/kW) x DemandReduction_{Month}(kW)$$

RESULTS

The objective of this section is to determine the Transmission Value from PV systems located in the distribution area of the three project sites.

Monthly demand reductions, the hour of day that the peak occurred, and the total demand reduction for the year are presented for Merton Substation in Figure 18. These are expressed as the reduction in peak demand (kW) for a 1 MW_{AC} system. Demand reductions only occur during the months of May through August because of the late timing of the peak load. For example, in April, the peak load occurred at 20:00 hours.

Tracking systems are most effective with the highest demand reduction in August for a 1-axis tracking system without tilt (tilting the tracker to the latitude angle optimizes annual energy production, not summer production). West and southwest-facing systems provide the greatest demand reduction for the fixed systems since these provide a better load match.

The 1-axis tracking system provides a total of 1,046 kW of demand reduction on an annual basis. By comparison, a “perfect match” of PV would provide 1000 kW of demand reduction each month for a total of 12,000 kW for the year.

Economic assumptions are presented in Table 1 and Transmission Values are presented in Table 35.

Table 35. Transmission Value per unit of installed PV capacity ($\$/kW_{AC}$).

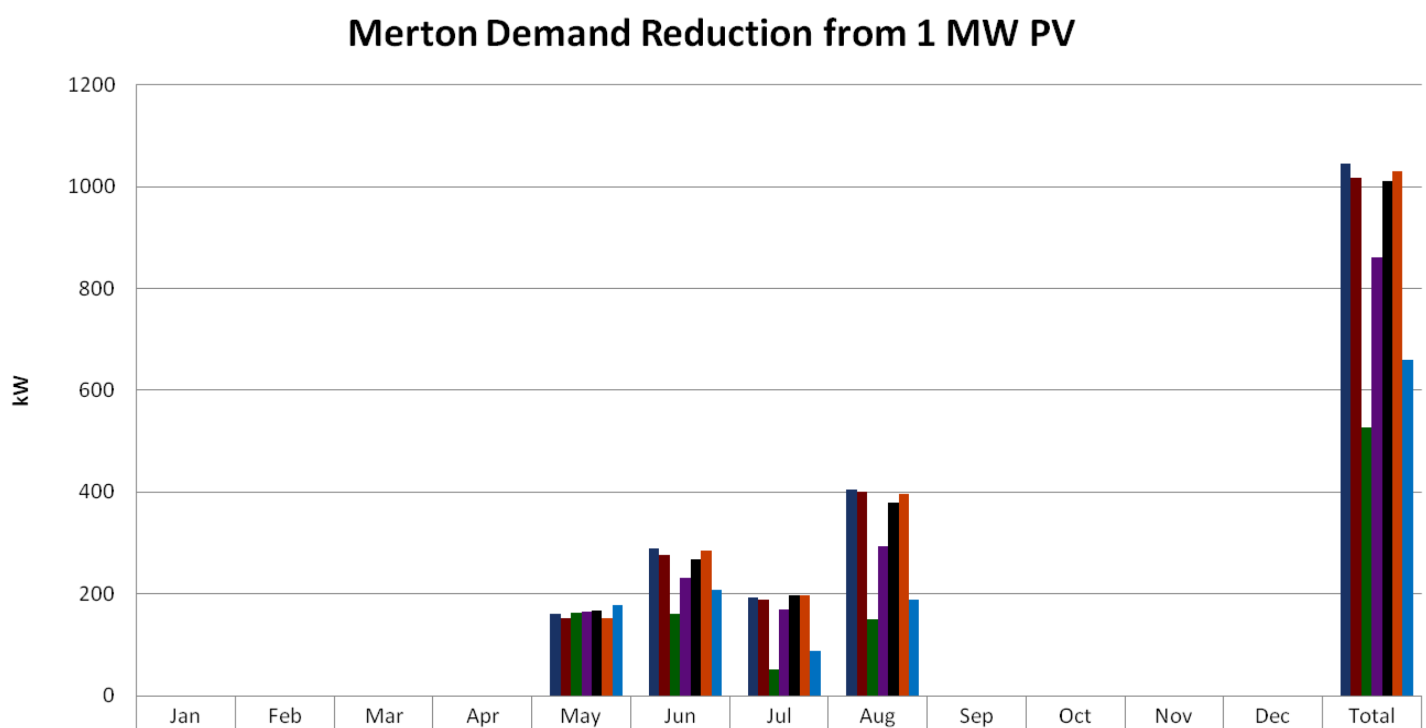
	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	49	47	25	40	47	48	31
Albers	39	39	18	28	33	36	20
Union Grove	53	51	25	39	46	49	31

