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The Value of Photovoltaics in the Distribution System

The Kerman Grid-Support Project

May 1995

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ABSTRACT

As part of the Photovoltaics for Utility Scale Applications (PVUSA) Project, Pacific Gas and Electric Company (PG&E) built the Kerman 500-kW photovoltaic power plant. Located near the end of a distribution feeder in a rural section of Fresno County, the plant was not built so much to demonstrate PV technology, but to evaluate its interaction with the local distribution grid and quantify available non-traditional grid-support benefits (those other than energy and capacity).

As demand for new generation began to languish in the 1980s, and siting and permitting of power plants and transmission lines became more involved, utilities began considering smaller, distributed power sources. Potential benefits include shorter construction lead time, less capital outlay, and better utilization of existing assets. The results of a PG&E study in 1990/1991 of the benefits from a PV system to the distribution grid prompted the PVUSA Project to construct a plant at Kerman.

Completed in 1993, the plant is believed to be the first one specifically built to evaluate the multiple benefits to the grid of a strategically sited plant. Each of nine discrete benefits were evaluated in detail by first establishing the technical impact, then translating the results into present economic value. Benefits span the entire system from distribution feeder to the generation fleet. This work breaks new ground in evaluation of distributed resources, and suggests that resource planning practices be expanded to account for these non-traditional benefits.

This report is one in a series by PVUSA on experiences and lessons learned through fielding PV systems at the Davis and Kerman, California, sites and at participating "host" utilities. Other topical reports address:

- Construction and safety experience in installing and operating PV systems
- Five-year assessment of emerging module technologies (EMTs)
- Balance-of-system designs and costs
- Power conditioning units, utility interface, and power quality
- Procurement, rating, and acceptance practices
- Data acquisition and analysis

EXECUTIVE SUMMARY

The Kerman Grid-Support Project was initiated to determine the magnitude of benefits provided by the Kerman photovoltaic (PV) power plant to PG&E and to improve and document methods to determine the value of distributed generation technologies.

It has been hypothesized that strategically sited PV generation could support parts of transmission and distribution (T&D) systems near or at overload conditions, as well as forestall utility T&D investments. A case study of Pacific Gas and Electric Company's (PG&E) Kerman Substation, near Fresno, California, was conducted to investigate this hypothesis.[1] This study concluded that a distributed PV plant located near the Kerman Substation could defer the replacement of a substation transformer and thereby capture financial savings. The study also found that the PV plant could deliver a significant series of other tangible non-traditional benefits to the utility network, in addition to the traditional energy and capacity values typically attributed to generation resources. As a result of this study, the Kerman 500-kW grid-support PV plant was constructed and began operation in 1993. It is believed that Kerman is the world's first plant designed and built specifically to measure the benefits of a PV system to the local utility distribution grid.

The Kerman Grid-Support Project confirms that a strategically sited PV plant can deliver non-traditional financial benefits to the utility. For Kerman, the resource's value *doubled* relative to a traditional central station resource planning perspective. This outcome challenges current resource planning methods to be expanded to adequately capture the impact of photovoltaics and other distributed generation resources.

BENEFITS EVALUATION APPROACH

A two-step approach is used to determine the value of the Kerman PV plant to PG&E. The first step is technical: Measured data are combined with existing utility engineering models and improved evaluation techniques to determine the operational effect of the grid-support PV plant on the utility system. The second step is economic: The technical results are combined with economic models to estimate the plant's value to the utility.

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[1]Shugar, D., R. Orans, A. Jones, M. El-Gassier, and A. Suchard, *Benefits of Distributed Generation in PG&E's Transmission and Distribution System: A Case Study of Photovoltaics Serving Kerman Substation,* Report 007.5-92.9 prepared for Pacific Gas and Electric Company, Research and Development, November 1992.

Table ES-1 presents an overview of the traditional and non-traditional benefits evaluated and final results. These results are specific to the Kerman plant and its location within the distribution system, as well as PG&E's present economic and regulatory operating environment.

Table ES-1

Kerman PV Plant Benefits Evaluated and Final Results ($1995)

Non-Traditional Benefits	Benefit Definition & Economics Driver	Technical Results	Economic Results Nominal ($/kW-yr)	High ($/kW-yr)
Externalities	*Fossil fuel emissions reduction.* Driver: Generation fleet fuel mix and externality valuation method	Pollution is reduced by 155 tons of CO_2 and half a ton of NO_X each year.	30	35
Reliability	*Local reliability enhancement.* Driver: Postpone planned expenditures to improve reliability	Voltage support is predictable and almost 3 V provided (on a 120-V base). Testing proves customer outage time can be reduced.	5	5
Loss Savings	*Real and reactive loss savings.* Driver: PV plant capacity factor and interconnection location	Real energy losses reduced by 58,500 kWh/yr (or 5% of plant output). Reactive power losses reduced by 350 kVAR.	15	15
Feeder	*Feeder/conductor upgrade deferral.* Driver: Magnitude of planned upgrade expenditures and load growth rate	Feeder capacity increased by 320 kW on peak. (Economic value is zero because no upgrades are planned for the Kerman feeder.)	0	0
Substation	*Transformer replacement and load-tap-changer maintenance deferral.* Driver: Magnitude of planned upgrade expenditures and load growth rate	Transformer cooled by more than 4°C and its capacity increased by 410 kW on peak day. Load-tap-changer maintenance interval extended by more than 10 years.	15	90
Transmission	*Transmission capacity deferral.* Driver: Marginal cost of transmission capacity	Transmission system capacity increased by 450 kW on peak.	45	45
Minimum Load	*Power plant dispatch savings.* Driver: Marginal cost of keeping peak load-following units on line	Minimum load savings confirmed. PV plant delivers 90% PV capacity coincident with peak load-following unit dispatch.	30	30
Traditional Benefits	**Benefit Definition & Economics Driver**	**Technical Results**	**Nominal ($/kW-yr)**	**High ($/kW-yr)**
Capacity	*System reliability enhancement.* Driver: Utility need for capacity to improve system reliability	Generation system capacity increased by 385 kW (ELCC about 77%).	10	50
Energy	*Energy generation displacement.* Driver: Fuel price of avoided energy generation resource	Plant achieved about 25% capacity factor, over 1,080 MWh/yr, highly correlated to PG&E loads.	145	155
TOTAL VALUE			295	425

The Kerman PV plant provides the PG&E system every benefit listed in Table ES-1. By locating generation near customer loads, the plant is able to deliver benefits spanning the distribution feeder, the substation, the high-voltage transmission system, and the generation fleet.

The second essential step of the benefits evaluation process is to translate each of the technical benefits into economic values. These values are then summed to derive the total value of the Kerman PV plant. The economic analysis is based on a life-cycle approach commonly used in utility resource planning. The results are levelized, expressed in $/kW-year based on the plant's 500-kW rating.

These results represent tangible economic benefits. Each benefit represents the value of the least-cost alternative the utility would otherwise employ in standard practice. For example, every kilowatthour of energy produced by the PV plant replaces a kilowatthour that PG&E would otherwise have to supply. The economic value of not supplying this energy from some other source is calculated over the 30-year project lifetime, brought to the present using the utility's discount rate, and then levelized to provide an annually recurring value.

ECONOMIC RESULTS

Table ES-1 and Figure ES-1 present the final economic analysis results for the Kerman PV plant (results have been rounded to the nearest $5 increment). Two sets of results are presented. The "nominal" value of the plant, at $295/kW-yr, represents the baseline evaluation under present (existing) conditions. The "high" value of $425/kW-yr represents a sensitivity to the Nominal Case. The High Case is developed to make the results applicable to a constrained distribution area while accounting for long-term plant performance. The High Case considers three factors that are different from the Nominal Case:

1. The Kerman feeder is assumed to be an isolated radial line (this eliminates load switching capability) which maximizes the amount of time the PV plant can defer the substation transformer replacement (impacts substation value).

2. PG&E will need bulk system generation capacity sooner than forecasted in the Nominal Case (impacts capacity value).

3. Kerman PV plant production is increased by about 10% to 1,190 MWh/yr, reflecting expected plant performance over its 30-year life (impacts externalities, electrical losses, and energy values).

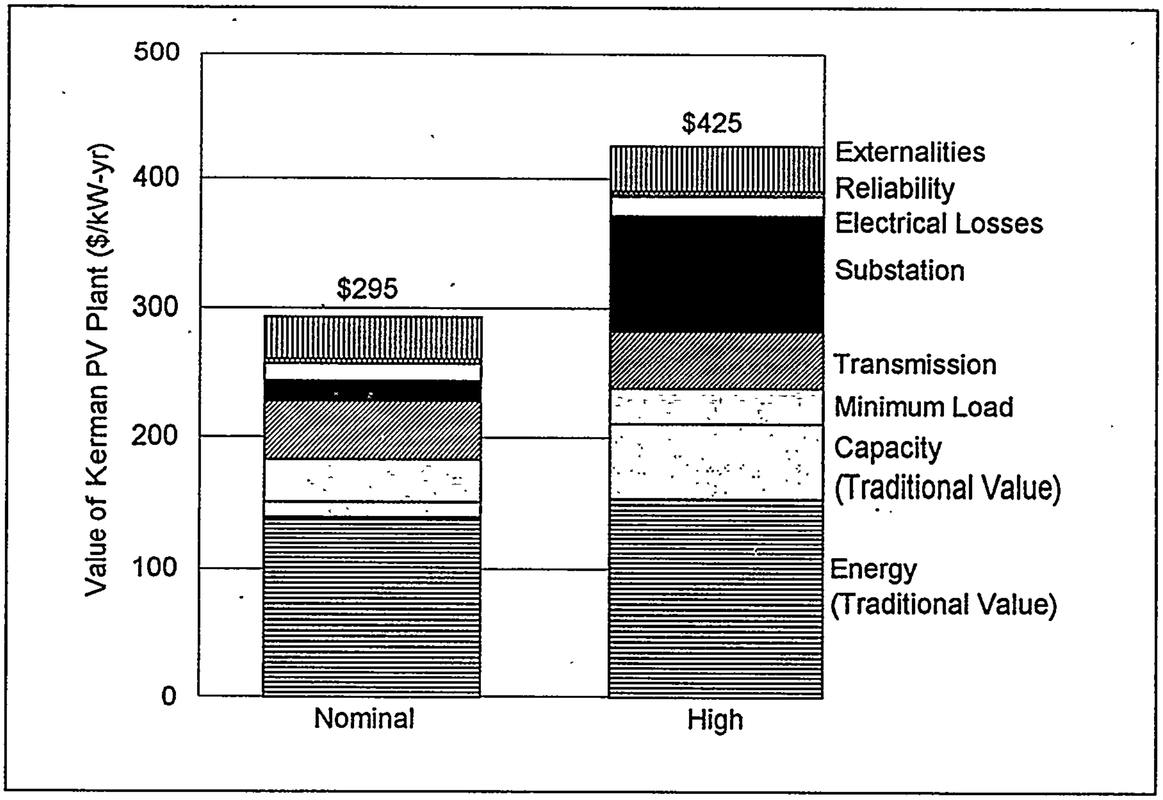

Figure ES-1. Value of the Kerman PV plant to PG&E ($1995).

Regardless of which set of factors are considered, one predominant conclusion is clear: The value of the Kerman plant is *doubled* by capturing non-traditional benefits. That is, the distributed PV plant is worth twice what it would be if evaluated from a traditional central station resource perspective. The equivalent levelized value of the PV generation is 14 to 20¢/kWh as a distributed resource versus 7 to 10¢/kWh evaluated as a central station resource..

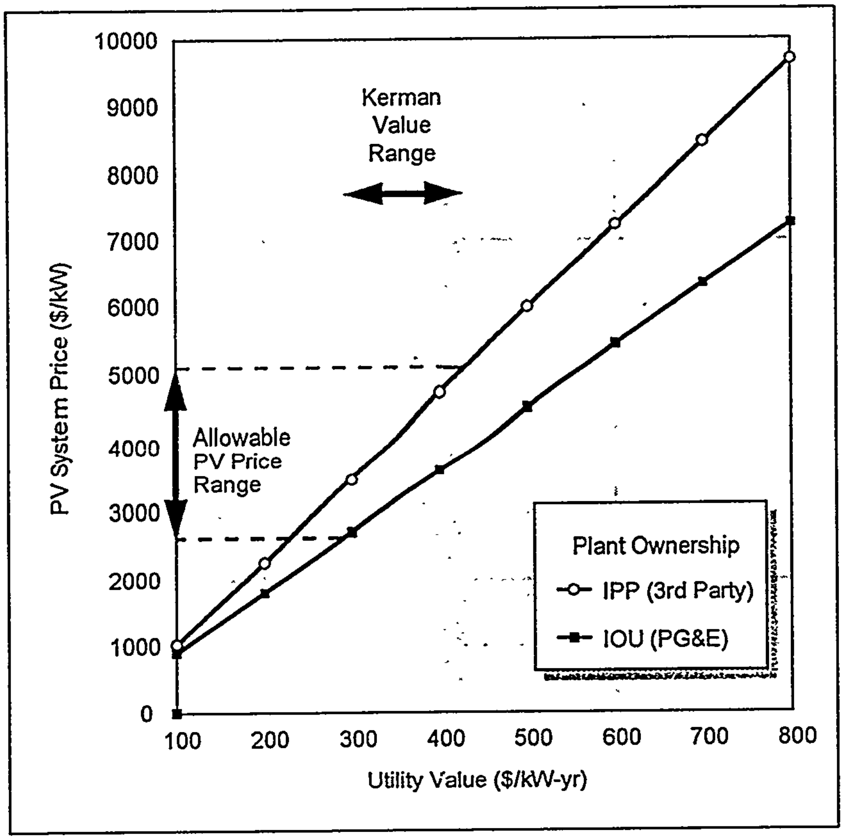

Figure ES-2. Allowable PV price depends on plant ownership.

ALLOWABLE PV PRICE

The allowable or break-even PV system price can be calculated once the economic value of the plant is established. The allowable price is the PV system price required just to balance the value and cost of ownership, including cost of capital, operation and maintenance (O&M), taxes, insurance, depreciation, and rate of return.

Figure ES-2 presents the allowable PV price as a function of plant value for two ownership scenarios: investor-owned utility (IOU), represented by PG&E, and independent power producer (IPP). The allowable PV price for the Kerman PV plant ranges between $2,700/kW and $3,800/kW for PG&E ownership, and from $3,400/kW to over $5,000/kW for IPP ownership. This is lower than PV system market prices, however, which are currently around $7,000/kW.

The IPP scenario is considered to be as likely as utility ownership as a result of electric utility restructuring, which is encouraging competitive bidding of generation and open access to the transmission and, perhaps, the distribution system. IPPs presently have several advantages over IOUs to finance power plant construction that can enable the IPP to afford a more expensive plant while maintaining profitability. Economic conditions under which IPPs operate suggest a 20 to 30% financial advantage (Figure ES-2). Cooperatives and municipals will also have some advantage over IOUs. Economics for both IOUs and IPPs are changing, however, and the differential may decrease substantially in the future.

Table ES-2 presents the key economic results for the Kerman grid-support PV plant.

Table ES-2

Value and Allowable PV System Price ($1995)

	Value of Kerman Grid-Support PV System			Allowable PV System Price IOU	Allowable PV System Price IPP
	$/kW-yr	$/kW	¢/kWh	($/kW)	($/kW)
Nominal Case	295	3,030	14	2,700	3,400
High Case	425	4,365	20	3,800	5,000

CONCLUSIONS

The following major conclusions are drawn from the Kerman Grid-Support Project:

- Data analysis and testing provide concrete evidence that both traditional and non-traditional benefits are measurable and significant for grid-support PV applications. The Kerman PV plant provides benefits that span the entire utility network, including the distribution feeder and substation, transmission system, and generation fleet.

- Non-traditional benefits double the overall value of the Kerman plant relative to a traditional central station resource planning perspective. The equivalent levelized value of the PV generation is about 300 to 430 $/kW-yr (14 to 20¢/kWh equivalent) as a distributed resource versus 150 to 215 $/kW-yr (7 to 10¢/kWh equivalent) evaluated as a central station resource.

- The allowable PV system price for the Kerman location is between $2,700/kW and $5,000/kW, depending on plant ownership and value scenarios. Evaluated as a traditional central station resource, the allowable PV system price range would be halved.

- The economic value of grid-support photovoltaics is driven by three factors: local system characteristics, solar resource and plant performance, and "global economics," including fuel cost projections, cost of capital, and marginal energy and capacity value. One-third of the difference between the 1992 Case Study and the results of this research is attributable to the change in global economics, which is independent of the evaluation approach. This highlights the importance of global economic assumptions and their impact on resource cost-effectiveness.

- Methods developed to evaluate the Kerman grid-support PV plant are generally applicable to other forms of distributed resources and applications.

The Kerman Grid-Support Project results are promising from a renewable and distributed resource perspective. The research broadens the understanding of value from strategically sited resources and provides methods for non-traditional benefit evaluation for resource planning and regulatory oversight.

Project Manager Brian K Farmer

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Research Director Gerald R. Miller

Gerald R. Miller

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Section 1

INTRODUCTION

BACKGROUND

A common practice of electric utilities encountering transmission and distribution (T&D) system overloads is to invest in new facilities such as substation transformers and T&D lines. This facilities expansion approach is capital-intensive and forces the utility to make long-term financial commitments to solve potentially short-term problems. In 1988, it was hypothesized that strategically sited photovoltaic (PV) generation could support parts of T&D systems near or at overload conditions and forestall utility T&D investments. An evaluation methodology was developed and a study was conducted of Pacific Gas and Electric Company's (PG&E) Kerman Substation, near Fresno, California. The conclusion of this study, detailed in a report referred to as the "1992 Case Study," indicated that the value of PV to the T&D system would exceed its traditional value of energy and generation capacity (Shugar et al. 1992).

Most importantly, this conclusion indicated the need for empirical validation, and PG&E consequently constructed a 500-kW PV demonstration plant at Kerman, California, as part of the PVUSA (Photovoltaics for Utility Scale Applications) project. PVUSA is a national public-private partnership that was initiated to assess and demonstrate the viability of utility-scale PV electric generation systems. The Kerman PV plant, commissioned for full operation in June 1993, is reported to be the first grid-support PV demonstration plant in the world.

OBJECTIVES

The Kerman Grid-Support Project has two primary objectives:

1. To determine the magnitude of benefits provided by the Kerman PV power plant to PG&E.
2. To improve and document methods to determine the value of distributed generation technologies.

BENEFITS EVALUATION APPROACH

The following elements represent the central parts of the research process:

- **Review 1992 Case Study:** The 1992 Case Study was used as a reference throughout this research effort. It provided the foundation and important insights from which new methods were developed and was extremely useful in performing the benefits evaluation.

- **Obtain Measured Data:** Data were obtained in two ways. First, an automated data system collected more than 130 parameters on a real-time basis, covering the solar resource at Kerman, PV plant performance, and utility distribution operation. This system stored the data every 10 minutes. Second, a variety of field tests were conducted to assess specific aspects of the interaction between the PV plant and the utility system. These tests included the effect of PV on distribution system voltage, energy losses, transformer and conductor temperatures, and distribution system reliability. Most of the research is based on data collected over the one-year study period from July 1, 1993 to June 30, 1994. Analysis of certain benefits, however, also uses data collected in June 1993, particularly June 25, because of peak load conditions on the Kerman substation transformer.

- **Develop Methods:** The 1992 Case Study methods for evaluating the technical interaction between the PV plant and the utility system were initially used. During the process of analyzing data, however, it was found that some of these methods did not adequately model the existing system. In some cases, the 1992 Case Study methods were modified, while in others, entirely new methods were developed using standard engineering practices and basic scientific principles.

- **Perform Technical and Economic Analysis:** Measured data were fed into existing utility engineering models to determine the technical or operational effect of grid-support PV on the utility system. Economic models were then applied to these technical results to estimate the value of grid-support PV to the utility.

Updated evaluation methods were developed for several of the value components, including transformer and feeder upgrade deferral, transformer load tap changer maintenance extension, real power loss savings, and the value of enhanced reliability. Although extensive work has been invested in updating the methodologies, only highlights of the work are presented in the body of the report. Detailed descriptions of work performed are provided in the appendices.

These appendices are a potentially valuable resource for the field of grid-support PV in particular, and distributed generation in general, because they develop generic evaluation methodologies. By incorporating utility-specific parameters, these methods can be used by other utilities. *The reader is urged to study these appendices prior to applying the results from the Kerman analysis to other projects.*

Analysis Definitions

Two analysis approaches are used consistently throughout this report for each of the value components under evaluation.

The *technical validation* approach calculates value based on measured PV plant and utility system data, updated evaluation methods, and the 1992 Case Study economic and load growth assumptions. Its focus is on ascertaining the technical validity, from an engineering perspective, of traditional and non-traditional value. The technical validation financial results use 1992 Case Study economic and load growth assumptions to facilitate a direct comparison. Results are reported in year 1992 dollars.

The *updated economics* approach calculates value using measured PV plant and utility system data, updated evaluation methods, and recent economic assumptions and evaluation methods. The intent of this approach is to provide a revised benchmark using recent economic information from PG&E and California regulators, coupled with improved evaluation methods. These results are presented in year 1995 dollars.

Presentation of Economic Results

Economic results are presented in two formats throughout the report: levelized ($/kW-yr) and present value ($/kW). These results represent tangible economic benefits, based on a life-cycle approach commonly used in utility resource planning. Each benefit represents the value of the lease-cost alternative the utility would otherwise employ in standard practice.

For example, assume that the load on an old substation transformer will soon exceed capacity and the least-cost alternative is to install a new, higher-capacity transformer to serve the growing load. Further assume that a grid-support PV plant can defer the transformer upgrade for 4 years, the PV plant and transformers have 30-year service lives, and the economic study period is 30 years. The financial savings of delaying the installation of the new transformer by 4 years is estimated in three steps:

1. Calculate the present value cost of installing the new substation transformer in year 1 of the study period, including operation and maintenance (O&M) over the 30-year service life. Subtract the salvage value of the old transformer.

2. Calculate the cost of installing the new transformer in year 5 instead of year 1 by escalating capital costs, adding O&M costs, and converting the total cost to year 1 present value dollars using the utility's cost of capital. Subtract the salvage values of the old and

new transformers (in this example, the new transformer has 4 years of salvageable service life at the end of the 30-year economic study period).

3. Subtract the step 1 present value cost from the step 2 cost. This difference is the financial savings of a 4-year substation transformer deferment. Appendix A provides a numerical example (see equation 8).

Table 1-1 lists PG&E-specific economic assumptions used in this report. Assume, for example, that the total value of a grid-support PV plant is \$425/kW-yr. Multiply this levelized benefit stream by 10.274 to translate it to a present value of \$4,365/kW. Multiply the present value by the capital recovery factor and divide by the utility's fixed charge rate for owning the PV system to determine the allowable or break-even PV system price of \$3,845/kW. The allowable PV system price is what the utility is willing to pay for a grid-support plant after accounting for all costs and benefits of undertaking project construction and operation, including taxes, insurance, depreciation, and O&M.

Table 1-1

Economic Assumptions

	1992 Case Study	Technical Validation	Updated Economics
Cost of Capital (%)	11	11	9
General Inflation Rate (%)	5.5	5.5	3.5
Project Life (years)	30	30	30
Capital Recovery Factor (CRF)	0.115	0.115	0.0973
Present Value Factor (1 ÷ CRF)	8.694	8.694	10.274
Fixed Charge Rate for PV Ownership[a]	0.1305	0.1305	0.1104
Base Year for Economic Results	1992	1992	1995

[a] The updated economics fixed charge rate has been adjusted downward to maintain consistency with a lower cost of capital and the 1992 Case Study. Break-even PV system price equals the present value of the PV system, multiplied by the capital recovery factor (CRF) divided by the fixed charge rate (FCR). CRF ÷ FCR is maintained at 0.881 for all cases.

Conducting a 30-year economic evaluation in the midst of a rapidly changing utility business climate is challenging. It is important to use caution when interpreting and extrapolating the report results: *They are site- and utility-specific, and will likely remain fluid during the transition to a more competitive California electric utility industry.* The final results, although considerable, are not as important as the evaluation methods developed through this research and the confirmation that distributed value is measurable and significant.

REPORT ORGANIZATION

The report is organized, in a sense, from the inside to the outside of the utility. The report begins with the siting and performance of the distributed PV resource, then moves on to evaluate the impact on the distribution feeder, substation transformer, and transmission system, followed by bulk generation benefits, and ending with environmental externalities.

Section 2 provides an overview of the siting, design, and performance of the Kerman photovoltaic plant, and presents validation results of a PV performance model. Sections 3 through 11 describe the evaluation details of the value components (feeder, substation, reliability, loss savings, transmission, energy, capacity, minimum load, and environmental externality), organized according as follows:

1. A brief description of the value component is given.
2. The 1992 Case Study and technical validation evaluation methodologies are discussed and compared, where applicable.
3. Tests performed at the plant and data requirements are described.
4. Technical validation results are presented.
5. Where applicable, technical validation results are compared to 1992 Case Study results, and the differences are discussed.
6. The impact of plant size on value is discussed.
7. Updated economics evaluation methods and results are presented and discussed, where applicable.

Section 12 presents conclusions and suggests follow-on activities.

Section 2

THE KERMAN PV PLANT

BACKGROUND

This section provides an overview of the siting, design, and performance of the Kerman photovoltaic plant. The validation of a computer simulation program which models PV system performance is also discussed in detail. The model is used as a diagnostic tool to confirm healthy plant operation, predict peaking and long-term performance, and investigate design features.

SITE SELECTION

The Kerman grid-support photovoltaic plant is located several miles outside the city of Kerman, which is about 15 miles west of Fresno in California's Central Valley. The plant is interconnected at 12.47-kV distribution voltage on Feeder 1103. Feeder 1103 is served by a 10.5-MVA transformer bank situated in PG&E's Kerman substation. The plant is approximately 8 circuit miles from the substation. Figure 2-1 presents a simplified circuit map.

Kerman Feeder 1103 was selected after screening 600 distribution feeders and 175 transformers in the San Joaquin Valley region (Shugar 1990). The screening process was conducted primarily on the basis of the match between the solar resource and transformer and feeder loads during peak load hours. Other criteria included transformer loading near its rating and sufficiently small load growth to enable deferral of a transformer upgrade with a moderate PV investment.

Once Kerman Feeder 1103 was selected, suitable plant sites were investigated. A general area was first identified to narrow the site selection process. This area was selected on the basis of maximizing local distributed value (e.g., reducing electrical losses and providing voltage support) and minimizing interconnection costs. Plant sites were then surveyed on the basis of land availability, type and cost, anticipated visual impact on immediate surroundings, and a final check of the interconnection point from the perspective of optimizing grid-support value.

The Kerman site was purchased by PG&E and covers approximately 10 acres. Minimal site preparation was necessary because the land was formerly agricultural and therefore quite level. The plant is

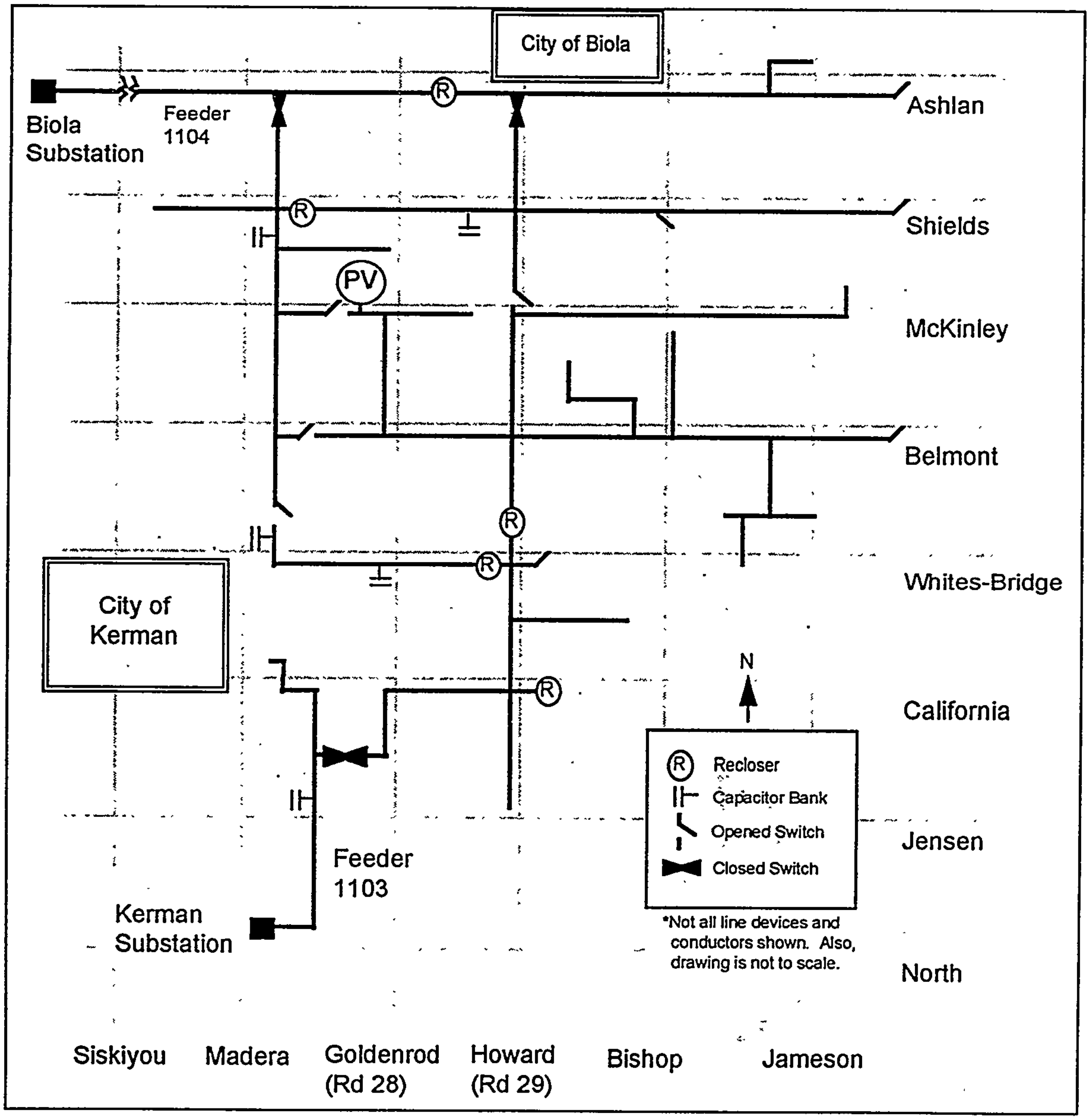

Figure 2-1. Kerman locator map. The PV plant is about 8 circuit miles from the substation.

inconspicuous, and visitors have remarked that they might have passed it by if they did not have explicit directions.

The Kerman area economy is driven largely by agriculture, and is classified as semi-rural from a utility T&D perspective. The customer demand mix on Kerman Feeder 1103 is about 40% residential, 23% commercial, 14% industrial, and 23% agricultural (mainly water pumping loads).

PV PLANT DESCRIPTION

The Kerman PV plant began full operation on the PG&E grid in June 1993, and is rated at 498 kWac at PVUSA Test Conditions.[1] The plant was purchased by competitive bid, with part of the selection criteria allocated to the projected economic value the system would provide to the utility.[2] Siemens Solar Industries was awarded the contract on the basis of a single-axis tracker design that enables the capture of the afternoon solar resource to provide peaking power. A summary plant description is presented in Table 2-1.

The plant is designed to run as an unmanned facility, and is remotely monitored and controlled by PG&E distribution operators via PG&E's computer network. Power production start-up and shutdown are accomplished automatically by the plant's two electronic inverters.

PV PERFORMANCE ESTIMATION IN THE 1992 CASE STUDY

The 1992 Case Study utilized a simplified simulation program to estimate PV plant performance. Power output from a horizontal north-south axis tracking plant, nominally rated at 500 kWac at PTC, was simulated using hourly weather data measured in 1989. The weather data come from a PG&E solar resource monitoring station in San Benito, located about 60 miles southwest of Kerman at an elevation of 1,500 feet. Of 14 PG&E solar resource monitoring stations, San Benito is geographically closest to Kerman.

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[1] PVUSA Test Conditions (PTC) are based on outdoor measurements of PV output at the 12-kV interconnection point, and are defined as 1,000 W/m^2 plane-of-array (POA) irradiance, 20°C ambient temperature, and a 1 m/sec wind speed.

[2] PV system suppliers were given a methodology to conduct design cost/value trade-offs for the competitive procurement of the Kerman plant. Part of the PVUSA selection criteria was the total anticipated economic value of the .idder's system, including local distributed benefits (Hoff, Shugar, and Wenger 1991).

Table 2-1

Kerman PV Plant Summary

System Rating	498 kWac at PVUSA Test Conditions
Interconnection Voltage	12.47 kV on PG&E Kerman Feeder 1103
System Supplier	Siemens Solar Industries
PV Modules	12,240 Siemens Solar Industries M55-VJ modules totaling 5210 m^2 in gross area, single crystal silicon solar cells; each module rated at 55 Wdc at STC conditions[a]
Trackers	Single-axis passive SunSeeker trackers by Robbins Engineering; Horizontal axis oriented north-south; Maximum tracker rotation angle of ± 50°
Power Conditioning Units	2 Omnion 3200 Series 275 kW maximum power point tracking inverters; self-commutated; each with six insulated gate bi-polar transistor (IGBT) bridges
Supervisory Control and Data Acquisition (SCADA)	Kerman plant is unattended and linked to PG&E's systemwide SCADA network for remote monitoring and control from the Fresno Division distribution operations center
Land	10-acre site; formerly agricultural; PV array field takes 5 acres; ground cover ratio is approximately 0.4
Site Buildings	One 12 foot by 16 foot prefabricated electrical control building; one temporary 40-foot trailer for visitors and R&D computers
Construction & Start-up Time	9 months
System Cost	$9,000/kWac (turn-key from Siemens Solar), site preparation, interconnection, and owner costs not included[b]

Source: Whitaker et al. 1994.

[a] Standard Test Conditions (STC) defined as 1,000 W/m^2 normal to the module suface, 25°C PV cell temperature, conducted under controlled laboratory conditions.

[b] See Jennings et al. 1993 for plant cost details.

A solar monitoring station was installed at the Kerman Substation in 1990. The data reveal that San Benito has a significantly better solar resource and a more moderate ambient temperature regime relative to the Kerman area. The annual solar resource is approximately 10% (±3% absolute) greater than Kerman's, with 5°C (±3°C) cooler temperatures during the summer. These factors alone account for about a 12% overprediction of annual energy and peak power output in the 1992 Case Study report.

The PV performance simulation used in the 1992 Case Study was based on perfectly tracking arrays. Also, treatment of plant downtime and miscellaneous plant losses, such as power conditioning efficiency, shading, soiling, and transformers, is not known. These factors probably contribute another 5% in performance overprediction.

MEASURED KERMAN PV PLANT PERFORMANCE

Use of a weather data set that is not representative of the Kerman climatic regime and modeling assumptions that do not reflect the characteristics of the installed Kerman plant result in an overprediction of performance of about 17% (± 3% absolute). The performance overprediction affects estimates of summer peaking capacity and total annual energy production.

Energy Performance

Measured plant performance spanning a 1-year period (July 1, 1993 to June 30, 1994) is used in the validation process. PV output is measured at the 12.47-kV utility distribution interconnection point by conventional metering and also by the site's data acquisition system.

The Kerman PV plant delivered 1,080,200 kWh to the PG&E grid during the 1-year validation period.[3] This translates to an annual capacity factor of 24.8%.[4] This energy production number is used to calculate

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[3] Energy production excludes site auxiliary power consumption. Site loads include a battery charger, air conditioning and lighting of the control building, and data acquisition and monitoring. These auxiliary loads totaled approximately 10,800 kWh, or 1% of PV output, over the 1-year validation period.

[4] The 1992 Case Study assumed the plant would produce a 31.7% annual capacity factor (1,383,250 kWh/yr)—28% higher than achieved during the validation period. The PVGRID computer simulation program, described in detail in the next subsection, was used to estimate the expected output of the plant using site weather data from July 1, 1993 to June 30, 1994. If the plant produced a 27.3% capacity factor for the validation period as expected, the 1992 Case Study performance assumption would be 16% higher.

energy-driven economic value components, including the value of energy generation, loss savings, and environmental externalities.[5]

Figure 2-2 presents the monthly plant energy production, POA solar insolation resource, and a performance index (PI). The PI is a dimensionless ratio defined as the monthly energy production expected (in MWh) divided by actual plant production (also in MWh). The PI indicates how well the plant is operating and can be used as a diagnostic tool.[6] Generally speaking, an index of less than 90% indicates significant underperformance due to problems such as excessive plant downtime, malfunctioning tracking devices, and electrical equipment failures.[7]

The plant performed quite well during the validation period, with an annual PI of 91%. The monthly PI shown in Figure 2-2 indicates, however, at least 3 months of substandard performance. This was primarily due to inverter downtime. A complete discussion of plant operation and maintenance is in the *PVUSA Quarterly Technical Report, First and Second Quarter 1994* (PVUSA 1994).

Capacity Performance

Measured data show that power output during the Kerman transformer peak load was 410 kW at 16:00 Pacific Standard Time (PST) on June 25, 1993.[8] The plant performed as designed, given a prevailing ambient air temperature of 42°C and a 930-W/m^2 POA irradiance.[9] The plant delivered 385 kW at the time of PG&E's system peak load at 15:00 PST on August 2, 1993. The plant also performed close to design given the same prevailing ambient conditions as during the local peak. For detailed discussions regarding the match between PV plant output and local and system load peaks, and its value, see Sections 4 and 9, respectively.

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5 Ideally, long-term average performance should be used to calculate energy-driven value components because economic value assumes a 30-year operating period. Since the value of the Kerman plant is supposed to be based exclusively on measured data, extrapolations of 30-year average performance have not been performed. Based on the past 4 years of site weather data, it appears that the actual performance during the validation period is probably 10% (± 3% absolute) below a long-term average. Also, it is believed that the first year of operation exhibited higher than 30-year average downtime due to lingering start-up failures and adjustments.

6 Various formulations of the PI are presently under evaluation (Townsend et al. 1994). The PI presented in Figure 2-2 uses the PVGRID simulation program to calculate expected production.

7 The PI should screen out all scheduled testing or maintenance-related outages, but include allocations for standard design factors, such as soiling and shading losses.

8 Based on half-hour average plant output from 15:30 to 16:00 Pacific Standard Time.

9 The 1992 Case Study assumed that the Kerman plant would produce 500 kW during the peak transformer loads. This is not necessarily a misguided assumption. The plant was procured, however, based on achieving 500 kW under PTC. This difference in actual versus assumed capacity led to overestimation of the capacity value in the 1992 Case Study.

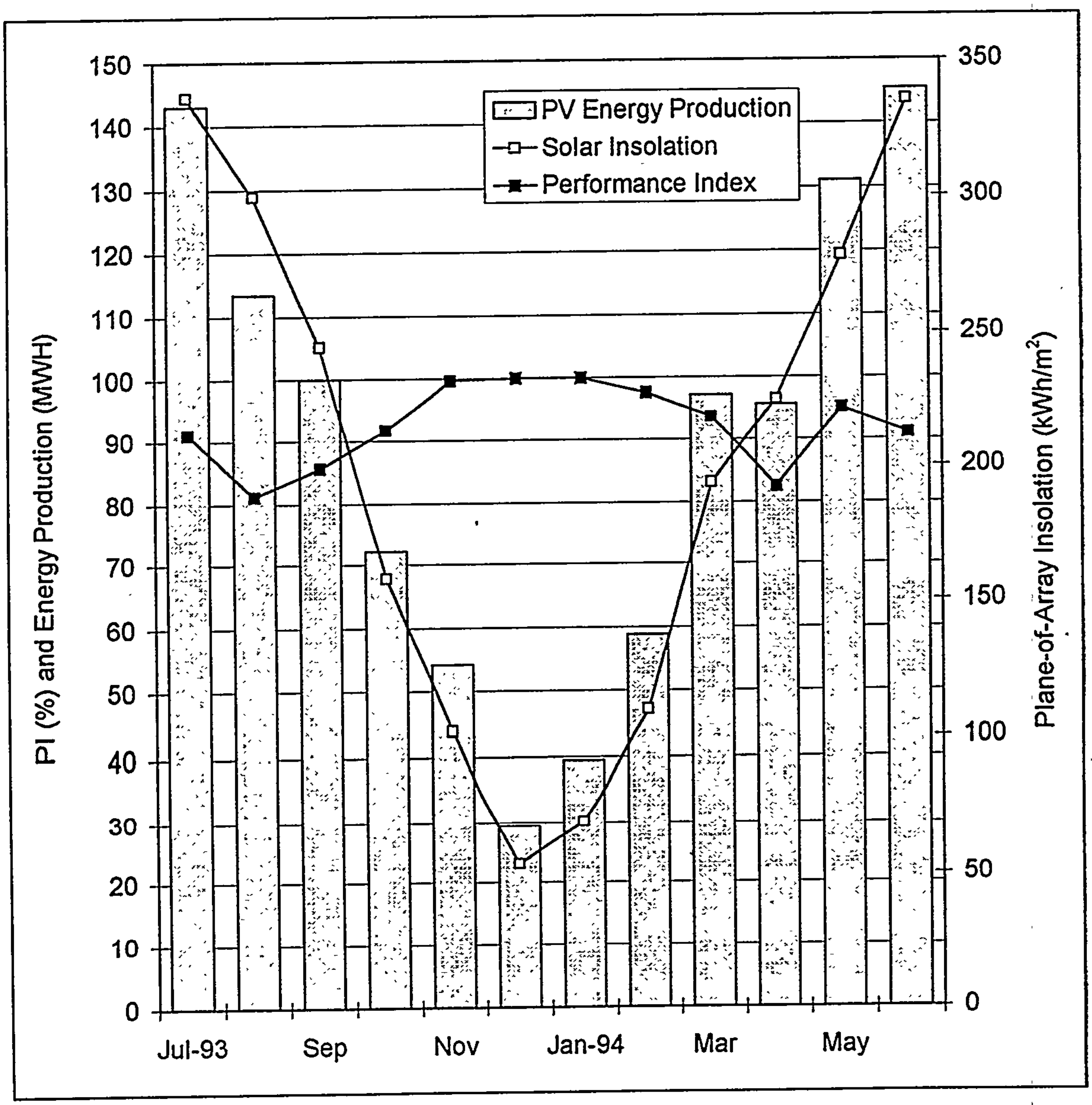

Figure 2-2. Kerman PV plant performance (measured July 1993 - June 1994).

Figure 2-3 presents average Kerman plant output over four different seasonal periods. These daily profiles are based on measured data averaged over every hour of the year. The data indicate expected output shapes, including a trend in lower afternoon production caused by elevated ambient temperatures. The "double-hump" profile is characteristic of north-south single-axis trackers due to the time-of-day dependence of the solar incidence angle. Note that the single-axis tracker design provides a fairly consistent level of power output during key system and local load hours—around 400 kW during the summer.

Tables 2-2 and 2-3 provide complete performance and weather summaries for the 1-year period (July 1, 1993 to June 30, 1994). These data are all based on measurements collected by the site's data acquisition system.

PV PERFORMANCE SIMULATION VALIDATION

The PVGRID computer simulation program has been used extensively in the validation process to (1) determine to what extent the 1992 Case Study overpredicted PV system performance using weather data from San Benito, California; (2) place an upper bound on PV system performance at Kerman used in the "high case" economic results; and (3) objectively assess Kerman plant performance over the 1-year monitoring period and during critical peak load conditions.

Several model enhancements based on measured Kerman plant data have resulted in a highly accurate simulation program. These modeling enhancements include passive tracking as a function of summer and winter operation, power conditioning units (PCUs) 1 and 2 efficiency as a function of dc power input, transformer losses as a function of ac current operating levels, and PV module temperature as a function of ambient conditions.

There are at least two factors motivating the use of the PVGRID model over other available simulation programs. The model is flexible and the evaluation team is familiar with the computer code, allowing sensitivity analyses and rapid modifications. Moreover, a tailored model can be used as a diagnostic tool to confirm healthy plant operation, predict peaking and long-term performance, and investigate plant design features.

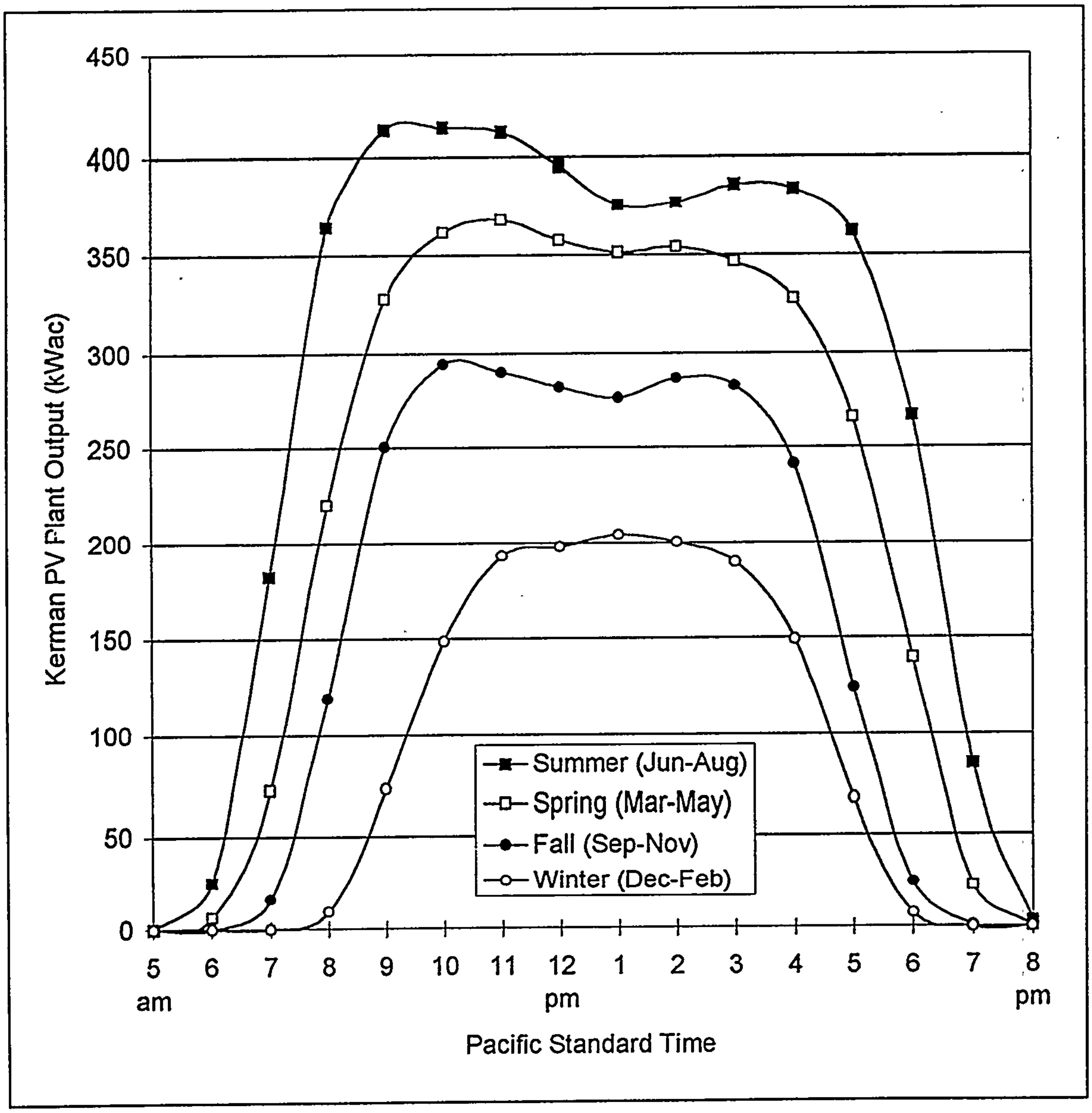

Figure 2-3. Kerman PV plant output, based on averaged measured data.