Conclusions

The Transmission Value analysis produced several observations and conclusions:

- PV reduced transmission demand during the months of May, June, July, and August.
- The peaks occurred too late in the evening (7 pm – 8 pm) during the rest of the year for PV to provide load reduction.
- Tracking systems and west-facing systems were more effective at reducing peaks because the peaks occurred late in the day even during the summer months.
- Transmission Values were low relative to other PV benefits. The maximum benefit was $\$53/kW_{AC}$ for a 1-axis tracking system at Union Grove, primarily due to the poor load match.
- Distribution Value was covered separately.

Figure 18. Merton demand reduction.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Peak	18:00	19:00	19:00	20:00	15:00	17:00	18:00	18:00	20:00	20:00	19:00	19:00	
1 Axis	0	0	0	0	161	289	192	405	0	0	0	0	1046
1 Axis Tilt	0	0	0	0	152	277	189	401	0	0	0	0	1019
South-30	0	0	0	0	164	161	52	151	0	0	0	0	528
SW-30	0	0	0	0	166	231	170	294	0	0	0	0	861
West-30	0	0	0	0	166	268	197	380	0	0	0	0	1011
West-45	0	0	0	0	153	285	197	397	0	0	0	0	1031
Horiz	0	0	0	0	179	207	88	188	0	0	0	0	661

7. Loss Savings Value

Approach

Introduction

Distributed generation technologies reduce system losses by generating power at the point of consumption rather than the point of generation. Loss savings are treated in this analysis as indirect benefits in that they “magnify” the value other benefits and are accounted for in a separate loss savings category.

For example, the generation benefit provided by PV represents the avoided wholesale cost of generating the electricity consumed by the customer. We Energies saves the cost of generating or purchasing a kWh at the point of production for every kWh produced by PV. In addition, We Energies avoids the need to produce supplemental energy to account for losses since PV produces electricity at the point of consumption.

Appropriate loss savings factors need to be determined to calculate the Loss Savings Value. A detailed derivation of these factors was done in a separate study conducted for Austin Energy by CPR[30] in 2006. This study uses the same methodology. The key points of the derivation include:

- 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.
- Energy-related and capacity-related benefits should be calculated on a marginal basis.
- Loss savings should be calculated relative to the DG location rather than to a central generation location. [31]

[30] “The Value of Distributed Photovoltaics to Austin Energy and the City of Austin”, Clean Power Research, 2006. This report can be found at www.cleanpower.com. See Appendix B for the Marginal Loss Savings derivation.

[31] For example, if T&D losses were reported to be 10 percent of the energy produced by central generation, then the loss savings provided by DG would be 0.1/(1 - 0.1) = 11 percent of the energy produced by DG. In this respect, 100 kWh produced by DG would be equivalent to 111 kWh of central generation because it would avoid 11 kWh of losses.

Transmission versus Distribution Loss Savings

The present study deviates from the Austin Energy study in one respect. Selected benefits (e.g., generation) have loss savings associated with distribution only, while other benefits (e.g., Fuel Price Hedge) have loss savings associated with transmission and distribution. The previously-calculated generation benefit, for example, included transmission loss savings since LMPs included transmission loss factors and were defined at physical nodes immediately before entering the distribution system.

Table 36 summarizes whether loss savings are associated with the distribution system only (D), the combined transmission-distribution system (T&D), or neither (N/A). Generation, transmission, and distribution loss savings only include distribution losses since these benefits were effectively valued at the point of connection to the transmission system (not at the generation source). Generation costs, for example, used LMP pricing at the pricing node, after transmission losses. Transmission pricing is taken at the distribution substation (not at the power plant). Fuel Price Hedge loss savings takes into account distribution and transmission losses because they are evaluated relative to the point of generation. The Environmental benefit has no loss savings because the value is derived from the amount of energy produced by PV, regardless of location.

Table 36. Loss characterization by benefit category.

	Merton	***Albers***	***Union Grove***
Generation	D	D	D
Transmission	D	D	D
Distribution	D	D	D
Environment	N/A	N/A	N/A
Fuel Price Hedge	T&D	T&D	T&D

Average Losses

Transmission losses into the WEC area were obtained from the Midwest ISO[32] as shown in Table 37. These losses corresponded to the time of average load. The average load losses were scaled to a value representing 100 percent load using the relation:[33]

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

where η is the percent losses at the time of the system average load, T represents the time of the average load and t represents the time of the peak. Hourly We Energies system load data[34] was analyzed for the power ratio, and the average, peak and peak/average ratio are shown in Table 38. The result of the calculation is shown as the average transmission losses at 100 percent load in Table 37.

Table 37. Transmission losses.

Average (average load)	1.90%
Average (100% load)	3.34%

Table 38. We Energies system load (kW).

Average	3,454,643
Peak	6,086,000
Peak/Average Ratio	1.76

[32] Transmission loss factors were taken from http://www.midwestiso.org/publish/Document/1d6630_11a6da4545e_-7f640a48324a?rev=1. Percentage losses were averaged across all transmission paths into area WEC.

[33] See the Austin Energy study, Appendix B ("Marginal Loss Savings"), equation 8.

[34] Provided by Eric Rogers to Drew Szabo on March 20, 2007, covering the period September 2003 through August 2006. For consistency with the other benefit calculations, system loads only from the period of 9/23/05 to 9/22/06 are used, with the 22 days of September 2006 taken from the identical days of 2005.

Distribution losses are presented in Table 39 for the three study areas of interest, as calculated at the 100 percent load condition by the We Energies Distribution Operations Department.[35] The distribution system in the areas of interest consists of two levels. The first level is a 24.9 kV distribution system and the second an 8.32 kV distribution system. The 24.9 kV system is supplied by 138 kV transmission and feeds all classes of customers directly (through utilization transformers), as well as providing supply to We Energies 24.9-8.32 kV substations.

Merton and Union Grove substations are all 24.9-8.32 kV substations supplied from a 24.9 kV feeder. Therefore, distribution losses include the 8.32 kV feeders, 24.9-8.32 kV substation transformers, the 24.9 kV feeders and the 138-24.9 kV substation transformers. Albers feeder projects involve only 24.9 kV feeders. Therefore, losses on the 8 kV feeders and 24.9-8.32 kV transformers would not be applicable.

The T&D upgrades associated with the projects listed below would reduce energy losses. No account was made for this fact in the study.

Table 39. Distribution losses.

	Merton	***Albers***	***Union Grove***
8.32 kV feeders	1.8%		1.8%
24.9/8.32 kV transformer	0.7%		0.7%
24.9 kV feeders	2.0%	2.0%	2.0%
138/24.9 kV transformer	0.4%	0.4%	0.4%
Average losses (100% load)	4.9%	2.4%	4.9%

[35] Data provided by John Nesbitt, 11/15/06.