Table 2-2
Kerman PV Plant Performance (July '93 through June '94)

	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	TOTAL
Production (kWh,ac)[a]	143,043	113,542	100,005	72,146	54,164	29,493	39,559	58,864	97,242	95,720	131,002	145,389	1,080,169
Maximum Power (kWac)[b]	518	464	436	418	379	310	364	454	523	518	533	509	533
Performance Index (%)[c]	91	81	86	92	100	100	100	98	94	83	95	91	91
Capacity Factor (%)[d]	38.6	30.6	27.9	19.5	15.1	8.0	10.7	17.6	26.2	26.7	35.4	40.5	24.8
Efficiency, ac (%)[e]	9.1	9.0	7.9	8.9	9.6	9.8	9.9	10.1	9.8	9.3	9.0	9.1	9.1
POA Insol. (kWh/m^2)[f]	301	242	242	156	108	58	77	113	190	198	278	308	2271
POA Insol. (kWh/m^2)[g]	337	301	245	158	102	54	71	110	194	225	278	335	2410

Table 2-3
Kerman Solar/Weather Summary (July '93 through June '94)

	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	TOTAL
Insol., 1-axis (kWh/m^2)[h]	358	319	272	175	129	64	79	115	198	255	293	344	2601
Insol., Horiz. (kWh/m^2)[i]	243	217	178	120	86	51	62	87	153	184	215	238	1834
Peak Irr. 1-axis (W/m^2)[j]	1114	1177	1100	896	814	722	773	862	1082	1132	1221	1137	1221
Tamb, min (°C)	15	7	10	9	-3	1	0	1	4	8	8	8	-3
Tamb, avg (°C)	27	26	24	20	12	9	9	11	16	18	21	25	18
Tamb, max (°C)	39	43	39	35	27	22	23	24	29	35	36	42	43
Windspeed, avg (m/sec)	3.1	2.9	2.5	1.9	2.0	1.9	1.9	2.5	2.7	3.3	3.2	3.5	2.6
Windspeed, max (m/sec)	6.6	6.6	7.4	7.1	10.6	8.5	8.6	11.4	11.0	7.8	7.9	7.8	11.4

[a] Electrical energy delivered to the grid, at 12.47 kV.
[b] Based on highest 1/2 hour average event for the month (as reported by PVUSA 1994).
[c] PI is defined as the measured energy production divided by the expected production as calculated by the PVGRID simulation model.
[d] Capacity factor is defined as the monthly PV production divided by the product of the plant rating (498 kWac) times the number of hours in the month.
[e] Efficiency is based on plane-of-array insolation, excluding insolation received when the PV system is down. See footnote f (as reported by PVUSA 1994).
[f] Insolation measured by global irradiance pyranometer mounted on an array support on row 5. Does not include insolation received during system outages (as reported by PVUSA 1994).
[g] POA insolation calculated by PVGRID. This is the average for the entire array field (accounts for passive tracker inaccuracies). Does not exclude POA when the PV system is down.
[h] Insolation measured by a single-axis tracking reference pyranometer, programmed to operate as a "perfect" single-axis tracker, located at the plant weather station.
[i] Global horizontal insolation.
[j] Peak solar irradiance measured by the reference single-axis tracking pyranometer.

PVGRID Modeling Steps

Plant performance estimates are based on half-hour averaged insolation, ambient temperature, and wind speed data collected from a weather station at the Kerman site. The PVGRID model calculates power output via six major steps:

1. The array tilt angle is calculated based on the time of day and year.
2. Determination of POA irradiance is based on the array tilt angle, relative position of the sun, and measured horizontal global and direct beam irradiance (interarray shading and soiling are also accounted for).
3. PV module temperature is estimated as a function of POA irradiance, ambient temperature, and wind speed.
4. Current-voltage (I-V) curves are constructed and the maximum power point found (dc losses resulting from mismatch and cable resistance are also accounted for).
5. PCU efficiency is found (includes air-conditioning losses used to control temperature in each PCU enclosure).
6. Ac power output at 12 kV is determined, subtracting transformer and other ac losses.

All of these modeling steps have been validated for the Kerman plant. Highlights of the PVGRID validation process are discussed below.

Passive Tracking

The Kerman plant has single-axis tracking arrays that track the sun about horizontal north-south axes using refrigerant R134a activated passive actuators built by Robbins Engineering. Figure 2-4 shows the layout of the Kerman plant. There are 8½ rows of PV arrays, with two PCUs located in the center of the field. Each array row is mechanically ganged together, except at the midpoint for separation of array fields. There are 17 independent source circuits. There are nine clinometers, one for each row, that measure tracker tilt angle.

Passive tracker performance impacts plant output and must be considered for accurate modeling. Figure 2-5 presents typical passive tracking performance for summer conditions. The circles are half-hour averages measured by the clinometers. There is significant spread in array tilt angles in the early morning and late afternoon, but the arrays track very closely to one another during most of the day. The PVGRID model was modified to simulate actual tr ıcker behavior; the modeled tracking angle is shown along with the

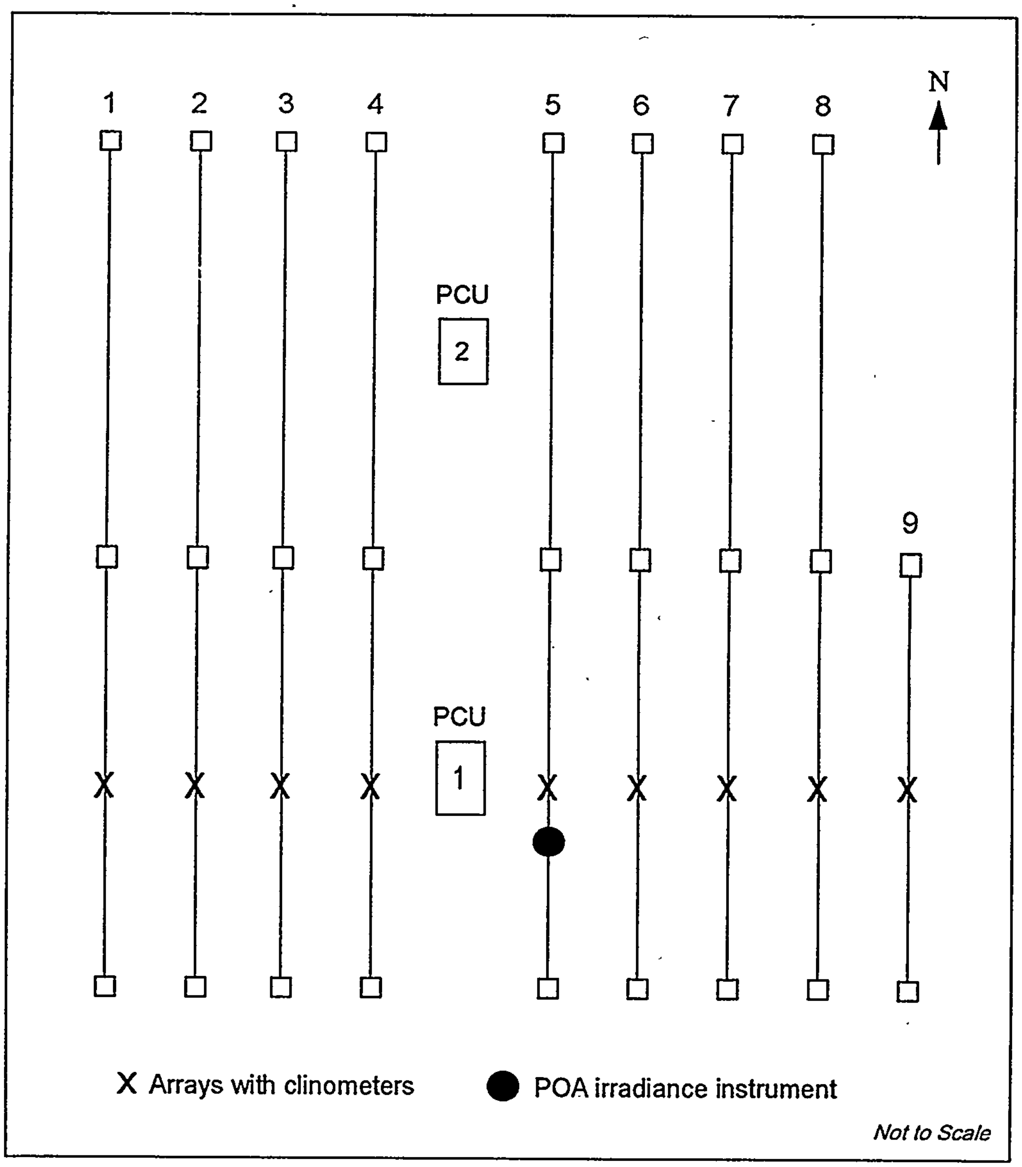

Figure 2-4. Kerman PV plant layout and selected instrumentation.

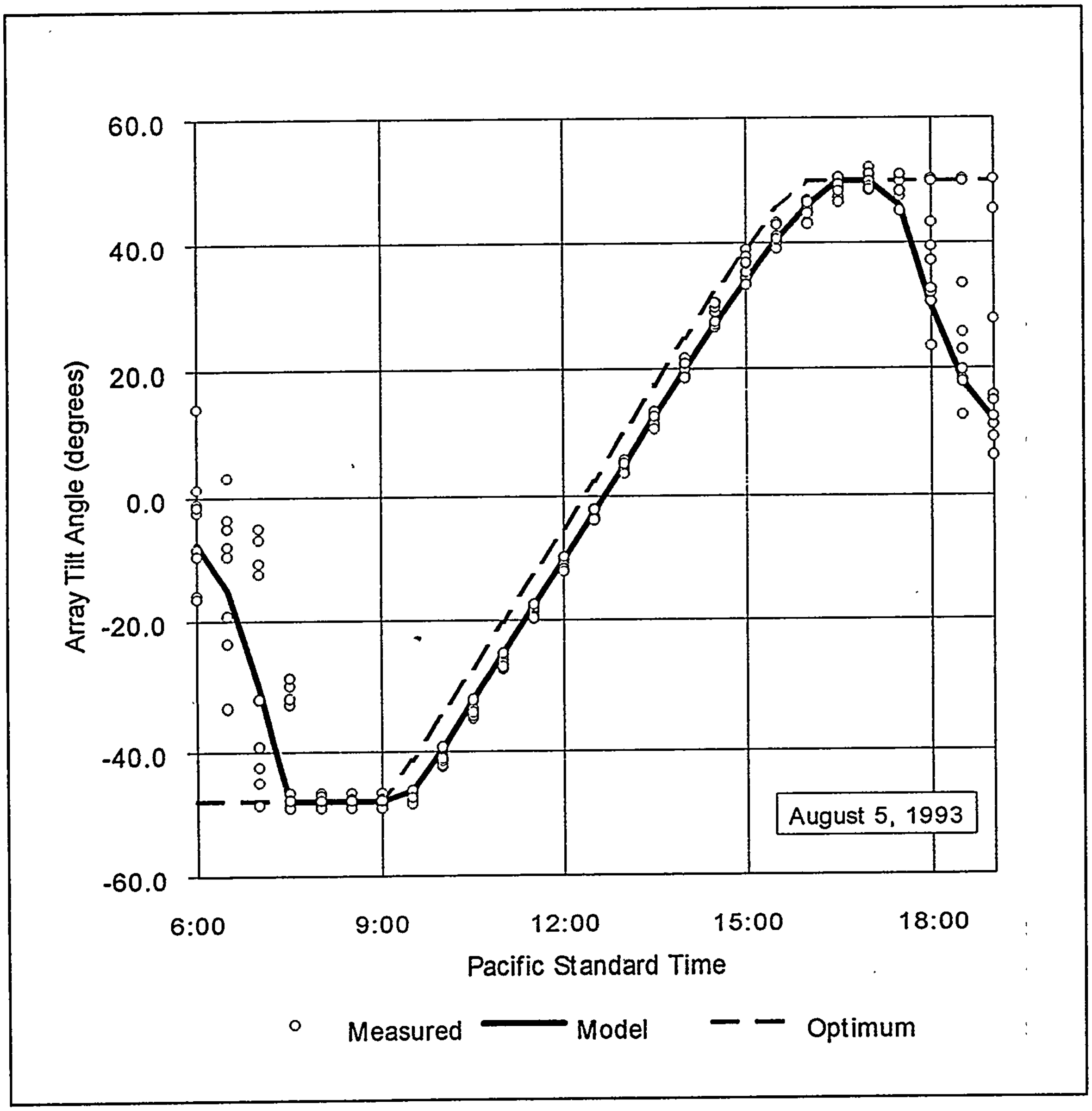

Figure 2-5. Passive tracking performance (measured, modeled, and optimum).

optimum tilt angle. The optimum tilt angle is the tilt angle that minimizes the solar incidence angle and, generally, maximizes energy capture.

Two trends are evident from the clinometer data: (1) most of the arrays backtrack towards the horizontal position in the late afternoon as a result of interarray shading; and (2) the arrays consistently lag the optimum tilt angle by about 5° during most of the day. These trends appear to be independent of time of year.

The tracking pattern of Row 5 is noteworthy because it is the location of a plane-of-array irradiance instrument (pyranometer). Row 5 is situated at the center of the field and has less afternoon shading because of the increased distance from Row 4 (see Figure 2-4). This causes Row 5 to have a markedly different tracking pattern in the late afternoon, causing the pyranometer measurements to inaccurately reflect irradiance captured by the rest of the field. This becomes important if the measured POA irradiance data are used to predict late afternoon and long-term performance. Row 1 tracks similarly to Row 5, as it is also situated with no afternoon shading. These tracking idiosyncrasies, and their effect on data collection, have been accounted for in the validation and adjustment of the PVGRID model.

Power Conditioning Units

The Kerman plant has two 275-kWac power conditioning units. PCU 1 is connected to 9 of the 17 source circuits, and PCU 2 is connected to the remaining 8 source circuits. Dc to ac conversion efficiency is measured by the PVUSA data acquisition system. A least-squares regression is performed to construct an efficiency equation as a function of dc input to each inverter. Figure 2-6 presents the curve fit and measured data for PCU 1. Over 3000 data points are presented, spanning a wide range of operating conditions.

Both PCUs demonstrate conversion efficiencies typically ranging from 91 to 94%, including air-conditioning loads.[10] An air-conditioning unit, rated at 15,000 Btu/hr (4.8 kW), serves each PCU enclosure. Air-conditioning loads can contribute up to a 2% absolute reduction in PCU efficiency during

[10] PCU efficiency is calculated by dividing measured dc power input by ac power output. The ac power measurement is downstream of the air conditioning unit service, therefore the PCU efficiency includes air conditioning loads.

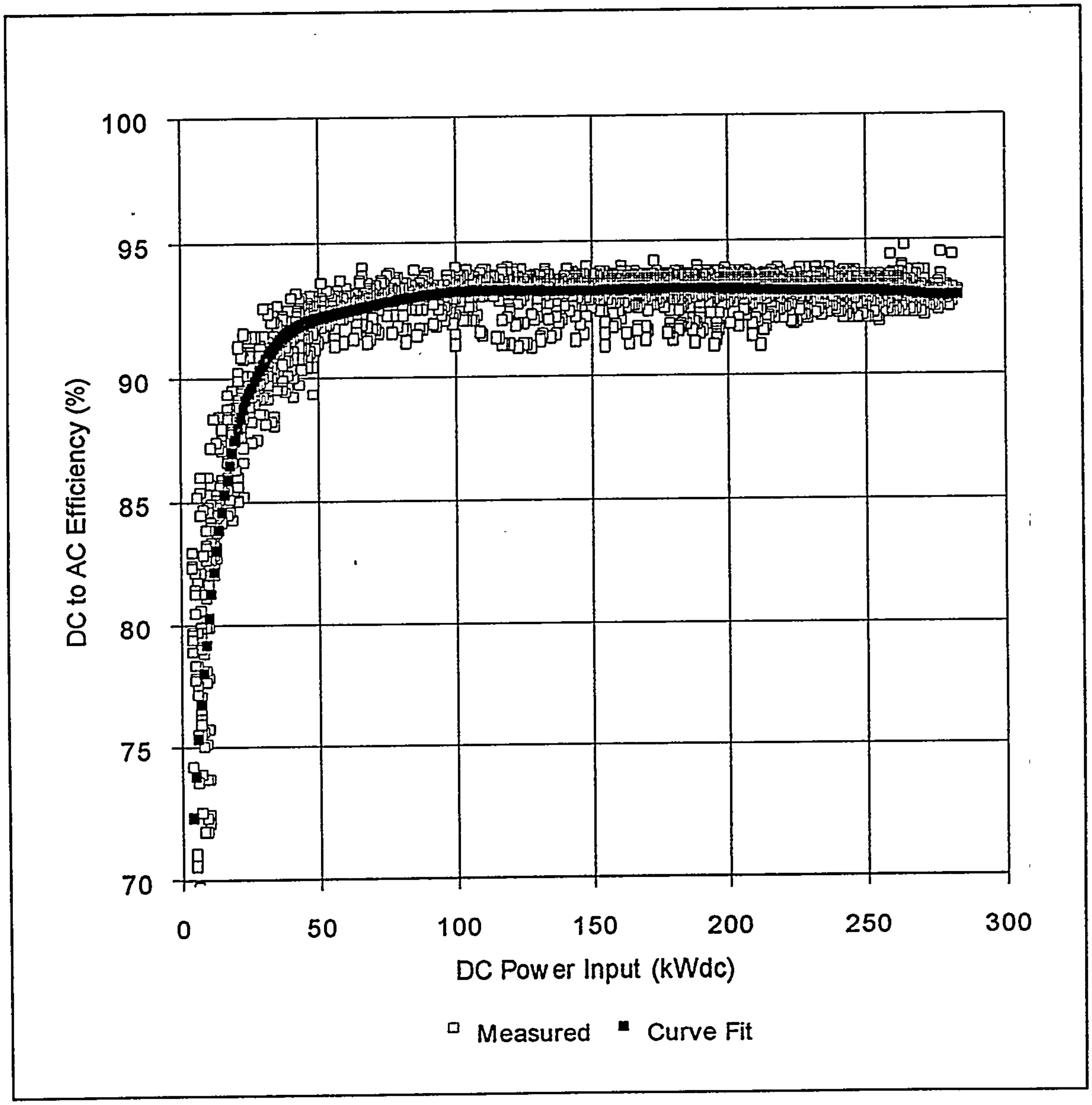

Figure 2-6. PCU 1 efficiency curve (includes air-conditioning load).

peak conditions, depending on cooling load and compressor run time. This explains, to some extent, the range in PCU efficiency under full power conditions shown in Figure 2-6.

PV Power Delivered at 12 kV

I-V curves are constructed and all efficiency losses are taken into account to model PV power delivery at 12 kV. Isolation and 12-kV step-up transformer efficiencies are included, amounting to 4 to 10 kW depending on ac current levels. Figure 2-7 presents actual versus modeled power levels for the local peak load day (June 25, 1993) and a representative winter day (November 18, 1993). The model exhibits close correlation with measurea results.

Soiling Impacts

Prior to summer 1994, the model had excellent correlation with measured data, typically predicting power output to within 2% on peak. Comparisons of data collected in late summer 1994 revealed that the model consistently overpredicted power output by approximately 8% (± 2% absolute). This overprediction may be attributed to soiling of the PV modules. Since the Kerman plant is adjacent to agricultural land under production, dust and particulate concentrations are high. The PV modules are cleaned only by precipitation, and there was none during June, July, and August 1994.

Performance reductions up to 20% have been attributed to soiling for PV systems located at the PVUSA site in Davis, California (PVUSA 1994). There is also significant agricultural activity adjacent to the Davis site. At this time, soiling tests have not been conducted at Kerman; however, an algorithm was developed to model soiling impacts as a function of time of year.[11]

PERFORMANCE IMPACT OF PASSIVE TRACKING ARRAYS

The validated PVGRID model can now be used to investigate plant design questions, such as the performance impact of passive versus active tracking arrays. Figure 2-8 presents PV power output as a percentage of what the plant would have produced, by season, if it were equipped with perfectly tracking

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[11] Soiling impacts are modeled as a sine wave, corresponding to precipitation events, with peak losses of around 8% occurring in late summer and minimal losses in winter. This model has not been validated. The impacts of soiling are very difficult to model, however, because the amount of light which passes through the module cover becomes increasingly dependent on the angle of incidence. The economic value of scheduling PV module washing may be worth its cost. For example, a 2% gain in value would result in an allowable cleaning budget of approximately $3,000 to $4,000 per year. This may be enough to have the array field cleaned at least twice during the summer.

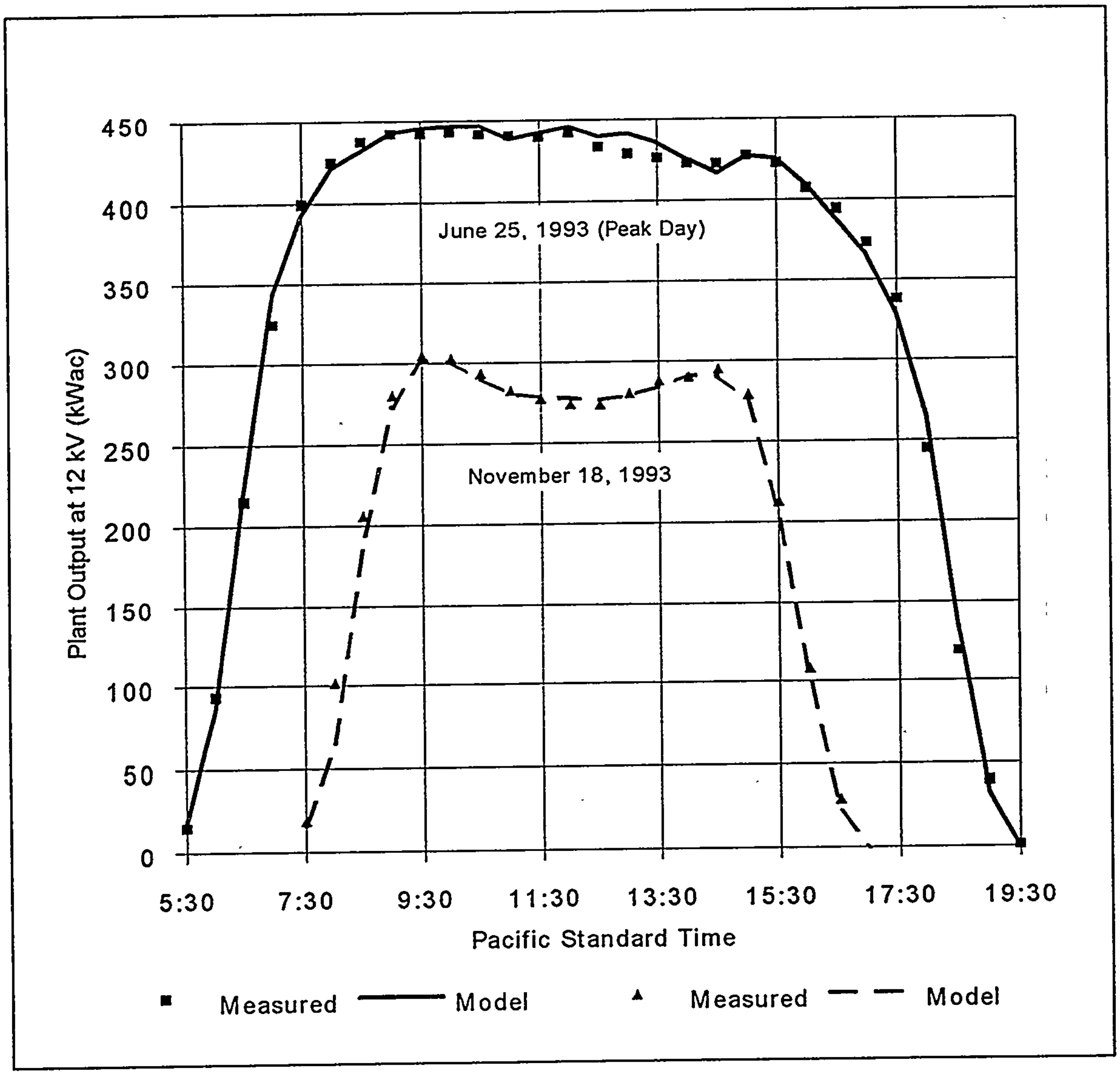

Figure 2-7. PVGRID model showing close correlation with measured data.

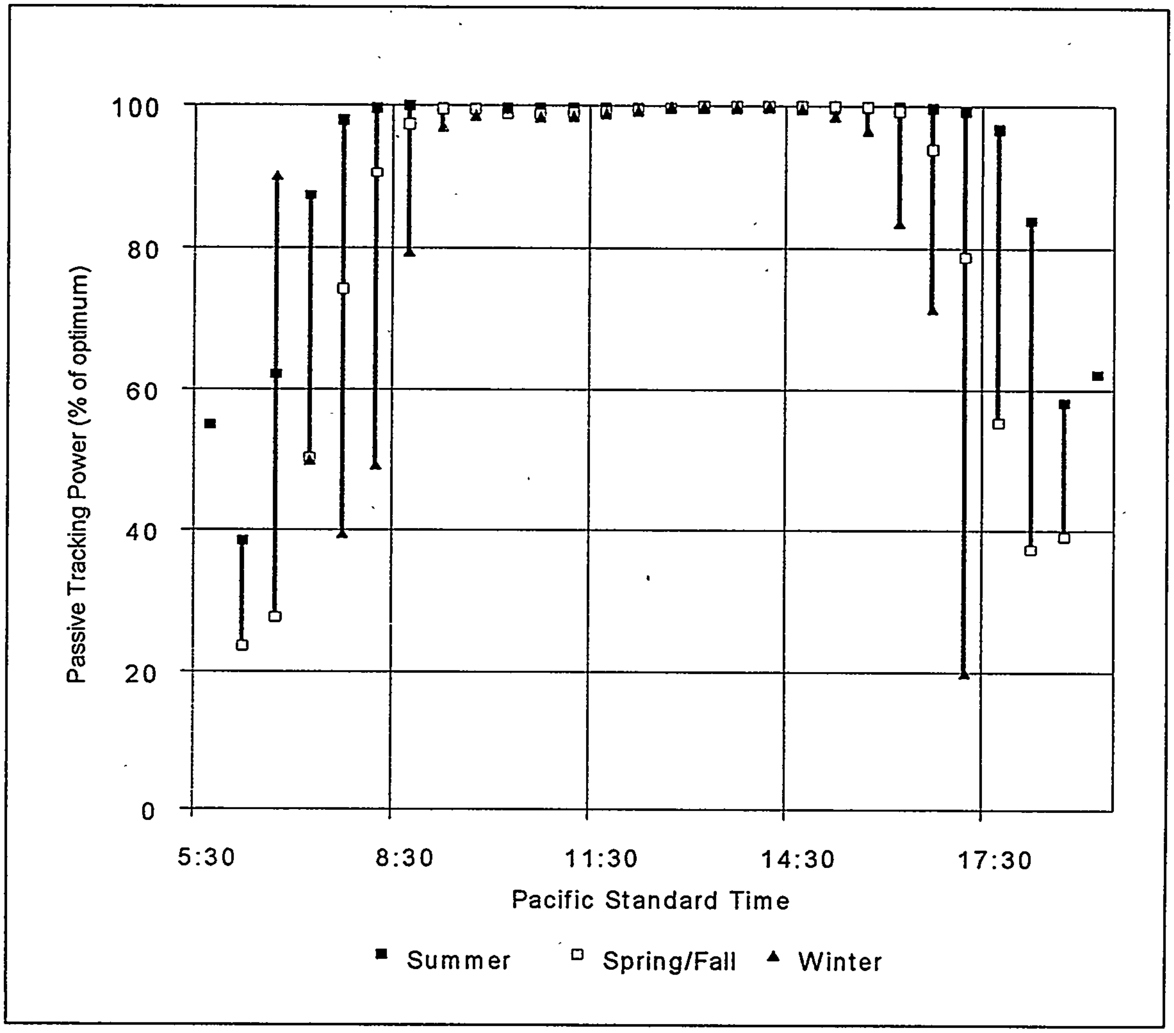

Figure 2-8. Passive tracking performance is excellent for peaking power.

arrays.[12] This plot shows that the passive tracking arrays achieve nearly 100% of optimum performance during the crucial peaking times of the day, particularly during the summer. Therefore, distributed value components that rely on peaking capacity are fully captured with passive trackers for the Kerman application.

Passive trackers, however, sacrifice energy capture during the early morning and late afternoon. Figure 2-9 presents monthly total PV energy production as a percentage of what the plant would have produced if it had perfectly tracking arrays. This translates to an annual energy delivery impact of about 5%,[13] the same reduction predicted by the system supplier. Distributed generation value components that are driven by energy delivery rather than peaking capacity will, in turn, scale downwards by about 5%.

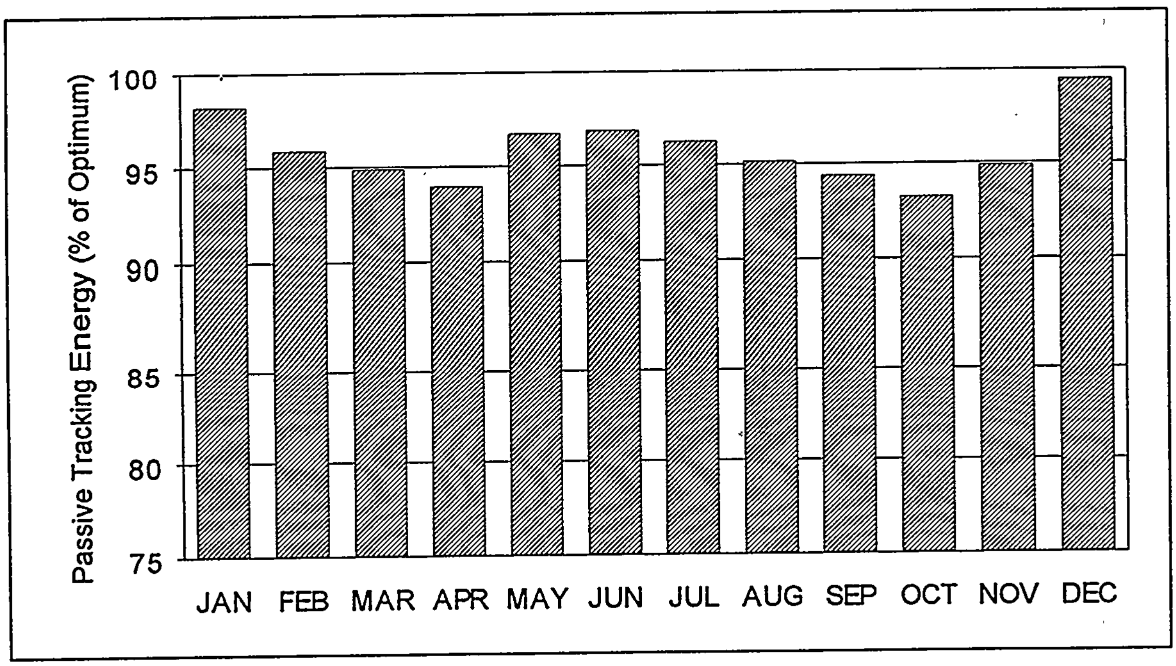

Figure 2-9. Passive tracking sacrifices annual energy delivery.

12 The perfectly tracking arrays are modeled with a maximum rotation angle of 50°, the same maximum angle as the Kerman passive trackers.

13 Annual passive tracking losses break down to a 4% energy delivery reduction during summer, 6% during spring/fall, and about 3% during winter.

PERFORMANCE CONCLUSIONS AND DISCUSSION

A validated performance model provides confidence in the validation of the value of grid-support PV and allows for comparisons to the 1992 Case Study. Kerman plant performance can be classified as very good, based on the 1-year benefits validation period. Reliable inverter operation is probably the most crucial area needing improvement.

From a power output perspective, the sacrifice due to passive tracking is quite small during Kerman feeder and transformer peaking periods. From an energy production perspective, the passive trackers produce about 5% less than perfectly tracking arrays on an annual basis. Grid-support values that rely on peaking capacity are fully captured with passive trackers, while benefits relying on energy production will scale downward.

Ancillary ac losses can be significant: the 12-kV step-up transformer, the PCU isolation transformer, and the two PCU air-conditioning units add up to about 10 to 18 kW of additional load on peak, depending on air-conditioning loading and cycling.

Plant output is sensitive to module temperature, with temperature-induced power output losses of about 50 kW during peak summer conditions, when ambient temperatures typically rise above 40°C.[14] Future grid-support applications may consider sizing the power plant according to weather conditions coinciding with the local peak load. Ultimately, a benefit/cost trade-off must be performed to optimally design the plant.

Based on the validated model, Table 2-4 presents estimated annual capacity factors using measured Kerman site weather data (the 1993-94 value uses measured plant output). For reference, the system supplier projected a 1991 capacity factor of 28.0%, also using 1991 Kerman site weather data.[15]

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[14] Temperature-induced power losses are relative to PTC of 20°C ambient temperature. The losses stated do not include other plant losses. Typical reduction in PV module power is 0.55% per °C.

[15] The system supplier's annual capacity factor projection was 27.8% based on their projected 0.502-MW plant rating. This capacity factor is adjusted to 28.0% to reflect the PVUSA 0.498-MW plant rating, which is the basis for PVGRID capacity factor estimates.

Table 2-4

Kerman PV Plant Annual Performance Estimates

Year	1991	1992	1993	1993-1994 (actual)
Annual Capacity Factor (%)[a]	27.5	25.2	26.9	27.3 (24.8)
POA Insolation (kWh/m^2)[b]	2,382	2,222	2,351	2,410
Ambient Temperature (°C)[c]	20.3	21.1	21.7	22.1

a Based on the PVGRID model and Kerman site weather data.
b Estimated by PVGRID.
c Annual average based on daytime readings only.

The 1992 Case Study did not use Kerman site weather data, nor did it utilize the PVGRID simulation program to evaluate distributed generation value. Since San Benito has a better solar resource and a more moderate ambient temperature regime than Kerman during the summer peak, the 1992 Case Study projected a 31.7% annual PV plant capacity factor. This caused an overprediction of energy-related and capacity-related value components. This overprediction highlights the importance of using weather data representative of local conditions when evaluating PV grid-support, as well as accurate performance modeling techniques and assumptions.

Section 3

FEEDER VALUE

VALUE DESCRIPTION

Grid-support PV is of value to a distribution feeder if it increases the available capacity of a capacity-constrained conductor. (The capacity constraint may be due to load or voltage problems.) It increases available capacity by serving some of the load locally. Additional capacity accommodates load growth and defers a feeder upgrade until fully needed. In the case of Kerman Feeder 1103, capacity is not constrained and there were no plans to upgrade the feeder. Thus, feeder upgrade deferral value at Kerman is zero.

Feeder upgrade deferral value is potentially important at other locations because of PV's large impact on a feeder and the cost of restringing a line. PV's impact is well illustrated at Kerman, where the 0.50-MW PV system met 0.0025% of PG&E's peak system load and 0.5% of Kerman's distribution planning area peak load, increased transformer capacity by 4%, and increased feeder capacity at the PV plant by 20%. This, combined with upgrade costs ranging from $50,000 to over $100,000 per mile for overhead conductors (underground conductor costs are much higher), suggests that some locations may have a substantial feeder upgrade deferral value.

EVALUATION METHODOLOGY

The 1992 Case Study identified the potential value of a feeder upgrade deferral but did not perform a detailed technical analysis. Thus, a methodology was developed for this report. Feeder upgrade deferral value is calculated by determining the increase in capacity due to the PV plant and converting this to economic value.

As described in Appendix B, time constants for small conductors are on the order of a few minutes. Thus, a PV plant designed to defer a specific feeder upgrade must have high availability during all critical hours, and it accomplished by calculating the difference between minimum available capacity with and without PV. Minimum available capacity without PV equals the minimum of the difference between feeder capacity and load. The same calculation is repeated for load with PV (PV output is adjusted to reflect electrical feeder loss savings). The difference between the two is added capacity.

The three inputs to this calculation are feeder capacity, load, and PV output. Load and PV output are based on measured data, whereas capacity must be estimated. One estimate is that capacity is always constant, which may result in errors. Another estimate, the one used in this research, is to adjust feeder capacity based on weather conditions. The capacity rating model, described in detail in Appendix B, is a simplified version of the accepted IEEE rating standard for bare overhead conductors. The simplification removes the iterative calculations required by the IEEE model in the solution for conductor capacity. Feeder capacity is estimated dynamically using measured weather conditions and this simplified model.

Model inputs include ambient temperature, irradiance, wind conditions, and the conductor's physical characteristics (e.g., conductor diameter, material type such as copper or aluminum, absorptivity, and emissivity. Since absorptivity and emissivity are unknown, they are both assumed to be 0.5, as suggested by the IEEE standard). Although the model accepts measured wind conditions, one would need to be assured that the analysis uses wind conditions at the worst section of the distribution feeder and that wind conditions do not change rapidly (shifting from high wind to low wind) during critical times. A more conservative approach is to use measured ambient temperature and irradiance data but to assume what PG&E has defined as emergency wind conditions (2 feet/second); this will understate system capacity.

TECHNICAL VALIDATION TESTING AND DATA REQUIREMENTS

A special test was conducted to demonstrate that output from the 0.50-MW PV plant at Kerman reduces conductor temperature on the smallest conductor (i.e., number 6 copper) on the feeder. This section describes test preparations and test results.

Several pieces of equipment were installed on utility equipment to perform this test. A NiTech donut was mounted on a conductor. This device, which looks like a large metal donut, is approximately 1 foot in diameter and 6 inches thick. It monitors line current, line temperature, and ambient temperature. The ground monitoring station for the NiTech donut was installed at the PV plant. It collects data from the NiTech donut and then transfers the data to R&D via modem.

Other key factors in understanding the relationship between conductor current and conductor temperature are wind speed and wind direction (see Appendix B). An anemometer was installed on the top of a power pole (about 10 feet away from the donut) to monitor wind speed and direction. A wire was run down the pole to a wooden box where data were collected. A cellular phone inside the box was used to transfer the data to Augustyn & Company, who collected the wind data.

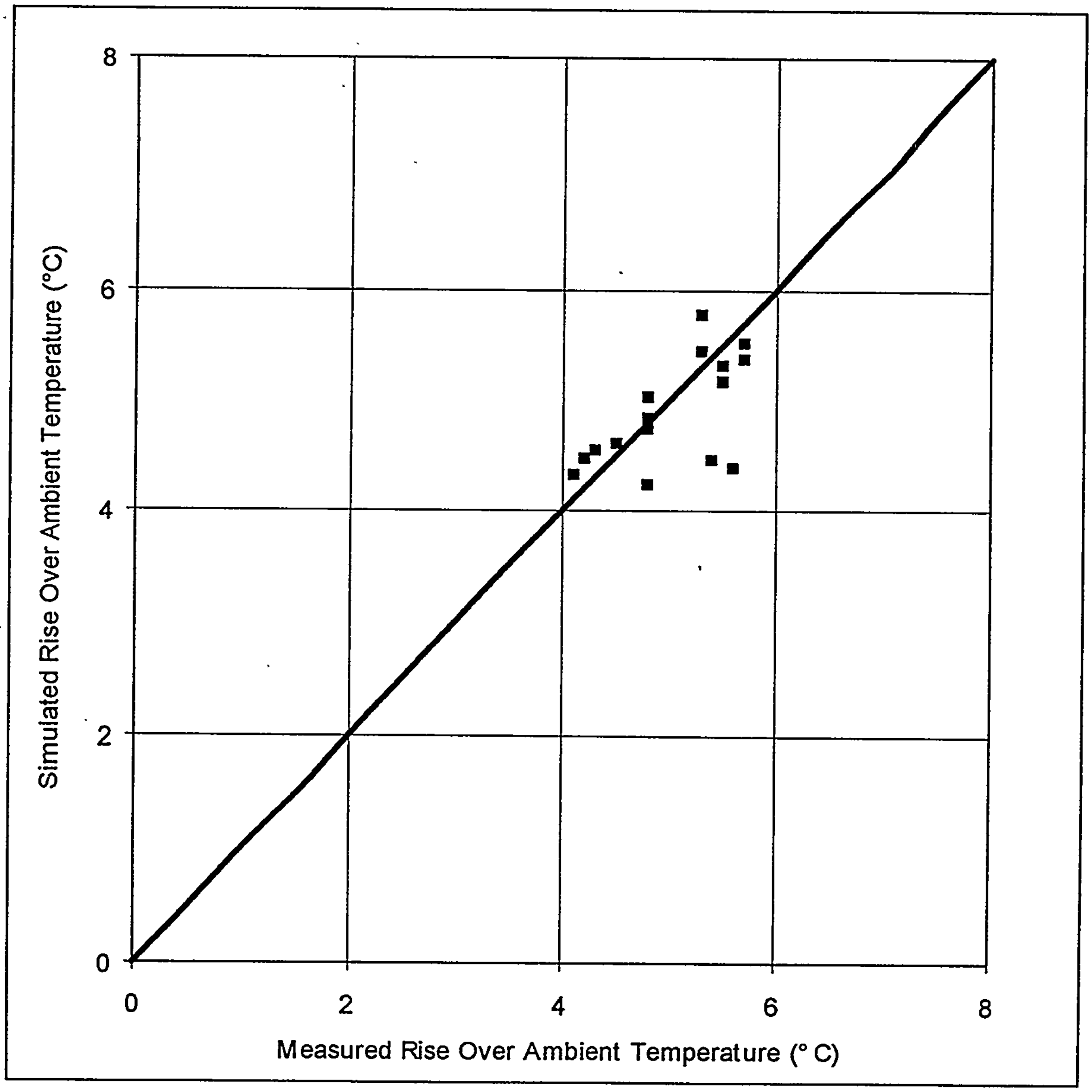
Several attempts were made to perform this test, each with limited success. The first attempt was made on June 16, 1994. The PV plant was turned on and off ten times between 9:00 and 15:00 PST. Although this day had good insolation and the PV plant worked well, the test results were inconclusive due to high wind speeds and low conductor load.

As plans were being developed to reconduct the test, a vehicle-pole accident took out an adjacent pole, the conductor snapped, and the NiTech donut fell to the ground. This greatly altered the shape of the donut and damaged its internal electronics.

A final attempt at the this test was made on September 27, 1994. Another NiTech donut was installed on the conductor. Load was transferred onto Kerman Feeder 1103 to create high-load conditions. Several problems occurred. There were communication problems between the NiTech donut and the ground station. There were high wind conditions. The weather was partly cloudy. Finally, one of the inverters at the PV plant did not come back on line when the district operator gave the appropriate command.

The only quantitative test result that is of value is presented in Figure 3-1. The limited results suggest that the modeled conductor temperature rise over ambient temperature is comparable to the measured value. The figure corresponds to a range of currents of around 50 amps on the conductor and about 5 meters per second wind speed.

When it was realized that there were communication problems with the NiTech donut during the September 27 test, the bucket truck supervisor suggested using PG&E's infrared temperature sensing van to evaluate conductor temperature. This van, which happened to be in the Kerman area, is designed to sense hot spots within the system. The van arrived and positioned itself to monitor line temperature as the load was changed. The van was able to sense the change in temperature of a conductor one-eighth of an inch thick almost 100 feet away.



Note: Each point represents 1 minute of data.

Figure 3-1. Conductor temperature rise over ambient temperature (10:32 to 10:47 PST, September 27, 1994).

Although the temperature measurements from the infrared temperature sensing van were not as accurate as the donut measurements, a new plan was devised to perform the test in the future. Rather than installing and coordinating multiple data systems, this test could be performed with a bucket truck, a hand-held ammeter, and a hand-held infrared temperature- sensing gun. A bucket truck crew could be dispatched to the location of interest on a hot, calm day when there is high load on the conductor. The bucket truck crew would manually measure conductor current and conductor temperature. The PV plant would be taken off line and the measurements would be repeated. This could eliminate much of the test's difficulty and complexity.

Although testing was conducted to validate the simplified IEEE model, model validation was not feasible. For this reason, it is assumed that the simplified model is accurate and is used in the value analysis.

TECHNICAL VALIDATION RESULTS

Kerman Feeder 1103 is not constrained and no distribution feeder upgrade is planned. Thus, to perform this analysis, it is assumed that the load shape on the conductor near the plant (the number 6 copper conductor) is identical to the feeder load shape but that the magnitude of the load is higher than actual. Load on this feeder section, measured PV plant output, and conductor capacity are presented in Figure 3-2. The conductor's capacity is calculated as described in Appendix B. Notice that the capacity is inversely correlated with PV plant output because conductor capacity decreases as irradiance and ambient temperature increase, whereas PV plant output increases with irradiance.

Figure 3-2 suggests that PV plant output occurs when capacity needs are the greatest. This is demonstrated even more clearly by subtracting load from capacity (Figure 3-3). When there is no PV, there is no available capacity at 15:30 because load equals capacity. When the PV is added, the least amount of available capacity is 320 kW at 18:30 PST. Thus, on this particular day, the PV plant increases feeder capacity by 320 kW. When the analysis is performed using a full year's worth of data, the result is unchanged: The 500 kW Kerman PV plant increases feeder capacity by 320 kW.

TECHNICAL VALIDATION RESULTS VS. 1992 CASE STUDY

A comparison is not applicable because the 1992 Case Study did not perform a detailed technical analysis.

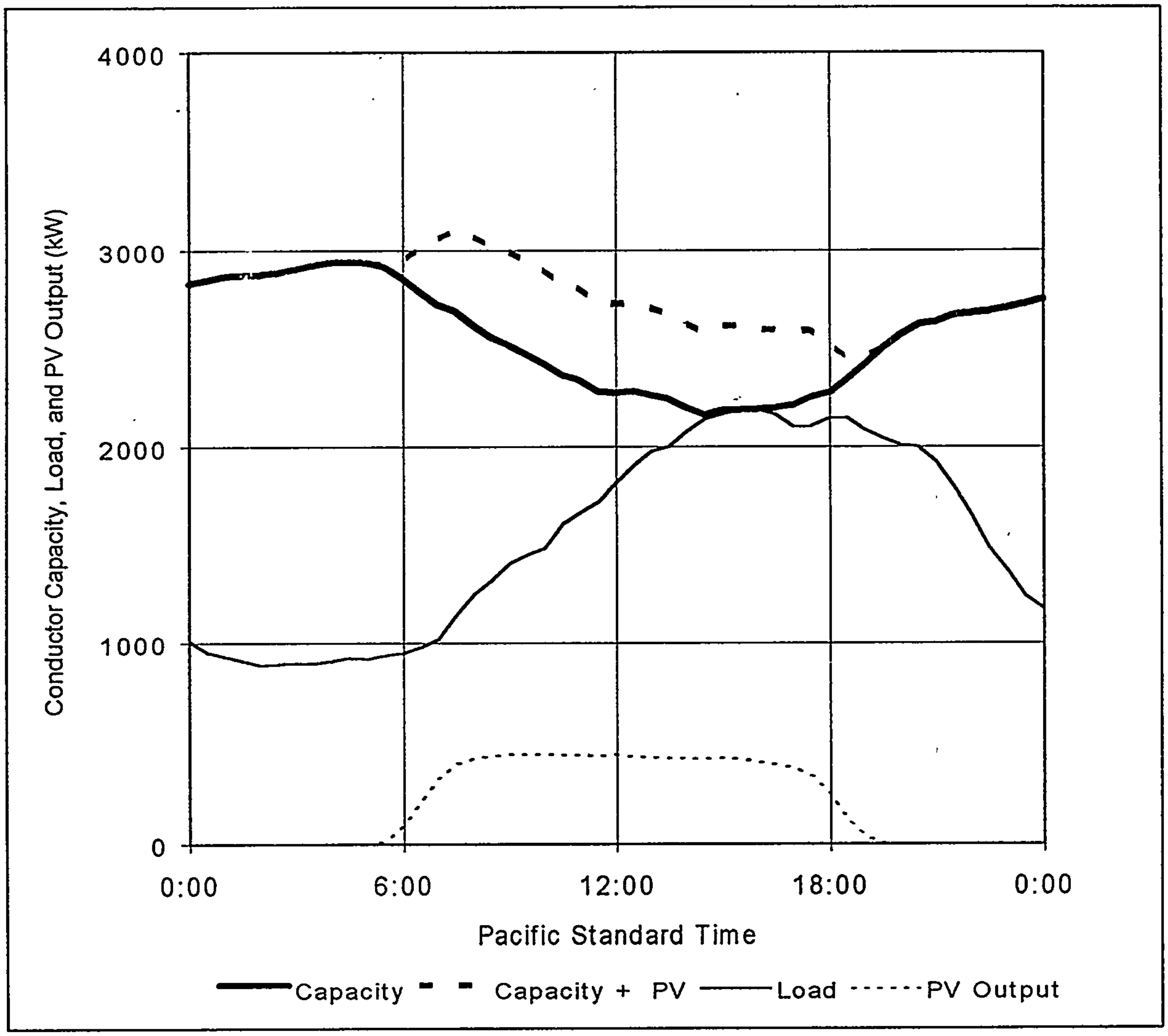


Figure 3-2. Conductor capacity and load and Kerman PV plant output (# 6 copper conductor) on June 25, 1993. The heavy solid line represents conductor capacity without the PV plant and the dashed line represents the capacity when the PV plant is added. Feeder loss savings of 3.5% are added to the PV plant output.

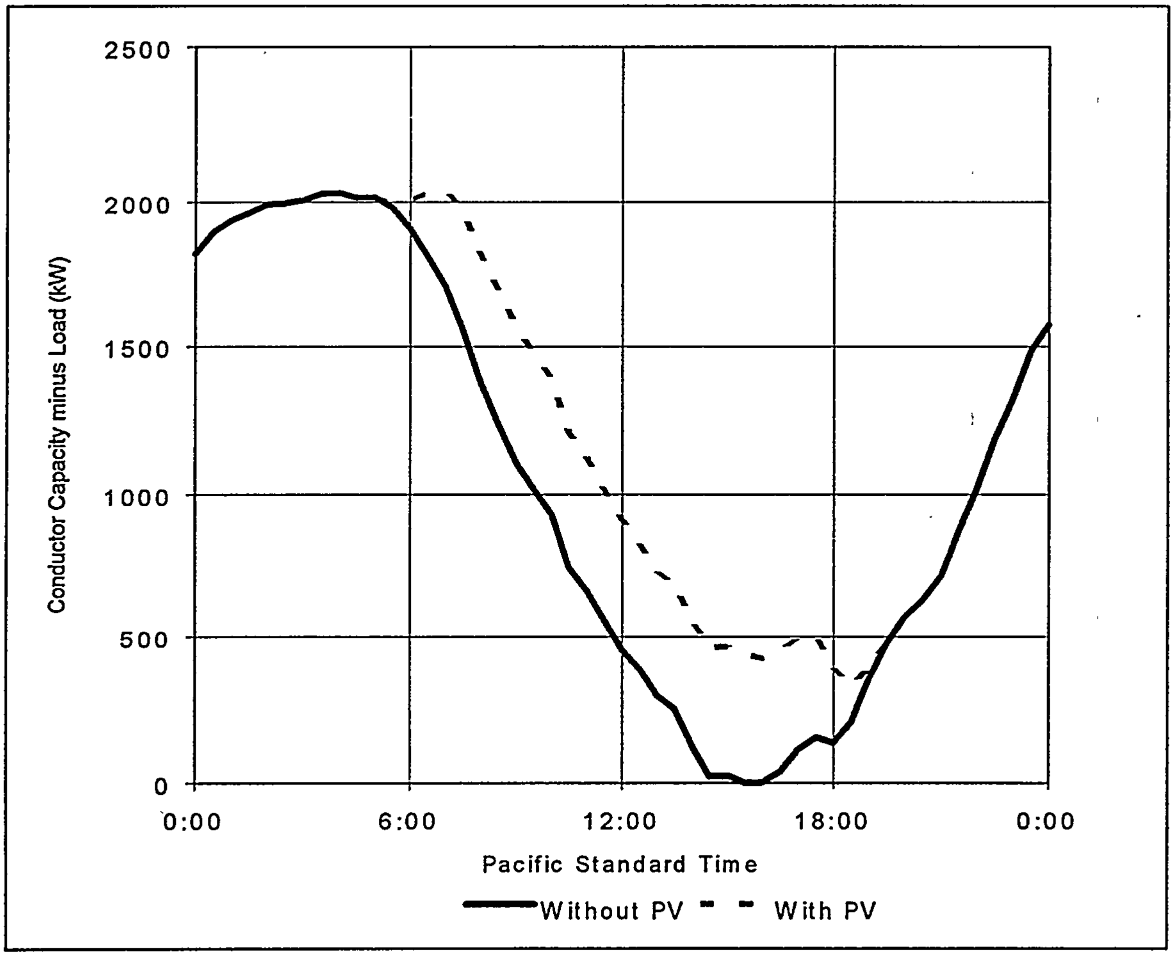


Figure 3-3. Conductor available capacity with and without PV (June 25, 1993).

VARIABLE PV PLANT SIZE

The 0.50-MW Kerman PV plant results are translated to other plant sizes (see Section 7). Figure 3-4 presents results using the weather-adjusted capacity approach as well as a constant capacity, or load reduction, approach. The load reduction method represents the difference between peak load with and without the PV plant. The two methods yield similar results for small plant sizes but the load reduction method underestimates added capacity at large plant sizes because the peak load shifts to later in the day. Figure 3-4 is unchanged if the analysis is based only on the peak day (June 25, 1993) rather than a full year's worth of data.

UPDATED ECONOMICS

Deferral value is the cost savings associated with postponing a capital investment. If one assumes a present value feeder upgrade cost of $100,000 per mile and an annual 1.5% load growth, the plant defers an upgrade for 10 years for a value of $11/kW-yr ($113/kW) per mile. This implies that deferring a 5-mile upgrade is worth over $50/kW-yr. Thus, although the value is zero at Kerman, value at other locations may be substantial.

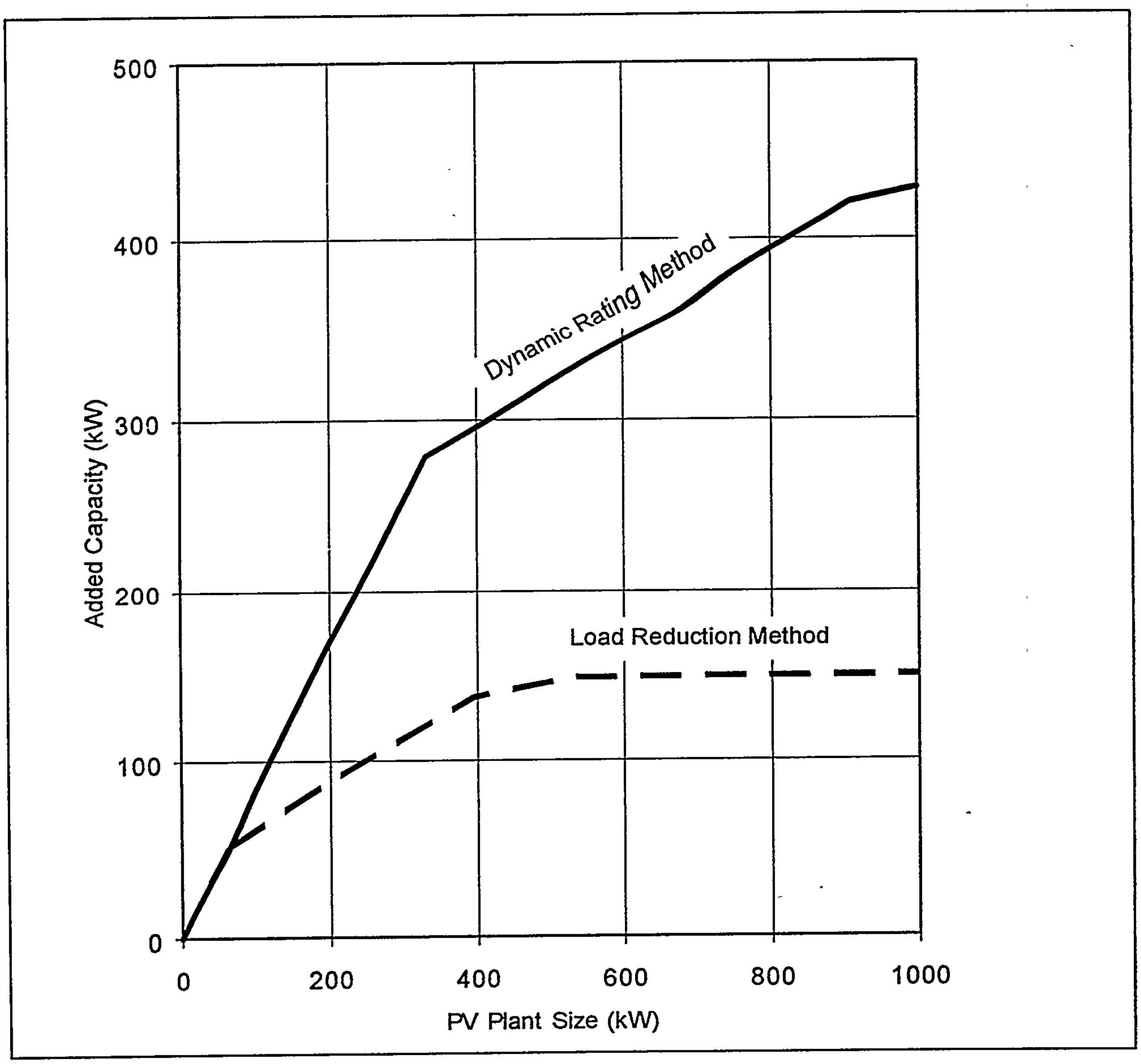


Figure 3-4. Added capacity versus PV size (dynamic rating and load reduction methods).

Section 4

SUBSTATION VALUE

The value of grid-support PV to a substation is defined to include the transformer upgrade deferral value as well as the value of the PV to voltage regulation devices. In the case of the Kerman Substation, voltage regulation devices include the transformer load tap changer and other voltage regulation devices on the feeder.

EXTEND DISTRIBUTION TRANSFORMER LIFE

Value Description

Grid-support PV can defer a substation transformer upgrade by supplying power on the low-voltage side of a transformer during peak usage. The reduced transformer load results in decreased transformer temperatures and, thus, additional capacity. This additional capacity can accommodate load growth and enable the utility to defer purchase of a new transformer until fully needed.

Evaluation Methodology

Although the 1992 Case Study performed preliminary analyses of the effect of PV output on transformer temperature using a transformer temperature model (see Appendix E.6.6 in the 1992 Case Study), the results were not fully conclusive. Rather, the transformer upgrade deferral value was based on the assumption that a "500-kW PV system could absorb load growth of 100 kW per year for a period of five years before a transformer upgrade would be necessary" (see page 4-5 in the 1992 Case Study). This implies that PV plant output was expected to be 0.50 MW during the peak hour of the year. Thus, one divides 0.50 MW of output by 0.10 MW per year of load growth to obtain a 5-year deferral.

This approach does not account for the fact that a PV plant rated at 0.50 MW may not produce 0.50 MW during the peak due to high ambient temperatures and less-than-ideal irradiance. The Kerman PV plant is rated at 0.498 MW at PTC. Moreover, this approach fails to account for the lack of a one-to-one relationship between peak load and transformer temperature.

A new method was developed to address the 1992 Case Study shortcomings. It is based on the reduction in transformer temperature as a result of a reduction in loads. It uses measured PV plant output and measured transformer load with PV. Added transformer capacity is determined by computing transformer hottest-spot temperature without PV using an IEEE transformer temperature model. This calculation is repeated for transformer load with PV. Load with PV is then increased until it has the same maximum hottest-spot temperature as the load without PV. This increase represents the added capacity. It is converted to years of deferral by dividing by an annual load growth estimate. The model, evaluation method, and results are described in detail in Appendix A.

In theory, this method requires a year's worth of data. In practice, one can use a data set corresponding to peak load and peak temperature conditions. In fact, results indicate that accuracy is obtained by analyzing only the worst day of the year; that is, when the load and ambient temperatures are high and PV output is low.

Technical Validation Testing and Data Requirements

The long thermal time constants associated with substation transformers make it insufficient to simply turn the PV plant on and off and measure a temperature reduction. Rather, the effect of PV output on transformer temperature must be estimated using a model. IEEE has developed a detailed model for loading power transformers.

The IEEE model simulates top-oil temperature and hottest-spot temperature rise over top-oil temperature. Top-oil temperature is the highest oil temperature in the transformer. Hottest-spot temperature rise over top-oil temperature is the greatest temperature rise anywhere in the transformer over the top-oil temperature.

Transformer top-oil temperature has been continuously monitored at the Kerman Substation since 1991. This extensive database facilitates evaluation of the accuracy of the IEEE model. Simulated top-oil temperatures were compared to measured top-oil temperatures under a range of conditions. These conditions included seven peak days in 1991 and ten peak days in 1992. In addition, the PV plant was cycled on and off five times over the course of three hours on July 1, 1993, thus enabling evaluation of the IEEE model's responsiveness to load changes.

Results indicated that the IEEE model required modification to reflect a time lag in the ambient temperature's effect on top-oil temperature. Simulated top-oil temperature was found to be a good estimate of measured data after the modification. Figure 4-1 compares simulated with measured top-oil temperature

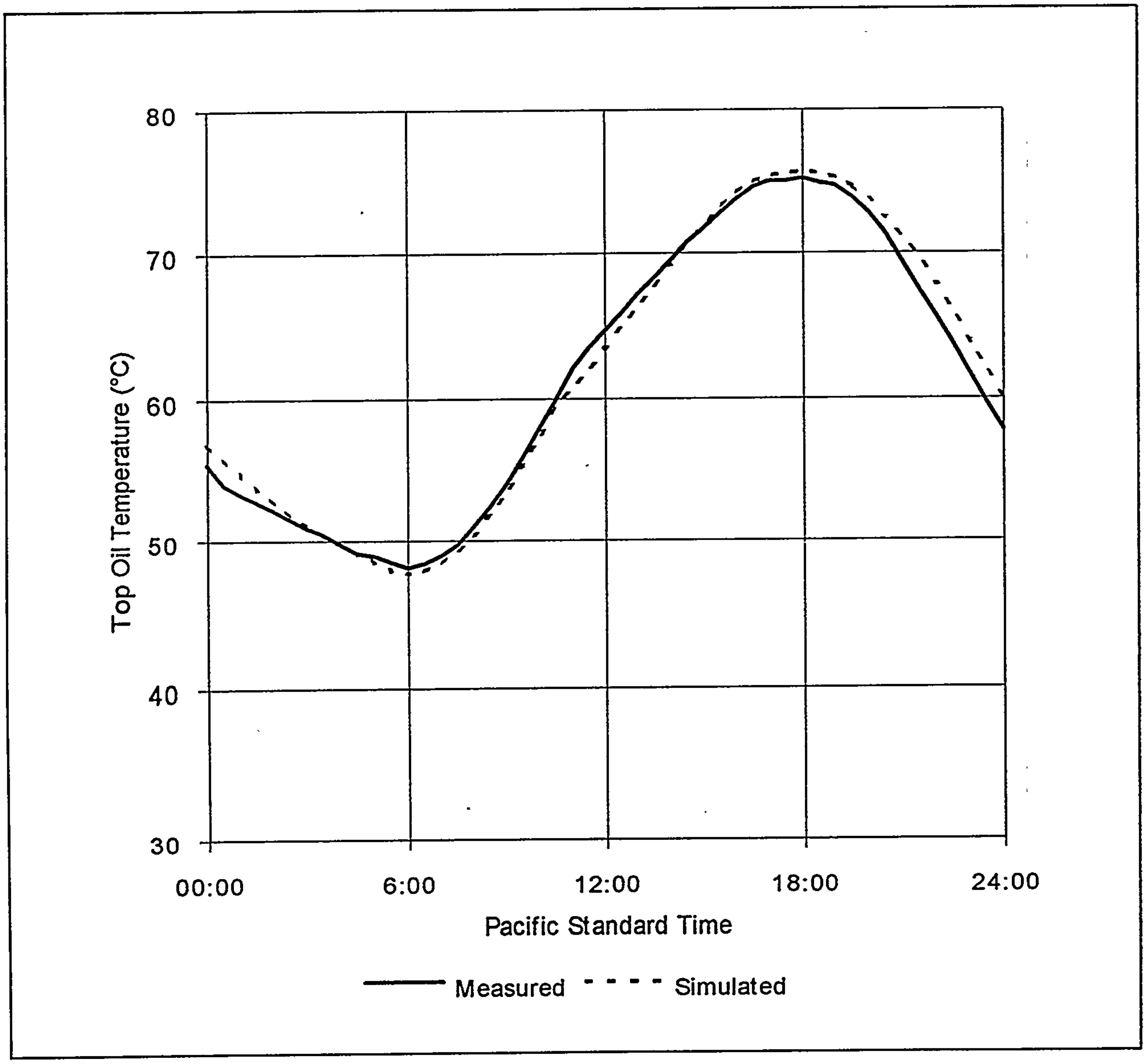


Figure 4-1. Measured and simulated transformer top-oil temperatures (July 3, 1991).

for the 1991 peak day; results are similar for other peak days in 1991, 1992, and 1993. It is assumed that the model accurately simulates hottest-spot temperature rise over top-oil temperature because hottest-spot temperature data are not accessible. Details of the model modification and validation are presented in Appendix A.

Technical Validation Results

Added transformer capacity is computed based on the highest peak days[1] between June 1, 1993 and July 31, 1994. Those days include June 25 and August 1-2, 1993, June 27-29, 1994, and July 11-13, 1994.[2] The hourly peak of 9.95 MW (with PV off line) occurred at 16:00 on June 25, 1993, closely followed by a 9.91-MW peak at 15:00 on August 2,1993.

Figures 4-2 and 4-3 calculate added capacity using June 25, 1993 data. Figure 4-2 presents transformer loads and Figure 4-3 presents transformer temperatures. Added capacity equals the growth in load so that the maximum hottest-spot temperature corresponding to load with PV and growth (heavy solid line) is the same as the maximum hottest-spot temperature corresponding to load without PV (thin solid line).

The peak load without PV occurred on June 25, 1993, and the peak load (and hottest-spot temperature) with PV occurred on August 2, 1993. Loads and ambient temperatures are similar on the two days but PV plant output is higher on June 25 because it is closer to the June 21 summer solstice. Results indicate that the PV plant reduced the maximum hottest-spot temperature by more than 4°C on this worst-case day (August 2, 1993), thus increasing transformer capacity by 0.41 MW. Approximately half of the increase comes from a lower top-oil temperature (a result of decreasing the load throughout the day). The other half comes from a reduction in hottest-spot temperature (a result of a lower peak load).

Deferral value is the cost savings associated with postponing a capital investment. Neglecting the salvage value at the end of the study period, deferral value is the difference between today's cost of a transformer and the discounted cost of a transformer purchased after the deferral period. In this case, the deferral period

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[1] The analysis excludes days with load transfers because the peak loads did not correspond to thermal peaks on the transformer. There was a 2-MW load transfer from 15:00 to 16:00 on July 6, 1993, a 4-MW load transfer from 9:30 until 14:30 on August 30, 1993, and a 3-MW load transfer from 7:30 to 11:00 on September 2, 1993.

[2] PV plant output data are adjusted to the appropriate full-plant output on June 28 and July 13, 1994. An event took both inverters off line at 15:06 on June 28; one inverter came back on line and the other had to be restarted the next day at 7:30. Both inverters came off line at 15:55 on July 13 and remained off line until they were restarted the next day at 9:30.

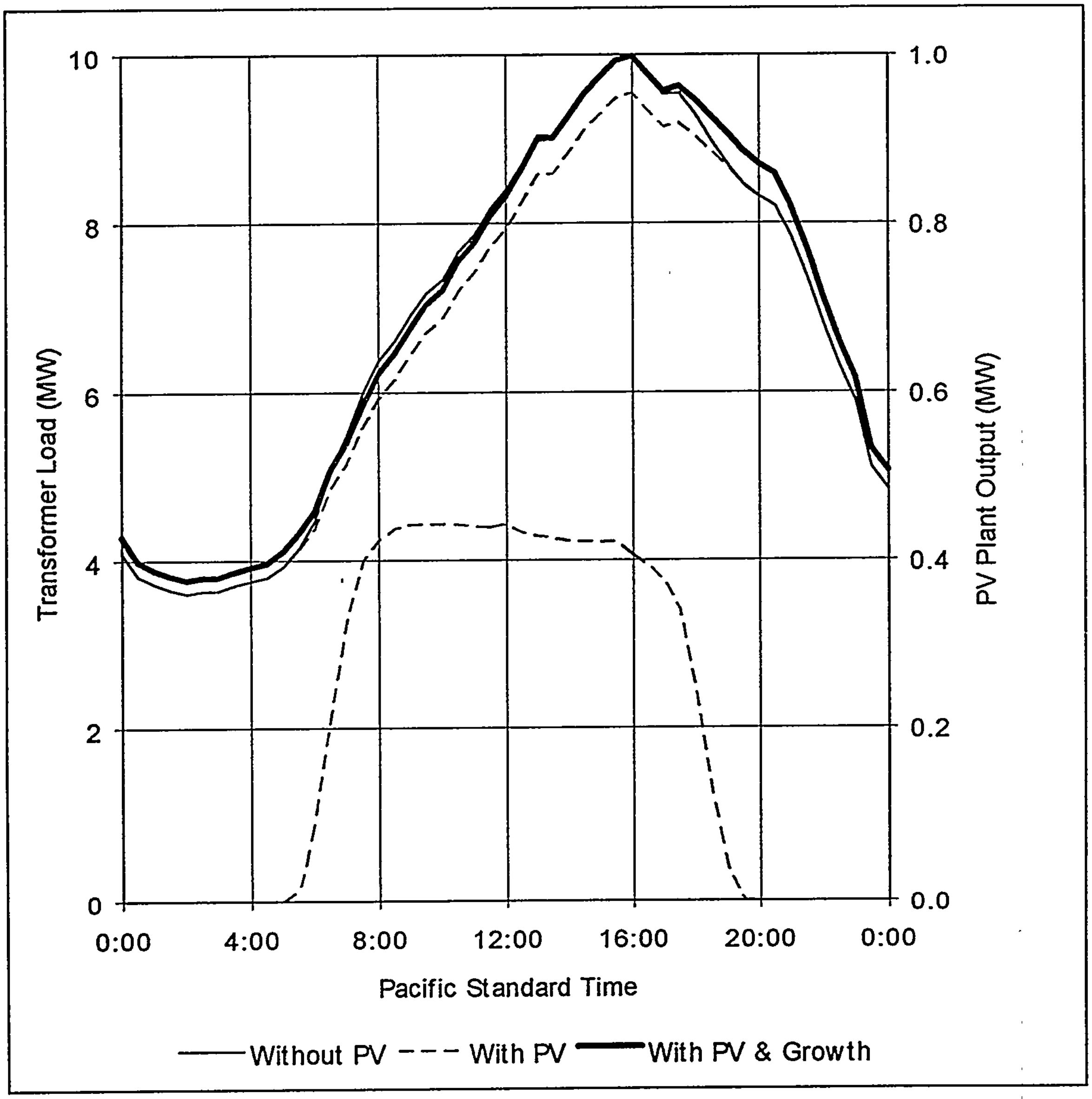


Figure 4-2. Transformer load and PV output on 1993 peak day (June 25, 1993).

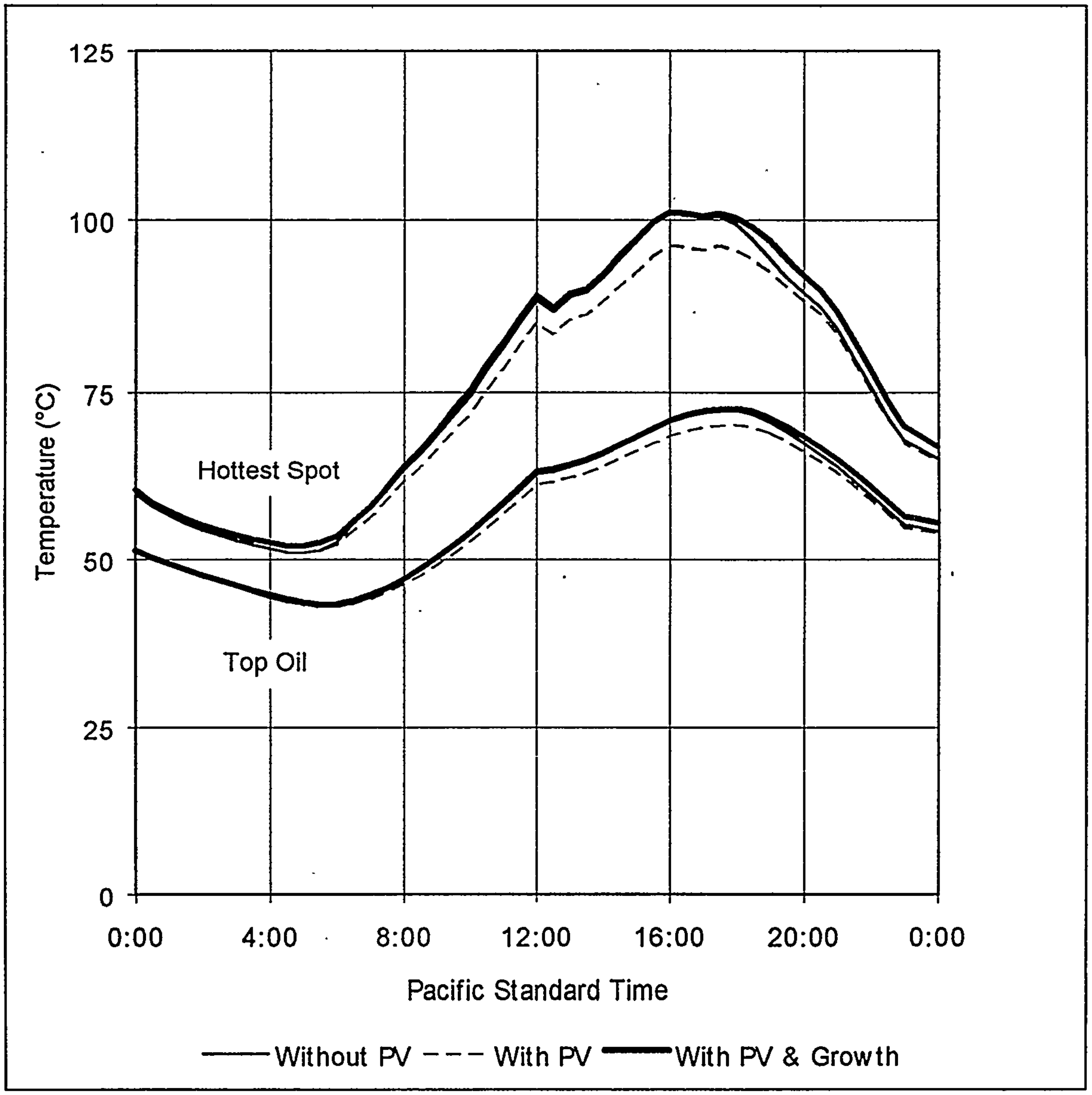


Figure 4-3. Transformer temperatures on 1993 peak day (June 25, 1993).

is 4.1 years: the PV plant allows for an additional 0.41 MW of load growth, and load growth is assumed to be 0.1 MW per year as in the 1992 Case Study. This corresponds to a deferral value of \$75/kW-yr (\$651/kW).

Technical Validation Results vs. 1992 Case Study

The 1992 Case Study estimated that the PV plant would defer a transformer upgrade for 5 years for a value of \$89/kW-yr (\$774/kW). Thus, the new estimate is 16% lower than the 1992 Case Study value. Although different methodologies are used, the difference in results is primarily due to PV plant output during the peak load. The 1992 Case Study assumed a 0.50-MW output during the peak. Measured output was 0.41 MW (including 5% loss savings) at 15:00 on August 2, 1993, due to the high ambient temperature (42°C) and less-than-perfect irradiance (930 W/m^2).

Variable PV Plant Size

The 0.50-MW Kerman PV plant results are translated to other plant sizes by scaling the Kerman PV plant output and performing an identical analysis using the new data. It is assumed that loss savings are a constant 5% of plant output. This is an acceptable assumption if plant capacity is distributed throughout the feeder rather than being all at one location. Figure 4-4 presents results using the thermal method described above as well as a load reduction method. The load reduction method represents the difference between peak load with and without the PV plant. The two methods yield almost the same result up to 1-MW PV plant sizes. The load reduction method plateaus once PV plant output reduces the peak load to load levels occurring during non-PV generating hours. The thermal method continues to add capacity due to the effect of oil precooling earlier in the day. Deferral value is calculated as before. It is interesting to note that Figure 4-4 is unchanged if the analysis is based only on data for August 2, 1993, versus a full data set.

Updated Economics

The 1992 Case Study estimated a load growth of 0.1 MW/yr and assumed a 5-year deferral. Although this may be an accurate estimate of the load growth on the individual transformer, it is most appropriate to use the load growth estimate for the entire area because load is easily transferable in the area. The area has an 80-MW capacity, and load growth is 1.5 MW/yr. At this load growth rate, 0.41 MW of added capacity from the PV plant will defer the need to install a transformer for about *three months rather than five years.*

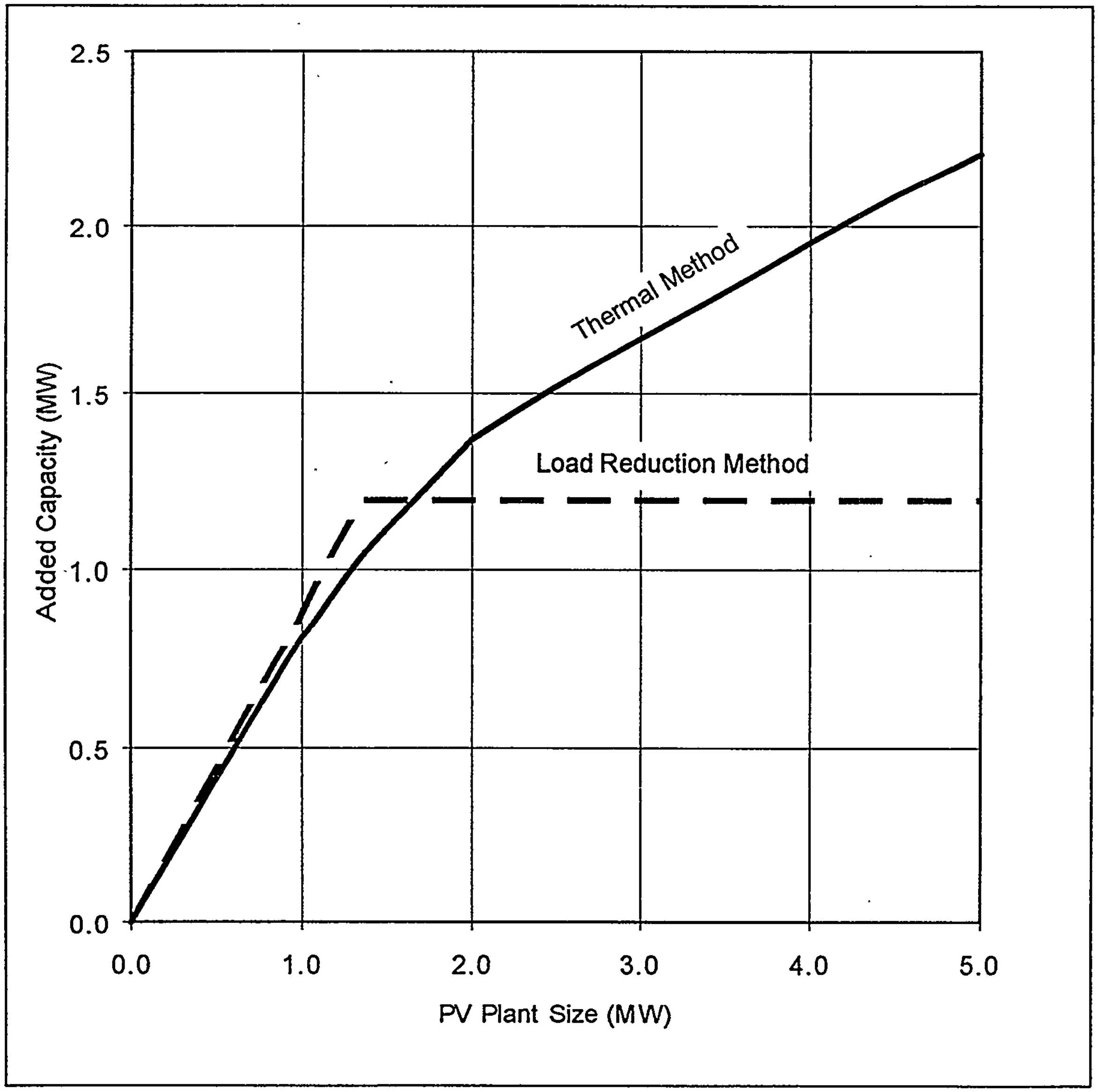


Figure 4-4. Added transformer capacity versus PV size (thermal and load reduction methods).

This translates to a marginal value of $11/kW-yr ($113/kW) based on a $1.4 million transformer cost (this is the present value cost based on cost estimates from the division planner for a 16-MVA transformer), 9% discount rate, and 3% escalation rate.

EXTEND LOAD TAP CHANGER MAINTENANCE INTERVALS

Value Description

A load tap changer (LTC) is located on the low-voltage side of a substation transformer. It regulates voltage for one or more distribution feeders to compensate for voltage drop at the worst location. Grid-support PV reduces the number of LTC operations (referred to as LTC changes), thus reducing LTC maintenance cost.

Evaluation Methodology

LTC operation is based on LTC voltage and LTC voltage range setting, feeder capacitor banks, and feeder load variation. The 1992 Case Study hypothesized that LTC changes are linearly related to load variation, and a PV plant reduces this variation. This hypothesis is evaluated by characterizing the relationship between LTC changes and load variation and calculating the PV plant's reduction in this variation.

Another, more direct approach is to evaluate feeder voltage support provided by the PV plant. This approach determines a PV plant's feeder voltage support and translates this support into a reduction in LTC changes. This is the approach used in the validation.

Two models were developed to assist in the evaluation: a feeder voltage support model and an empirically derived model relating LTC changes to LTC voltage range settings (see Appendix C for details). The voltage support model is based on the engineering principle that voltage drop equals current times resistance. The model predicts that voltage support at any feeder location is the product of PV plant output and conductor resistance of the direct path between the transformer and PV plant. This implies that, while voltage depends on feeder current, voltage support is independent of feeder current. In addition, only a portion of the feeder (i.e., not all the way to the point of interest) is of consequence.

Technical Validation Testing and Data Requirements

The feeder voltage support model is validated by measuring voltage support at various plant output levels and feeder locations. A loss savings test (July 1, 1993) and a reliability test (July 6, 1993), both of which involved cycling the PV plant, provide data to evaluate voltage support at the PV plant as a function of PV plant output. Another test was performed to measure voltage support along the feeder (May 26, 1994).

Figure 4-5 presents measured and predicted voltage support at the PV plant versus plant output for various feeder loads. Measured data are based on 10-minute averages recorded at the PV plant. High load conditions were created on July 6, 1993, by transferring load from adjacent feeders to Kerman Feeder 1103. The figure suggests that voltage support is linearly related to PV plant output and is *independent of feeder load* as predicted.

Voltage support along the feeder was measured on May 26, 1994 (see Appendix D for detailed test results). Figure 4-6 identifies measurement locations and conductor type. Figure 4-7 presents voltage support results at various feeder locations. (Voltage support is normalized by dividing by measured PV plant current times rated plant current to correct for differences in PV plant output.) The voltage support model predicts that switches 49 and 83 should have the same voltage support since they both connect to the same point on the path between the transformer and PV plant. This prediction is confirmed by Figure 4-7, which also confirms that voltage support is a function of the distance on the direct path between the transformer and PV plant.

Voltage support reduces the number of LTC changes by allowing the LTC voltage range setting to be changed. This is due to the fact that the voltage support provided by the PV plant is available when it is most needed. Figure 4-8 presents the measured number of LTC changes for 1990 (voltage range setting of 3.8 V), 1991, 1992 (voltage range setting of 5.0 volts), and 1993 (voltage range setting of 2.5 volts). All points represent a year's worth of data except 1993, which is based on 40% of the year and scaled to an annual estimate. Measured points are on a non-linear curve, as suggested by model results.

Technical Validation Results

The 1992 Case Study hypothesized that LTC changes are linearly related to load variation and a PV plant reduces this variation. Measured load data and historical LTC changes confirm that LTC changes are linearly related to load variation. Results indicate, however, that the 0.5-MW PV plant only reduced load variation by about 2%. That is, the PV plant's reduction in load variation has an inconsequential effect on extending LTC maintenance intervals.

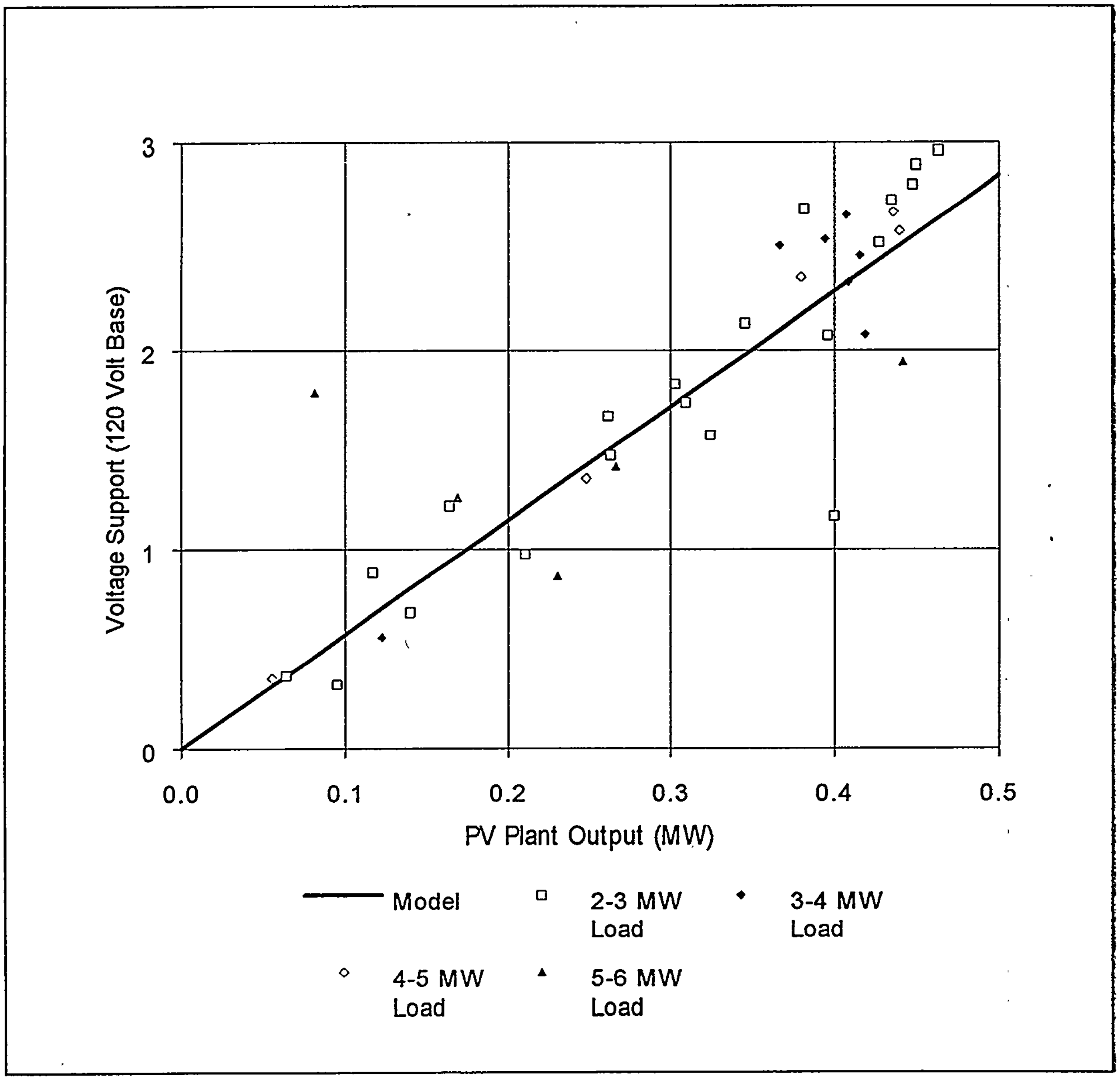
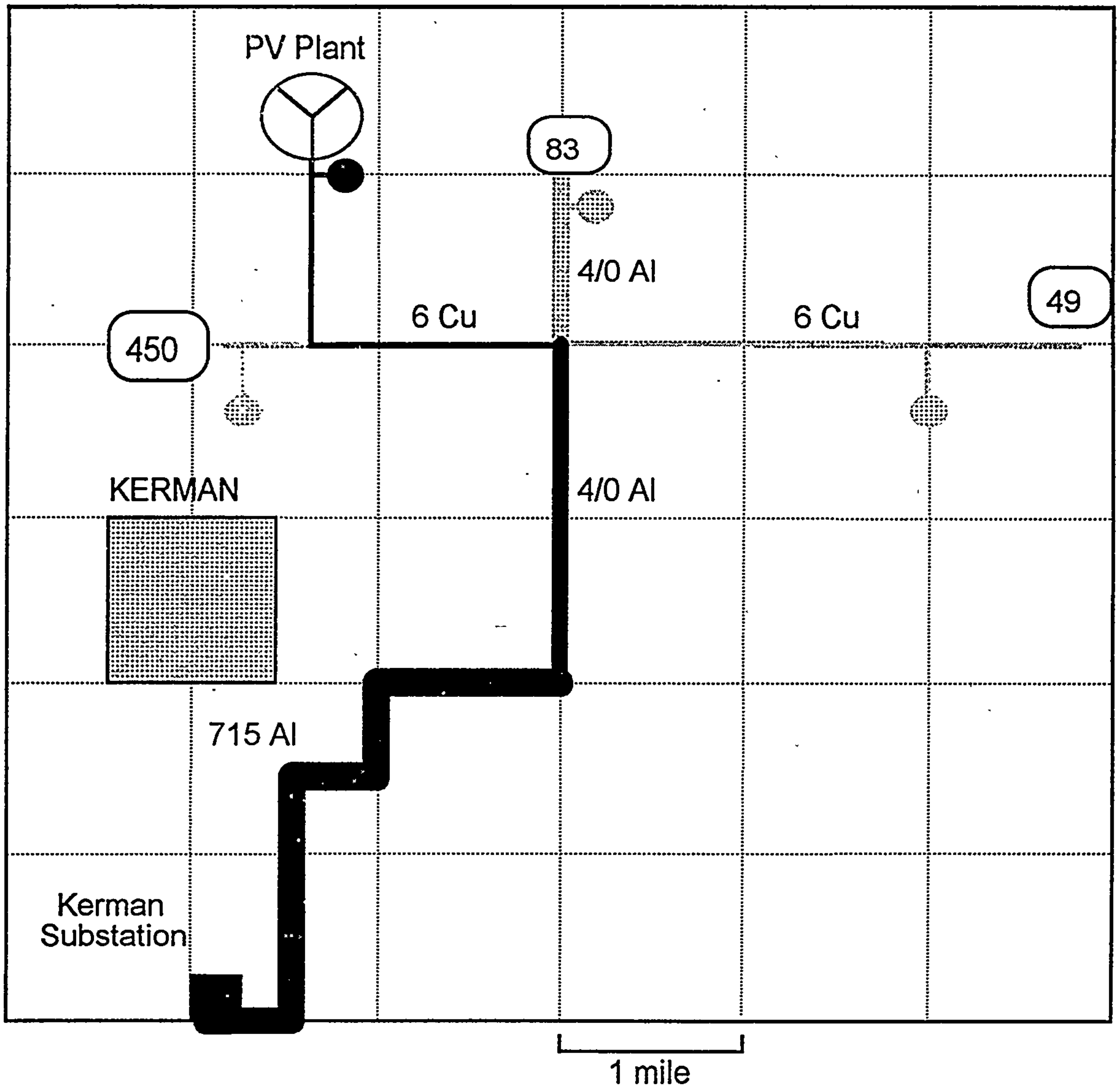


Figure 4-5. Linear relationship between voltage support at PV plant and output (July 1 and 6, 1993).



Note: Circles represent measurement locations. Line thickness and shading represent conductor type and path (direct or indirect) between the transformer and the PV plant.

Figure 4-6. Voltage support test on Kerman 1103 distribution circuit (May 26, 1994).

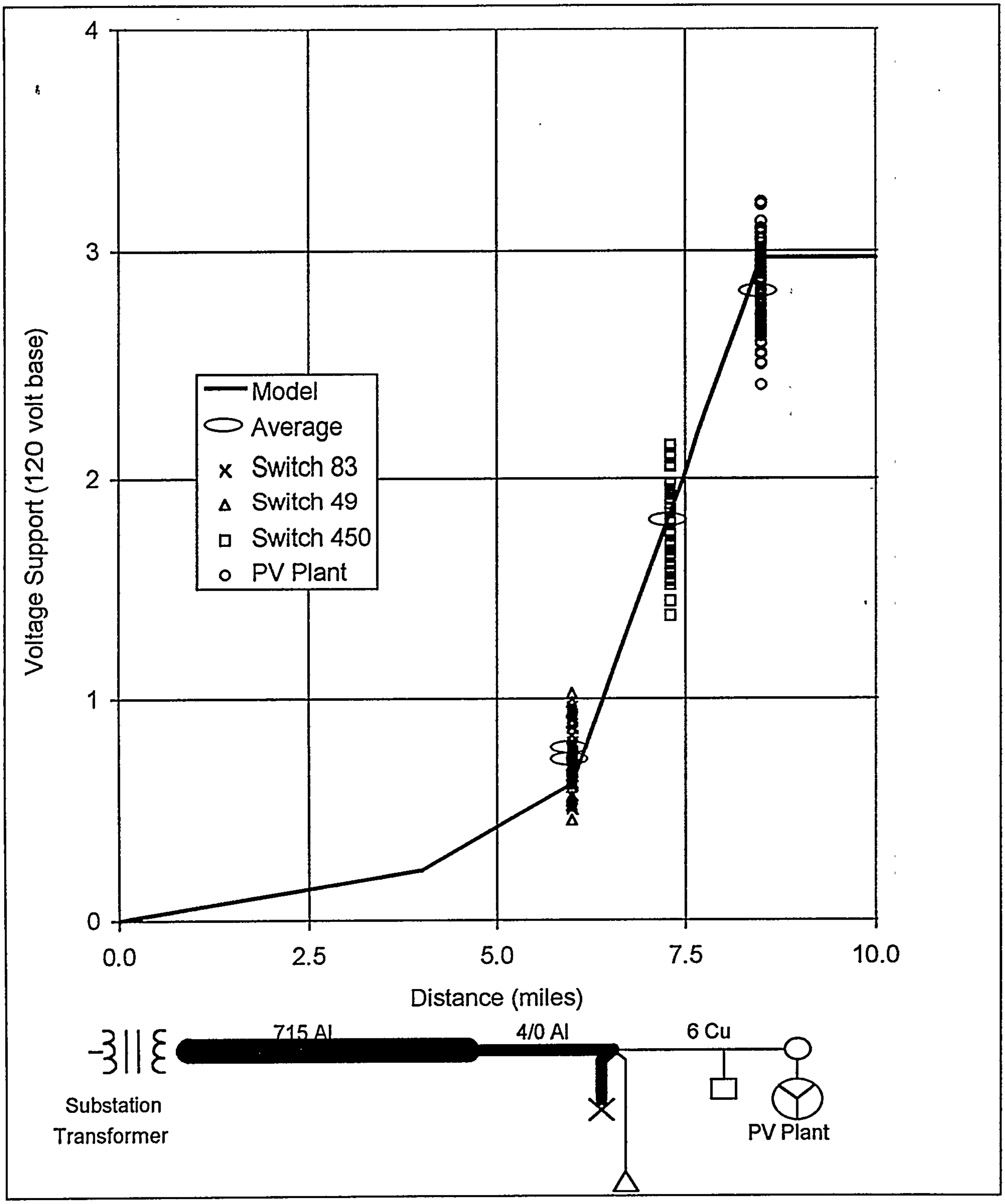


Figure 4-7. Voltage support is a function of distance on direct path between transformer and PV plant (May 26, 1994).