Hourly Loss Factors

Next, the losses saved were considered from the perspective of the customer-generator. Marginal loss factors were calculated for each hour during the year because the benefits were calculated using hourly values and the loss factors varied hourly depending upon the load. The loss factors represent marginal loss savings—defined as the change in generation per unit change in consumption. The calculation is based on the relation[36]

$$LF_i = \frac{dP_i^0}{dP_i^1} = \left(\frac{1}{1 - \eta_T \left(\frac{P_i^0}{P_T^0} \right)} \right)^2$$

where, T represents the time of the peak, i represents the hour, and η_T is the average loss percentage at the peak hour.

Separate hourly loss factors were calculated for transmission and distribution. The distribution loss factors represent the losses between the distribution substation and the customer, while the transmission loss factors represent the losses between a typical generator on the system and the distribution substation. The combined T&D hourly loss factor is:

$$LF_{T\&D\,i} = LF_{T\,i} \times LF_{D\,i}$$

Loss Savings Percentages

Loss savings percentages for each benefit were calculated as follows. The loss savings percentage for generation represents the percentage increase in the $/kW$_{AC}$ generation benefit value associated with avoided losses. It is calculated as:

$$LS_{gen} = \frac{\sum_i LF_{D\,i} \times LMP_i \times E_i - \sum_i LMP_i \times E_i}{\sum_i LMP_i \times E_i}$$

The baseline Generation Value determined previously corresponds to the second term in the numerator. The value for each hour is the product of the LMP for that hour and the energy generated by PV. However, the actual Generation Value, including the effect of losses in the

[36] See the Austin Energy study, Appendix B ("Marginal Loss Savings"), equation 20.

distribution system, is represented by the first term in the numerator. The percentage is calculated to facilitate the presentation of losses as a separate benefit category.

Both transmission and distribution benefits represent the effective capacity of the PV system as measured at the distribution substation and were calculated using the distribution loss factors. The environmental and fuel price hedge benefits, on the other hand, were calculated from the combined T&D loss factors.

RESULTS

Loss savings percentages were calculated in Table 40 using the above equations and summed over the year. Notice that the percentages are higher for the Fuel Price Hedge Value since these include both transmission and distribution losses. Also note that Albers percentages are noticeably lower than the other locations due to the higher voltages.

Table 40. Loss savings percentages by value component and configuration.

Generation Value	***1 Axis***	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	4.2%	4.2%	4.1%	4.3%	4.4%	4.5%	4.2%
Albers	2.3%	2.3%	2.2%	2.3%	2.4%	2.4%	2.3%
Union Grove	4.6%	4.6%	4.5%	4.7%	4.8%	4.9%	4.6%
Transmission Value							
Merton	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
Albers	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Union Grove	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Distribution Value							
Merton	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
Albers	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Union Grove	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Hedge Value							
Merton	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%
Albers	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%
Union Grove	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%

The Loss Savings Value was calculated by applying these percentages to the previously calculated benefits as shown in Table 41. For example, the Generation Value for a 1-axis tracking system at Merton was determined previously to be \$1,522/kW$_{AC}$. Applying the loss savings of 4.2 percent (from Table 40) resulted in a loss savings for this benefit of \$64/kW. Repeating this calculation for the other four benefits and summing resulted in a total Loss Savings Value of \$226/kW.

Table 41. Loss Savings Value per unit of installed PV capacity (\$/kW$_{AC}$).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	124	135	103	103	90	85	90
Albers	77	85	65	63	55	51	56
Union Grove	134	146	110	109	96	91	96

8. SUMMARY AND CONCLUSIONS

SUMMARY

The objective of this report is to present the results of the value analysis from the perspective of We Energies at a specific point in time. The individual value components are summarized in Table 42, including Generation, Transmission, Distribution, Environmental, Fuel Price Hedge, and Loss Savings Values. Each of these are presented by location and PV system configuration. Table 43 levelizes the results to a per unit energy value. Figure 19 and Figure 20 present the total values graphically in terms of per unit of installed capacity and per unit of energy. Figure 21 presents the value components for Merton substation for the various configurations and Figure 22 presents the value components for a South-30 configuration at the three locations.