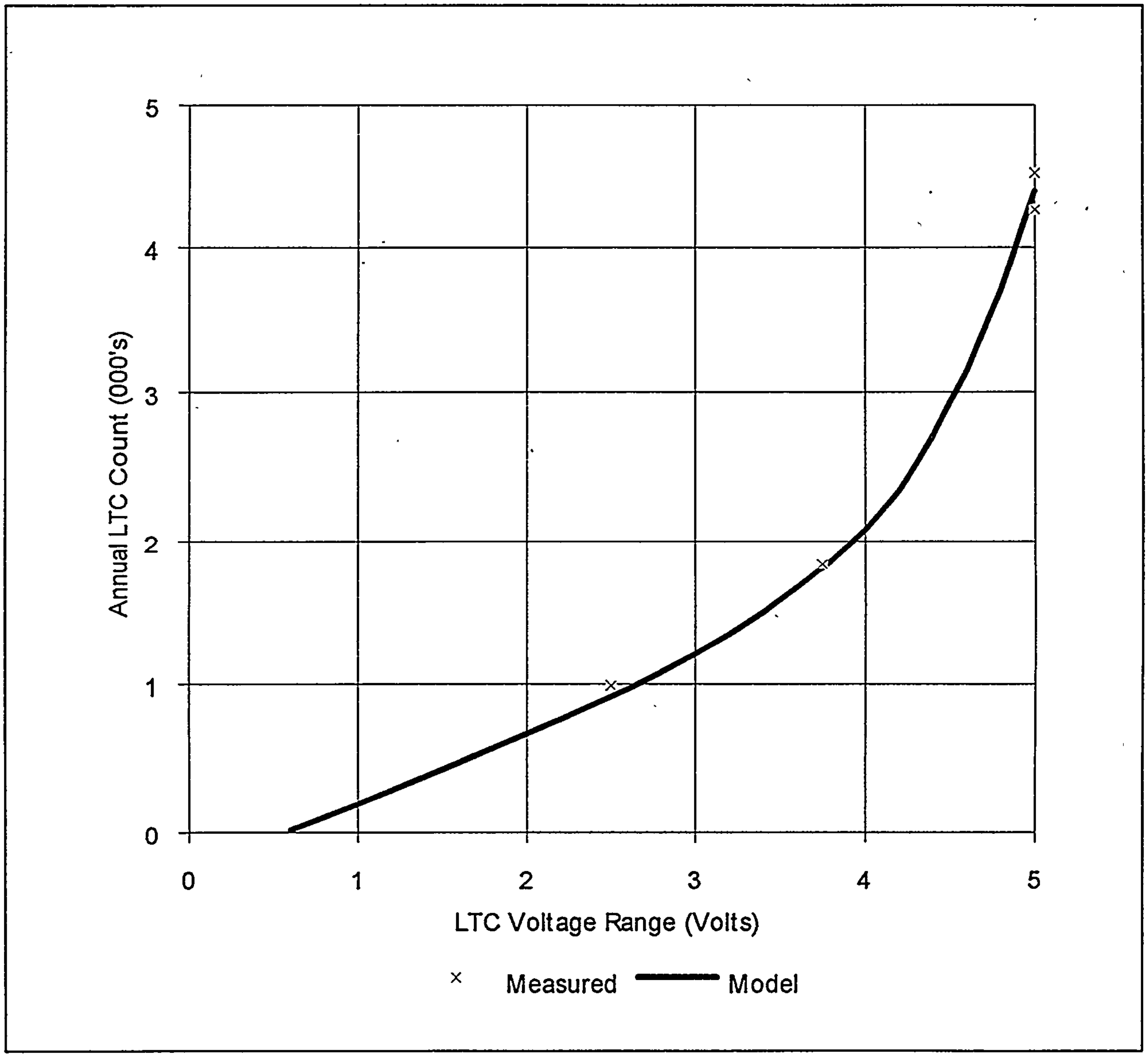


Figure 4-8. Annual LTC changes as a function of LTC voltage range setting.

The PV plant did provide enough voltage support to allow the Kerman area distribution planner to reset the LTC voltage range setting from 5.0 to 2.5 V at full load. This, along with the 1992 Case Study maintenance assumptions and the models verified in the previous sections, changes the maintenance interval frequency from 5 to 18 years for an economic value of $11/kW-yr ($96/kW). Adding the 1992 Case Study's $2/kW-yr ($17/kW) value estimate to other line devices results in a total voltage support value of $13/kW-yr ($113/kW). (All voltage support results from the 1992 Case Study have been adjusted to correct a double counting of inflation error.)

Technical Validation Results vs. 1992 Case Study

The new estimate more than doubles the $6/kW-yr result from the 1992 Case Study value because the source of value to the LTC is different than initially anticipated. The 1992 Case Study hypothesized that the PV plant would reduce the load variation and, thus, the number of LTC changes. Although correct, the effect is minimal and has almost no value. Instead, a more direct way to determine the value of the PV plant to the LTC is to assess the voltage support that the PV plant provides the LTC. Since the LTC does not have to regulate voltage as much, the operation of the LTC is reduced.

Variable PV Plant Size

Appendix C presents a method to value voltage support as a function of PV plant size. Simply stated, one calculates minimum feeder voltage with and without the PV, determines a new LTC voltage range setting, and converts this to economic value. Figure 4-9 presents the economic value for PV plant sizes up to 2.5 MW. The figure suggests that the 0.50-MW PV plant at Kerman obtains more than three-quarters of the potential voltage support value. The curve begins to flatten as the size of the PV system increases because the location of minimum voltage shifts from one location on the feeder to another location.

Updated Economics

The 1992 Case Study assumed an LTC maintenance cost of $23,000 occurring every 20,000 LTC changes. According to a Fresno distribution planner and PG&E's maintenance documents, LTCs are routinely inspected every 4 to 6 years, and worn parts are replaced during the inspection. The estimated parts replacement cost at the Kerman substation is revised to $15,000, occurring every 50,000 LTC changes. This reduces LTC value from $11/kW-yr to $3/kW-yr ($31/kW) for a total voltage support value of $5/kW-yr ($51/kW).

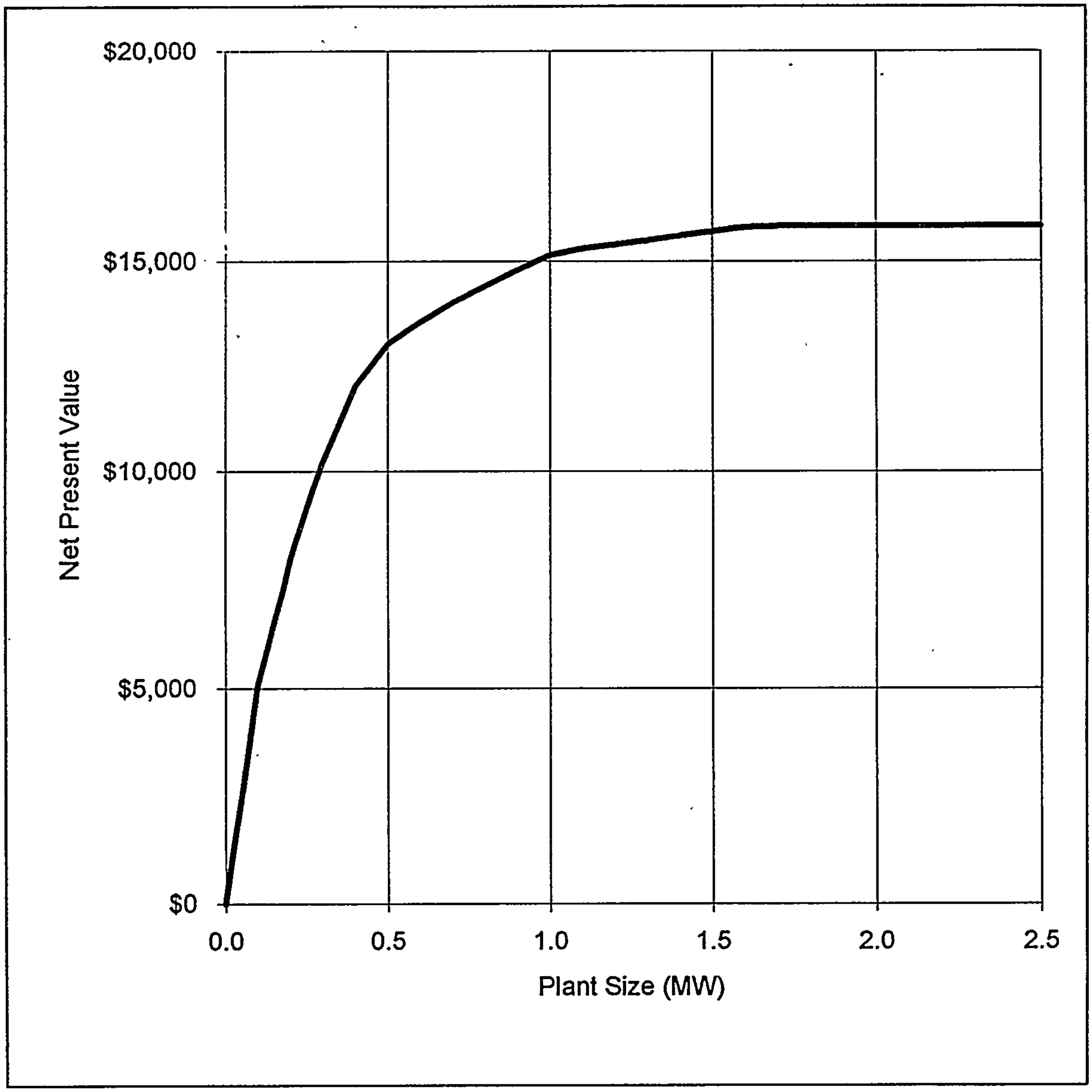


Figure 4-9. Voltage support value versus PV plant size.

Section 5

LOCAL RELIABILITY VALUE

VALUE DESCRIPTION

Local reliability value captures the improvements to customer service reliability that result from reducing outages. One advantage of a localized generation resource, such as a grid-support PV plant, is that the presence of the generation resource can reduce outage time and enhance customer service reliability.

Unlike service interruptions caused by generation capacity shortfalls, local T&D system outages typically occur without warning (see Section 9, System Capacity Value, for treatment of generation reliability). The distributed generation resource, as evaluated here, is treated as a means to reduce customer outage-minutes, as opposed to a means to completely eliminate service interruptions (e.g., uninterruptible power supply [UPS]).

EVALUATION METHODOLOGY

The 1992 Case Study developed a six-step method to calculate the value of local reliability enhancement resulting from the utilization of a PV plant to reduce customer outage time (Shugar et al. 1992). A value of service (VOS) methodology is used to translate the reduction in outage time to a monetary value. The six steps are described as follows:

1. Select the site. The ability of the PV plant to improve reliability is extremely site-dependent. The relative location and rating of circuit switching and protection devices (e.g., switches, reclosers, fuses, and capacitors) must be considered. Factors such as outage frequency, customer type (and the value they place on reliability), and load distribution also need to be included in site selection. A good starting point to select a site of high reliability value is near a normally open switch that separates circuits that backfeed each other during outages.

2. Estimate "salvageable" outage time: Based on existing outage records for the area, preferably recorded over a period of years, one must discern which outages and what percentage of their time can be reduced. The goal is to arrive at an annual average salvageable outage time. The location of both the generating source and the outage location relative to the distribution line devices needs to be considered. It is assumed, for Step 2, that the generation resource is fully dispatchable. The average time it takes crews to isolate the cause of the service interruption to allow backfeeding to occur is subtracted from the salvageable outage time.

3. Estimate the size of customer loads exposed to outages: These estimates are used to determine the expected unserved energy (EUE) that results from outages. Ideally, this estimate is determined by customer daily and seasonal load data that are segregated by location on the feeder relative to the affected distribution line devices.

4. Calculate the potential load savings attributable to the generation facility: The 1992 Case Study considered "minimum" and "maximum" load-saving scenarios. The minimum scenario assumes that the recoverable load savings attributable to the PV plant are limited to the customer loads that could be supported by PV generation output only. The maximum savings scenario assumes that all of the loads exposed to outages are credited to the generation resource, even when the recovered loads exceed PV output. These minimum and maximum scenarios enable the reliability value estimate to be bounded.

5. Estimate the expected load savings (kWh): The estimated expected annual average load savings is based on the probability of outage frequency derived in Step 2 and the minimum and maximum load savings calculations from Step 4.

6. Determine the monetary value of the expected load savings: The estimated value of avoiding outages is based on VOS estimates. VOS numbers represent the average value customers place on the avoidance of partial and full outages, and are commonly referred to as "outage costs." These outage costs are derived from surveys of PG&E's four major customer classes. A weighted average outage cost is calculated based on the customer mix for each line segment under consideration. The expected load-saving estimates derived in Step 5 are multiplied by the weighted average VOS numbers to arrive at minimum and maximum values of reliability.

In summary, the 1992 Case Study approach carefully sites the generation source to optimize service restoration; obtains historical outage data; develops estimated probabilities of outages for each line segment under study; determines the amount of potential load savings (salvageable load) that can be captured by a fully dispatchable generation source; determines the amount of load that can be restored by a PV generation source; obtains representative VOS numbers and weights them by the customer mix on each line segment considered; and multiplies the weighted VOS by the salvageable load to calculate the value of added reliability.

An alternative evaluation method is presented and used in the "Updated Economics" subsection in this chapter.

TECHNICAL VALIDATION TESTING AND DATA REQUIREMENTS

Tests were conducted during the summers of 1993 and 1994 to validate two hypotheses:

1. The Kerman PV plant can be utilized during distribution system disturbances to reduce the duration of customer outages.

2. The Kerman PV plant boosts feeder voltage in a predictable way, enabling a distribution operator to anticipate voltage support anywhere on the feeder as a function of plant output. This voltage support information can be used as a guide to restore customers during outages.

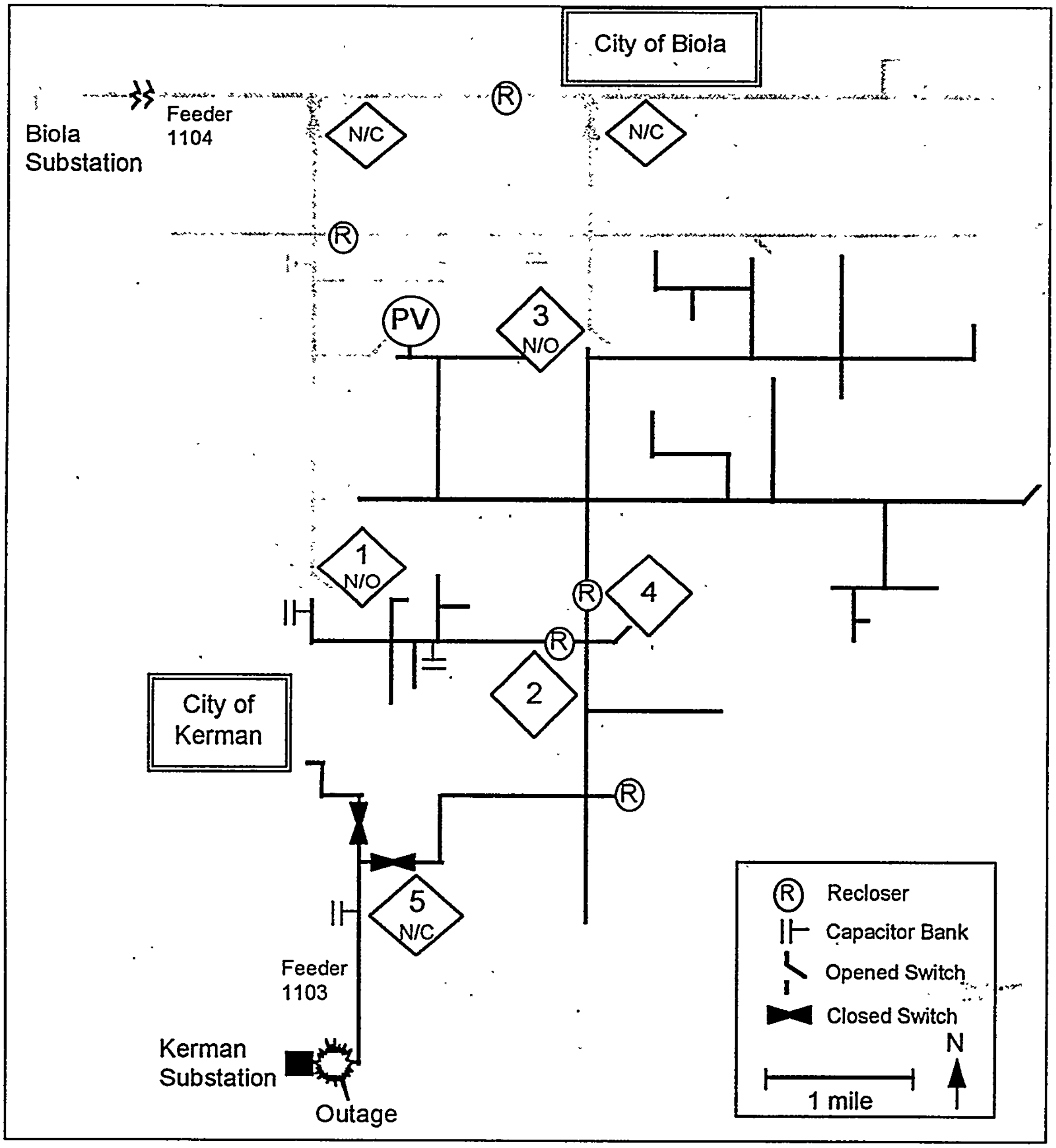
Hypothesis #1 (Restoring Customers During Outages)

A series of distribution operations were conducted on clear sunny days in July and August 1993. Four outage situations were simulated by operating switches and line reclosers: "Outages" at the Biola substation, conducted during peak and off-peak load conditions, and "outages" at the Kerman substation, also conducted during peak and off-peak loading.

Figure 5-1 presents an example of a field test simulating an outage from the Kerman substation. During Phase 1 of the test, the plant is taken off line, Switch 1 is closed, Recloser 2 is opened, Switch 3 is closed, and Recloser 4 is opened. Once Reclosers 2 and 4 are opened, a significant portion of Feeder 1103 is isolated from the Kerman substation, and the Biola Feeder 1104 backfeeds and picks up Feeder 1103 customers. During Phase 2, the PV plant is brought on line, then Recloser 4 is closed, and Switch 5 is opened. These operations extend the area fed by Biola 1104.

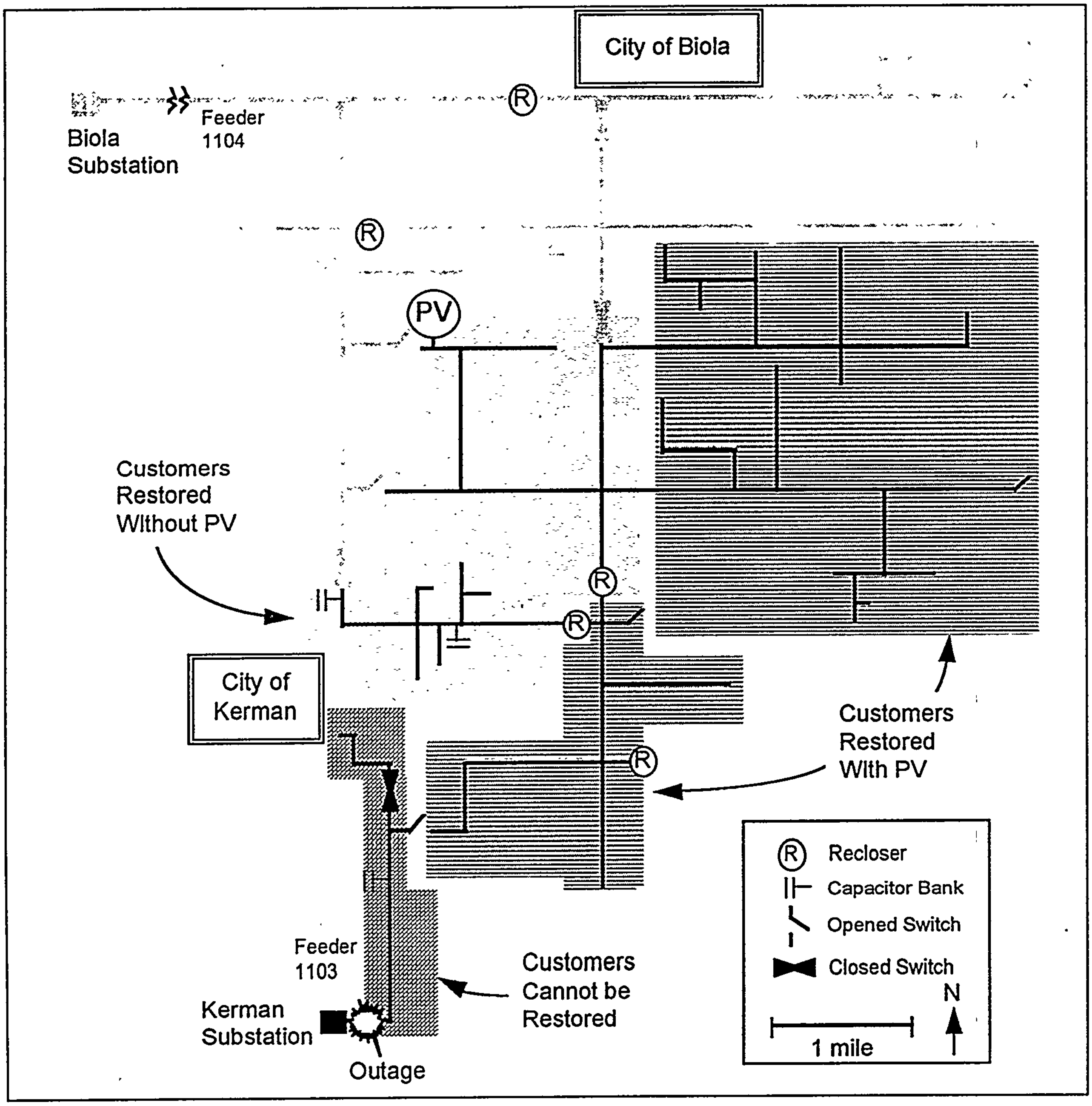
The limiting factor for transferring load is voltage. A minimum secondary single-phase voltage of 114 V (120-V base) must be maintained at the customer's meter (110 V under emergency conditions). During the switching operations, PG&E personnel monitor voltage along the distribution line segments to ensure that minimum voltage is being maintained. Customer load is brought on line through switching operations until the minimum voltage is reached. This determines the area that can be served.

Figure 5-2 presents the final results of this test, conducted during peak load hours. With the PV plant on line, a large number of Feeder 1103 segments can be restored from the Biola substation. The PV plant provides the voltage support necessary to maintain minimum voltage levels along these line segments. If an outage did occur at the Kerman substation, service to these Kerman 1103 customers could continue provided the plant was on line. Otherwise, electric service would be interrupted.



Note: N/C = normally closed switch position; N/O= normally open switch position

Figure 5-1. Kerman substation outage simulation: switching operation sequence. The numbered diamonds point to line devices that were operated to examine the line sections that could be picked up out of the Biola substation (Biola Feeder 1104, shown in gray), with the plant off line and with the plant on line.



Note: Tests conducted and results reported by Sam Dooms, Dan Shugar, and PG&E Fresno Division personnel.
Not all line equipment are included in this figure to simplify the illustration.

Figure 5-2. Kerman substation outage simulation: PV plant picks up customer loads. The shaded areas represent customers who are either restored or not restored from the simulated Kerman substation outage. With the PV plant off line, only the line segments in the upper left shaded area can be restored by the Biola substation.

The area adjacent to the Kerman substation cannot be restored because of voltage limitations, even with the PV plant on line.

It was estimated that Kerman PV plant operation enabled an additional 170 customers to be restored, with a total load of 950 kW (testing conducted by Sam Dooms and Dan Shugar, formerly of PG&E). Technically, the amount of load that can be restored as a result of the Kerman PV plant is limited to total PV plant output. Because there are a limited number of sectionalizing switches installed in any given area, utility personnel cannot restore line segments in fine enough increments to meet minimum voltage requirements. Therefore, the voltage boost supplied by the plant is sufficient to extend the restored area while, in effect, taking credit for load that would have been restored if additional sectionalizers were available. This is a clarification that is relevant to the voltage support models developed in this report to alert the reader that Ohm's Law has not been violated.

Figure 5-3 presents results of the testing sequence described above, only the test was conducted during lower line-loading, off peak. Because of lower line loads which translate into higher line voltages, a much larger segment can be restored from the Biola substation. Note, however, that a segment that previously could not be restored with the PV plant on line (shown in Figure 5-2), can now be restored (it was estimated that 470 customers with loads totaling 500 kW could have service restored).

Based on these test results, the first hypothesis was validated: The PV plant provides voltage support enabling the restoration of customer load under field-tested outage conditions.

Hypothesis #2 (Voltage Support is Predictable)

The second hypothesis states that feeder voltage support can be predicted given any level of PV output and feeder location, independent of load. Data collected from the first set of reliability tests conducted in July 1993 were used in conjunction with test data measured in May 1994 to validate this hypothesis. Voltage support testing details are found in Section 4 and Appendix D.

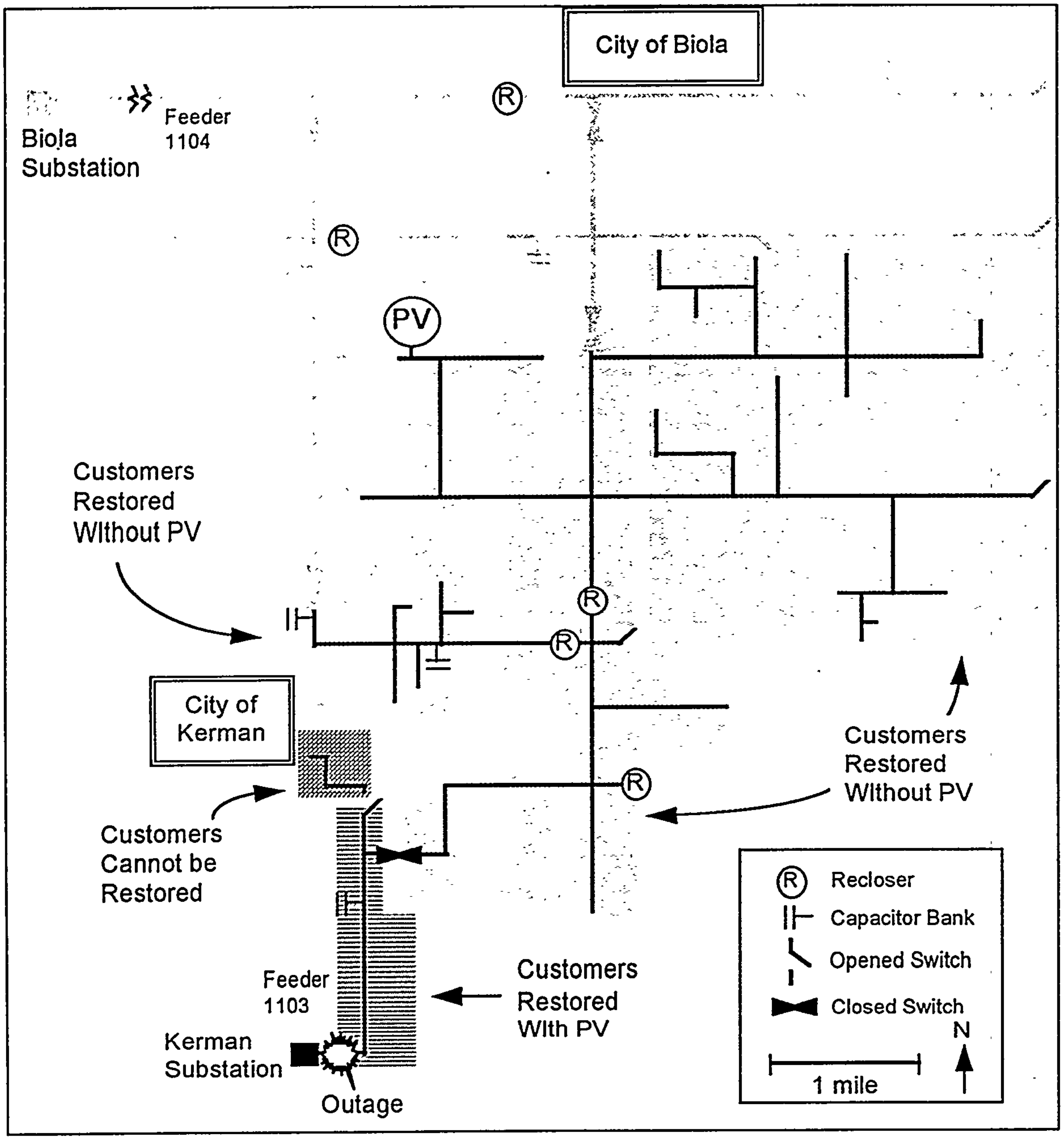


Figure 5-3. Kerman substation outage simulation: test results during off-peak loading.

Figure 5-4 presents sample voltage support results that have been confirmed with measured test data. The levels of voltage support and corresponding amount of load that could be restored during an outage are shown for various locations. PV plant output is assumed to be near 500 kW. A voltage boost of 3.3 V (on a 120-V base) is available near the PV plant, for example, and a total customer load of 500 kW could be restored. (Loads greater than 500 kW may be restored, depending on the location of sectionalizing switches. See comments made in the previous reliability test subsection.)

The amount of power or current available to restore customers during outages depends on feeder segment resistances. For example, Figure 5-5 shows that a 2-V boost is available at Point A, corresponding to 370 kW of available power to restore customers. To determine restoration power, simply multiply the PV plant output (500 kW) by line resistance (at a line temperature of 75°C) from Point B to Point C (at the Kerman substation) divided by the line resistance from Point A to Point C (500 kW times 4.3 Ω divided by 5.8 Ω).

These results confirm the second reliability hypothesis: Voltage support can be predicted for any feeder location as a function of PV output. A look-up table could be predetermined for Feeder 1103 that calculates voltage support and available power or current as a function of PV plant output and circuit location. Utility personnel could utilize this look-up table to optimally restore customers during distribution disturbances.

TECHNICAL VALIDATION RESULTS

Utility distribution personnel balance loads and configure line sections, in large part, according to two criteria: (1) the current carrying capacity of the distribution hardware, and (2) maintaining distribution system voltages. During outage events, these criteria especially come into play as the utility attempts to restore customers by backfeeding power to them from adjacent energized line sections.

The impact of the PV plant on the current carrying capability of distribution conductors and transformers has been discussed extensively in Sections 3 and 4 and Appendices A and B. Validation of voltage support and testing are covered in Section 4 and Appendices C and D. Reliability testing is discussed in this

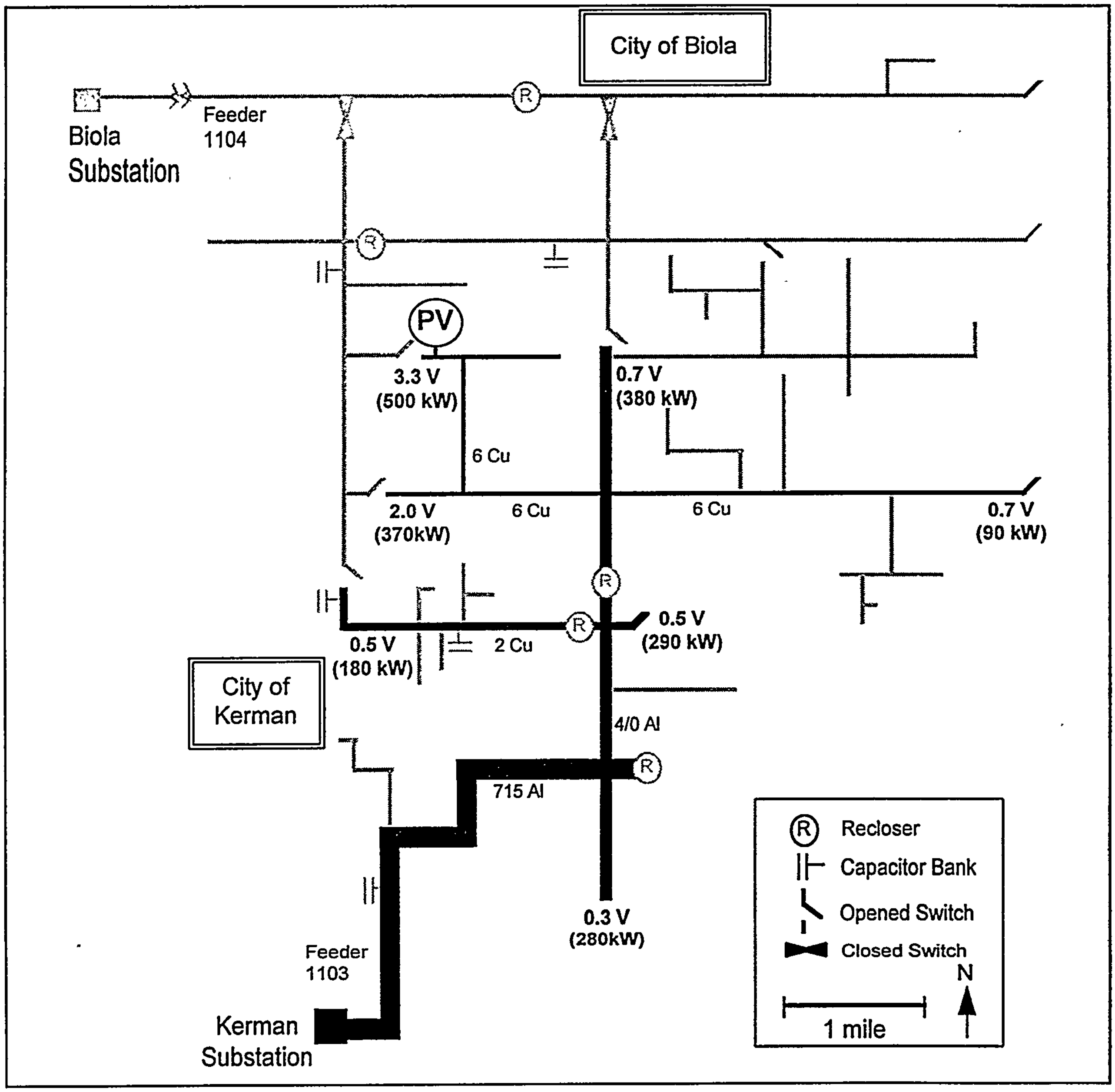


Figure 5-4. **PV plant provides predictable voltage support along Feeder 1103. Relevant line sections of Feeder 1103 are shown in black along with conductor type (e.g., 715 Al corresponds to 715 MCM aluminum conductor). The thicker the conductor, the higher the rating and the lower the resistance.**

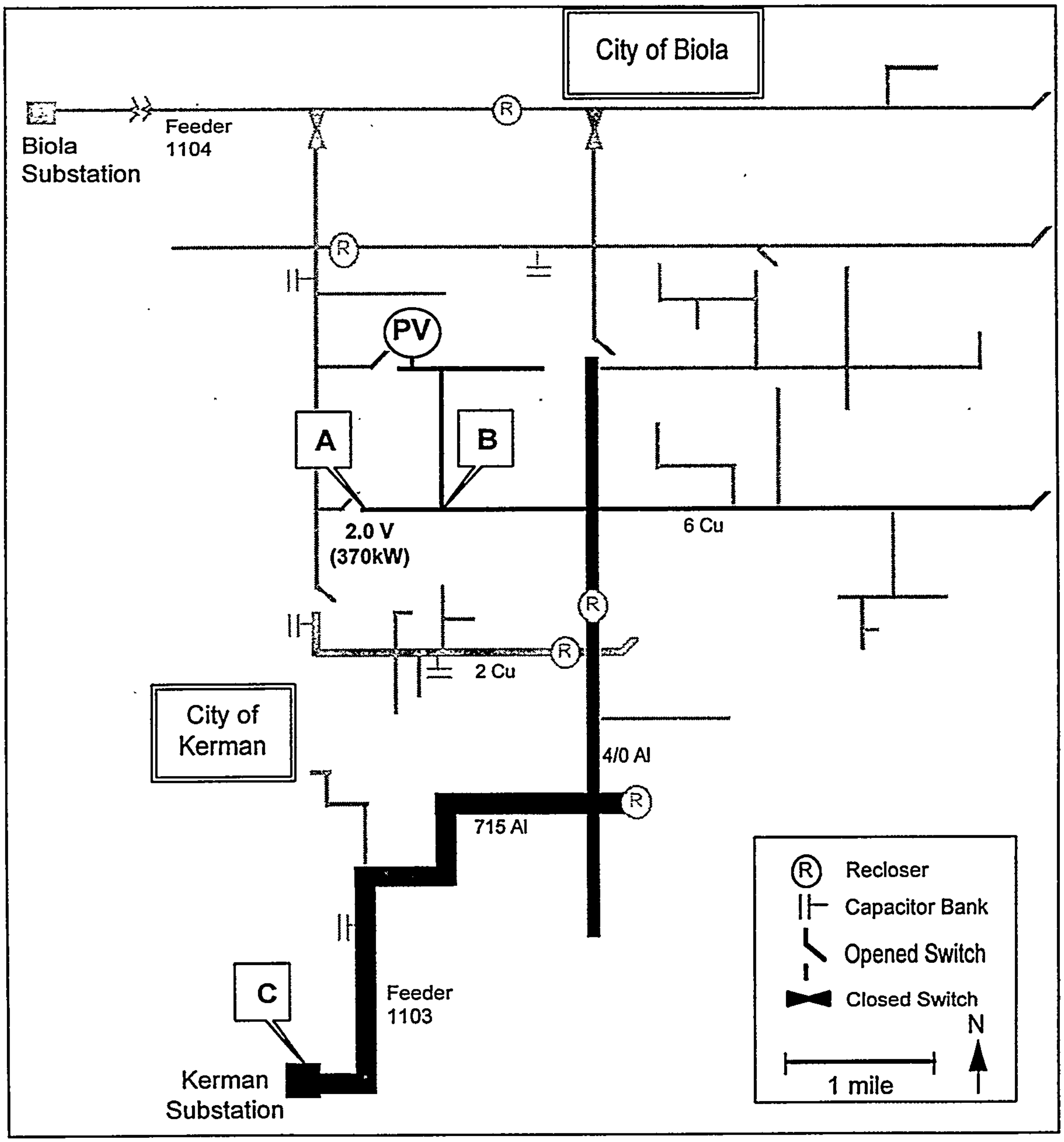


Figure 5-5. Available restoration load for Point A depends on line resistances.

section. The sum of this research confirms that the Kerman PV plant provides voltage support in a predictable way, and this boost can help restore customers during distribution outage events.[1]

TECHNICAL VALIDATION RESULTS VS. 1992 CASE STUDY

To translate these results into an economic value, three relevant questions are posed: Will utility personnel utilize the Kerman PV plant to speed customer service restoration during outages? What is the value if they do? Is there an alternative method that can provide the equivalent capability?

Since coming on line in June 1993, the Kerman PV plant has yet to be used in a reliability enhancement capacity. According to PG&E distribution personnel, there has not been an opportunity and, even if there were, it is unlikely that personnel would "risk" using the plant in this way because of a lack of experience in utilizing the plant for voltage support (Personal communication, Joaquin Buendia, PG&E Fresno Division, May and October 1994). This lack of experience could be remedied through formal training.

The 1992 Case Study assumed that the Kerman plant could be used to reduce customer outages. Three potential sites were analyzed, one of which was near the eventual location of the Kerman plant. Based on 4 years of historical outage data, it was estimated the Kerman plant could help mitigate a maximum of 5.3 outages/year, with each outage lasting 4.3 hours, equating to about 23 hours of outage time per year. This maximum salvageable outage time is based on the analysis of outages along five distribution line segments and the customer loads on these segments. Based on the availability of the PV plant, taking into account outages that occur at night, a salvageable load savings of 2,220 kWh/yr is estimated.

Value of service estimates are used to translate the salvageable load savings into an economic value. Table 5-1 lists the VOS numbers for PG&E's four major customer classes for avoiding full outages. VOS estimates assumed in the 1992 Case Study are presented. Updated estimates are presented for comparison purposes. With the exception of the residential customer class, updated VOS estimates have been reduced dramatically.

A weighted average VOS estimate is determined by the customer mix on each line segment. The 1992 Case Study developed a weighted average VOS of $26.35/kWh in year 1988 dollars. Multiplying the VOS

[1] Advanced inverters are now available that ..ave the ability to inject or consume VARs, enabling improved control and even larger amounts of voltage support.

estimate of $26.35/kWh by the salvageable load savings estimate of 2,220 kWh/yr results in an economic value of $58,500/yr. The 1992 Case Study assumed that VOS estimates would rise by 6.6% annually. Assuming an 11% cost of capital and a 30-year project life, the 1992 Case Study estimated the levelized reliability value at $205/kW-yr in year 1992 dollars (this translates to a present value of $1,782/kW). Based on the updated VOS estimates presented in Table 5-1, this value would decline to about $76/kW-yr ($781/kW). The weighted average customer load on Kerman feeder 1103 is as follows: 40% residential, 23% commercial, 14% industrial, and 23% agricultural. Also, a 3.5% annual escalation rate for the VOS estimates is assumed.

Table 5-1

Value of Service Full Outage Costs in Year 1992 Dollars ($/kWh)

	Residential	Commercial	Industrial	Agricultural
1992 Case Study	5.0	70.8	70.8	10.6
Updated Estimates[a]	5.0	34.3	11.5	5.6

Note: Customer outage costs depend on several factors, including amount of advance notice, time of year, time of day, and outage duration. These full outage costs are based on system capacity shortfalls with known duration and customer notification prior to the interruption. Outage costs based on random distribution service interruptions are likely to be even higher. On the other hand, customers consistently place a much lower value on "partial" outages, whereby they are able to maintain some of their critical loads. Partial outage VOS numbers are typically 15 to 20% of full outage VOS estimates.

[a] Updated PG&E VOS estimates as of March 1994 (PG&E Market Research Department). The updated estimates are based on customer surveys taken in 1986, 1988, 1990, and 1991, for the residential, commercial, industrial, and agricultural classes, respectively.

While the 1992 Case Study makes a reasonable attempt to quantify salvageable load savings, determining the reliability value of the Kerman plant should be revised for the following reasons:

- Customer VOS estimates may be used to compare and justify reliability enhancement projects, but they do not represent actual capital costs.
- If the VOS methodology were an actual least-cost alternative, then its value would be credited as it is for system capacity planning (see Section 9).
- Customer VOS estimates are not used at the distribution planning level.
- Customer VOS methodology is frequently criticized as being an inaccurate reflection of what customers are actually willing to pay.

Comments regarding the 1992 Case Study economic evaluation should not detract from the importance of the technical findings. Testing and analysis show that the Kerman PV plant could be used in a dynamic way to restore customer load during outage events. It is expected that the evolution of research, engineering, and economics will enable the utilization of this capability and its proper valuation.

UPDATED ECONOMICS

Based on discussions with PG&E distribution planners, PG&E is moving away from VOS as a decision-making basis for distribution planning investments in reliability improvements (Personal communication, Joel Ibarbia and John Monestario, PG&E, May and June 1994). The value of avoiding outages as reflected by VOS numbers does not accrue directly to the utility, unless the utility is able to charge customers directly for the enhancement.[2] This may appear to be in conflict with a recent move by PG&E and the California regulating commissions to rely on customer value of service to determine reserve margins for generating capacity planning (see Section 9 for details). The argument for using VOS for capacity planning, and not for distribution planning, is that capacity-related outages can be predicted with enough certainty to give customers notification of impending service interruptions. Also, the frequency and duration of capacity shortfalls are more predictable in contrast with the random nature of distribution outages. VOS also represents the least-cost alternative compared to adding marginal system capacity. On the other hand, VOS is greater than the least-cost hardware upgrade to enhance distribution-level reliability.

As an alternative to the VOS methodology, PG&E's present budget practices were investigated to identify a possible proxy for placing a value on the Kerman plant. Presently, PG&E allocates fixed budgets for distribution system reliability enhancement. These budgets are allocated on the basis of a reliability index that weights the duration and frequency of outages for PG&E's 14 operating divisions.

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2 PG&E and other utilities are exploring options to provide customers with "premium power services." One example is siting a UPS on the customer's premise. The utility owns and maintains the UPS and charges the customer for the service, complete with a guaranteed minimum reliability level. This type of arrangement enables the utility to recover the costs of the reliability service enhancement directly from the customer who benefits, without raising electric rates and negatively impacting customers who do not benefit from the reliability enhancement.

The Fresno Division, which includes the Kerman area, received $750,000 for reliability improvements in 1994 and will receive approximately $500,000 for each of the next 5 years.[3] The Fresno Division allocates this budget on the basis of ranking all 295 division circuits according to outage duration and frequency. Each year, the worst 10 to 15 circuits receive enhancements, such as installing fuses and reclosers to isolate faults and reinforcing weak ties to improve load transfer capability. Most of the money is earmarked for fault isolation to maximize the number of customers which can be immediately restored once the fault is isolated.[4]

For the 1994 reliability budget exercise, Kerman Feeder 1103 was ranked number 180 out of the 295 Fresno Division feeders. The number 1 ranking belongs to the least reliable circuit. It is not anticipated, therefore, that Feeder 1103 will receive reliability enhancement funding in the near future. From the Division's perspective, the reliability value of the Kerman plant is zero (Personal communication, Joaquin Buendia, PG&E distribution planner responsible for Kerman Feeder 1103, May 1994).

Another reasonable proxy to value the Kerman plant's reliability value is to identify standard distribution hardware that, if installed, could perform the same voltage support capability as the Kerman plant. In other words, the reliability value of a distributed generation resource is the cost of installing standard distribution hardware that provides the equivalent reliability enhancement.

PG&E's FDRCAL distribution planning model was used to determine that a 900-kVAR switched capacitor bank located near the PV plant would provide at least the same level of voltage support as the PV plant under peak load conditions. The capacitor bank would be located on Belmont Avenue, west of Madera on feeder 1104 (see Figure 2-1). This bank could be installed at a gross financial cost of $11,000 in year 1995 dollars. Multiplying by a levelization factor of 20% which accounts for taxes, insurance, and O&M, brings the annual cost to $2,200/yr or about $4/kW-yr.

[3] The 1992 Case Study estimated the Kerman plant provides a reliablity value of $102,500 each year. This implies that the PV plant is worth 20% of the entire Fresno Division's annual reliability enhancement budget, while Kerman Feeder 1103 represents less than 1% of the total Fresno Division capacity. This puts the magnitude of the 1992 Case Study estimate in perspective.

[4] This is in contrast to the voltage support-type enhancement the Kerman plant provides. The PV plant does not aid fault isolation but is rather a local source of capacity that enables a backfeeding circuit to be extended further than it could be without the plant.

It was originally thought that 2 miles of line would be reconductored to increase feeder tie capacity, at a cost of $100,000. It was determined, however, that only a capacitor bank would have to be installed, at about 10% of this cost. This highlights the site-specific, case-by-case nature of valuing reliability enhancement and the difficulty of developing generalized models and formulations to calculate value.

The updated economics value ($4/kW-yr) is a dramatic reduction compared to the 1992 Case Study value ($205/kW-yr). The updated value, however, is more consistent with the reliability value assigned by other utilities who have examined distributed generation (Keane 1994). Regardless of its economic value, there is a general consensus that distributed generation reliability value is difficult to quantify, largely subjective, site- and utility-specific, evolving in understanding, and will receive new treatment under utility performance-based ratemaking regulation.

The VOS methodology is likely to be more applicable over time as localized generation resources increase in penetration. This is particularly true for customer on-site generation that provides a means of backing up the customer's power supply. In this case, the VOS numbers will become a more accurate reflection of the value to the customer when the customer actually pays for such a service.

Section 6

LOSS SAVINGS VALUE

Loss savings are divided into two parts: real power and reactive power. Real power loss savings are classified as either capacity or energy loss savings. Capacity loss savings lessen the need for capital upgrades by reducing peak loads on distribution, transmission, and generation system equipment. The value of capacity loss savings is the savings in finance charges that result from postponing a capital investment until a future date. The value of this loss savings is incorporated into the other value components, such as the deferral value of substation transformers. Energy loss savings reduce electricity generation requirements. The value of energy loss savings is the cost savings realized by reducing O&M expenses of existing generation plants.

Reactive power loss savings are only of the capacity type. Specifically, they reduce a utility's need for capacitors.

REAL POWER LOSS SAVINGS

Value Description

Real power losses occur as current flows through conductors, transformers, and other T&D system devices. The magnitude of the losses is related to current flow and resistance of the devices. Grid-support PV can reduce losses because it reduces the need to transport energy over long distances by serving some of the load locally.

Evaluation Methodology

The 1992 Case Study based all loss savings results on loss savings estimates during one set of peak load conditions. That is, loss savings were only calculated for the peak hour of the year. Feeder loss savings were calculated using PG&E's FDRCAL program, and transformer loss savings were estimated based on transformer resistance. Transmission system loss savings were determined using the General Electric Optimal Power Flow program maintained by PG&E's Transmission Planning Department. The 1992 Case Study states that "the peak loss reductions are converted to annual energy savings using the system LDC [load duration curve]. Specifically, the peak loss reduction in kilowatts is multiplied by the square of the normalized load duration curve." Upon review of the 1992 Case Study, however, it appears that this conversion was not performed. Thus, the 1992 Case Study used the peak load losses for the entire year rather than an adjusted result based on the distribution of load.

The 1992 Case Study approach can be improved in two areas. First, it bases all of the loss savings results on one set of peak load conditions. This fails to account for the potential that the PV plant may at times actually increase power losses on a feeder rather than reduce them. For example, PV output could increase the amount of current flowing through high-resistance sections of the feeder during off-peak conditions. Second, since it uses all 8,760 hours worth of load data (i.e., every hour in the year) to scale peak loss savings to annual energy loss savings, times when the PV plant is not operating and thus has no impact on loss savings (e.g., night time) are included in the analysis. These hours have no effect on loss savings.

For these reasons, feeder and transformer loss savings were determined by developing a loss savings model; transmission system loss savings (both capacity and energy) were assumed to be the same as in the 1992 Case Study because there was no alternative way to validate the results. The feeder and transformer loss savings model is based on the engineering principal of I^2R losses. The model is a function of feeder load, distribution of load along the feeder, feeder resistance, and PV plant output.

The model has two important characteristics:

1. The distribution of load on the feeder has no impact on loss savings only when feeder load is zero. At this point, loss savings are negative and simply equal the square of the PV plant output current times feeder resistance. From a graphical perspective, this means that the y-intercept of a plot of loss savings versus feeder load is known with certainty.

2. Loss savings are linearly related to feeder load, given some distribution of load on a feeder at a constant PV plant output.

The loss savings model development and application are presented in detail in Appendix E.

Technical Validation Testing and Data Requirements

Four sets of loss savings tests were performed (one on July 22, 1993, and three on August 24, 1993) by turning the plant on and off and measuring feeder load at the substation with the PV plant *on line* and *off line*. This was repeated at least eight times for each set of tests. The loss savings achieved over the entire distribution line is the difference between load with PV *off line* and the sum of load with PV *on line* and PV output.

Figure 6-1 presents the feeder load during one of the tests. Each horizontal line represents 10 kW; this is the magnitude of the expected loss savings at a 3.5-MW feeder load and 0.40-MW PV plant output. Notice that there was a 1-second delay between the time the PV plant was taken off line and the time the load stabilized at its new value: The measurement device (transducer) required a half second to stabilize once the plant was turned off. In addition, the plant was turned off in two phases, with a half-second delay between phases.

The loss savings are very small relative to feeder load and thus are difficult to measure. For example, using the loss savings model mentioned above, loss savings are anticipated to be about 5 kW (0.005 MW) for a 2.9-MW feeder load and a 0.40-MW PV plant output. This represents a value that is less than 0.2% of feeder load.

Figure 6-2 presents the loss savings test results for all tests after screening out data that included obvious load instabilities. Each horizontal line represents 10 kW as in Figure 6-1; that is, Figure 6-2 spans a range of 60 kW, whereas Figure 6-1 spans 500 kW. Data used to develop the "predicted line" in Figure 6-2 are specific to Kerman Feeder 1103, and are presented in Appendix E.

As pointed out above, the y-intercept of the predicted loss savings line is known with certainty and, given a fixed distribution of feeder load and PV plant output, the predicted loss savings must be linear with feeder load. Considering the time delay required to perform loss savings measurements (more than 1 second) and the magnitude of the loss savings to be measured (0.2 to 0.3% of feeder load for the tests performed), measured data tend to validate the model.

Technical Validation Results

Capacity loss savings at the transformer equal the sum of feeder and transformer loss savings. The 1993 feeder and transformer peaks occurred coincidentally on June 25 at 16:00 PST. Using the validated model and feeder resistance, estimated load distribution on the feeder, and transformer resistance, feeder loss savings were estimated to be 17 kW and transformer loss savings were estimated to be 6 kW. Thus, total loss savings on the feeder and the transformer at the peak load were 23 kW, or 5% of the PV plant rating.

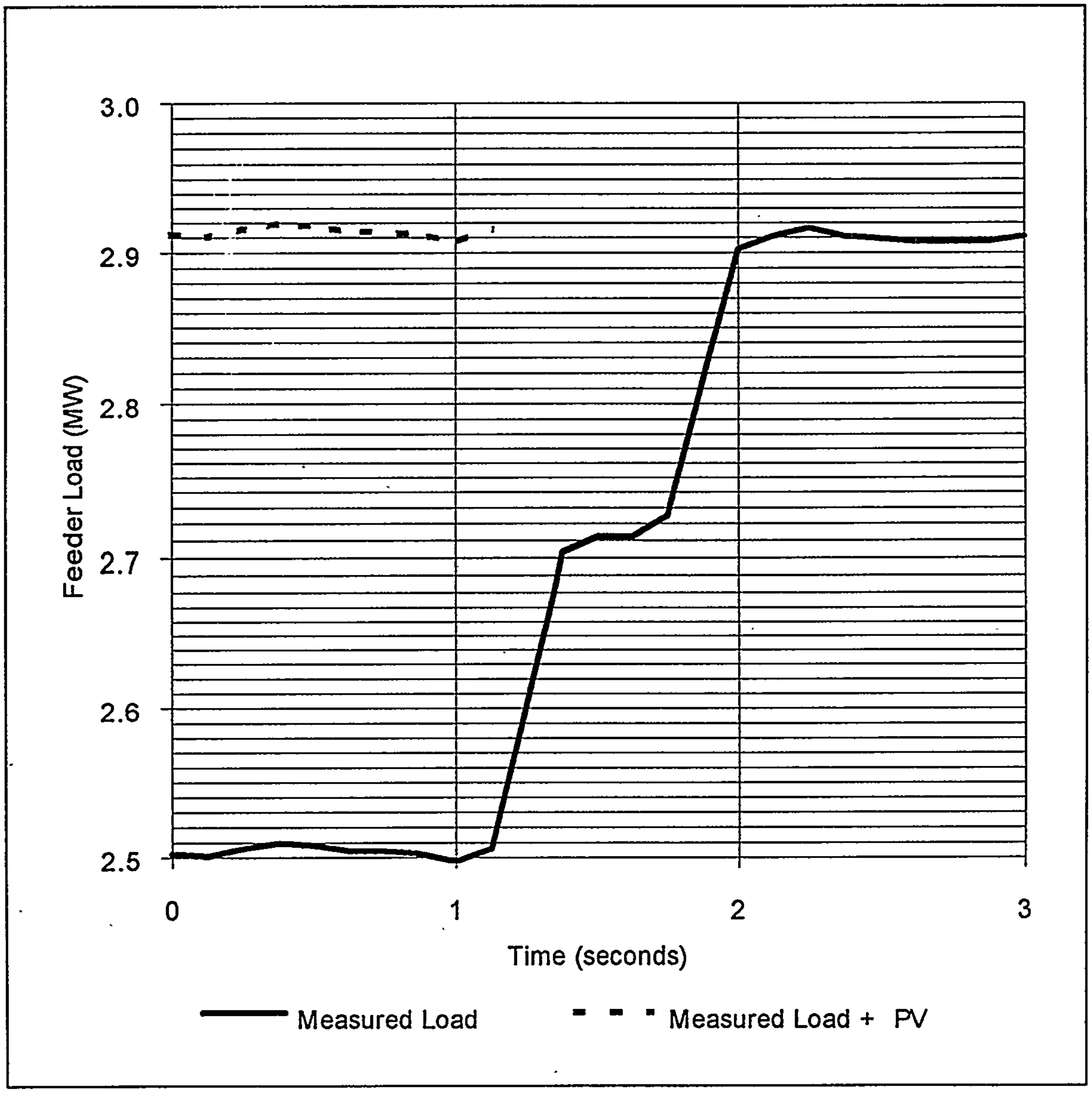

Figure 6-1. Feeder load when PV plant is taken off line.

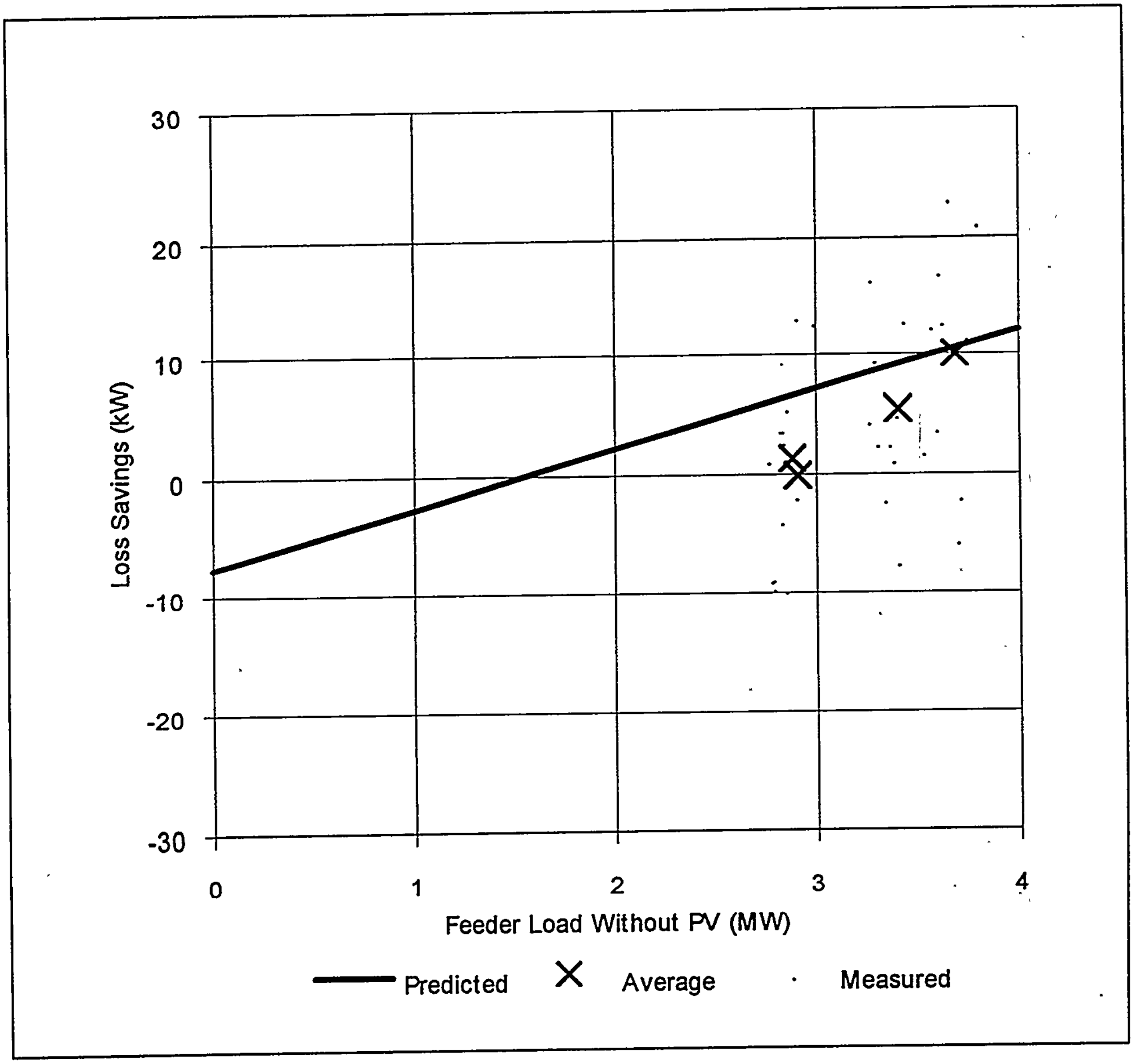

Figure 6-2. Measured and predicted feeder loss savings. Since PV plant output was fairly constant at 0.40 MW during the testing, the solid line is the predicted loss savings for a plant output of 0.40 MW at various feeder loads, the x's are the average of the measured loss savings for each of the four sets of tests, and the dots are the individual loss savings measurements.

The capacity loss savings are incorporated into other value components, such as the substation transformer and generation capacity values.

Annual energy loss savings equal the sum of feeder, transformer, and transmission system loss savings. Feeder and transformer loss savings were estimated using the validated model and measured transformer loads, measured feeder loads, and measured PV plant output from July 1, 1993, through June 30, 1994. That is, feeder and transformer loss savings were calculated for 8,760 hours using measured data. Note, however, that the model accounts for the fact that loss savings equal zero whenever PV plant output is zero. Thus, many of the 8,760 hours are zero and are effectively excluded from the analysis. Details of this calculation are presented in Appendix E.

Feeder loss savings equal 1.6% and transformer loss savings equal 0.7% of the plant's annual energy production. This translates to 25,000 kWh. Transmission system loss savings were not verified but were based on the 1992 Case Study and are estimated to be 33,500 kWh. This is a total of 58,500 kWh/yr for an economic value of $8/kW-yr ($70/kW).

Technical Validation Results vs. 1992 Case Study

The 1992 Case Study estimated peak feeder and transformer loss savings to be 38 kW, as opposed to the updated value of 23 kW. Most of the difference is due to the fact that the 1992 Case Study anticipated that the PV plant would be operating at 0.5 MW during the time of the peak as opposed to the actual value of 0.41 MW. In addition, the 1992 Case Study assumed that the peak loads would be 20% higher than they actually were. Some of the difference is due to a different plant location than was assumed in the 1992 Case Study.

The 1992 Case Study predicted annual energy loss savings of 96,000 kWh/yr for a value of $21/kW-yr ($183/kW). Thus, the technical validation result is 61% less than the 1992 Case Study. Part of the difference is that the 1992 Case Study anticipated that the PV plant would have a higher annual capacity factor. Another part of the difference is that the 1992 Case Study calculated loss savings based on a different plant location. Adjusting for both of these factors, however, it is still estimated that the loss savings would be 40% less than the 1992 Case Study value. Part of the remaining difference is probably attributable to the peak results, which were not scaled to annual energy loss savings results using the LDC approach mentioned above. Another part is due to the difference in methodologies.

Variable PV Plant Size

Appendix E describes in detail how to calculate the value of loss savings as a function of PV plant size. Figure 6-3 presents the results of the analysis. In essence, the equation used to generate Figure 6-3 is a constant dollar value times the quantity of plant size minus one-half plant size squared.

Updated Economics

Based on the new per unit value of energy from PG&E's System Power Value tables (PG&E 1993), the updated value is $8/kW-yr ($82/kW).

REACTIVE POWER LOSS SAVINGS

Value Description

Utilities strive to maintain adequate voltage in the distribution system, often through the use of shunt capacitors. Used correctly, shunt capacitors bring power factors closer to unity. PV output that correlates well with peak loads can reduce reactive power losses (and thus shunt capacitors) because reactive power losses are related to current flow and device reactance.

Evaluation Methodology

The 1992 Case Study calculated feeder reactive loss savings using PG&E's FDRCAL program, and transformer reactive loss savings were estimated based on transformer reactance. Transmission system reactive loss savings were determined using the General Electric Optimal Power Flow program maintained by PG&E's Transmission Planning Department.

This report estimates feeder and transformer reactive power loss savings by developing a reactive power loss savings model similar to the real power loss savings model. This model employs the same engineering approach as the PG&E FDRCAL model used in the 1992 Case Study.

Technical Validation Testing and Data Requirements

No special tests were performed specifically to evaluate reactive loss savings on the feeder. During the real power loss savings tests mentioned in the previous section, however, data were collected that could be used to evaluate reactive power loss savings on the feeder.

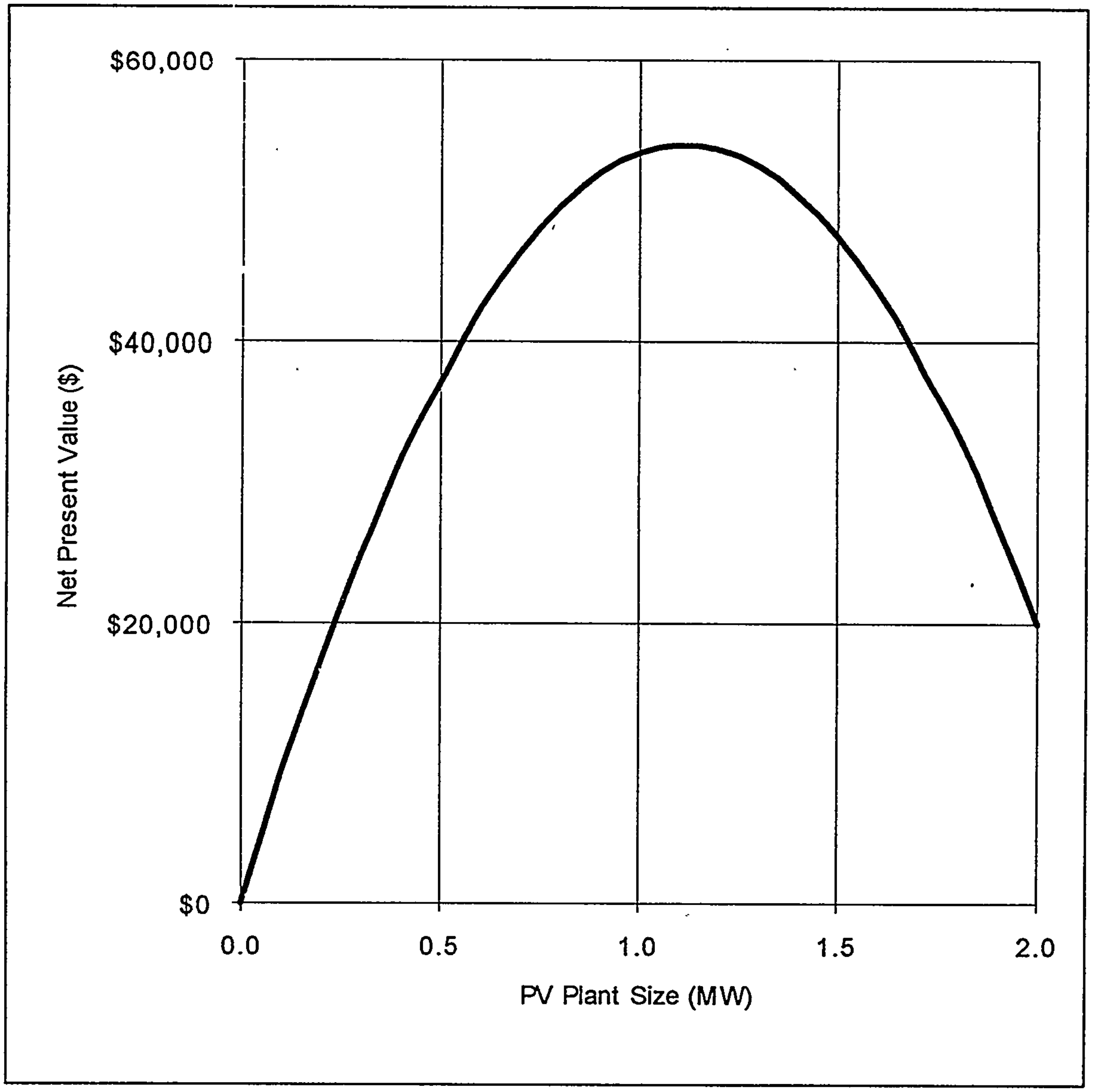

Figure 6-3. Energy loss savings value as a function of plant size.

Data from the tests on August 24, 1993, were used to determine reactive loss savings on the feeder. The three sets of tests on this day showed average increases in the feeder of 30 kVAR (at a 2.9-MVA feeder load), 45 kVAR (at a 3.5-MVA feeder load), and 50 kVAR (at a 3.8-MVA feeder load). (Note: each of the measured numbers was increased by 20 kVAR based on an estimated plant capacitance of 20 kVAR when the plant was turned off.) These estimates match the prediction of the feeder reactive loss savings model.

Technical Validation Results

Using the validated model and peak load conditions, reactive power loss savings at the peak hour are estimated to be 50 kVAR on the feeder and 74 kVAR on the transformer. The 1992 Case Study estimate of 225 kVAR on the transmission system is assumed.

The value of reactive power loss savings is based on the avoided cost of installing shunt capacitors to provide the equivalent capability. Shunt capacitor costs vary as a function of voltage levels. The assumed incremental cost for a capacitor installed on the distribution system is $9/kVAR ($1992) and $59/kVAR is assumed for substation (70 kV) and transmission system (230 kV) voltages (Shugar et al. 1992). This translates to an economic value of about $18,000. Utilizing a fixed charge rate of 0.156 brings the value to $6/kW-yr ($52/kW).

Technical Validation Results vs. 1992 Case Study

The 1992 Case Study estimated the value of reactive power loss savings to be $10/kW-yr ($87/kW): Three percent of the value is due to savings on the feeder, 48% to the transformer, and 49% to the transmission system. Twenty-five percent of the difference between the 1992 Case Study value and the technical validation value is due to the fact that the 1992 Case Study anticipated that the PV plant would be operating at 0.5 MW (as opposed to the actual value of 0.41 MW) and that the peak loads would be 20% higher than they actually were. The remaining difference between the two values is that the 1992 Case Study attributed feeder kVARs to both the feeder and the transformer rather than just the feeder, thus double-counting part of the value. The 1992 Case Study estimate and the technical validation test result are the same after adjusting for these conditions.

Section 7

TRANSMISSION SYSTEM VALUE

VALUE DESCRIPTION

Grid-support PV can be of value to both the utility's subtransmission and bulk transmission systems. It is of value if it increases the systems' available capacity. It accomplishes this by serving some of the load locally, thus reducing the load on the systems.

The method of economic analysis used to determine the value of the grid-support PV system depends upon how well the system is interconnected. It can be argued that highly interconnected systems, such as bulk transmission systems, should be evaluated using a marginal cost approach, while less interconnected systems, such as subtransmission systems, should be evaluated using a project deferral approach. From an economic perspective, a marginal cost approach always has the potential to result in some value, whereas a project deferral approach results in value only if an upgrade is planned and a sufficiently large PV plant delays that upgrade.

One would determine the value of PV to the sub- and bulk transmission systems separately and sum the results if the PV plant contributes value to both systems. The added capacity that the PV plant provides to the subtransmission system must be calculated and converted to economic value. Likewise, a similar calculation is performed for the bulk transmission system.

EVALUATION METHODOLOGY

The 1992 Case Study did not differentiate between sub- and bulk transmission system values. It estimated total transmission capacity savings in a similar manner to the generation system capacity. Specifically, it multiplied the system average marginal transmission capacity cost from the 1990 General Rate Case by the load carrying capability (LCC) of the PV plant.

No subtransmission system upgrade projects are currently planned for the Kerman subtransmission area. There are, however, excellent data describing the load on the subtransmission system. Conversely, value exists in increasing the capacity of the bulk transmission system but the technical data required to determine the capacity increase associated with a PV plant are not readily available. For these reasons, the validation approach determines the added capacity that the PV system provides to the subtransmission system (i.e., the technical result for a project deferral approach), which is then assumed representative also for the bulk transmission system. This added capacity is then multiplied by the average transmission system marginal cost (i.e., the economic result for a marginal cost approach).

As described in Appendix A, the time constant for conductors is less than 15 minutes. One implication of this is that a PV plant designed to defer a specific subtransmission upgrade project must be available during all of a transmission system's critical hours. This is accomplished by performing a worst-case analysis. A second implication is that, unlike the case of substation transformers, there is no inter-temporal relationship between load at one time and capacity at another time. This simplifies the analysis.

A worst-case analysis is performed by evaluating the minimum available capacity with and without PV. Minimum available capacity with PV is the minimum of capacity minus load plus PV output. Minimum available capacity without PV is the minimum of capacity minus load. Since the PV is located on the distribution feeder, electrical loss savings on the feeder, substation transformer, and transmission system are added to the PV plant output.

One way to calculate transmission capacity is to assume that capacity is constant at all times. As will be shown later in the section, this may result in errors. Another way is to adjust capacity for measured weather conditions. That is the approach taken in this chapter. The model used to calculate capacity is described in detail in Appendix A. It is a simplified version of the accepted IEEE rating standard for bare overhead conductors. The simplified model is a modification of the IEEE standard so that it does not require iterative calculations in the solution for conductor capacity.

Inputs to the model include ambient temperature, irradiance, wind conditions, and conductor characteristics. Although the model accepts measured wind conditions, one would need to be assured that the analysis uses wind conditions at the worst section of the transmission system and that wind conditions do not change rapidly (i.e., they do not go from high wind to low wind) during critical times. A conservative approach is to use measured ambient temperature and insolation data and PG&E's established emergency wind conditions of 2 feet/second; this will understate system capacity.[1]

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[1] It is further assumed that conductor temperature reaches a point where there is no excess capacity on the worst hour of the time period.

TECHNICAL VALIDATION TESTING AND DATA REQUIREMENTS

Measured 70-kV subtransmission system load data for the Kerman vicinity were obtained from PG&E's Regional Electric Operations Center in Fresno. Area load is the sum of the loads on the 230/70-kV bank transformers supplying the area (Kearney and Helm substations) and the output of the Agrico cogeneration plant. Data were obtained for 92 days (2,208 hours) from June 1, 1993, to August 31, 1993. The light solid line in Figure 7-1 presents subtransmission system load for two of the highest load days during that period. PV plant output data were measured at the 0.50-MW Kerman PV plant. These data were adjusted up by 7% to reflect electrical loss savings (5% on the distribution system and 2% on the transmission system). The dashed line in Figure 7-1 is measured PV plant output adjusted for loss savings.

TECHNICAL VALIDATION RESULTS

The subtransmission system's hourly capacity rating (dark solid line in Figure 7-1) is calculated by assuming that current flows into the Kerman area through one of two 3/0 copper conductors. Area capacity is the sum of the capacity of the two conductors. As presented in Figure 7-1, the transmission capacity is inversely correlated with PV plant output. This is due to decreasing conductor capacity as insolation and ambient temperature increase. The figure suggests that, from a capacity perspective, PV plant output occurs when transmission capacity needs are the greatest.

Added capacity is determined by calculating available capacity with and without the Kerman PV plant for every hour between June 1, 1993, and August 31, 1993. Available capacity without PV is the minimum of the difference between system capacity and load. For example, Figure 7-1 shows that there is 60 MW of available capacity at midnight on June 26, whereas there is no available capacity at 15:00 on June 26. When the 0.50-MW Kerman PV plant is added to the system, results indicate that transmission system capacity increases by 0.45 MW, or 90% of the plant's rating. Eighty-three percent of the added capacity is from plant output and 7% is from the associated loss savings of the feeder, substation transformer, and transmission system.

The 1992 Case Study reported an avoided transmission system cost of $50/kW-yr ($439/kW) for a 500-kW capacity increase. Thus, the transmission capacity value of the Kerman PV plant is 0.9 times $50/kW-yr or $45/kW-yr ($391/kW).

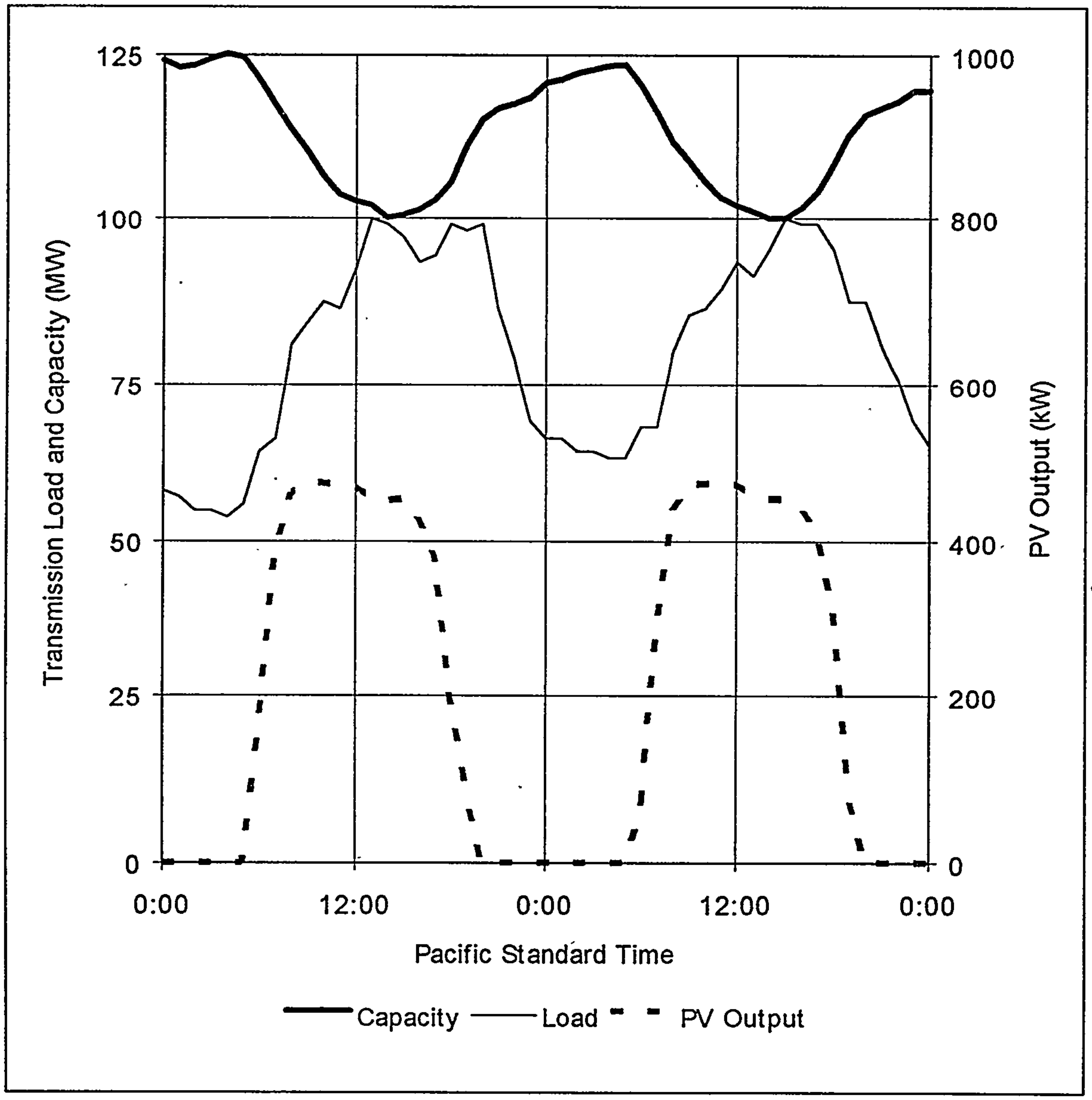

Figure 7-1. Transmission capacity and load and Kerman PV output (June 25-26, 1993).

TECHNICAL VALIDATION VS. 1992 CASE STUDY

The updated test result is 5% less than the 1992 Case Study estimate of $47/kW-yr ($410/kW). All of the difference is attributable to the difference in the added capacity calculations. While the final results are very similar, the evaluation methodology used in this chapter is far more stringent than that used in the 1992 Case Study. The 1992 Case Study calculated an added transmission system capacity of 95% using a load carrying capability approach. A load carrying capability approach allows for the PV plant to be unavailable during some critical hours and still have substantial value. The worst-case approach of this chapter, in contrast, estimated an added transmission system capacity of 90%. A worst-case approach means that there would be no added capacity if the plant had full output for every hour of the time period except for the worst hour when there was no output.

VARIABLE PV PLANT SIZE

The results for the Kérman PV plant can be converted to results for any PV plant size since there are no inter-temporal affects between load and capacity, and PV output scales linearly with size (e.g., if a 0.50-MW PV plant produces 0.45 MW on June 25 at 12:00, a 5.0-MW PV plant will produce 4.5 MW on June 25 at 12:00). This is accomplished by calculating available capacity with and without a large PV plant for each hour in the analysis, linearly interpolating between the two sets of points, and taking the lower bound of the result.

Figures 7-2 and 7-3 illustrate the process with the assumption that the largest PV plant size is 20 MW (i.e., 40 times the Kerman plant). Available capacity without PV for every hour equals capacity minus load. Available capacity with 20 MW of PV equals capacity minus load with 40 times the Kerman PV plant output from Figure 7-1.

Figure 7-2 (and the associated points for all of the other hours between April 1 and August 31) contains the data necessary to determine added capacity as a function of PV plant size. Added capacity for any particular hour of the time period is the linear interpolation between capacity minus load and capacity

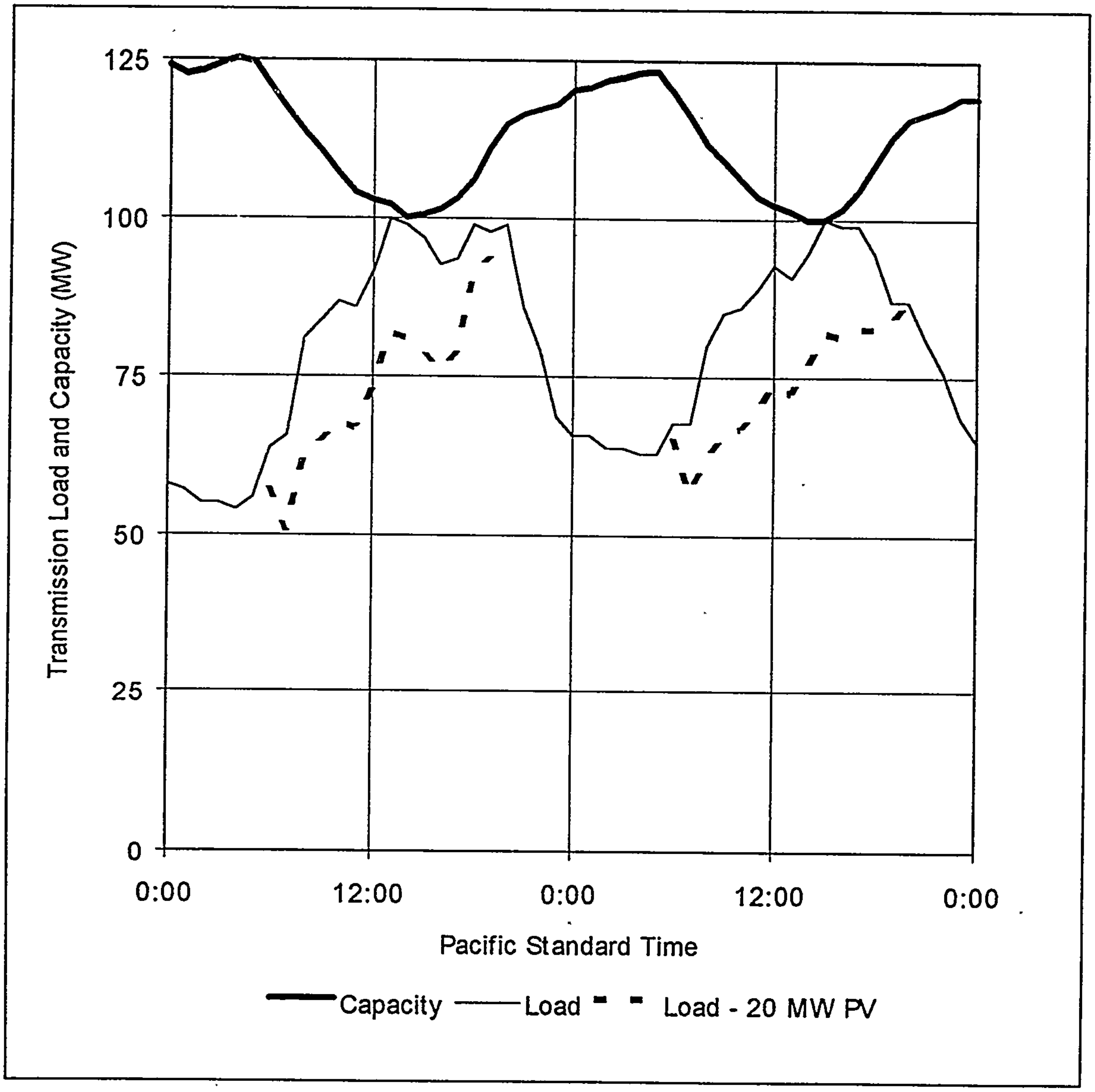

Figure 7-2. Transmission capacity, load, and load minus 20 MW PV (June 25-26, 1993).

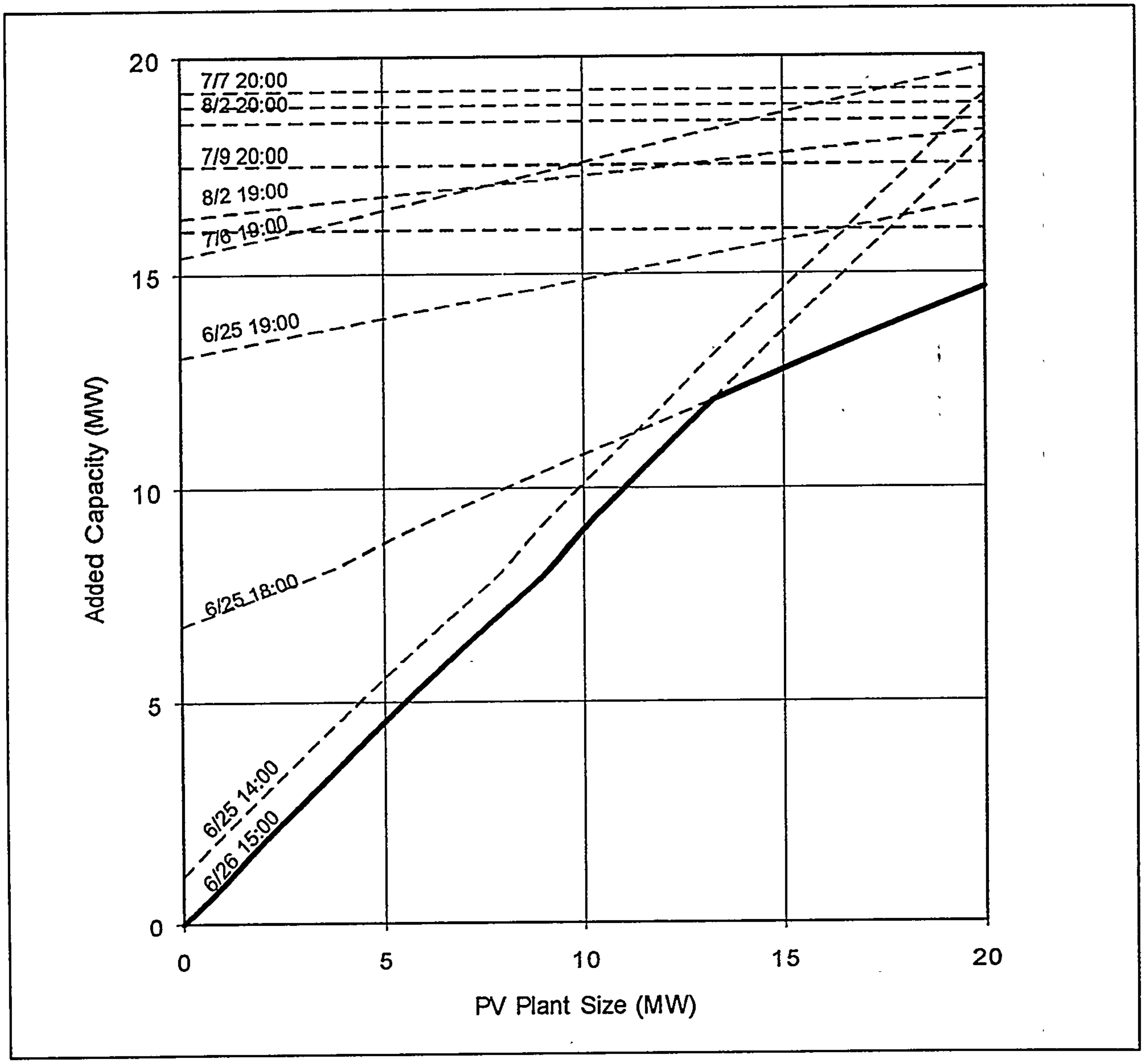

Figure 7-3. Added capacity by hour versus PV plant size. The heavy solid line represents the lower bound.

minus load with 20 MW of PV. Linear interpolations for 9 of the worst 2,208 hours are presented in Figure 7-3.[2]

The following example illustrates how one line in Figure 7-3 is developed using data in Figure 7-2. First, select the time of 15:00 on June 26. There is no available capacity when there is no PV, and there is 18 MW of available capacity when there is 20 MW of PV. Added capacity for all PV plant sizes between 0 and 20 MW for June 26 at 15:00 are on the line connecting these two points. Another way to develop this same curve is to recognize that the y-intercept in Figure 7-3 is the difference between capacity and load, and the slope of the line is the normalized PV plant output at a given hour.

The minimum added capacity at any hour in the analysis for a given PV plant size is of interest because this is a worst-case analysis. This is obtained by repeating the analysis presented in the previous paragraph for all hours and taking the lower bound as the result (the heavy solid line in Figure 7-3). Figure 7-3 suggests that the peak hour begins at 15:00 on June 26 when there is no PV and shifts to 18:00 on June 25 when there is more than 13 MW of PV.

Several comments are in order about Figure 7-3. First, added capacity increases by 90% of the PV plant's rating for PV plant sizes up to 13 MW. This means that the marginal value of a PV plant is constant up to a plant size of 13 MW. Second, this analysis yields different results than a peak load analysis in that it takes into account the effect of weather on transmission system capacity, and it gives consideration to every hour between June 1 and August 31.

The importance of the weather's effect on transmission system capacity cannot be stressed strongly enough for large PV plant sizes. Figure 7-4 highlights this fact by repeating the analysis of Figure 7-3 with the assumption that system capacity is unaffected by weather conditions. In essence, this is the assumption made in a peak load reduction approach.

2 Two screening procedures can be used when actually performing the analysis to limit the number of hours that need to be considered. First, only hours where there is less than 20 MW of available capacity and no PV need to be considered because hours with more than 20 MW of available capacity will not be the worst-case hour, even if the corresponding PV output is zero. Of the 2,208 hours, 168 hours in the analysis remained after this screen. Second, only hours with less than 20 MW of available capacity when there is 20 MW of PV need to be considered. Twelve of the 168 hours remained after this screen.

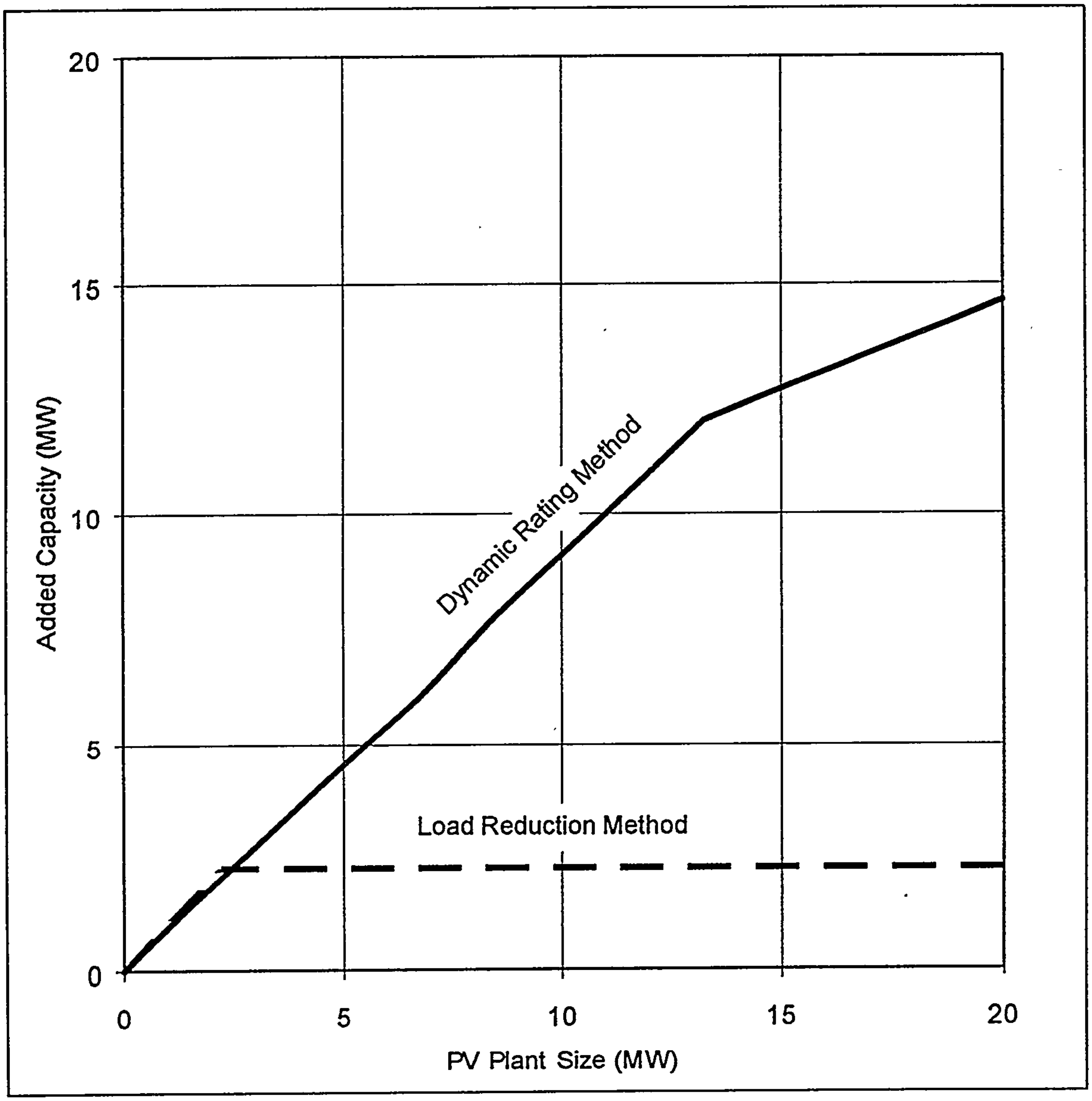

Figure 7-4. Added capacity versus PV size (dynamic rating and load reduction methods).

Figure 7-4 suggests that a peak load reduction approach slightly overestimates the added capacity at small plant sizes but substantially underestimates added capacity at large plant sizes. In fact, if 10.0 MW of PV were installed in the area, the weather-adjusted capacity approach estimates that there would be an added capacity of 9.0 MW, whereas the peak load reduction approach estimates that there would be an added capacity of 2.2 MW. The peak load reduction approach overestimates added capacity at small plant sizes because the peak load occurs at 16:00 on July 7, when PV plant output adjusted for losses is 0.49 MW; the minimum available capacity (i.e., capacity minus load) occurs at 15:00 on June 26, when PV plant output is 0.45 MW. It underestimates added capacity at large plant sizes because the *peak load* shifts to 20:00 on July 9 when there is no plant output while the *minimum available capacity* occurs at 18:00 on June 25 when PV output is 0.20 MW.

Section 8

ENERGY GENERATION VALUE

VALUE DESCRIPTION

The PV plant's energy production reduces the utility's total system energy demand that would be satisfied by other resources. This energy generation value is calculated by totaling the avoided variable costs of production that the PV resource offsets. For PG&E, the marginal cost of an additional unit of intrastate pipeline capacity needed to serve the next increment of electric demand is also included in the marginal energy cost calculation (PG&E 1993).

EVALUATION METHODOLOGY

The value of Kerman plant energy production is evaluated with PG&E's "System Power Values" (SPVs). The Electric Utility Production Cost and Financial Model (Elfin), a calculation-intensive computer simulation, is the proxy for development of marginal energy costs for California utilities.[1] PG&E developed SPVs as an approximation to Elfin model results, enabling cost-benefit resource evaluations without rerunning Elfin.

SPVs are long-term forecasts of the marginal value of energy and capacity at the generation level. SPVs are primarily driven by demand forecasts, resource availability, and fuel prices. They vary as a function of load demand; as demand increases, more expensive sources of electricity are used, thereby increasing the SPV. SPVs are used to evaluate the cost-effectiveness of supply- and demand-side resources, and are used in resource acquisition decision analysis and planning.

The SPV-based methodology utilized in the Kerman 1992 Case Study calculated energy value via a three-step process: (1) construction of an LDC, which arranges the utility's total system load in descending order from the highest, or peak, load of the year to the lowest; (2) determination of the amount of PV generation that was generated during each of the system LDC intervals; and (3) multiplication of the total PV generation by the value of energy as a function of LDC interval.

[1] Elfin was developed by Environmental Defense Fund (EDF) of Oakland, California. EDF continues to make improvements to the model and provides analysis expertise and modeling support to many clients, including PG&E and other California utilities, the CEC, and ratepayer advocacy groups (EDF 1994).