CONCLUSIONS

For the time period during which this study was conducted, this analysis leads to the following conclusions:

- Value per unit of installed PV ***capacity*** (\$ per kW_{AC}) was approximately linearly related to energy production for the variations configurations and thus value per unit of ***energy*** (\$ per kWh) was relatively independent of location and configuration.
- Value per unit of energy was about \$0.15 per kWh over the PV system's 30 year lifetime. This value is sensitive to the data (especially the value of energy) that was used at the time of the study and should be interpreted within that context.
- There was significant variation in value that is related to system configuration due to the difference in the amount of annual energy production.
- There was minimal variation in value that is related to system location.
- Generation, Environmental, and Fuel Price Hedge Value components comprised the highest portion of total value.
- Transmission and Distribution Value components were small in comparison to other components.
- Loss Savings Value was small but not insignificant.

Table 42. Value components per unit of installed capacity by location and configuration ($\$/kW_{AC}$).

	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz
Generation Value							
Merton	1,522	1,682	1,338	1,273	1,080	1,001	1,134
Albers	1,536	1,691	1,340	1,282	1,095	1,017	1,144
Union Grove	1,536	1,691	1,340	1,282	1,095	1,017	1,144
Environmental Value							
Merton	1,321	1,458	1,134	1,062	891	822	960
Albers	1,343	1,477	1,144	1,075	907	838	973
Union Grove	1,343	1,477	1,144	1,075	907	838	973
Fuel Price Hedge Value							
Merton	680	751	584	547	459	423	494
Albers	692	761	589	554	467	432	501
Union Grove	692	761	589	554	467	432	501
Distribution Value							
Merton	145	143	45	129	149	149	70
Albers	49	49	11	30	39	45	16
Union Grove	147	145	43	92	116	132	56
Transmission Value							
Merton	49	47	25	40	47	48	31
Albers	39	39	18	28	33	36	20
Union Grove	53	51	25	39	46	49	31
Loss Savings Value							
Merton	124	135	103	103	90	85	90
Albers	77	85	65	63	55	51	56
Union Grove	134	146	110	109	96	91	96
Total Value							
Merton	3,842	4,217	3,229	3,154	2,716	2,527	2,778
Albers	3,737	4,101	3,168	3,033	2,595	2,419	2,710
Union Grove	3,905	4,270	3,252	3,152	2,726	2,557	2,801

Table 43. Value components per unit of energy by location and configuration ($/kWh).

	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz
Generation Value							
Merton	0.0610	0.0611	0.0625	0.0634	0.0642	0.0645	0.0625
Albers	0.0605	0.0606	0.0620	0.0631	0.0639	0.0642	0.0622
Union Grove	0.0605	0.0606	0.0620	0.0631	0.0639	0.0642	0.0622
Environmental Value							
Merton	0.0529	0.0529	0.0529	0.0529	0.0529	0.0529	0.0529
Albers	0.0529	0.0529	0.0529	0.0529	0.0529	0.0529	0.0529
Union Grove	0.0529	0.0529	0.0529	0.0529	0.0529	0.0529	0.0529
Fuel Price Hedge Value							
Merton	0.0273	0.0273	0.0273	0.0273	0.0273	0.0273	0.0273
Albers	0.0273	0.0273	0.0273	0.0273	0.0273	0.0273	0.0273
Union Grove	0.0273	0.0273	0.0273	0.0273	0.0273	0.0273	0.0273
Distribution Value							
Merton	0.0058	0.0052	0.0021	0.0065	0.0089	0.0096	0.0039
Albers	0.0019	0.0018	0.0005	0.0015	0.0023	0.0028	0.0009
Union Grove	0.0058	0.0052	0.0020	0.0045	0.0068	0.0083	0.0030
Transmission Value							
Merton	0.0020	0.0017	0.0011	0.0020	0.0028	0.0031	0.0017
Albers	0.0015	0.0014	0.0008	0.0014	0.0019	0.0023	0.0011
Union Grove	0.0021	0.0018	0.0012	0.0019	0.0027	0.0031	0.0017
Loss Savings Value							
Merton	0.0050	0.0049	0.0048	0.0051	0.0054	0.0054	0.0049
Albers	0.0031	0.0030	0.0030	0.0031	0.0032	0.0032	0.0031
Union Grove	0.0053	0.0052	0.0051	0.0054	0.0056	0.0057	0.0052
Total Value							
Merton	0.1539	0.1531	0.1507	0.1572	0.1614	0.1628	0.1533
Albers	0.1473	0.1470	0.1466	0.1493	0.1515	0.1528	0.1475
Union Grove	0.1539	0.1530	0.1505	0.1552	0.1592	0.1616	0.1524