TECHNICAL VALIDATION TESTING AND DATA REQUIREMENTS

A full year's worth of hourly system load and corresponding PV performance data from the same year are required. If actual PV performance data are not available, a validated PV simulation program is recommended. Model validation may necessitate verification testing.

Measured Kerman PV plant production data spanning July 1, 1993, to June 30, 1994, are used. The data are in a half-hour average format and are reduced to hourly averages. Corresponding hourly PG&E system load data are downloaded from PG&E's mainframe computer system.

TECHNICAL VALIDATION RESULTS

Figure 8-1 presents the first two steps of the energy valuation: PG&E's system LDC and the corresponding PV energy generated for each of the LDC intervals. Each LDC interval contains 10%, or 876 hours, of the year's total 8,760 hours of load and generation data. The system load is expressed in megawatts, with a peak load of 15,331 MW.[2] PV generation is expressed as a percentage of the total annual PV generation; for example, the Kerman PV plant produced over 20% of its annual energy generation during the top 10% of PG&E's system loads. The favorable correlation of system loads with PV output shown in Figure 8-1 is typical for solar installations in PG&E's service area.

Figure 8-2 presents the 10 daily load profiles containing the top 50 hours of the PG&E system load duration curve. Measured Kerman PV output for these 10 days has been scaled to a nominal 2,500-MW rated PV plant, for illustration purposes, and subtracted from the load.[3] This figure demonstrates how PV consistently provides energy and capacity to the bulk generation system on peak. Even on August 3, when clouds and high temperatures reduced electrical output, the PV plant effectively shaves the system peak.[4]

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2 The PG&E peak system, or customer, load of 15,331 MW does not include power transfers and exports. Although PG&E's peak load on its generators was closer to 20,000 MW, energy value calculations are based on system loads.

3 PV plant output was adjusted on June 28 and July 1 to account for inverter reset problems.

4 Plant output data, and no recorded maintenance events, suggest the plant was functioning properly on August 3. Low irradiance levels suggest significant cloud cover caused low plant output. A blown fuse on one of the source circuits, repaired on August 4, would only account for about a 6% reduction in plant output, not including any ancillary inverter losses caused by the minor voltage imbalance.

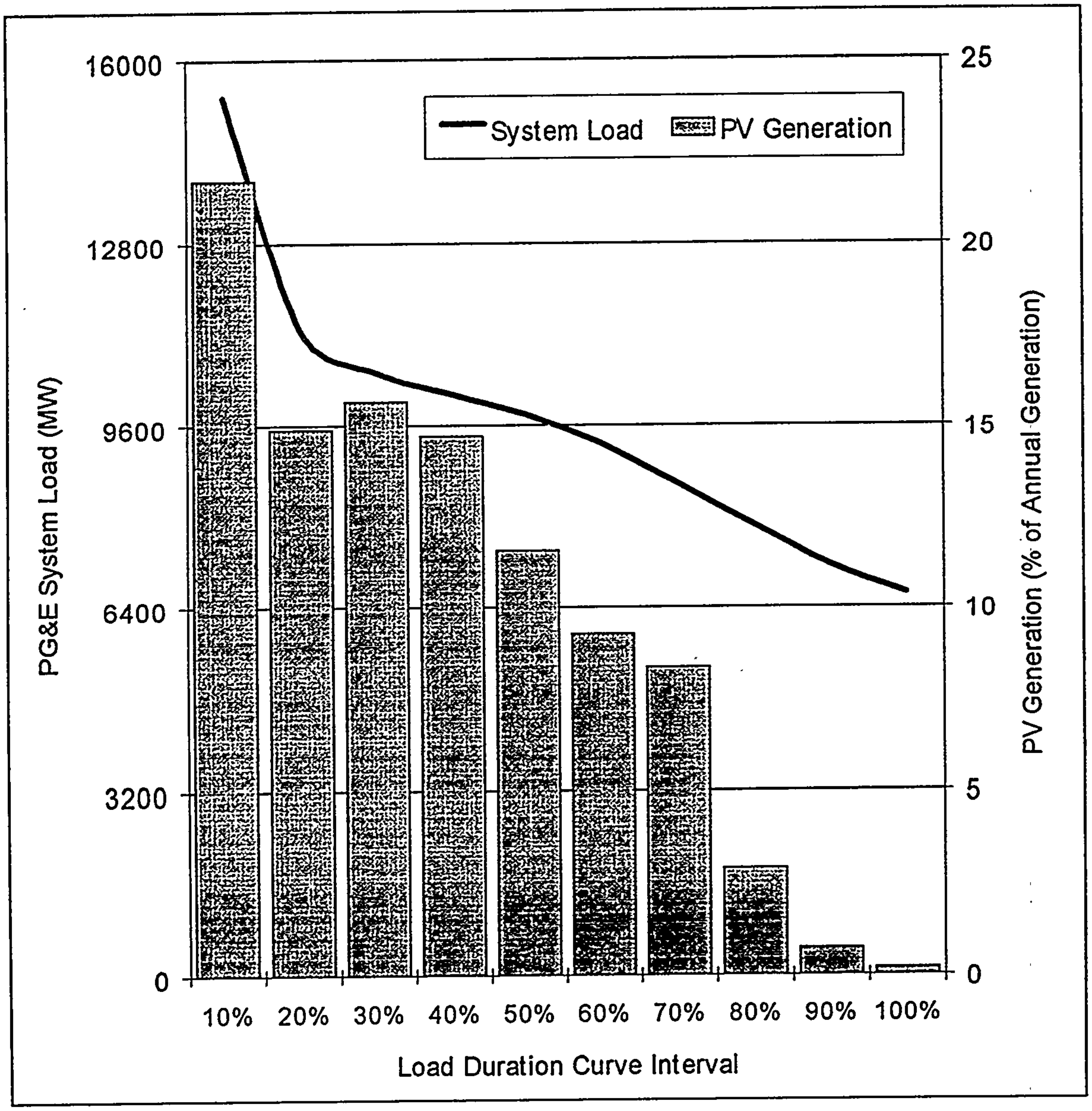

Figure 8-1. First two steps of energy value calculation: LDC and PV output match.

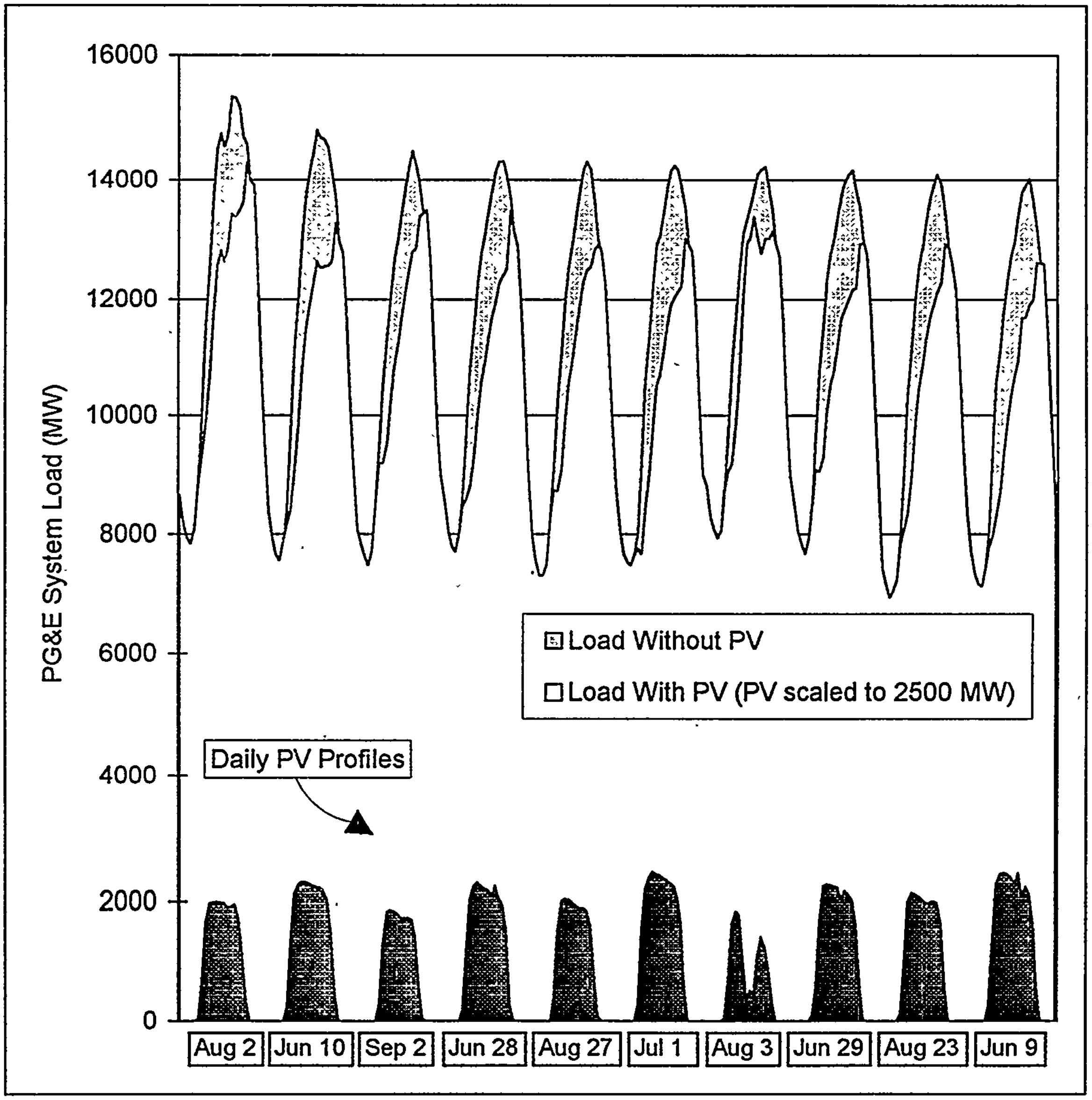

Figure 8-2. PG&E system load versus PV output for top 10 load days.

Table 8-1 contains the third step of the energy value calculation. For each system LDC interval, the corresponding amount of PV generation is multiplied by the SPV to yield energy value. For example, the Kerman PV plant generated a total of 234,689 kWh during the top 876 system load hours. Multiplying this energy production by the SPV of $0.087/kWh yields a total value of $20,418 for the 10% LDC interval.

Table 8-1

PV Plant Energy Generation Value ($1992)

LDC Interval (%)	PV Plant Generation (kWh)	SPV ($/kWh)	PV Energy Value ($/yr)
10	234,689	0.087	20,418
15	81,131	0.081	6,572
20	79,200	0.077	6,098
25	88,776	0.078	6,925
30	80,554	0.076	6,122
40	158,880	0.065	10,327
50	125,263	0.057	7,140
60	100,083	0.055	5,505
70	90,572	0.049	4,438
80	31,513	0.043	1,355
100	9,508	0.034	323
Annual	1,080,169		75,223 $/yr (151 $/kW-yr)

Multiplying the remaining SPVs by the amount of PV energy generation for each LDC interval results in a total annual energy value of $151/kW-yr ($1,313/kW). This translates into a levelized energy value of $0.07/kWh, assuming the Kerman plant produces 1,080 MWh every year of the 30-year plant operating life. See Section 6 for an accounting of electrical loss savings, obtained by reducing the amount of power delivered over T&D equipment since the Kerman plant is located near a load center.

TECHNICAL VALIDATION RESULTS VS. 1992 CASE STUDY

The technical validation result is 22% less than the 1992 Case Study estimate of $194/kW-yr ($1687/kW). The difference is due to variances in actual versus predicted plant performance. The actual distribution of PV generation by LDC interval was very close to the predicted distribution, but the predicted generation totals were significantly greater.

The 1992 Case Study estimated that the Kerman PV plant would produce 1,383 MWh/yr compared to the 1,080 MWh/yr production measured during the 1-year validation period (July 1993 through June 1994), a 22% difference.[5] This variance in performance is accounted for by different PV plant design assumptions and weather data used in the 1992 Case Study calculations, in addition to actual plant downtime during the validation period. Plant downtime contributes 35% of the variance, and 1992 Case Study performance overestimation contributes about 65% of the variance. For a description of PV plant performance, see Section 2.

VARIABLE PV PLANT SIZE

The energy value of the plant will scale linearly with size up to significant penetration levels. The SPVs approach can be used for plant sizes up to 100 MW (PG&E 1993). Beyond 100 MW, production cost simulations must be run to determine the impact on power purchases and dispatch of other generation resources. This can be accomplished with a model such as Elfin.

UPDATED ECONOMICS

PG&E continues to use SPVs to evaluate the cost-effectiveness of supply- and demand-side resources. The formulation and use of SPVs, however, has changed significantly since the time of the 1992 Case Study. For example, a set of SPVs has been developed to analyze resource acquisition from the regulatory perspective (PG&E 1993). These SPVs include emission adders accounting for environmental externalities (see Section 11). Other sets of SPVs have been developed to account for uncertainty in fuel price and hydrological conditions. Yet other sets are presently being developed to represent various scenarios that may be played out in the regulatory arena. These include the effect of "open access" to the generation system for large industrial customers.

Figure 8-3 presents four different sets of SPVs. These represent the average marginal energy value, across all demand periods. The first set, the Regulatory Power Values, are based on Elfin computer simulations, incorporating the California Energy Commission's (CEC) resource mix, fuel cost, and load growth

[5] The "expected output" of the Kerman PV plant for the validation period was 1,191 MWh, a capacity factor of 27.3%. The expected output is based on the validated PVGRID simulation. If the Kerman plant performed as expected, the energy value would also increase by about 10%, to a value of $166/kW-yr. This also applies to the updated economic value. See Section 2 for plant performance details.

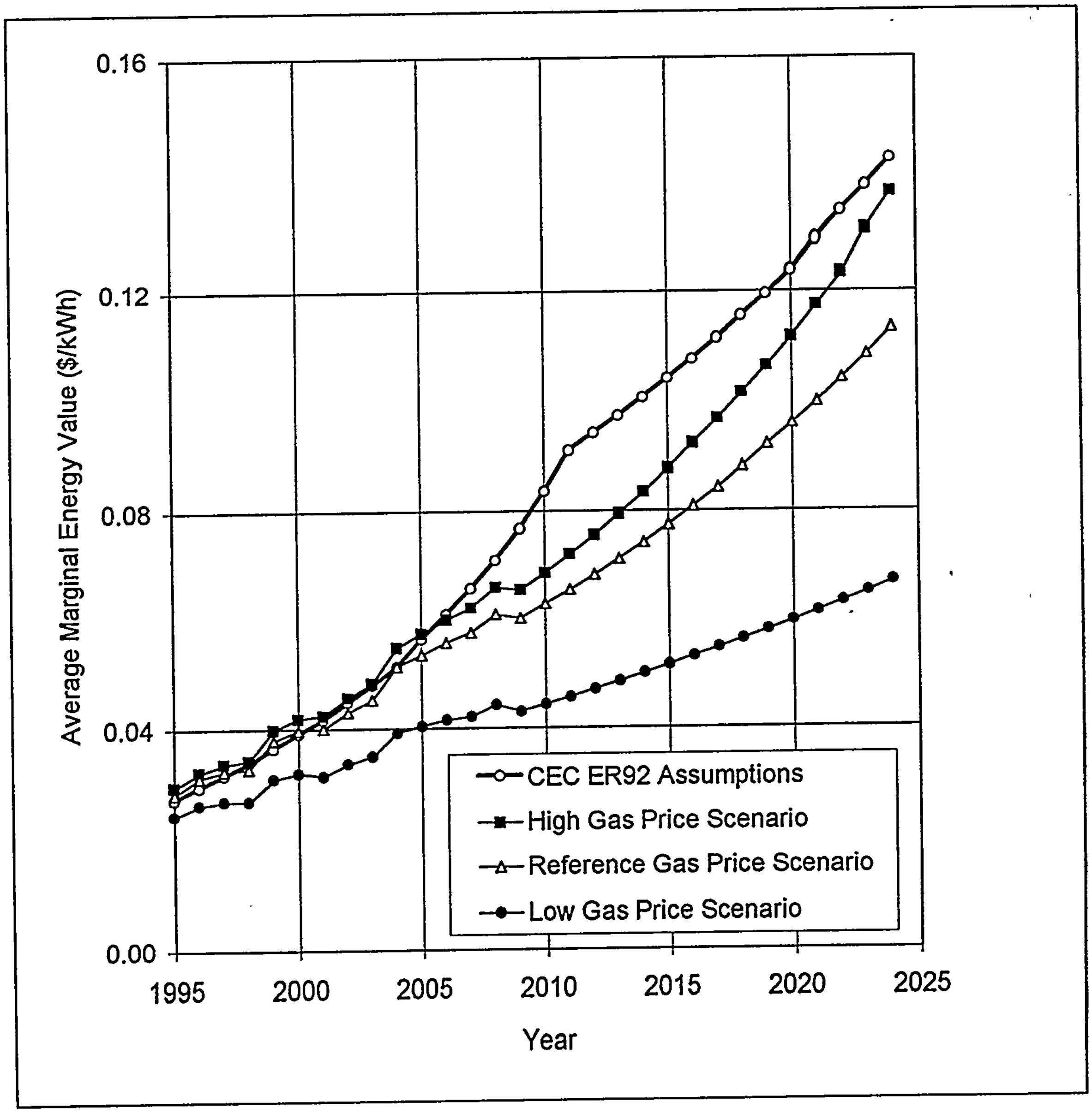

Figure 8-3. Marginal energy values for regulatory and scenario planning.

assumptions over a 20-year planning horizon.[6] These SPVs are synonymous with the CEC's 1992 Electricity Report, referred to as "ER92" (CEC 1993).

Also plotted are three sets of SPVs developed by PG&E for internal planning purposes (PG&E 1993). These SPV scenarios incorporate different resource planning assumptions than those used to develop the Regulatory Power Values; however, they are not intended to supersede the Regulatory Power Values. The primary difference is the price of as-delivered gas, and its rate of escalation. Note that even the "High Gas Price Scenario" has lower SPVs than the Regulatory Power Values: Gas prices assumed in the 1992 Electricity Report are much higher than those in more recently developed Scenario SPVs. Figure 8-4 presents gas price assumptions used to develop the SPVs and Regulatory Power Values. The variation in the SPV scenarios highlights the uncertainty in quantifying marginal energy value, and gas prices, over long evaluation periods.

PG&E recommends that resource cost-effectiveness be tested using all of these SPV sets to ascertain the range of energy value under resource, gas price, load, and regulatory uncertainty. The SPV sets are provided in time-of-use, or demand period, format for a 20 year planning horizon.[7] Table 8-2, for example, presents the time-of-use marginal energy values for the year 1995. There is significant differentiation between on-peak and off-peak value, some 40% in summer and 20% in winter. This reflects the lower heat rates (efficiencies) of plants dispatched on peak and/or the use of peaking gas combustion turbines, which have relatively high operating costs.

To determine the total energy value of the Kerman PV plant, measured plant output during the 1-year period (July 1, 1993, to June 30, 1994) are segregated into demand periods. These energy sums are then multiplied by the corresponding demand period marginal energy value for each year of the 30-year study period. The resulting annual value stream is brought to the present, assuming a 9% cost of capital.

6 The Zero Intercept Methodology (ZIM) is used to develop marginal energy values. Three simulations are run for each time period of interest: a base case with expected load, and two cases which incrementally increase and decrease load. The difference in production costs is then divided by the total change in load (kWh) to produce marginal energy values. (PG&E 1993)

7 The SPVs are escalated at rates between 3 and 5% beyond the 20-year planning horizon for the Kerman analysis, which assumes a 30-year operating life.

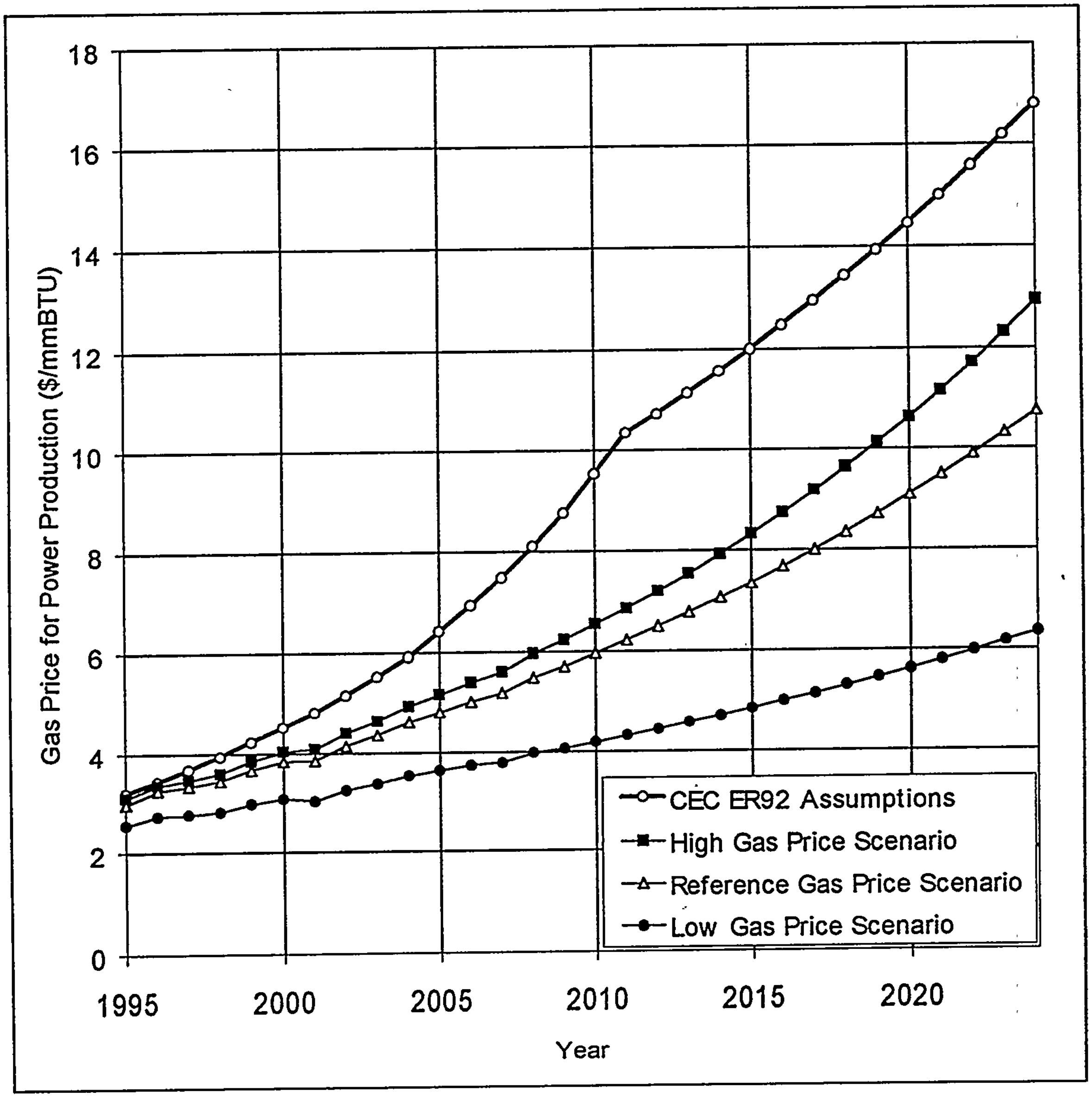

Figure 8-4. Gas price assumptions for development of marginal energy values.

Table 8-2

Marginal Energy Values for Year 1995 ($1995)

($/kWh)	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial-Peak	Winter Off-Peak	Annual (average)
Regulatory Power Values	0.0383	0.0265	0.0254	0.0317	0.0250	0.0273
High Gas Price	0.0343	0.0259	0.0240	0.0371	0.0308	0.0295
Reference Gas Price	0.0328	0.0248	0.0230	0.0356	0.0296	0.0282
Low Gas Price	0.0278	0.0210	0.0195	0.0309	0.0257	0.0242

Time Periods (PG&E 1993) are for the Regulatory Power Values. Slightly different time periods are specified for the gas price scenario SPVs, but these do not impact the Kerman PV analysis. Super Off-Peak energy values are omitted as they do not apply to the Kerman analysis.

Summer (May 1-Oct 31): Peak (Monday-Friday, 1200-1800), Partial-Peak (Monday-Friday, 0800-1200 and 1800-2100), Off-Peak (Monday-Friday, 2100-0100, 0500-0800) and (all day Saturday and Sunday except 0100-0500), Super Off-Peak (All days, 0100-0500)

Winter (November 1-April 30): Peak (none), Partial-Peak (Monday-Friday, 0800-2100), Off-Peak (Monday-Friday, 2100-0100, 0500-0800) and (all day Saturday and Sunday except 0100-0500), Super Off-Peak (All days, 0100-0500).

Figures 8-5 and 8-6 present the PV output and total energy value by demand period, respectively. Most of the value comes from the "summer months" of May through October. As noted earlier, this demonstrates the natural dispatching feature of PV, which provides most of its energy during higher periods of demand, reducing the need for higher-cost generation.

Table 8-3 presents the updated economic value of energy produced by the Kerman PV plant for the four different sets of SPVs. The range in value is quite significant, from $87/kW-yr to $143/kW-yr.[8] At this time, the Regulatory Power Values serve as the accepted proxy to determine the energy value of the Kerman PV plant. The energy valuation method, however, is likely to change many times in the near future as the role of competition in the California electric utility industry unfolds.

Table 8-3

Total Energy Value for Different Planning Assumptions ($1995)

	CEC ER92 Assumptions	High Gas Price Scenario	Reference Gas Price Scenario	Low Gas Price Scenario
Energy Value ($/kW-yr)	143	129	119	87
Energy Value ($/kW)	1,471	1,326	1,218	895

8 These values would increase by about 10% if the Kerman plant performed as expected. See footnote 5.

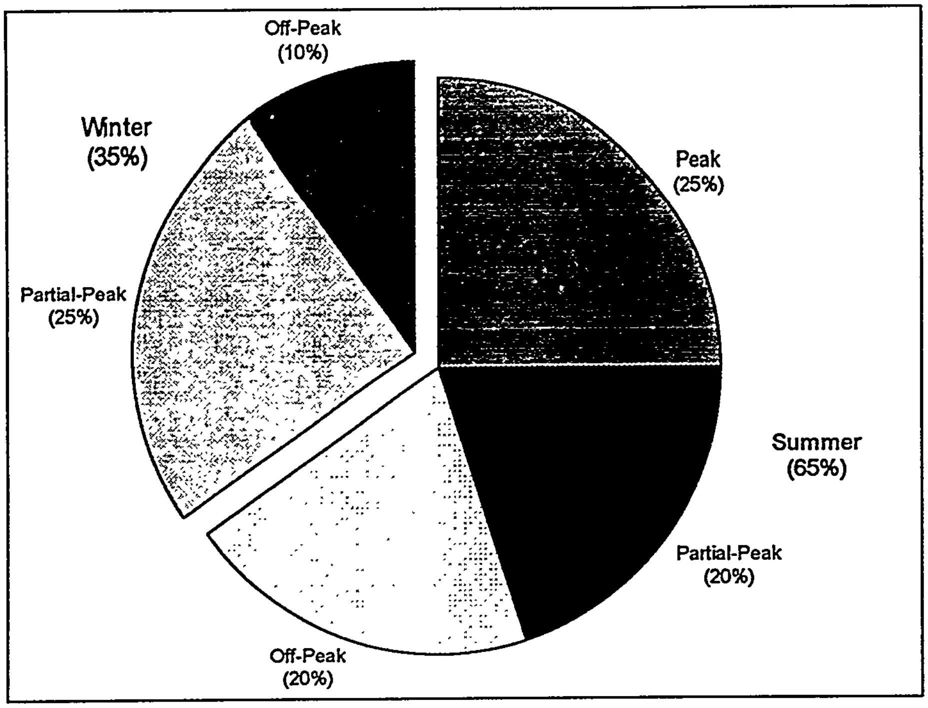

Figure 8-5. Kerman plant output by demand period (% of 1,080 MWh).

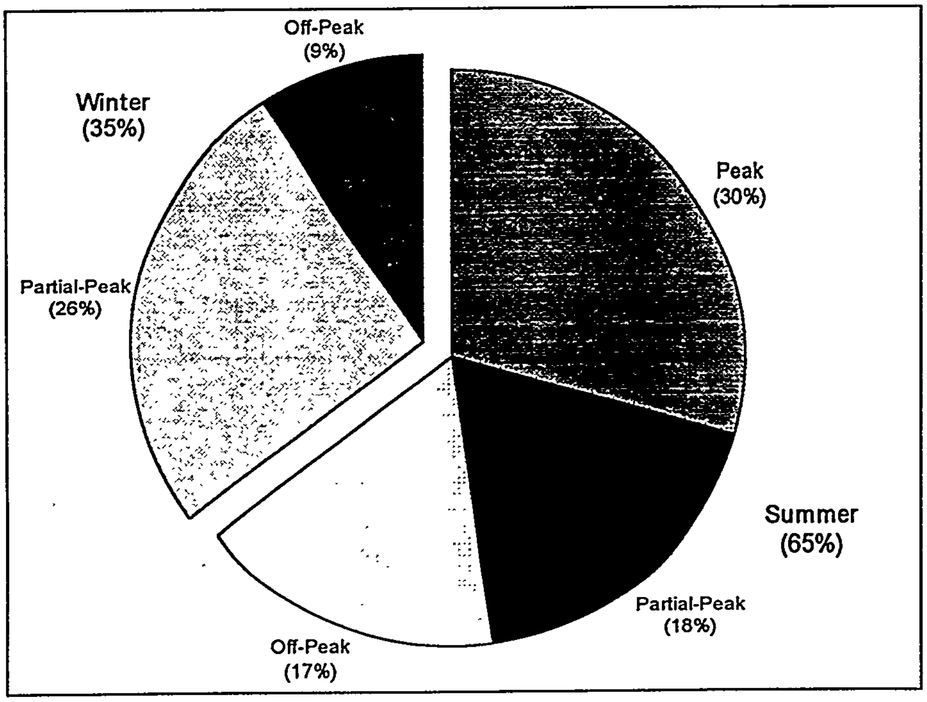

Figure 8-6. Energy value of the Kerman PV plant, by demand period.

Section 9

SYSTEM CAPACITY VALUE

VALUE DESCRIPTION

Capacity value is the amount utilities are willing to pay to maintain system reliability against capacity-related outages. Adding PV generation to the utility system provides an incremental amount of added reliability. This system capacity value is calculated by assessing utility system reliability with and without the generation resource.

EVALUATION METHODOLOGY

One utility industry planning standard to ensure long-term reliability against bulk power outages is the 1-day-in-10-years loss of load probability (LOLP). LOLP is the estimated amount of time that the utility's installed generation capacity will not be able to meet all customer load. The 1-day-in-10-years criterion translates into a capacity shortfall of not meeting demand for 2.4 hours in 1 year or 1 day in 3,650 days, depending on whether hourly or daily peak load is used in the LOLP calculations.

The amount of reserve capacity a utility is required to maintain is determined by meeting the LOLP reliability criterion. Up until the 1990 time frame, PG&E used the 1-day-in-10-years LOLP for capacity planning, resulting in a reserve requirement of approximately 22.5% of the peak system load. After this time frame, PG&E began using a VOS-based methodology to determine reserve requirement. The VOS methodology is discussed in the Updated Economics subsection in this chapter.

The higher the reserve capacity requirement, the higher the cost to maintain service reliability. Utility and regulatory investment decisions in supply- and demand-side resources, and the value of capacity, are largely driven by meeting reserve requirement targets. Once the reserve requirement target has been established, the Energy Reliability Index (ERI) is used to translate the reserve requirement into a marginal capacity value. The ERI is a measure of the degree to which a utility requires, or does not require, adding capacity. The CEC defines the ERI by the following exponential equation (PG&E 1993):[1]

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[1] The CEC and the California Public Utilities Commission (CPUC) regulate California's investor-owned utilities. Among other things, the CEC predicts how long-run electricity demands will grow, plans how demand will be served, and sets reserve margin targets. The CPUC oversees the recovery of utility supply- and demand-side costs and determines the magnitude and timing of utility needs for purchasing power. The purview of both agencies depends to a large extent on the accepted reliability target.

$$ERI = 0.5^{\left(\frac{RM_A - RM_T}{2.2}\right)}$$

RM_A is the utility's actual (or forecasted) reserve margin, and RM_T is the target reserve margin, both expressed in units of percent. For example, a utility with a forecasted reserve margin of 20% and a target reserve margin of 17% would result in an ERI of 0.39. An ERI less than 1.0 indicates that new generation capacity is not needed to increase system reliability. As the ERI approaches and exceeds 1.0, new capacity should be added to the system to meet reliability standards.

To determine the marginal capacity value, the ERI is multiplied by the avoided cost of new capacity on the margin. A commonly used benchmark is the cost of a gas combustion turbine. Unlike a gas turbine, however, PV is not dispatchable and cannot claim full-generation capacity credit.

The load carrying capability (LCC) of the plant must be calculated to establish the degree to which the PV plant provides the equivalent level of dispatchability to help meet peak loads. By adding PV capacity, the utility's LOLP is reduced. The LCC is the additional load, in MW, that can be added to the system until the LOLP returns to the same value without the PV resource. It is approximated by the following equation (see Hoff 1987 for calculation details):

$$LCC \approx (m) \ln \left\{ \frac{\sum_{i=1}^{8760} e^{\left[\frac{-(L_{peak} - L_i)}{m}\right]}}{\sum_{i=1}^{8760} e^{\left[\frac{-(L_{peak} - (L_i - PV_i))}{m}\right]}} \right\}$$

The calculation is based on 8,760 hours of system load and PV output data. L_{peak} is the system peak load for the entire year, in MW. L_i is the system load for hour i, in MW. PV_i is the PV plant output for hour i, in MW. Finally, m is the Garver Characteristic which, for PG&E, is 400 MW. It is defined as the inverse slope of the ln(LOLP).

Once the LCC is calculated, the following four steps are executed to calculate the total generation capacity value:

1. Peak power availability (PPA) is determined by dividing the LCC by the PV plant's rating.
2. The avoided cost of a gas combustion turbine is levelized by the utility's capital carrying charge rate (variously known as the fixed charge rate and levelization factor). Annually recurring O&M and general and administrative expenses are added.
3. The ERI is multiplied by the levelized gas combustion turbine cost obtained in step 2 to calculate marginal capacity value.
4. The PPA is then multiplied by the marginal gas turbine cost obtained in step 3.

TECHNICAL VALIDATION TESTING AND DATA REQUIREMENTS

The system capacity value data requirements are the same as those required to calculate energy generation value, as described in Section 8. A full year's worth of hourly system load and corresponding PV performance data from the same year are required to calculate the LCC. No testing is required. If actual PV performance data are not available, however, a validated PV simulation program is recommended. This may require validation testing.

Measured Kerman PV plant production data spanning July 1, 1993, to June 30, 1994, are used. The data are in a half-hour average format and are reduced to hourly averages. Hourly PG&E system load data from the same time period are downloaded from PG&E's mainframe computer system.

Figure 9-1 presents the highest loads for PG&E's system and the corresponding PV plant output to illustrate data requirements and the match between system peak loads and PV output.[2] The figure contains data which are taken from the top 25 load hours from the year's 8,760 hours. The data are expressed as percentages of peak system load and PV plant rating. PV output during the top 25 hours is excellent, with three-quarters of the points exceeding 80% of the plant's rating.

2 PV output, as defined for this section, includes the reduction of electrical losses on the T&D system. These average about 7.8% during peak loads (3.2% on the transmission system, 1.2% on the substation transformer, and 3.4% on the distribution feeder; see Section 6, Loss Savings). Also, PV plant output data were adjusted on June 28 and July 1 to account for inverter reset problems.

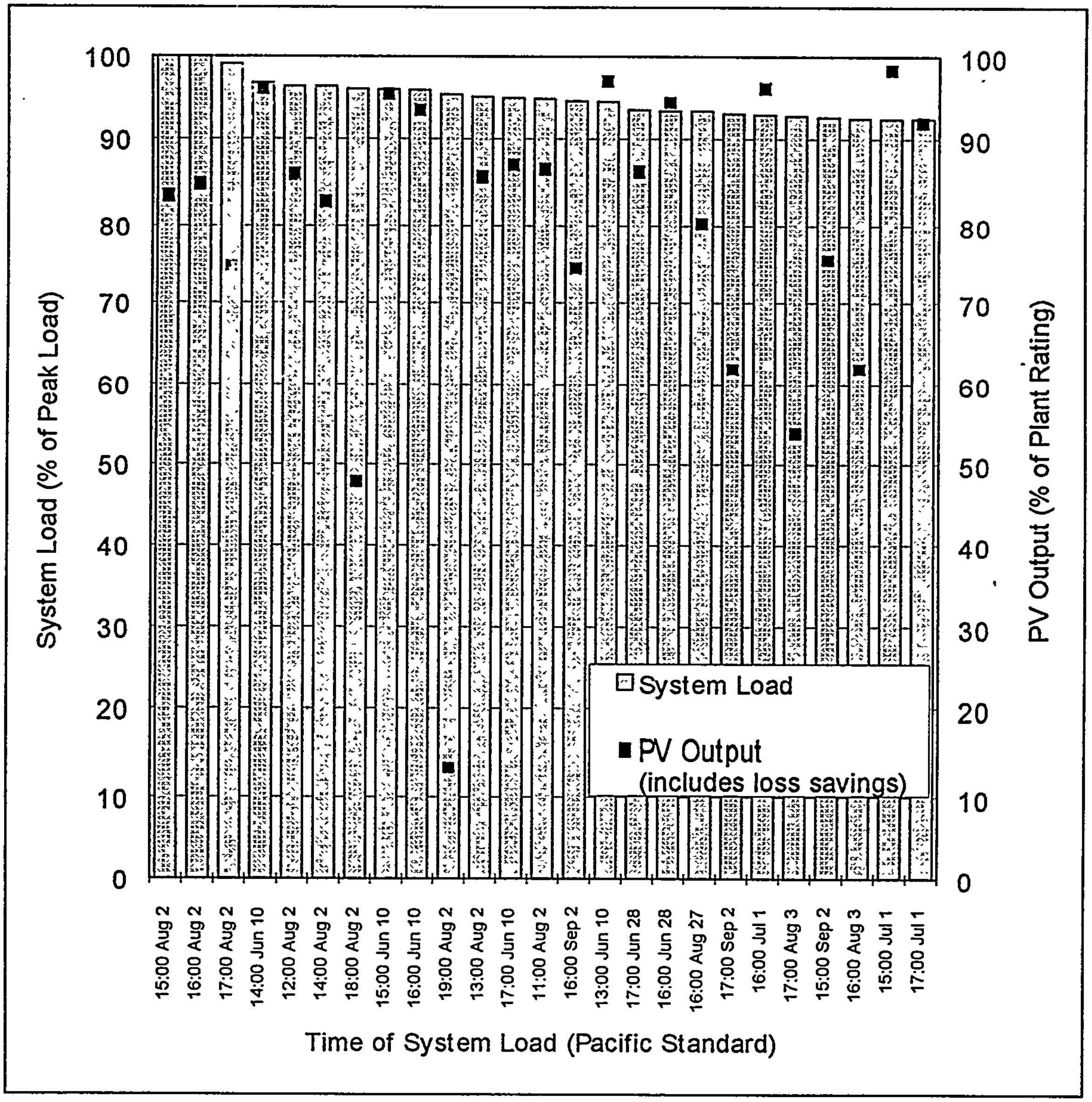

Figure 9-1. Top 25 system load hours shows good correlation with plant output.

TECHNICAL VALIDATION RESULTS

A load carrying capability of 384 kW is calculated based on measured PG&E system loads and Kerman plant output, including electrical loss savings. That means the 498 kW rated Kerman plant has an equivalent fully dispatchable generation capacity of 384 kW. Dividing the LCC by the plant's 498 kW rating yields a PPA of 77%. As Figure 9-1 illustrates, it is not surprising that a relatively high PPA results, since the top load hours factor most heavily into the PPA calculation.

Figure 9-2 presents the same data as Figure 9-1, organized by the time of system load. The figure again shows the correlation of afternoon peak load and PV output. The timing of system and local loads are critical factors in determining plant value and optimizing plant design. PG&E's peak system loads generally occur from 14:00 to 16:00 PST. The timing of peak system loads is well matched with the timing of local peak loads on the Kerman feeder and transformer (see Sections 3 and 4 for details). This is the best possible situation, where the plant's design can simultaneously be optimized for system and local value. In the case of Kerman, it was found that a single-axis tracker design was optimal from a cost/value perspective. (See Hoff, Shugar, and Wenger 1991 for a discussion on optimizing plant design from a value perspective.)

Figure 9-3 presents PV output, without loss savings, versus the solar resource for the top 25 load hours. This figure highlights the importance of high-quality solar resource data for predicting the performance and value of PV plants from a load-matching perspective.

To determine the system capacity value of the Kerman PV plant, the 1992 Case Study assumed the cost of a gas turbine to be $452/kW, as adopted in PG&E's 1990 General Rate Case. Assuming a capital carrying charge factor of 14.36%, the levelized cost is $65/kW-yr. Avoided O&M and general and administrative costs are added, boosting this value to $74/kW-yr.[3] The Kerman power plant PPA of 77% is multiplied by $74/kW-yr, to yield a validated generation capacity value of $57/kW-yr ($496/kW) in year 1992 dollars.

3 An O&M and G&A (general and administrative) cost of $5.16/kW-yr was taken from PG&E's 1990 General Rate Case. This value was multiplied by a recurring expense rate of 1.83 calculated at an 11% cost of capital, 6% inflation, and a 30-year project life; consistent with PG&E economic and engineering practices.

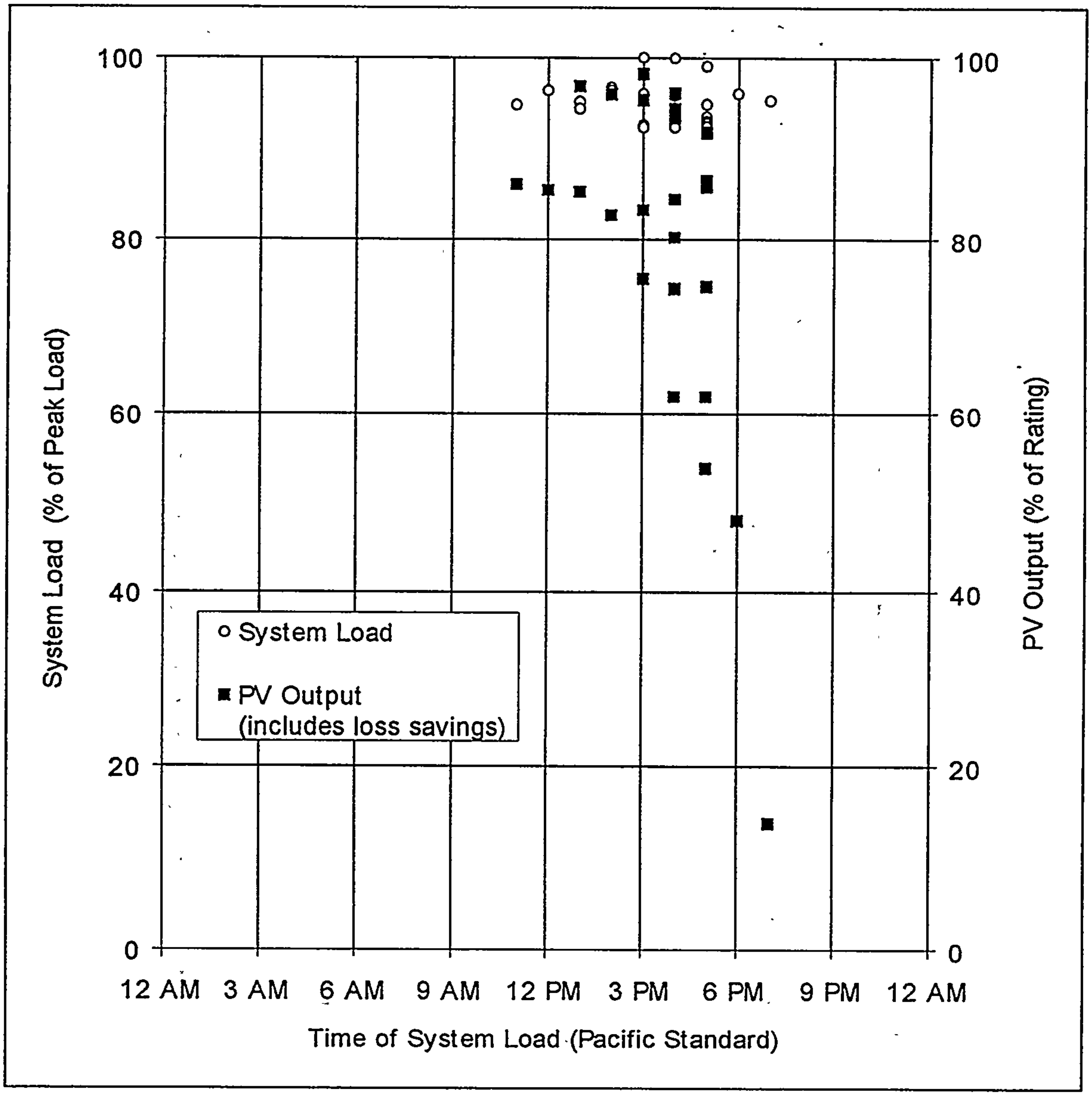

Figure 9-2. System load and PV output timing is important to PV design and value.

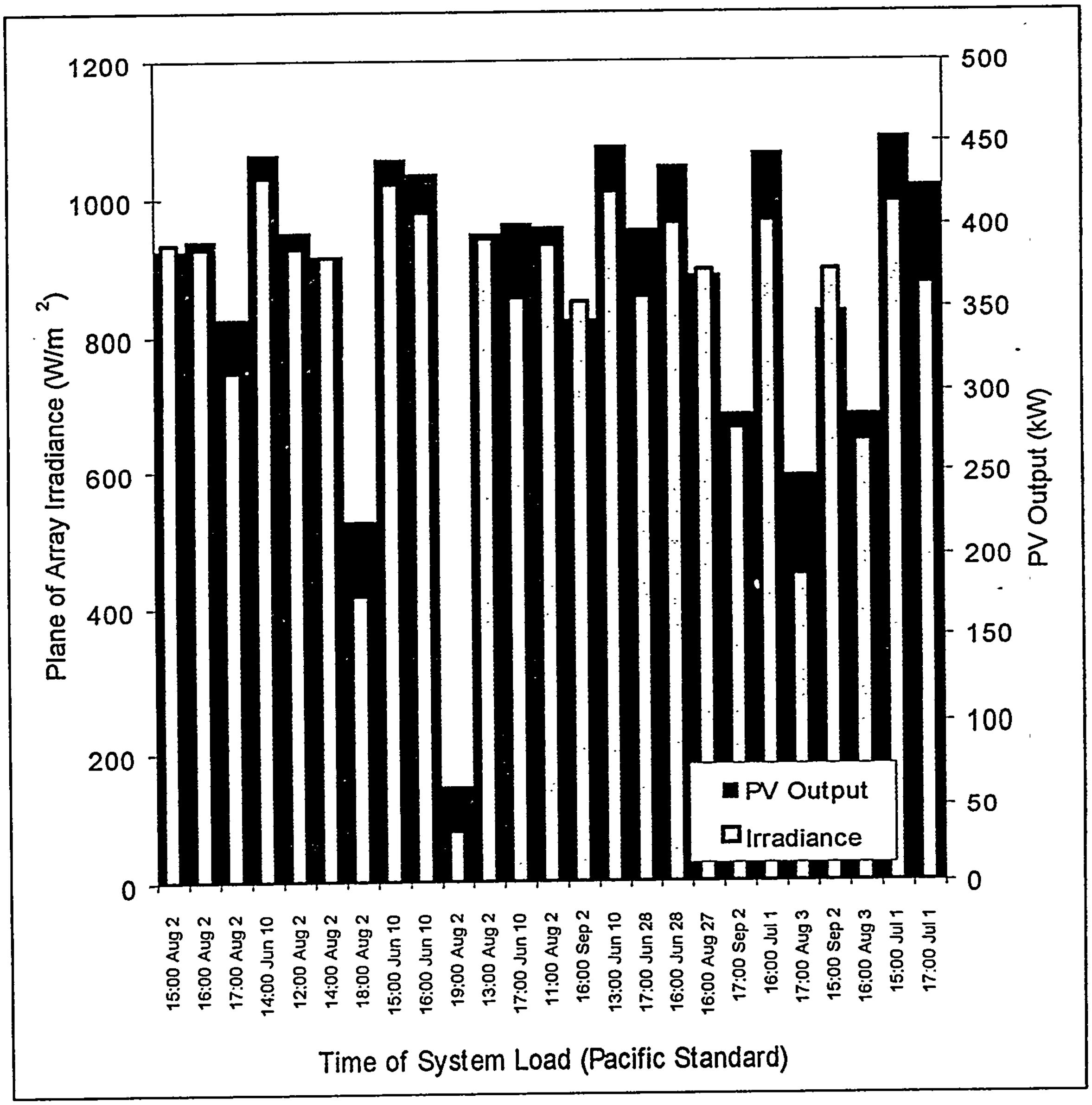

Figure 9-3. Top 25 load hours: A close correlation between PV output and the solar resource.

TECHNICAL VALIDATION RESULTS VS. 1992 CASE STUDY

The technical validation result is 21% less than the 1992 Case Study estimate of $72/kW-yr ($626/kW). The difference is due to variances in actual versus predicted plant performance. Actual performance resulted in a lower PPA. Also, higher peak loss savings were assumed in the 1992 Case Study.

The 1992 Case Study predicted a PPA of 97%, including loss savings, compared with the technical validation PPA of 77%.[4] This accounts for the 21% decrease in capacity value.

Adding the electrical loss savings to PV output accounts for the effective load reduction to the bulk generation system. Test results, described in Section 6, found that peak transformer and distribution feeder loss savings are about 4.6% of the PV plant rating. Adding 3.2% transmission loss savings, PG&E's systemwide average, brings loss savings to 7.8% during peak load hours. This is a 35% reduction relative to the 1992 Case Study, which assumed loss savings totaled 12%. The impact of this difference is a 4 percent overestimate of generation capacity value.

VARIABLE PV PLANT SIZE

The capacity value of the plant will roughly scale with size up to fairly large penetrations, perhaps to 50 MW. There are at least two factors that must be considered, however, in valuing capacity as PV plant size is increased: (1) impact on electrical losses on the T&D system; and (2) impact on dispatching other generation resources.

The impact on electrical losses is site-dependent. Electrical losses can actually increase for larger plant sizes interconnected particularly at distribution voltages. This is the case for the Kerman plant, where it has been shown that loss savings value peaks at a plant size of approximately 1 MW and drops down thereafter.

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4 If the Kerman PV plant performed as expected, according to the PVGRID simulation, the PPA would be 81%, with loss savings. The higher PPA would increase the capacity value by 5% to $60/kW-yr. This percentage increase also applies to the updated economic value. The measured and expected PPAs of 77 and 81%, respectively, are significantly lower than PPAs previously estimated for Kerman and other locations within the PG&E service area. These PPAs are typically estimated at around 87%, with loss savings. It appears this is primarily due to poorer-than-anticipated load matching, with a larger fraction of the load duration curve's top hours occurring later in the day than in previous years. Since the Kerman PPA is based on only one year's measurements, it should be used with discretion until long-term data can confirm the result.

For installations exceeding approximately 5 MW, interconnection will likely be at higher voltage transmission, thereby eliminating potential electrical loss reduction to distribution transformers and lines. For example, the Kerman feeder could probably accommodate a plant up to 1 MW in size before it would need to be interconnected at transmission voltages or moved to a higher capacity feeder. PV plants located near load centers on transmission lines can, however, reduce electrical losses. On the other hand, electrical losses may increase for larger penetrations of PV that are not located near load centers.

Power flow studies for systems exceeding 50 MW would likely be required to determine electrical losses on a case-by-case basis, due to the complex interaction of generation and load on high-voltage transmission networks. For detailed discussions on electrical losses, see Section 6 and Appendix F.

Peak power availability calculations were made for larger plant sizes and are presented in Table 9-1. These PPAs are calculated by scaling up the measured Kerman plant data. The results indicate that the higher the penetration, the lower the PPA. This is because load peaks are shifted to later in the day as penetration increases. Once electrical losses are determined, the capacity value, for plant sizes up to 100 MW, is obtained by following the evaluation methodology described in this section.

Table 9-1

Peak Power Availability as a Function of PV Plant Size

Plant Size (MW)	0.5	5	50	100	500	1000
PPA (%)	77	72	71	71	69	64

Note: PPAs for plants greater than 0.5 MW do not include loss savings adjustments, either positive or negative. These must be calculated on a case-by-case basis and depend on interconnection location. Also, these results are specific to the Kerman area based on one year's measured data. Confirmation of PPA over a longer period of time is recommended.

To more accurately determine capacity value for plant sizes greater than 100 MW, production cost simulations would need to be run to ascertain the impact of the PV resource on utility power purchases and dispatch of other generation resources. This can be accomplished with a model such as Elfin.

UPDATED ECONOMICS

As described in the Evaluation Methodology subsection in this chapter, the target reserve margin is a key element in determining the value of capacity. PG&E has moved from a LOLP 1-day-in-10-years criterion for reliability planning to a VOS approach. The VOS approach has been adopted by the CEC and the CPUC and is used to determine target reserve margin.

VOS is generally expressed as the value customers place on avoiding service interruptions. This value is commonly referred to as "outage costs." The VOS approach to capacity planning is to weigh the cost of incremental reliability enhancements against the customer value of those enhancements (Keane and Woo 1991). The goal is to minimize the sum of the utility's capacity costs and the value of those capacity additions from the customer perspective. The VOS method is viewed as an improvement since it is a more "market-based" approach compared to the 1-day-in-10-years LOLP methodology. The criticism of the 1-day-in-10-years criterion is that it is a somewhat arbitrary way to determine the level of the utility's reserve capacity and ignores customer input.

California has a three-stage Electrical Emergency Plan (EEP) which dictates how customer outages are initiated by the utility in cases of capacity shortfalls, as follows (Keane and Woo 1991):

- Stage 1 is initiated when the capacity reserve margin falls below 5% of peak load. The utility makes emergency appeals to customers to voluntarily reduce load. Customers who volunteer to curtail receive 4 to 6 hours advance notice of the utility curtailment, and would endure partial outages of up to 4 hours.

- Stage 2 is initiated when reserve margins drop to 3% of peak load. Public appeals are intensified and partial outages are invoked, lasting about 4 hours. Customers receive about 2 to 4 hours advance notice of the curtailment.

- Stage 3 is initiated when reserve margins fall to 1.5% of peak load. Rotating blackouts are instituted, subjecting customers to 1-hour complete power outages. Customers receive about 1 hour advance notice of the impending outage.

Surveys of PG&E's major customer classes are used to determine outage costs according to the EEP action plan. The weighted average value of outage costs, based on the customer class contribution to peak load, are \$2.52/kWh for Stage 1 and 2 partial outages, and \$17.81/kWh for Stage 3 full outages, in 1991 dollars (PG&E 1993).

These outage costs are used to predict the value of the expected unserved energy (EUE) resulting from the initiation of EEP actions. The EUE is balanced against the cost of adding capacity, until an optimum reserve margin is derived. PG&E uses the EGRET reliability model to determine optimal reserve margin based on the value of service methodology.

Moving to the VOS-based approach has lowered target reserve margins to about 17% of peak load (CEC 1993). Previously, target reserve margins were approximately 22.5% based on the 1-day-in-10-years LOLP. Figure 9-4 presents the ERI as a function of target and forecasted reserve margins adopted by the CEC in ER92 (CEC 1993). The impact of resetting the target reserve margin can be seen in the figure: based on the "new" target reserve margin of 17%, the ERI is well below 1.0, indicating a capacity surplus position for the foreseeable future. This greatly reduces marginal capacity value.

On the other hand, the forecasted reserve margin can play just as important a role in altering the ERI. If demand grows faster than anticipated or if demand-side management program effectiveness falls below expectations, for example, forecasted reserve margins would decrease and capacity values would increase. In any case, one conclusion of this research is that determining reserve margins is key to reliability planning and valuing capacity.

The ERI is multiplied by the levelized cost of a gas combustion turbine to calculate marginal capacity value. Figure 9-5 presents four sets of marginal capacity value streams and the cost of a gas combustion turbine, in real inflated dollars (PG&E 1993). The set denoted "CEC ER92 Assumptions" adopts the CEC's resource planning assumptions as detailed in ER92 (CEC 1993).

The low ERI values calculated using the CEC's resource assumptions result in very low capacity values over the 15-year period. Driving the low capacity values is the presumed availability of ample spot capacity supplies to meet summer peak demand (about 1,200 MW), and the CEC subtracts out demand-side management savings from projected load when forecasting reserve margin. These assumptions increase forecasted reserve margins, lowering ERIs and the marginal value of adding capacity to improve reliability.

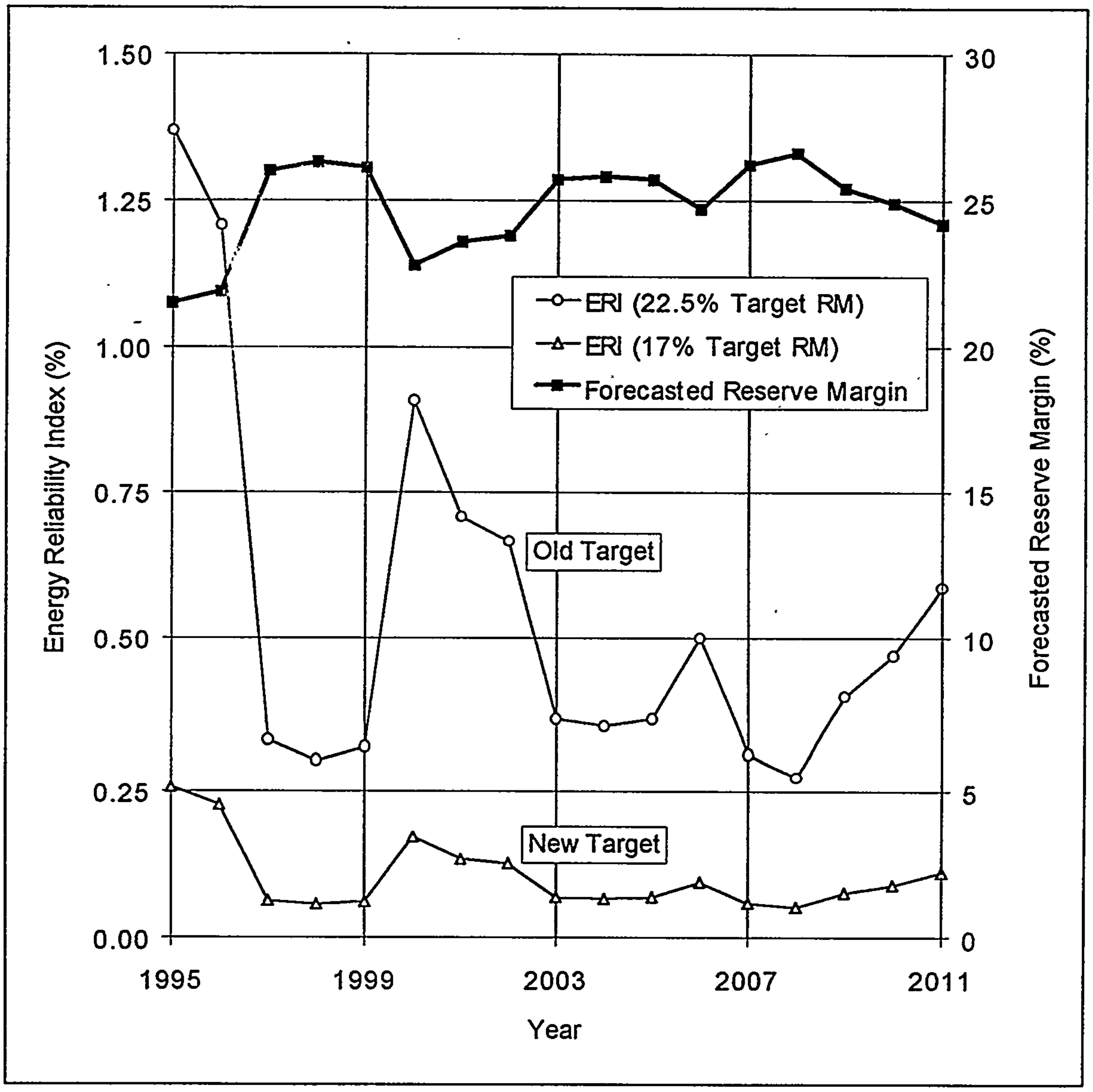

Figure 9-4. ERI is highly dependent on target and forecasted reserve margins.

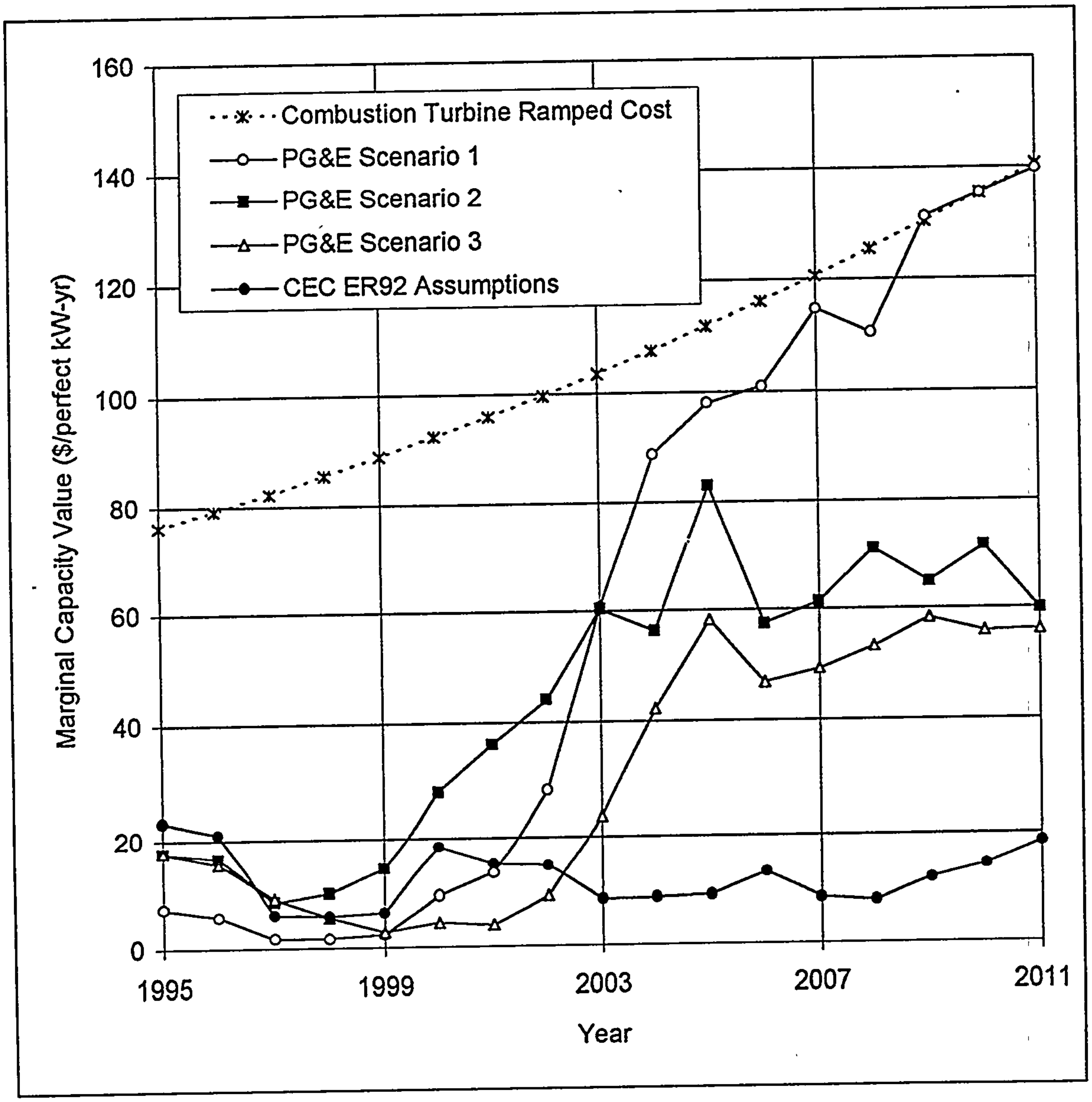

Figure 9-5. Marginal capacity value for regulatory and scenario planning.

Clearly, reliability planning and forecasting reserve margin are assumption-driven. Recognizing this, PG&E recommends that resource cost-effectiveness be tested using different scenarios to test economic robustness under resource, load, and regulatory uncertainty. Scenario 1 of Figure 9-5 corresponds to resource assumptions developed by PG&E as a reference case. Scenarios 2 and 3 are examples of sensitivities which consider possible outcomes of utility restructuring and open access.

Each scenario follows a similar pattern until the end of the decade. Capacity value is low because of the availability of spot purchase capacity to meet peak loads. After the year 2000, the need for capacity ramps up at different rates. Scenario 1, for example, assumes that PG&E's capacity position reaches balance around the year 2004 (the target reserve margin is reached) and capacity value increases to the avoided cost of a gas combustion turbine by the year 2009.[5]

To determine the total updated economic value of capacity achieved by the Kerman PV plant, it is assumed that the PPA is 77% over a 30-year evaluation period. The PPA is the measure of the plant's dispatchability to meet peak loads and includes downtime. The PPA is multiplied by the marginal capacity value streams shown in Figure 9-5.[6] The resulting annual value stream is brought to the present, assuming a cost of capital of 9%.

Table 9-2 presents the updated economic value of capacity achieved by the Kerman PV plant for the four different planning scenarios. There is a wide range, from $12/kW-yr to $53/kW-yr. At this time, the assumptions adopted by the CEC serve as the baseline proxy to determine the capacity value of the Kerman PV plant. The PG&E scenario-based assumptions are sensitivities to the baseline.

The disparity in value is illustrative of the complex nature of long-term resource planning. Resource assumptions and reliability planning methods can dramatically change the utility's forecasted and target reserve margins, which in turn dramatically change the value of capacity. It is likely that the forecasted value of capacity will change many times in the near future with the restructuring of the California electric utility industry.

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5 Although the ERI reaches 1.0 at the year 2004, according to Scenario 1, the marginal value does not attain that of a combustion turbine immediately: Capacity cannot be purchased in very small increments just to meet demand.

6 The capacity value streams are escalated from the year 2012 to 2024 to obtain 30-year streams. Escalation rates for the CEC regulatory case and the PG&E scenarios are 3.8% and 3.5%, respectively. The streams are based on the ramped cost of a gas combustion turbine, divided by a factor of 85% to account for the forced outage rate.

Table 9-2

Total Capacity Value for Different Planning Assumptions ($1995)

	CEC ER92 Assumptions	PG&E Scenario 1	PG&E Scenario 2	PG&E Scenario 3
Capacity Value ($/kW-yr)	12	53	40	27
Capacity Value ($/kW)	125	547	408	282

Section 10

MINIMUM LOAD VALUE

VALUE DESCRIPTION

Many utilities rely on their smaller fossil units to meet a portion of their peak demand. These units are operated at minimum load during off-peak hours to be prepared to satisfy peak demand. Fossil units operated at minimum load have significantly reduced efficiencies. Thus, the energy cost of these units during off-peak hours exceeds that of available alternatives.

Sufficient quantities of PV may eliminate the need for the peak contribution of some fossil units. These units no longer need to be operated at minimum load during off-peak hours because they are not required to satisfy peak demand. Instead, other units supply the off-peak energy at a lower cost. The minimum load savings is the difference between the cost of generation produced at minimum load and the lower cost of the available alternative.

EVALUATION METHODOLOGY

The 1992 Case Study estimated minimum load savings by using results from a PG&E study entitled *Comparison of Solar Thermal Troughs with Photovoltaics as a PG&E Central Station Resource in the 1990s* (Dickerson et al. 1991). This study showed minimum load savings for a 134-MW single-axis tracking PV plant over a study period of 1996 to 2025. The figures were generated using the difference between the weeknight subperiod production cost in PROMOD (a simulation model similar to Elfin used by PG&E) with and without the PV generation.

It is difficult to add much to what was presented in the 1992 Case Study because the system must be redispatched once large quantities of PV are added. One approach to validating results is to rerun the production simulation model using measured PV plant output data. This approach, however, is unlikely to increase the reader's understanding of why minimum load savings occur.

A more interesting approach is to examine the interaction between PV output and the fossil units using measured data. This approach replaces some of the fossil generation capacity with PV, redispatches the remaining fossil units, and determines if the new generation portfolio adequately satisfies peak demand. It does not attempt to recalculate the value from the 1992 Case Study, but only confirms the existence of that value.

TECHNICAL VALIDATION TESTING AND DATA REQUIREMENTS

The analysis is based on measured system load, measured output from all of the fossil units in PG&E's system, and measured PV plant output from the 0.50-MW PV plant at Kerman. Measured PV plant output is increased by 8% to account for loss savings through the generation system. Fossil generation data were available from January 1, 1994, through June 30, 1994. A stretch of system peak days occurred on June 27, 28, and 29; the analysis is based on these three days.

The analysis could be performed for a 134-MW PV plant because this was the assumption for the 1992 Case Study and because this is approximately the size of the smallest fossil unit that could be turned off if PV were added. For illustration purposes, however, it is more interesting to evaluate the effect of a much larger PV penetration. This is accomplished by scaling output from the Kerman PV plant up to 2,500 MW.

Technical Validation Results

Figure 10-1 presents system load and two combinations of fossil and PV plant output on June 27, 28, and 29. As the figure suggests, the fossil units reduced the magnitude of system peaks by following the load with output ranging from 1,600 MW to 4,300 MW.

Instead of having 4,300 MW of fossil capacity (the greatest amount of output from fossil units anytime during the 3-day period), 2,300 MW of fossil are replaced by 2,500 MW of PV; the remaining 2,000 MW of fossil are operated at base load. Although the relationship is not perfect, the figure suggests that the two generation portfolios are very similar in the way they satisfy demand. That is, the dispatch associated with 2,300 MW of fossil is very similar to 2,500 MW of PV when the remainder of the fossil units are operated at base load. This confirms that there is minimum load savings associated with PV.

One can obtain a high-level estimate of the effectiveness of PV. Since 2,500 MW of PV and 2,000 MW of base-load fossil is approximately equivalent to 4,300 MW of fossil, the system obtains about 90% of the PV's capacity. That is, the PV is very effective at supplying capacity to the system.

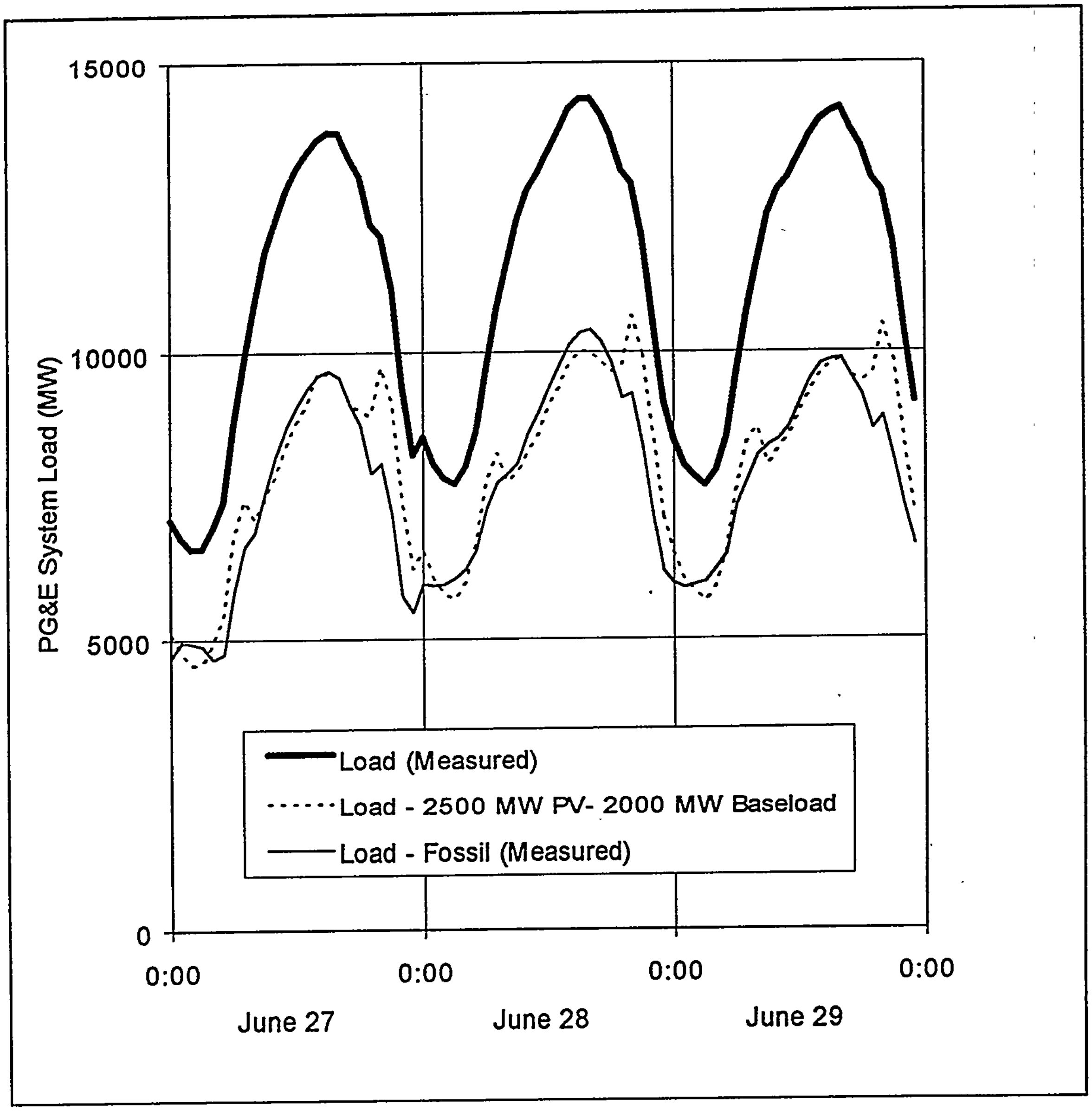

Figure 10-1. A new generation portfolio with 2,500 MW of PV is approximately equivalent to 2,300 MW of fossil (June 27, 28, and 29, 1994). The heavy solid line represents system load, the dashed line represents the construction of a new generation portfolio, and the thin solid line represents measured system load minus measured fossil plant output.

TECHNICAL VALIDATION RESULTS VS. 1992 CASE STUDY

The 1992 Case Study estimated minimum load savings of $28/kW-yr ($243/kW). No attempt is made to recalculate this value by rerunning the production simulation model. In addition, the source of this value is based on the capacity, not the energy, that PV provides to the system. Value is obtained if the PV plant supplies sufficient capacity to enable some fossil units to be turned off. The previous section suggests that this is accurate, and thus, no change is made in the 1992 Case Study minimum load value estimate.

VARIABLE PV PLANT SIZE

The results section was based on 2,500 MW of PV. This represents almost 15% of PG&E's 1994 peak system load. Results suggest that even at this high penetration, the PV plant is 90% effective. This suggests that the minimum load savings estimate is constant with PV plant size.

Section 11

ENVIRONMENTAL EXTERNALITIES

VALUE DESCRIPTION

Environmental externalities account for the costs and benefits to society of electric power generation which are not explicitly accounted for in electric rates. For the utilities and regulatory agencies which consider externalities in electric resource planning, externalities are generally taken to be the costs to society resulting from fossil power plant emissions. Externality costs associated with the risk of nuclear power plant operations, fossil fuel spills and mining, or from the aquatic impacts of cooling water, for example, have not yet been universally incorporated into the quantification of externalities in utility resource planning.

Although externalities generally have a negative connotation, they can also include positive attributes such as increased employment and resource diversity. Such positive attributes are not, at this time, explicitly considered in the California regulatory arena with respect to electric resource planning and are therefore not taken into account in this research.

The quantification of externalities, their adoption by state governments and utilities, and their role in resource planning continue to be hotly debated. Although inclusion of externalities in utility resource planning is mandated in at least a dozen states, including California, its evaluation and treatment is evolving (Pace University 1991).

In California, environmental externalities are set by the California Energy Commission and have been adopted by the California Public Utilities Commission in the Biennial Resource Planning Update (BRPU) process. Utility selection of new generation resources must take into consideration the costs associated with residual air emissions.

At this time, externalities have not conveyed enough of an economic advantage for renewable generating resources to compete successfully with fossil-fuel-based power. Legislators and regulators recognize the value of renewable energy sources and have fallen back on mandating "set-asides," which require utilities to purchase a predetermined amount of power from renewables purely on the basis of their environmental and diversity benefits.[1]

For example, Kenetech Corporation won over 200 MW of windpower contracts on the basis of set-asides.[2] These set-asides, however, are already being contested by at least one California utility who has argued that in light of emerging competition and electric utility deregulation, the utility should not bear the burden of uneconomic generation purchases. The issue of who pays for societal costs, and hence the treatment of environmental externalities, will only grow in importance as deregulation unfolds. How this issue is resolved could have significant bearing on the advancement of renewable energy technologies.

EVALUATION METHODOLOGY

Environmental value is defined as avoided environmental externality costs. To derive environmental value, "emission adders," allocated on a demand period basis, are multiplied by PV plant output. Every kilowatthour produced by the PV plant displaces a kilowatthour, and the emissions that would have been produced by load-following fossil plants. Emission adders represent the social benefits from reduced emissions due to the addition of the Kerman PV plant to the PG&E resource mix.

These emission adders were developed with the Elfin data set provided by the CEC.[3] The Elfin data set contains resource assumptions adopted by the CEC and is used in Iterative Cost-Effectiveness Methodology (ICEM) capacity expansion simulations to develop marginal energy, capacity, and emissions costs.[4]

To avoid running ICEM every time a new resource evaluation is needed, PG&E developed a set of SPVs which approximate ICEM marginal costs. PG&E's SPVs contain marginal energy value, capacity value, and emission adder components.

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1 Set-asides have been earmarked as an interim measure until such time that externality costs and benefits can be more definitively defined and quantified. The CEC is concerned by California's extensive reliance on natural gas and the concomitant risk inherent in fuel price uncertainty. Set-asides improve resource diversification and help protect ratepayers from potential price shock (CEC 1993).

2 200 MW of firm, dependable capacity, translates to over 900 MW based on turbine ratings.

3 Anita Wolff of EDF ran a series of Elfin production simulations based on the PG&E data set which was modified to more accurately model the output profile of the Kerman PV plant. Pacific Energy Group supplied the Kerman output profiles to EDF.

4 The latest version of Elfin contains new supply- and demand-side optimization routines—Iterative Cost Effectiveness Methodology (ICEM) and Iterative Test for Resource Effectiveness (ITRE). These decision routines utilize capital, O&M, shortage, production, and emission costs to determine the most cost-effective resource expansion plan.

For the 1992 Case Study, the emission adders are based on the "revealed preference approach," which uses the cost to control power plant emissions at the point source as a proxy for emissions value (i.e., the cost to control pollution at the stack). These values, presented in Table 11-1, are detailed in the CEC's 1990 Electricity Report (CEC 1991). They were adopted by PG&E and the CPUC, and submitted in PG&E's 1993 General Rate Case (Shugar et al. 1992). It is interesting to note that there is little time-of-day differentiation between these values. For example, the average annual value is $0.0122/kWh, compared to the summer peaking value of $0.0134/kWh.

Table 11-1

Emissions Adders Used in 1992 Case Study ($1993)

	Summer			Winter		Annual
	On-Peak	Partial-Peak	Off-Peak	Partial Peak	Off-Peak	(average)
Emissions Adders ($/kWh)	0.0134	0.0126	0.0112	0.0141	0.0114	0.0122

Note: Time Periods:

Summer (May 1-Oct 31): Peak (Monday-Friday, except holidays, 1200-1800), Partial-Peak (Monday-Friday, except holidays, 0830-1200 and 1800-2130), Off-Peak (Monday-Friday, 2130-0830) and (all day Saturday, Sunday, and holidays)

Winter (November 1-April 30): Peak (none), Partial-Peak (Monday-Friday, except holidays, 0830-2130), Off-Peak (Monday-Friday, except holidays, 2130-0830) and (all day Saturday, Sunday, and holidays)

The 1992 Case Study assumed these adders would escalate annually at a rate of 5% over the 30-year analysis period. PV plant production, taking into account electrical loss reductions totaling 5.3%, is multiplied by the emissions adders to obtain total environmental value.[5]

TECHNICAL VALIDATION TESTING AND DATA REQUIREMENTS

A full year's worth of PV performance data is needed, in time increments of at least one hour. No testing is required. If actual PV performance data are not available, however, a validated PV simulation program is recommended.

5 Reducing electrical losses reduces power plant emissions in the same manner as PV energy production. The annual electrical loss reduction of 5.3% comprises three components: the reduction of losses on the bulk transmission system (3%), substation transformer (0.7%), and the Kerman feeder (1.6%).

Measured Kerman PV plant production data spanning July 1, 1993, to June 30, 1994, are used. The data are in a half-hour average format. A computer program was written to read in the PV kilowatthour data and segregate it into PG&E's demand periods. These kilowatthour totals were multiplied by the emissions adder corresponding to each demand period, per Table 11-1, to yield total annual environmental value.

TECHNICAL VALIDATION RESULTS

The total environmental value of the Kerman PV plant, based on one year's worth of measured energy production data and the 1992 Case Study economic assumptions, is $47/kW-yr ($409/kW).

TECHNICAL VALIDATION RESULTS VS. 1992 CASE STUDY

The technical validation result is 24% less than the 1992 Case Study estimate of $62/kW-yr ($539/kW). The difference is driven by variances in actual versus predicted plant performance. Also, the 1992 Case Study assumed a 10.5% cost of capital, reported the value in 1993 dollars (not in 1992 dollars), and did not utilize a loss savings adjustment factor.

The Kerman PV plant yielded a measured capacity factor of 24.8%, compared with a 31.7% capacity factor assumed in the 1992 Case Study.[6] This factor alone accounts for about 94% of the difference in value results. For a description of PV performance, see Section 2.

VARIABLE PV PLANT SIZE

The environmental value of the plant will scale linearly with size-up to a very large penetration level, probably in excess of 100 MW. Penetration levels beyond 100 MW may produce step changes in fossil plant dispatch and emissions. This effect is being investigated by utilizing the Elfin production simulation program in collaboration with the Environmental Defense Fund.

UPDATED ECONOMICS

The CEC has moved away from using cost to control estimates to quantify the societal value of reduced emissions (CEC 1993). The accepted practice to value reduced emissions is now based on a "damage function" methodology, whereby the damage from residual power plant emissions is quantified. This

[6] The Kerman PV plant was "expected" to produce a 27.3% capacity factor for the July 1993 through June 1994 validation period. The expected output is based on the validated PVGRID simulation. If the Kerman plant performed as expected, the environmental value would increase by about 10%, to a value of about $52/kW-yr. This also applies to the updated economic value. See Section 2 for plant performance details.

damage function attempts to quantify the value to society in terms of, for example, avoided damage to human health, cropland, livestock, visibility, and buildings.

A computer simulation program developed by the CEC called the Air Quality Valuation Model (AQVM) is used to determine emissions value in \$/ton/year for nitrogen oxides (NO_X), reactive organic gas (ROG), carbon monoxide (CO), sulfur oxides (SO_X), and particulate matter under 10 microns (PM10) as a function of air basins. Table 11-2 and 11-3 present sample analyses. Table 11-2 presents the emission reduction values based on the damage function for the San Joaquin Valley air basin. The emission reduction values, covering California and out-of-state power transfers, are integrated into Elfin and ICEM models in the form of data sets.

Based on ICEM simulations, PG&E developed a 20-year set of emission adders which correspond to PG&E's 20-year resource expansion plan. Table 11-3 presents the adders for year 1995. Unlike the values used in the 1992 Case Study, the value of emissions reductions during summer peak hours is worth twice that of the average annual emission value. This is primarily due to the displacement of NO_X, which causes ozone and smog formation and is particularly acute in summer when reaction times are shortened by high sunlight availability. (Personal communication, Environmental Defense Fund, October 1994).

The updated emissions adders, however, have declined dramatically relative to the adders used in the 1992 Case Study. In fact, the updated values are about half the 1992 Case Study values. This is primarily attributable to the emission valuation methodology, whereby the CEC damage function results in much lower values than using cost to control estimates.

To highlight the difference between these evaluation methods, Figure 11-1 presents the PG&E-developed emission adders over the 30-year evaluation periods for the 1992 Case Study and the updated economics case. The adders are expressed as annual averages. For the updated economics case, the adders are developed according to PG&E's 20-year resource expansion plan, and then escalated by 3.5% per year.

Table 11-2

Emission Reduction Values for San Joaquin Valley

	NO_x	SO_x	ROG	PM10	C[a]	CO
Value ($/Ton) 1989 Dollars	$6,473	$1,500	$3,711	$3,762	$28	$0
Value ($/lb) 1995 Dollars	$3.98	$0.92	$2.28	$2.31	$0.017	$0

Source: CEC 1993

[a] Carbon values based on out-of-state power transfers adopted by the California Energy Commission (CEC 1993).

Table 11-3

Emission Adders for Updated Economics ($1995)

	Summer			Winter		Annual
	On-Peak	Partial-Peak	Off-Peak	Partial Peak	Off-Peak	(average)
Emissions Adder ($/kWh)	0.0123	0.0061	0.0065	0.0075	0.0051	0.0061

Note: Time Periods

Summer (May 1-Oct 31): Peak (Monday-Friday, 1200-1800), Partial-Peak (Monday-Friday, 0800-1200 and 1800-2100), Off-Peak (Monday-Friday, 2100-0100, 0500-0800) and (all day Saturday and Sunday except 0100-0500), Super Off-Peak (All days, 0100-0500)

Winter (November 1-April 30): Peak (none), Partial-Peak (Monday-Friday, 0800-2100), Off-Peak (Monday-Friday, 2100-0100, 0500-0800) and (all day Saturday and Sunday except 0100-0500), Super Off-Peak (All days, 0100-0500)

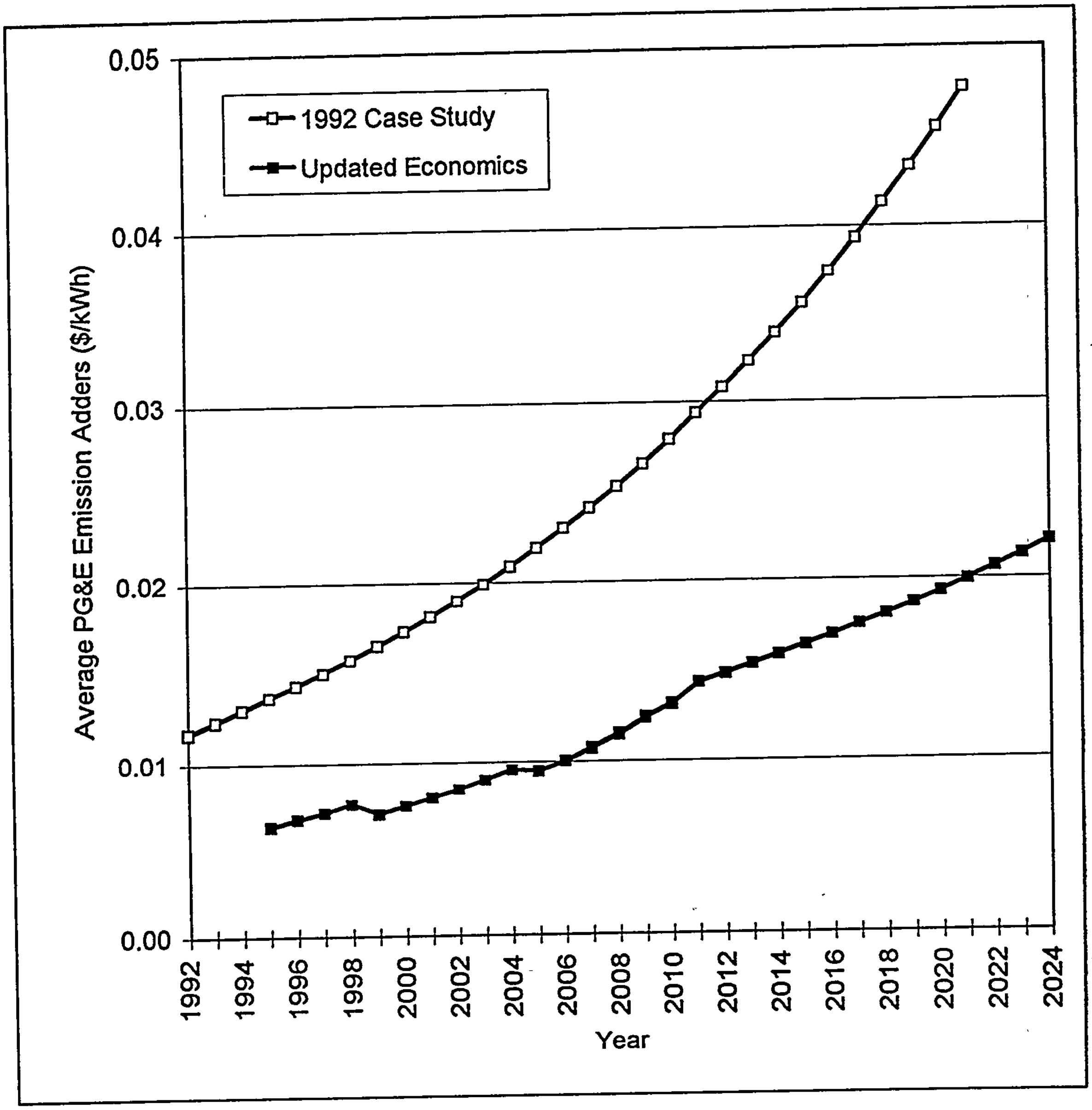

Figure 11-1. Average emission adders, 30-year stream, current year dollars.

To obtain the value of avoiding power plant emissions, the measured PV plant data are segregated into demand periods and multiplied by the corresponding emissions adder for each year. These value components are then present-valued to obtain the total value, and a loss savings adjustment factor of 5.3% is applied. Figure 11-2 presents the total value by demand period. Clearly, most of the value comes from the combination of higher summer emission adders and higher summer PV production. The total updated economic value of externalities, assuming a 9% cost of capital and the updated emission adders, is \$31/kW-yr (\$319/kW) in year 1995 dollars.

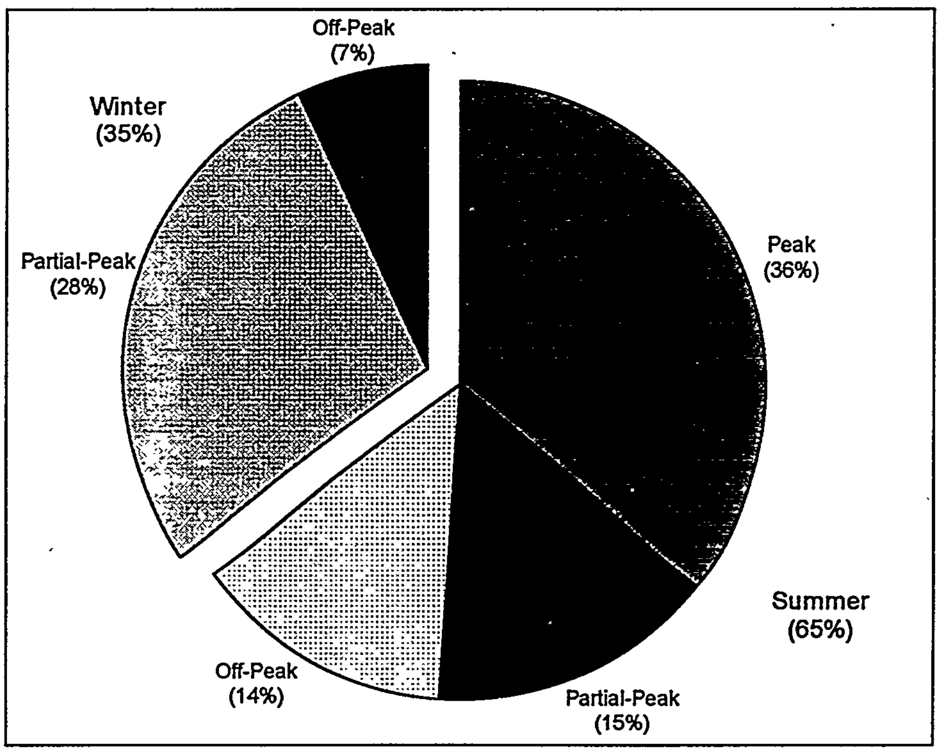

Figure 11-2. Environmental value by demand period, updated economics case.

Elfin Simulations

Elfin production simulation results were used to gain further insight to estimate the total emission reductions achieved by the Kerman PV plant over a 30-year operating life. The reduction in annual emissions over a 20-year period is calculated by conducting two Elfin computer simulations (commonly referred to as an "in/out" analysis; Elfin simulations conducted by Environmental Defense Fund, July 1994). The first simulation includes the Kerman plant in the PG&E resource mix; the second simulation does not. Table 11-4 presents a sample of the average avoided emissions estimated for every megawatthour produced by the Kerman plant for the year 1995.

Table 11-4

Average Avoided Emissions for Kerman PV Plant (year 1995)

	NO_X	SO_2	Particulates	CO_2 [a]
lb/MWh[b]	1.508	0.478	0.037	248
lb/mmBtu[c]	0.156	0.040	0.004	27.6

[a] PG&E's average CO_2 rate for all fossil plants in 1993 was approximately 1,195 lb/MWh (or 123 lb/mmBtu of fuel input), assuming the following average factors: 7.8 lb/gal oil, 88% carbon by weight in oil, and 359 scf/lb-mole methane. All natural gas is assumed to be 100% methane. In 1993, 93% of PG&E fossil unit generation was fueled by natural gas and 7% with oil. (Source: PG&E Steam Generation)
[b] Based on an average heat rate of approximately 9,700 Btu/kWh.
[c] Based on fuel input.

Based on the Elfin simulations, the Kerman plant will displace approximately 4,700 tons of CO_2, 13 tons of NO_X, 3 tons of SO_2, 1 ton of particulates, and 0.5 ton of ROG over a 30-year operating life. Figure 11-3 presents the contribution of these emission reductions to the total environmental externality value of the Kerman plant. Reductions in CO_2 and NO_X account for over 95% of the total externality value.[7]

Pace University Alternative Analysis

Pace University has extensively examined environmental externalities for electricity production (Pace University 1991). The suggested Pace methodology is essentially the same as the recently adopted California methodology: The value of avoided residual air emissions is based on avoided damages to society. Externality value (or cost) is assigned on a dollars per pound (year 1991 dollars) of avoided emissions basis, as follows: \$2.03/lb for SO_2, \$0.82/lb for NO_X, \$1.19/lb for particulates, and \$0.0068/lb for CO_2.

7 The total externality value of the Kerman PV plant, based on the Elfin production simulations, is the same as that calculated using PG&E's regulatory power values discussed in the updated economics section, namely \$31/kW-yr (\$319/kW).

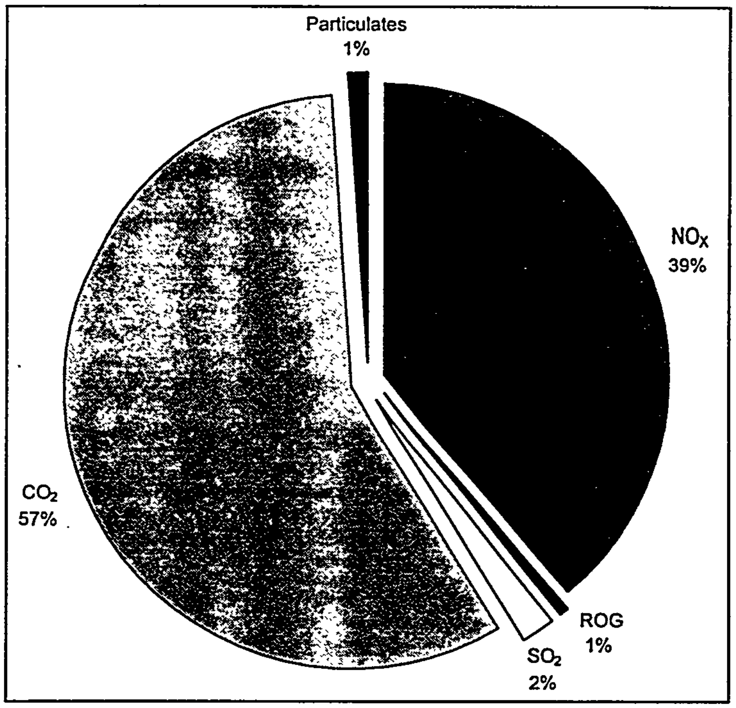

Figure 11-3. Externality value contribution by emission type (percent of $319/kW).