Figure 19. Total value per unit of installed PV capacity by system configuration and location.

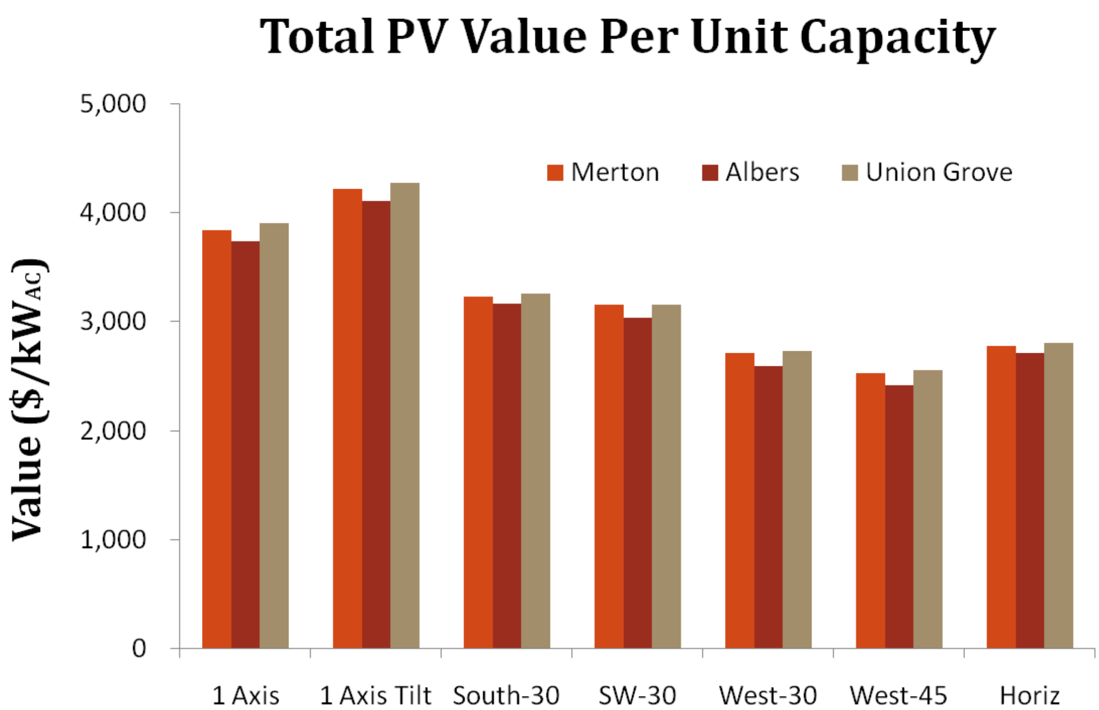


Figure 20. Total value per unit of energy by configuration and location.

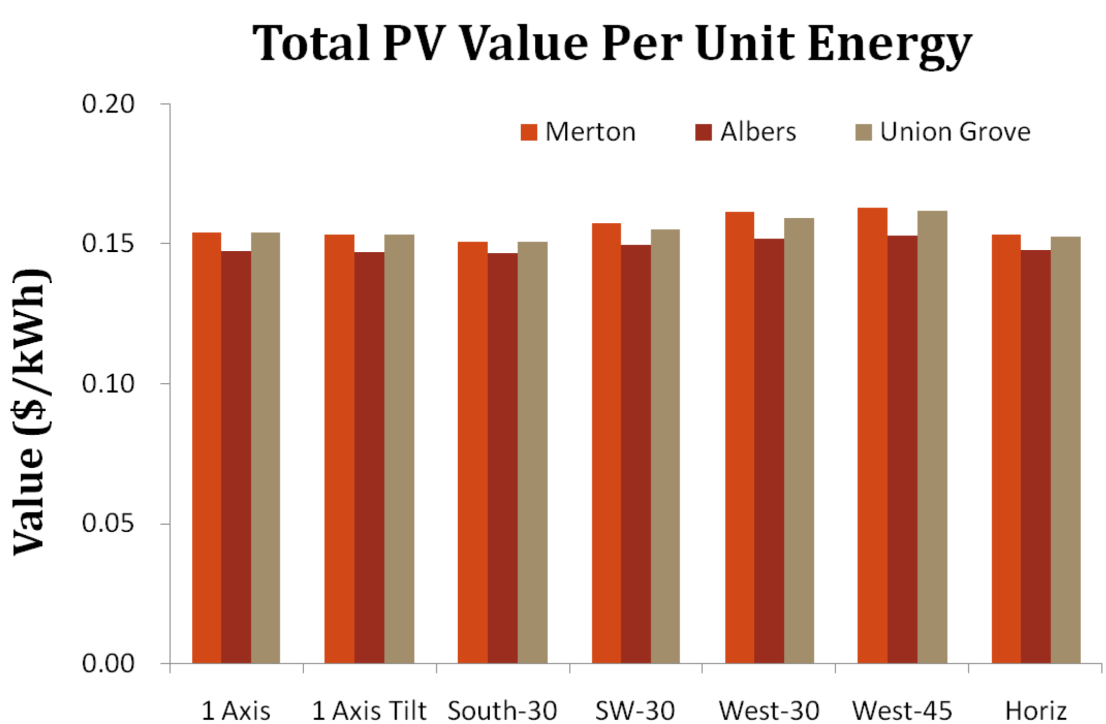


Figure 21. Value per unit of installed PV capacity by configuration for Merton Substation.

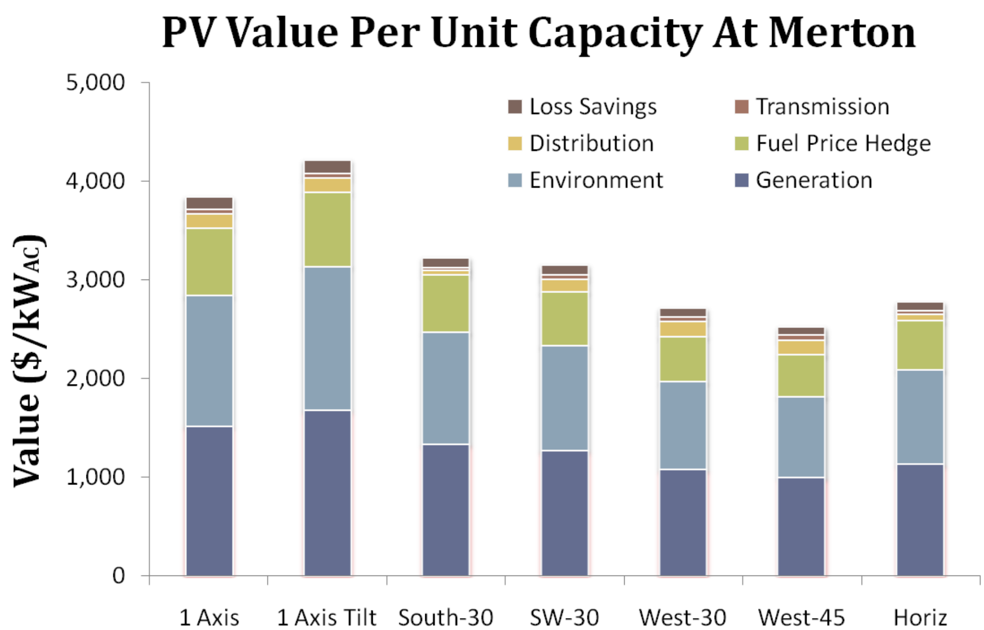
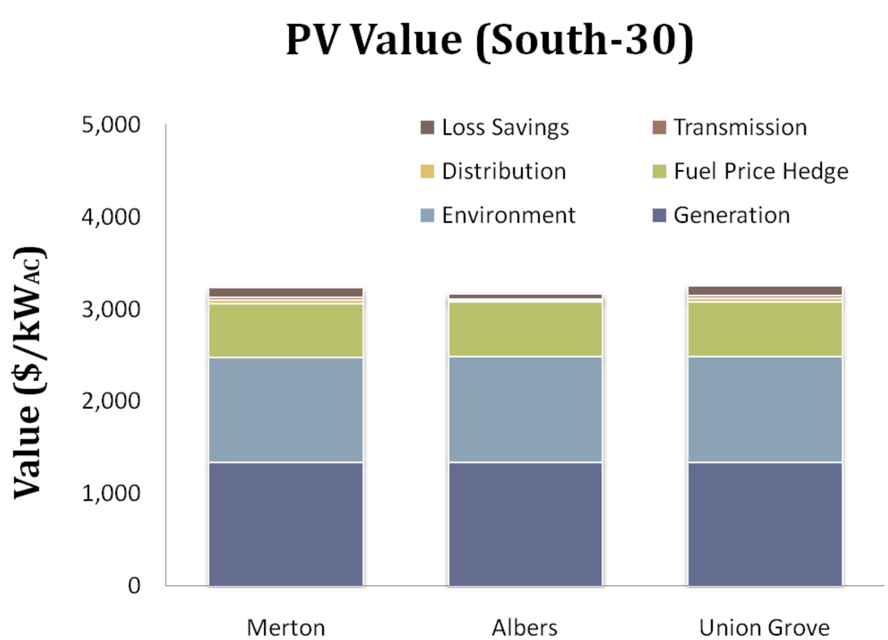


Figure 22. Value per unit of installed PV capacity by location (South-30 orientation).



NEXT STEPS

The following cautions must be observed in considering these results:

- The results of this study are sensitive to the LMPs used. The following table compares some statistics of the LMPs used in the study to the LMP statistics for the period September 2008 through August 2009. A comparison of the two shows that the LMPs have changed significantly. There is a need to rerun this study to obtain a better reflection of the current value of PV as the LMPs change.

	LMPs used in Study			*LMPs year ending Aug. 2009*		
Node	***Max***	***Min***	***Avg***	***Max***	***Min***	***Avg***
GERMANOT1	273.24	4.83	48.72	144.12	-21.69	30.74
PARIS01S1	199.72	5.20	48.36	142.46	-24.51	30.29
PLPRG41	195.59	4.96	45.67	139.39	-38.79	29.10

- The MISO LMPs only reflect energy value and do not include capacity value. The value of generation capacity is very low at this time and was not included in the economic valuation. Future studies should include the generation capacity value of PV.
- We Energies RRC are not currently tradable outside of Wisconsin. This analysis assumes that RECs can be traded across state lines. Further evaluation is required to assess this.
- The Transmission Value depends upon whether PV is claimed as a generation resource or as negative load. This analysis assumed that PV was operating as negative load and that ATC prices are not reallocated as a result of the installation of PV. PV as a generation resource or ATC price reallocation will require a different analysis.