The Pace assumptions are applied to the Kerman test case by using the in/out Elfin production simulation results, which estimate the change in emissions caused by the Kerman PV plant. The change in emissions is multiplied by the Pace University externality assumptions, escalated at an annual rate of 3.5% and extended by 10 years for the 30-year study period. The cash flow stream is brought to the present, in year 1995 dollars, to yield a value of $12/kW-yr ($123/kW), or about $0.006/kWh (including 5.3% electrical loss savings).

These results are 60% less than the updated economics results, using the present California regulatory evaluation method. This is primarily because Pace's avoided emissions values for NO_X are about 75% lower. The value for avoided SO_2 emissions is about 2.5 times that of the San Joaquin Valley value, but since SO_2 emissions are small for PG&E's electric supply mix, this does not have a large impact on the Pace-derived total externality value of the Kerman PV plant.

Section 12

SUMMARY, CONCLUSIONS, AND FUTURE RESEARCH

This section provides a summary of the final project results and conclusions and offers suggestions for future research.

RESULTS SUMMARY

Kerman PV Plant Value

The Kerman Grid-Support Project confirms that a strategically sited PV plant can deliver non-traditional financial benefits to the utility. For Kerman, the resource's value *doubled* relative to a traditional central station resource planning perspective. This outcome challenges current resource planning methods to be expanded to adequately capture the impact of photovoltaics and other distributed generation resources.

Table 12-1 presents an overview of the traditional and non-traditional benefits and final results. The Kerman PV plant provides the PG&E system every benefit listed in the table. By locating generation near customer loads, the plant is able to deliver benefits spanning the distribution feeder, the substation, the high-voltage transmission system, and the generation fleet.

Figure 12-1 presents the final economic analysis results for the Kerman PV plant in two ways. The "nominal" value of the plant, at $295/kW-yr, represents the baseline evaluation. The "high" value of $425/kW-yr represents a sensitivity to the Nominal Case. The High Case is developed to make the results applicable to a constrained distribution area while accounting for long-term plant performance. The High Case considers three factors that are different from the Nominal Case:

1. The Kerman feeder is assumed to be an isolated radial line which eliminates load switching capability and maximizes the amount of time the PV plant can defer the substation transformer replacement (impacts substation value).

2. PG&E will need bulk system generation capacity sooner than forecasted in the Nominal Case (impacts capacity value).

3. Kerman PV plant production is increased by about 10% to 1,190 MWh/yr, reflecting expected plant performance over its 30-year life (impacts externalities, electrical losses, and energy values).

Table 12-1

Kerman PV Plant Benefits Evaluated and Final Results ($1995)

Non-Traditional Benefits	Benefit Definition & Economics Driver	Technical Results	Economic Results Nominal ($/kW-yr)	Economic Results High ($/kW-yr)
Externalities	*Fossil fuel emissions reduction.* Driver: Generation fleet fuel mix and externality valuation method.	Pollution is reduced by 155 tons of CO_2 and half a ton of NO_X each year.	30	35
Reliability	*Local reliability enhancement.* Driver: Postpone planned expenditures to improve reliability.	Voltage support is predictable and almost 3 V provided (on a 120-V base). Testing proves customer outage time can be reduced.	5	5
Loss Savings	*Real and reactive loss savings.* Driver: PV plant capacity factor and interconnection location.	Real energy losses reduced by 58,500 kWh/yr (or 5% of plant output). Reactive power losses reduced by 350 kVAR.	15	15
Feeder	*Feeder/conductor upgrade deferral.* Driver: Magnitude of planned upgrade expenditures and load growth rate	Feeder capacity increased by 320 kW on peak. (Economic value is zero because no upgrades are planned for the Kerman feeder.)	0	0
Substation	*Transformer replacement and load-tap-changer maintenance deferral.* Driver: Magnitude of planned upgrade expenditures and load growth rate.	Transformer cooled by more than 4°C and its capacity increased by 410 kW on peak day. Load-tap-changer maintenance interval extended by more than 10 years.	15	90
Transmission	*Transmission capacity deferral.* Driver: Marginal cost of transmission capacity.	Transmission system capacity increased by 450 kW on peak.	45	45
Minimum load	*Power plant dispatch savings.* Driver: Marginal cost of keeping peak load-following units on line.	Minimum load savings confirmed. PV plant delivers 90% PV capacity coincident with peak load-following unit dispatch.	30	30
Traditional Benefits	**Benefit Definition & Economic Driver**	**Technical Results**	**Nominal ($/kW-yr)**	**High ($/kW-yr)**
Capacity	*System reliability enhancement.* Driver: Utility need for capacity to improve system reliability.	Generation system capacity increased by 385 kW (ELCC about 77%.)	10	50
Energy	*Energy generation displacement.* Driver: Fuel price of avoided energy generation resource.	Plant achieved about 25% capacity factor, over 1,080 MWh/yr, highly correlated to PG&E loads.	145	155
Total Value			295	425

ELCC = Effective load-carrying capability

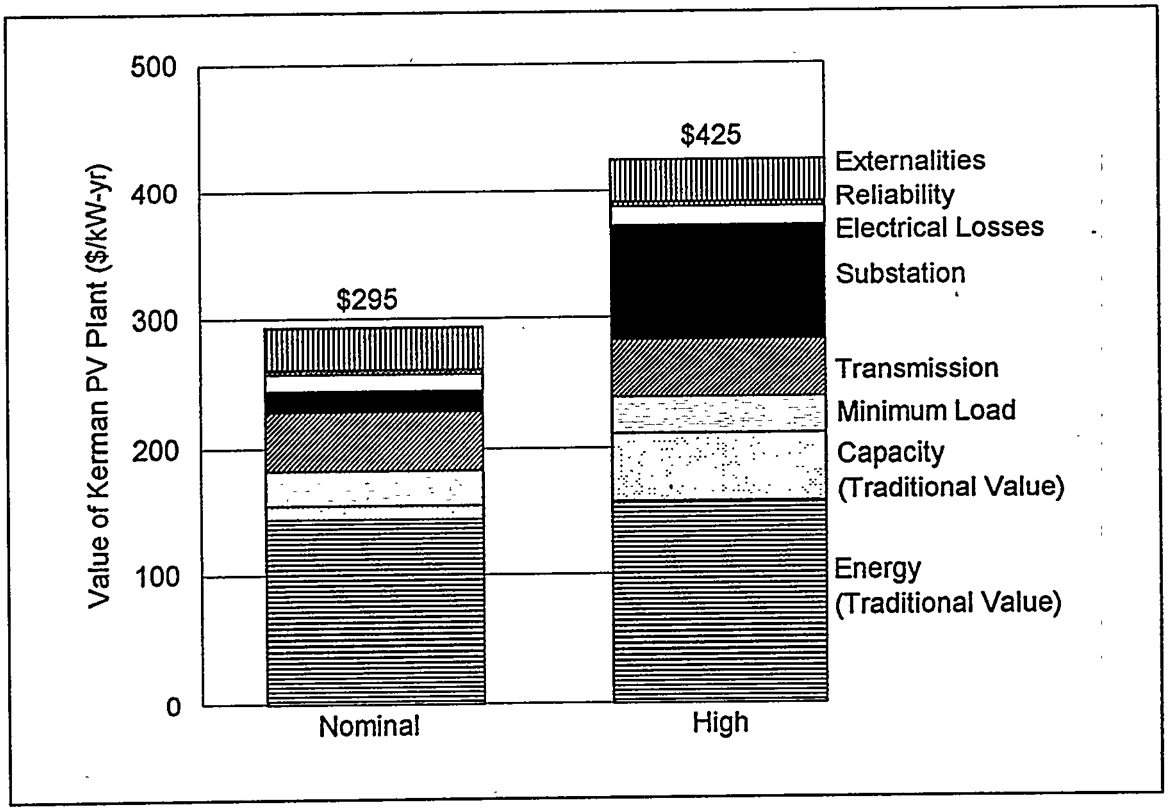

Figure 12-1. Value of the Kerman PV plant to PG&E ($1995).

> Regardless of which set of factors are considered, one predominant conclusion is clear: The value of the Kerman plant is *doubled* by capturing non-traditional benefits. That is, the distributed PV plant is worth twice what it would be if evaluated from a traditional central station resource perspective. The equivalent levelized value of the PV generation is 14 to 20¢/kWh as a distributed resource versus 7 to 10¢/kWh as a central station resource.

Allowable PV Price

The allowable or break-even PV system price can be calculated once the economic value of the plant is established. The allowable price is the PV system price required just to balance the value and cost of ownership, including cost of capital, O&M, taxes, insurance, and depreciation.

Figure 12-2 presents the allowable PV price as a function of plant value for two ownership scenarios: the investor-owned utility (IOU), represented by PG&E, and the independent power producer (IPP). The allowable PV price for the Kerman PV plant ranges between $2,700/kW and $3,800/kW for PG&E ownership, and from $3,400/kW to over $5,000/kW for IPP ownership. This is lower than PV system market prices, however, which are currently around $7,000/kW.

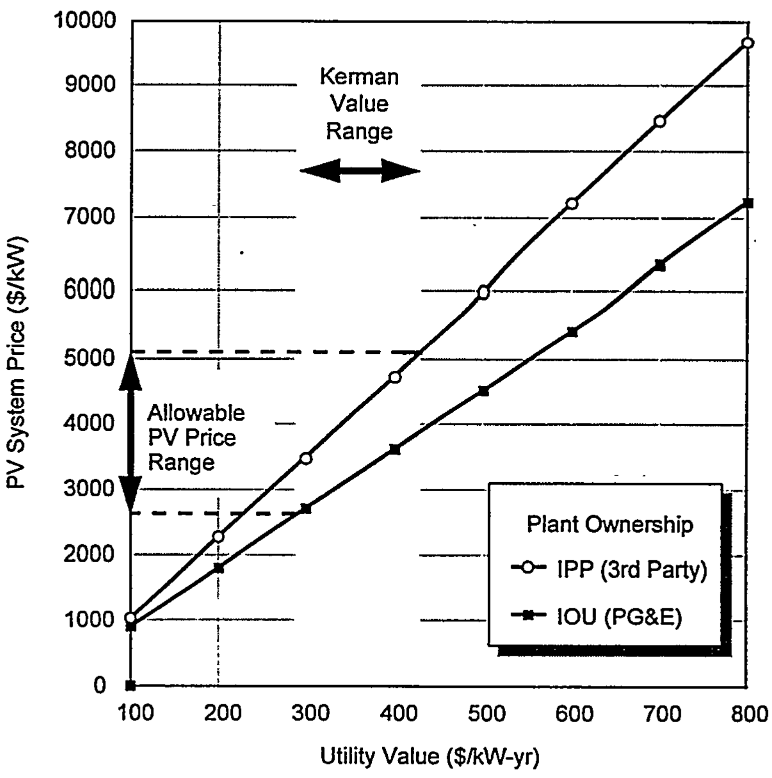

Chart concept by M. Lotker.

Figure 12-2. Allowable PV price depends on plant ownership. IPP break-even PV prices are based on a 20% return on equity and 10% return on debt, 10% cost of capital, 10% federal solar energy tax credit, 15-year loan life, 5-year double-declining balance depreciation and an annualized payment stream to the IPP equivalent to the sum of traditional and non-traditional utility PV grid-support benefits (pers. comm., M. Lotker, formerly of Siemens Solar Industries, 1994). Revenue and tax implications associated with insurance, O&M, G&A, property tax, and project income have also been considered.

The IPP scenario is considered to be as likely as utility ownership as a result of electric utility restructuring, which is encouraging competitive bidding of generation and open access to the transmission and, perhaps, the distribution system. A plausible scenario is that third-party IPPs, perhaps even unregulated subsidiaries of IOUs, will finance and construct distributed generation resources as this market develops.

IPPs presently have several unique advantages over IOUs to finance and build power plants, including access to tax credits, flexibility with debt-to-equity ratios and financing, and, in many cases, access to sources of lower-cost capital. Because of these advantages, the IPP can afford a plant that is more expensive, while maintaining profitability. Economic conditions under which IPPs operate suggest a 20 to 30% financial advantage. Electric cooperatives and municipal utilities enjoy similar ownership advantages and would, in general, have an economic PV cost line comparable to the IPP line in Figure 12-2. Economics for both IOUs and IPPs are changing, however, and the differential may decrease substantially in the future.

Table 12-2 presents the key economic results for the Kerman grid-support PV plant.

Table 12-2

Value and Allowable PV System Price ($1995)

	Value of Kerman Grid-Support PV System			**Allowable PV System Price** IOU	IPP
	$/kW-yr	**$/kW**	**¢/kWh**	**($/kW)**	**($/kW)**
Nominal Case	295	3,030	14	2,700	3,400
High Case	425	4,365	20	3,800	5,000

Comparison to 1992 Case Study

The 1992 Case Study was the logical starting point for our research since it comprehensively estimated the technical and economic value of the Kerman PV plant prior to construction. Figure 12-3 presents four sets of economic results for comparison purposes. The 1992 Case Study bar is the projected value of grid-support PV at Kerman from that study. (Qualifying facility [QF] savings identified in the 1992 Case Study have been excluded from the analysis because they represent transfer payments and the treatment of QF contracts in future resource planning is highly uncertain.) The technical validation bar is an intermediate calculation to facilitate a direct comparison between the estimated preplant construction

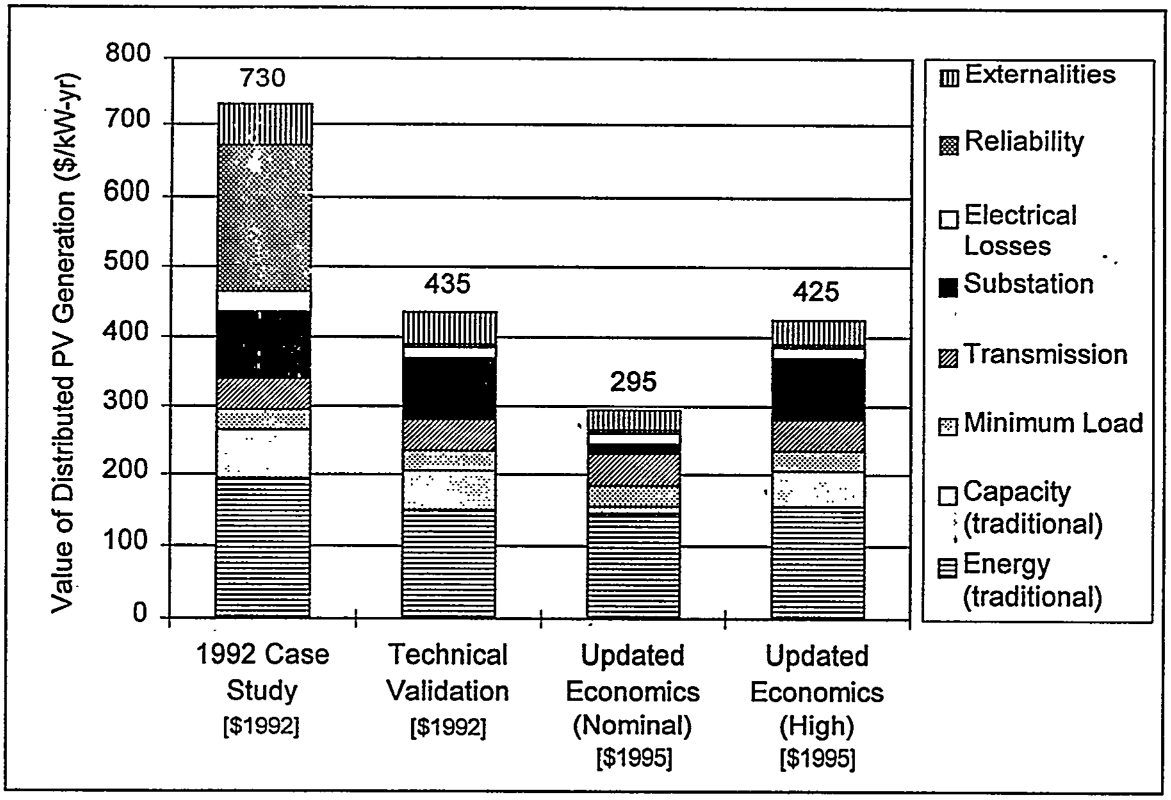

Figure 12-3. Case Study and updated results of the value of the Kerman PV plant.

value and the actual postplant construction value. The technical validation is based on measured plant and utility system data and updated evaluation methods, but maintains the 1992 Case Study economic and load growth assumptions to allow a direct comparison with the 1992 Case Study results. The two updated economics bars are based on the same information used in the technical validation, but include the most recent economic and load growth information from PG&E and California regulators. Table 12-3 presents the results for each component in levelized and present value formats.

Table 12-3

1992 Case Study and Updated Results

Benefits	1992 Case Study Estimates		Technical Validation		Updated Economics Nominal		Updated Economics High	
	$/kW-yr	$/kW	$/kW-yr	$/kW	$/kW-yr	$/kW	$/kW-yr	$/kW
Non-Traditional								
Externalities	60	520	45	390	30	310	35	360
Reliability	205	1,780	5	45	5	50	5	50
Electrical Losses	30	260	15	130	15	155	15	155
Feeder[a]	0	0	0	0	0	0	0	0
Substation	95	825	90	780	15	155	90	925
Transmission	45	390	45	390	45	460	45	460
Minimum Load	30	260	30	260	30	310	30	310
Traditional								
Capacity	70	610	55	480	10	100	50	515
Energy	195	1,695	150	1,305	145	1,490	155	1,590
Total Value	**730**	**6,340**	**435**	**3,780**	**295**	**3,030**	**425**	**4,365**

Note: Net present values are in $/kW. 1992 Case Study and technical validation values are in $1992. Updated economics values are in $1995. All results rounded to the nearest $5.

[a] The economic value is zero because there are no upgrades planned for the Kerman feeder.

The postplant construction results indicate that the value of grid-support PV at Kerman is significantly less than that projected in the 1992 Case Study. Nevertheless, most of the 1992 Case Study evaluation methods were fundamentally sound and broke new ground by developing a framework to evaluate non-traditional benefits. The reduction in value is primarily due to the fact that the 1992 Case Study:

- Assumed that the Kerman feeder is an isolated radial line and that no load could be transferred from it to relieve overloading. Actually, the Kerman feeder is not an isolated radial line, but rather is part of an interconnected distribution planning area that facilitates load transfers to nearby adjacent feeders and substation transformers. Load transfers are commonly used to avoid transformer upgrades. The planning area has a load growth rate of about 1.5 MW/yr, which significantly shortens the substation transformer upgrade deferral from that estimated in the 1992 Case Study.

- Calculated local reliability value using a value of service approach. Although customer VOS estimates may be used to compare and justify reliability enhancement projects, they do not represent actual capital costs required to solve reliability problems. The updated local reliability enhancement value is based on the avoided installation of a capacitor bank on the Kerman circuit to provide the same operational benefits as the PV plant.

- Overestimated plant performance by using weather data from an area with a better solar resource and a more moderate ambient temperature regime relative to the Kerman area. This proportionately inflated all of the value components in the 1992 Case Study.

- Performed the analysis in an economic environment of higher prices and costs. The updated traditional energy and capacity values are lower because of low natural gas prices and a regulatory assumption that PG&E does not need capacity for the foreseeable future, respectively. The updated externality value is lower because of a recent regulatory change in valuing avoided fossil power plant emissions.

The Kerman site was ideal from the perspective of validating the technical benefits of distributed PV grid-support. The site was not ideal, however, from an economic benefits perspective. Although the final values for particular benefits were lower than anticipated, this does not imply that other sites may not be of higher value. Because non-traditional benefits are derived from diverse characteristics of the electric system, they will vary widely with respect to each other, depending on local system conditions. A location where large expenditures are about to be incurred, and that has low spare capacity, slow load growth, and is poorly interconnected (e.g., an isolated radial line) would likely have been of higher value than Kerman.

CONCLUSIONS

The following major conclusions are drawn from the Kerman Grid-Support Project:

- Data analysis and testing provide concrete evidence that both traditional and non-traditional benefits are measurable and significant for grid-support PV applications. The Kerman PV plant provides benefits that span the entire utility network, including the distribution feeder and substation, transmission system, and generation fleet.

- Non-traditional benefits double the overall value of the Kerman plant relative to a traditional central station resource planning perspective. The levelized value of the PV plant is about 300 to 430 \$/kW-yr (14 to 20¢/kWh equivalent) as a distributed resource versus 150 to 215 \$/kW-yr (7 to 10¢/kWh equivalent) evaluated as a central station resource.

- The allowable PV system price for the Kerman location is between $2,700/kW and $5,000/kW, depending on plant ownership and value scenarios. If evaluated as a traditional central station resource, the allowable PV system price range would be halved.

- The economic value of grid-support photovoltaics is driven by three factors: local system characteristics, solar resource and plant performance, and "global economics," including fuel cost projections, cost of capital, and marginal energy and capacity value. One third of the difference between the 1992 Case Study and the results of this research is attributable to the change in global economics, which is independent of the evaluation approach. This highlights the importance of global economic assumptions and their impact on resource cost-effectiveness.

- Methods developed to evaluate the Kerman grid-support PV plant are generally applicable to other forms of distributed resources and applications.

The Kerman Grid-Support Project results are promising from a renewable and distributed resource perspective. The research broadens the understanding of value from strategically sited resources and provides methods for non-traditional benefit evaluation for resource planning and regulatory oversight.

FUTURE WORK

A set of improved evaluation methods was developed as a part of this research effort. The improvements focus on evaluating the technical interaction between distributed generation and the utility system. Although the research was performed specifically to apply to grid-support PV, results are generally valid for all distributed technologies.

Distributed generation is of value because it either satisfies capacity requirements or reduces variable costs. While there may be ten or more specific value components, only two basic evaluation methods are required to determine the value of distributed generation. One method determines the capacity value of distributed generation, and another determines the reduction in variable cost. The initial development of a method to calculate capacity value is described in Appendix F; the method to calculate the reduction in variable costs remains to be developed.

Although initial research warrants thorough evaluation, in practice, methods must be made straightforward and easy to use, while retaining accuracy. Only then will such methods be adopted and widely used. Future work to formulate analytic foundations for quantifying distributed resource value should focus on development and application of a simplified distributed generation evaluation method.

Test Accuracy of Simplified Evaluation Method

The effect of assumptions, and thus the accuracy of the simplified method, should be determined. This could be accomplished by calculating the value of distributed generation using data from existing case studies with the simple method and comparing these results to the Case Study results. The case studies could include the EPRI/PG&E Delta District study of targeting demand-side management for T&D benefits (Orans et al. 1991) as well as the four distributed PV generation case studies sponsored by Sandia National Laboratories (Lambeth 1992, Austin Electric 1994, El-Gassier et al. 1994, Plains and NEOS 1994). It could also be tested for other forms of distributed generation as part of the DOE Distributed Utility Valuation Project.

Develop Software

The validated method should be encoded into a software package. Greater usage will be obtained if the model is be developed to facilitate comparisons between other distributed generation technologies as well as demand-side management alternatives.

The completed software would be useful to a variety of parties. Utility distribution planners could use it to perform an initial evaluation of the economic feasibility of specific distributed generation projects. Utility system planners could use the software to assess the market for distributed generation in their service territory, thus helping to set priorities about the level of effort that should be invested in distributed generation. Regulatory agencies could use it for resource planning and utility investment decision analysis. Government agencies and analysts could use the software to assess the national potential for distributed generation and to prioritize research and incentive budgets. Finally, manufacturers and system suppliers could use it to optimize system design and understand target markets.

Section 13

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Appendix A

THE VALUE OF GRID-SUPPORT PHOTOVOLTAICS TO SUBSTATION TRANSFORMERS

THE VALUE OF GRID-SUPPORT PHOTOVOLTAICS TO SUBSTATION TRANSFORMERS

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Abstract — **Strategically sited grid-support photovoltaic (PV) applications have been proposed to provide value (cost savings) to electric utilities experiencing transmission and distribution (T&D) system overloads. These applications can potentially defer transformer and transmission line upgrades, extend equipment maintenance intervals, reduce electrical line losses, and improve distribution system reliability. This paper calculates the economic value of strategically placed grid-support PV to a substation transformer. Results at Pacific Gas and Electric Company indicate that the 0.50 MW PV plant in Kerman, California can defer a transformer upgrade for 4.6 years for a value of $398,000. These results are site specific.**

I. INTRODUCTION

The standard practice of electric utilities experiencing transmission and distribution (T&D) system overloads is to upgrade equipment. In 1988, it was hypothesized that strategically sited photovoltaics (PV) could benefit overloaded parts of the T&D system [1]. An evaluation methodology was developed and applied to a test case (Kerman Substation near Fresno, California). Simulated data suggested that value of PV to the T&D system could exceed its value to the bulk generation system [1].

The importance of this finding indicated the need for empirical validation. This led to a 0.50 MW PV demonstration project at Kerman, California as part of project PVUSA (PV for Utility Scale Applications). PVUSA is a national cooperative research and development effort under the auspices of the United States Department of Energy.

PVUSA developed plant specifications [2] and designed a research test plan [3] to determine the value of PV to the T&D and bulk generation systems. The Kerman PV plant, completed in June, 1993, is reported to be the first grid-support PV demonstration in the world.

Grid-support PV can provide many values to T&D systems. It can defer transformer and transmission line upgrades, extend equipment maintenance intervals, reduce electrical line losses, and improve distribution system reliability, all with cost savings to utilities.

This paper focuses on the economic value of strategically placed grid-support PV to substation transformers. It calculates the transformer upgrade deferral value for the Kerman Substation using the following approach. Reduction in the transformer's hottest-spot temperature is determined using an IEEE transformer temperature model and measured transformer and PV plant data on the 1993 peak load day. The temperature reduction is converted to allowable load increase and then to years of deferral using annual load growth estimates. Value is a function of years of deferral and other economic parameters.

II. APPROACH

Grid-support PV defers a substation transformer upgrade by supplying power on the low voltage side of a transformer during peak usage. The reduced transformer load results in decreased transformer temperatures and longer life. A cooler transformer can accommodate additional load growth and enable the utility to defer purchase of a new transformer until fully needed.

The number of years of deferral can be calculated by determining the PV plant's reduction in peak load and dividing by projected annual load growth. This approach, however, fails to account for the fact that peak load is not the only factor affecting transformer temperature.

Fortunately, much is known about transformer performance [4, 5]. The IEEE has even developed a detailed model (called the IEEE model in this paper) for loading power transformers [6]. The guide to the model bases its transformer loading recommendations on the degradation effects of temperature and time on winding

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insulation deterioration. It assumes an exponential relationship between transformer life and the transformer's highest, or hottest-spot, temperature.

The guide acknowledges that it is very difficult to accurately predict the cumulative effects of temperature and time on winding insulation deterioration [6]. This makes it problematic to convert hottest-spot temperature reduction provided by a PV plant to transformer life extension.

Some utilities (such as Pacific Gas and Electric Company) use the IEEE model as a decision tool to determine when a transformer upgrade is needed based on a transformer's hottest-spot temperature rather than transformer loss of life. This paper extends that practice to calculate allowable load increase. It uses the IEEE model to compute transformer hottest-spot temperature for transformer load with no PV. This calculation is repeated for transformer load increased by some percentage minus PV plant output. Allowable load increase is the percentage increase in load that results in the two scenarios having the same maximum hottest-spot temperature.

Allowable load increase is converted to years of deferral using annual load growth estimates. Upgrade deferral value is a function of years of deferral and other economic parameters.

III. BACKGROUND

The approach described in the previous section requires transformer hottest-spot temperature estimates. Fortunately, much work has been invested in developing a model to estimate hottest-spot temperature [6]. Some have used the IEEE model to evaluate hottest-spot temperature reduction provided by PV [1, 2, 7]. Slight changes need to be made in the model, however, since it was intended to use average ambient temperature under peak load conditions while this research uses measured ambient temperature under a range of conditions. This section describes the model and inaccuracies that might occur when using the model in such a manner.

The IEEE model suggests that hottest-spot winding temperature (θ_{hs}) is the summation of ambient temperature (θ_a), top-oil temperature rise over ambient temperature (θ_o), and hottest-spot conductor temperature rise over top-oil temperature (θ_g):

$$\theta_{hs} = \theta_a + \theta_o + \theta_g . \tag{1}$$

Top-oil temperature rise (θ_o) is a function of ultimate top-oil temperature rise over ambient temperature (θ_u), initial top-oil temperature rise over ambient temperature (θ_i), elapsed time (t), and the thermal time constant (τ_0). Hottest-spot conductor temperature rise (θ_g) is a function of the ratio of load to rated load (K), hottest-spot conductor temperature rise over top-oil temperature at rated load [$\theta_g(fl)$], and a term m, which accounts for the effect of variations in the hot spot gradient due to changes in loading.

$$\theta_o = \left(\theta_u - \theta_i\right)\left(1 - e^{\left(-t / \tau_0\right)}\right) + \theta_i \tag{2}$$

$$\theta_g = \theta_g(fl) K^{2m} \tag{3}$$

The ultimate top-oil temperature rise over ambient temperature and thermal time constant in (2) are:

$$\theta_u = \theta_{fl}\left(\frac{K^2 R + 1}{R + 1}\right)^n \tag{4}$$

$$\tau_0 = \tau_r \frac{\left(\dfrac{\theta_u}{\theta_{fl}}\right) - \left(\dfrac{\theta_i}{\theta_{fl}}\right)}{\left(\dfrac{\theta_u}{\theta_{fl}}\right)^{1/n} - \left(\dfrac{\theta_i}{\theta_{fl}}\right)^{1/n}} \tag{5}$$

$$\tau_r = \left(C \theta_{fl} / P_{fl}\right) \tag{6}$$

where θ_{fl} is the top-oil temperature rise over ambient temperature at rated load, R is the ratio of load loss at rated load to no load loss, τ_r is the thermal time constant at rated load, C is the transformer's thermal capacity, P_{fl} is the total power loss, and n is the exponential power of total loss versus top-oil temperature rise. n affects the magnitude of the ultimate top-oil temperature rise and C affects the rate of top-oil temperature change.

Research performed for this paper suggests that caution is needed when using measured ambient temperature in the IEEE model. As shown in (1), ambient temperature directly affects hottest-spot temperature. Unlike top-oil temperature rise, no time lag is associated with a change in ambient temperature. This is not a problem when using average ambient temperature but may result in errors if ambient temperature varies. Ambient temperature varies daily by more than 25 °C in the field.

IV. RESULTS AND DISCUSSION

A. Modification of IEEE Model

Transformer top-oil temperature has been continuously monitored at the Kerman Substation since 1991 using temperature probes. These probes have an absolute accuracy of +/- 1.5 °C at 100 °C. The thirty-year old transformer at the Kerman Substation is an OA/FA (65/65 °C) 8400/10500

KVA transformer. No load losses are 14.421 kW and total losses at the OA rating are 61.965 kW. This translates to total losses at the FA rating of 74.287 kW. The average winding rise over top-oil temperature and top-oil rise over ambient temperature are 60.7 °C and 49.2 °C at the OA rating and 60.6 °C and 43.0 °C at the FA rating. The core and coils weigh 24,800 lbs, the tank weighs 17,965 lbs, and there are 3,177 gallons of oil in the tank.

As described in the previous section, hottest-spot temperature is needed for the analysis. The measurements at the Kerman Substation, however, include only top-oil temperature. Thus, evaluation of the IEEE model is based on the comparison of measured and simulated top-oil temperatures. The IEEE model's calculation of hottest-spot temperature rise over top-oil temperature is assumed to be correct because there was no way to verify it.

Fig. 1 presents simulated top-oil temperature using the IEEE model (light dashed line) as presented in [6] and measured transformer temperature (dark solid line) for the Kerman Substation on the 1993 peak day. Simulated top-oil temperature is the sum of ambient temperature plus top-oil temperature rise over ambient temperature.

Data (presented in Table 1) were collected as follows. Load, top-oil temperature, and fan status were monitored at the substation transformer every 5 seconds and half-hour averages stored for analysis. The fan started at 12:23 and stopped at 23:43. Ambient temperature was measured 8 miles away from the transformer at the PV plant every 5 seconds and half-hour averages stored for analysis.

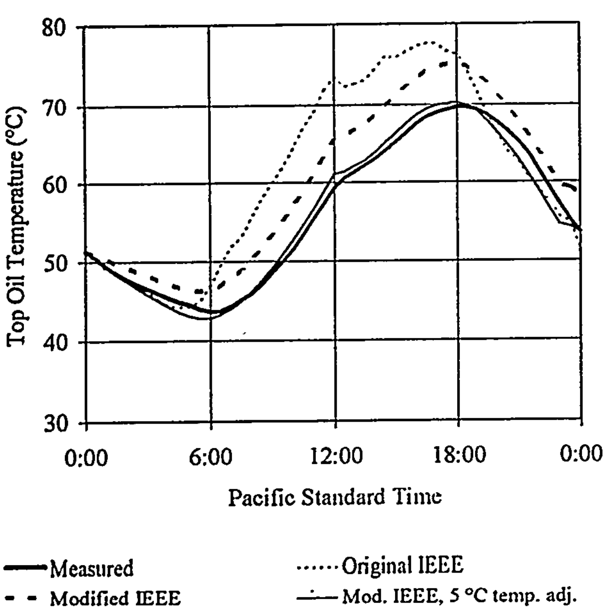

Fig. 1. Accuracy of top-oil temperature simulations (June 25, 1993).

Fig. 1 shows that the Original IEEE curve is shifted several hours earlier than the measured curve. As shown by the Modified IEEE curve (dark dashed line) the IEEE model's accuracy is improved by including a time lag in the effect of ambient temperature on top-oil temperature. This is accomplished by moving ambient temperature from the hottest-spot equation (1) to the ultimate top-oil temperature equation (4). Modified equations are:

$$\theta_{hs} = \theta_o' + \theta_g \tag{1a}$$

$$\theta_u' = \theta_{fl}\left(\frac{K^2R+1}{R+1}\right)^n + \theta_a . \tag{4a}$$

All top-oil temperatures (θ_o', θ_i', and θ_u') are now in units of *absolute* top-oil temperature rather than top-oil temperature *rise* over ambient temperature. The time constant, τ_0, however, is still based on θ_u and θ_i rather than θ_u' and θ_i'.

As seen in Fig. 1, although the shape of the modified IEEE and measured temperature curves are the same, there is still a magnitude error. One possible way to explain this error is that the ambient temperature measured at the PV plant, which is 8 miles away, is different than that seen by the substation transformer. There is a much better match to the data if it is assumed that the ambient temperature at the substation is 5 °C lower than the ambient temperature at the PV plant (light solid line).

Table 1. Load, ambient temperature, measured top-oil temperature, and cooling fan status (June 25, 1993).

Time	Load (MVA)	Ambient (°C)	Top-oil (°C)	Fan Status	Time	Load (MVA)	Ambient (°C)	Top-oil (°C)	Fan Status
0:00	4.09	23.9	51.3	Off	12:00	7.93	38.5	59.3	Off
0:30	3.81	23.2	50.4	Off	12:30	8.24	38.1	60.6	On
1:00	3.71	22.5	49.4	Off	13:00	8.57	38.8	61.4	On
1:30	3.64	22.3	48.5	Off	13:30	8.59	39.5	62.2	On
2:00	3.59	22.1	47.8	Off	14:00	8.83	41.0	63.0	On
2:30	3.62	21.8	47.1	Off	14:30	9.09	42.3	64.0	On
3:00	3.62	21.0	46.6	Off	15:00	9.28	41.8	65.2	On
3:30	3.69	20.3	46.0	Off	15:30	9.47	42.1	66.4	On
4:00	3.74	19.7	45.4	Off	16:00	9.53	42.3	67.5	On
4:30	3.79	19.7	44.9	Off	16:30	9.31	42.5	68.5	On
5:00	3.92	19.8	44.6	Off	17:00	9.12	42.5	69.0	On
5:30	4.13	20.5	44.1	Off	17:30	9.17	41.6	69.4	On
6:00	4.38	22.4	43.7	Off	18:00	9.03	41.3	69.7	On
6:30	4.84	24.6	43.8	Off	18:30	8.84	39.6	69.7	On
7:00	5.14	26.5	44.4	Off	19:00	8.65	37.3	69.4	On
7:30	5.58	27.1	45.1	Off	19:30	8.46	34.7	68.7	On
8:00	5.93	28.9	46.0	Off	20:00	8.31	32.6	67.7	On
8:30	6.15	30.6	47.2	Off	20:30	8.21	30.9	66.6	On
9:00	6.44	31.6	48.6	Off	21:00	7.85	30.4	65.3	On
9:30	6.70	32.7	50.0	Off	21:30	7.35	29.3	63.6	On
10:00	6.87	34.1	51.6	Off	22:00	6.81	29.1	61.5	On
10:30	7.19	35.8	53.4	Off	22:30	6.32	28.7	59.4	On
11:00	7.41	36.5	55.4	Off	23:00	5.89	28.2	57.3	On
11:30	7.71	38.2	57.4	Off	23:30	5.09	27.5	55.3	Off

B. Modified Model Accuracy

Table 2 compares the accuracy of the original and modified IEEE models using ten peak days in 1992 and five peak days in 1993. Results indicate that the modified IEEE model more accurately predicts top-oil temperatures for the Kerman Substation transformer and suggest more accuracy for transformers under field conditions in general. In addition, a 5 °C ambient temperature adjustment (this adjustment is not recommended in general) improves model accuracy. Note that results in the following section are essentially unaffected by the 5 °C adjustment since the analysis is based on relative temperature comparisons and the adjustment addresses a scaling problem. Failing to use the modified model, however, can result in substantial error.

Table 2. Root mean square error analysis on 15 peak days.

	Original IEEE	Modified IEEE
No ambient temp. adjustment	8.2 °C	5.1 °C
5 °C ambient temp. adjustment	6.1 °C	1.9 °C

C. Allowable Load Increase Provided by PV

The modified model can be used to evaluate the allowable load increase provided by the PV. The following four figures present two allowable load increase analyses using the 1993 peak day (June 25, 1993). In all figures, transformer load without PV is the dark solid line, transformer load with load increase is the light dashed line, and transformer load with load increase minus PV plant output is the light solid line. Figs. 2 and 3 use measured PV output data from the 0.5 MW PV plant while Figs. 4 and 5 scale measured output by a factor of 10 to a plant size of 5.0 MW. Transformer and feeder losses are taken into account in the analysis.

The analysis is performed as follows. The initial transformer load in Fig. 2 (dark solid line) is increased by some percentage throughout the day (light dashed line) and then decreased by PV plant output (light solid line). The allowable load increase percentage is selected such that the maximum hottest-spot temperature in Fig. 3 is the same without PV (dark solid line) as with increase and PV (light solid line). The figures suggest that the PV plant reduced the maximum hottest-spot temperature by 4 °C, half of which came from a lower top-oil temperature due to a decrease in load throughout the day. The allowable load increase is 4.6 percent or 0.46 MW at the peak.

Figs. 4 and 5 repeat the analysis for a 5.0 MW PV plant. The allowable load increase is 22.9 percent or 2.29 MW at the peak. Notice that in this case, the new peak load occurs later in the day and is larger than the original peak load.

Fig. 6 presents the allowable load increase as a function of PV plant size. For comparison purposes, results using the original IEEE model and a load reduction approach are included. The figure indicates that all results are similar at small PV plant sizes. At larger sizes, however, the original IEEE model overestimates and the load reduction method underestimates the allowable load increase. The original IEEE model overestimates because it models the transformer

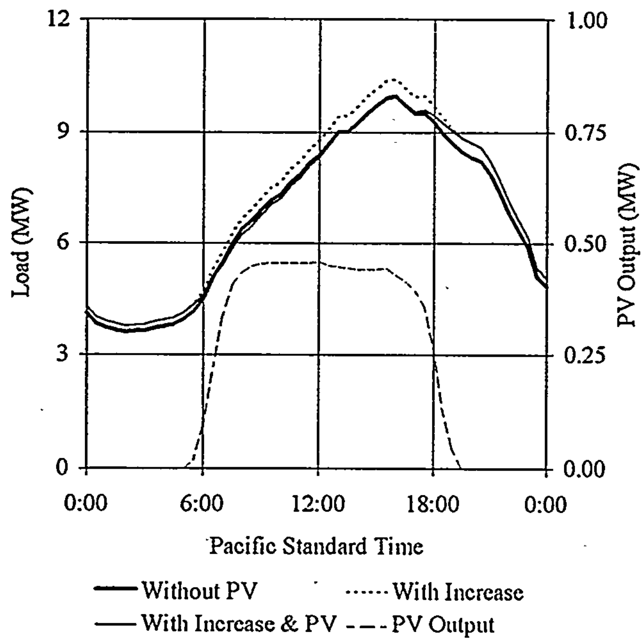

Fig. 2. Transformer load without PV, with 4.6% load increase, and with 4.6% load increase and 0.5 MW PV on peak day (June 25, 1993).

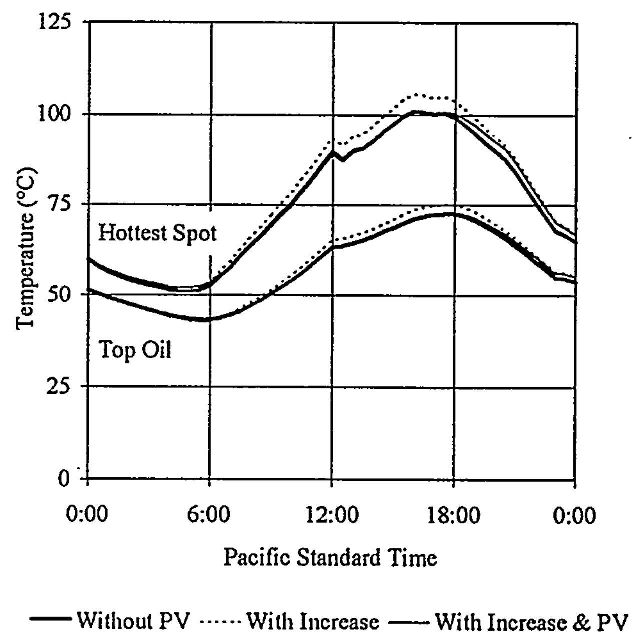

Fig. 3. Transformer temperatures without PV, with 4.6% load increase, and with 4.6% load increase and 0.5 MW PV on peak day (June 25, 1993).

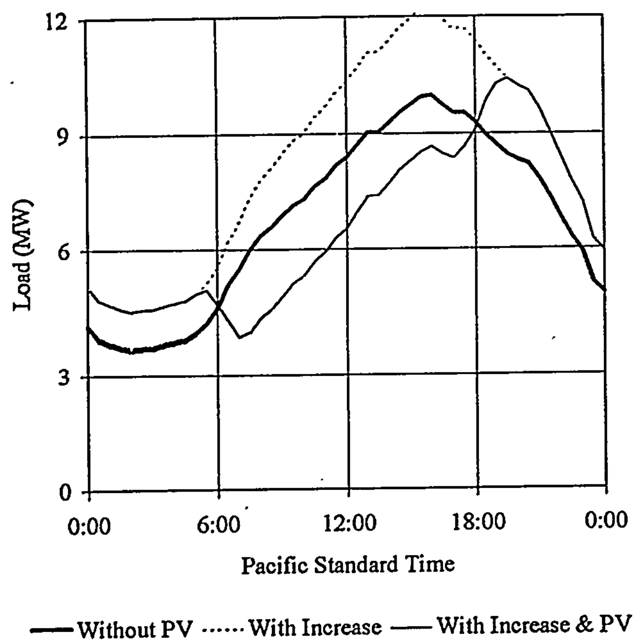

Fig. 4. Transformer load without PV, with 22.9% load increase, and with 22.9% load increase and 5.0 MW PV on peak day (June 25, 1993).

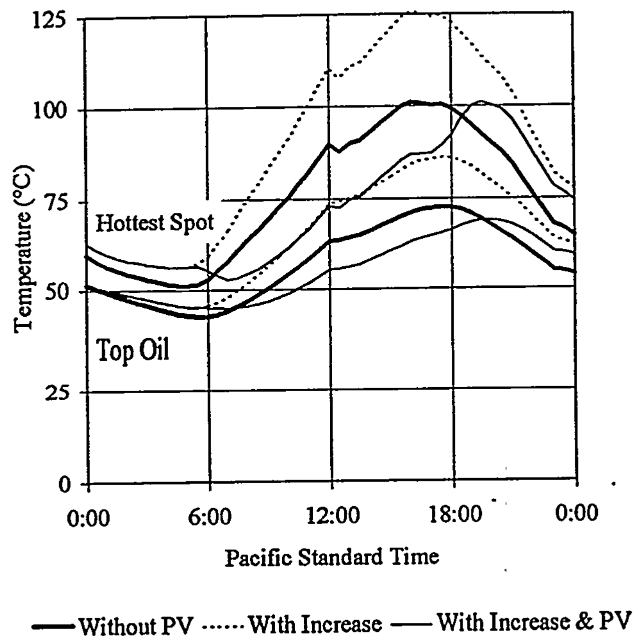

Fig. 5. Transformer temperatures without PV, with 22.9% load increase, and with 22.9% load increase and 5.0 MW PV on peak day (June 25, 1993).

peak temperature as occurring earlier in the day than it actually does. The load reduction method underestimates because, as Figs. 4 and 5 show, even as the peak shifts to times when the PV is not operating, PV output earlier in the day cools the transformer's oil. Errors on the order of 30 percent are seen in Fig. 6.

V. ESTIMATED TRANSFORMER DEFERRAL VALUE

This section converts the allowable load increase from the previous section into the value of grid-support PV to the substation transformer in two steps. First, the allowable load increase is translated to number of years of deferral. Second, years of deferral is combined with economic parameters to calculate value.

The number of years of deferral (n_d) equals the allowable load increase divided by the annual load growth:

$$n_d = \frac{allowable\ load\ increase}{annual\ load\ growth}. \tag{7}$$

Value of grid-support PV to the substation transformer, in net present value (NPV) terms, equals:

$$Value = C(1+CSC)\left\{\left[1-\left(\frac{1+r}{1+c}\right)^{n_d}\right]+S\left[\frac{n_d}{life}\left(\frac{1+r}{1+c}\right)^{life}\right]\right\} \tag{8}$$

The terms outside the curly brackets equal the upgrade cost adjusted for capital specific costs such as taxes, insurance and other costs. Deferral value equals the first term in the curly brackets times this value; salvage value of the new transformer at the end of the study period equals the second term in the curly brackets times this value. It is estimated that upgrade cost (C) is $1,050,000, capital specific costs (CSC) are 33 percent, inflation (r) is 2.5 percent, cost of capital (c) is 10 percent, percent of investment that can be salvaged (S) is 50 percent, and transformer life ($life$) is 30 years.

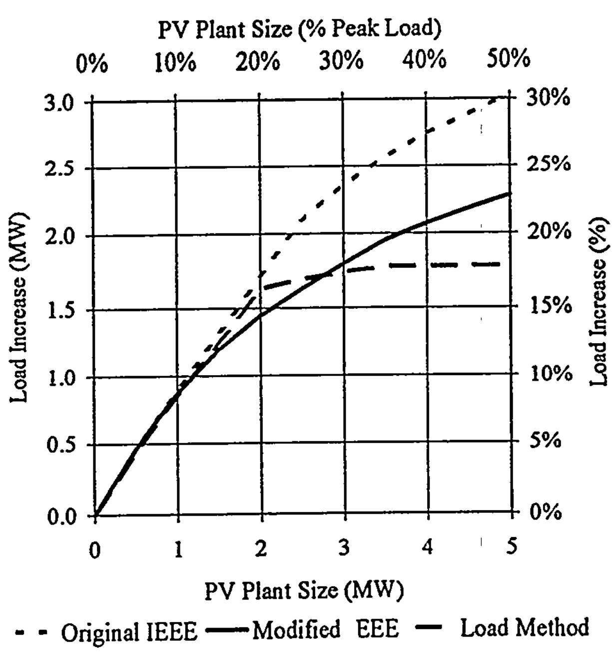

Fig. 6. Allowable load increase versus PV plant size.

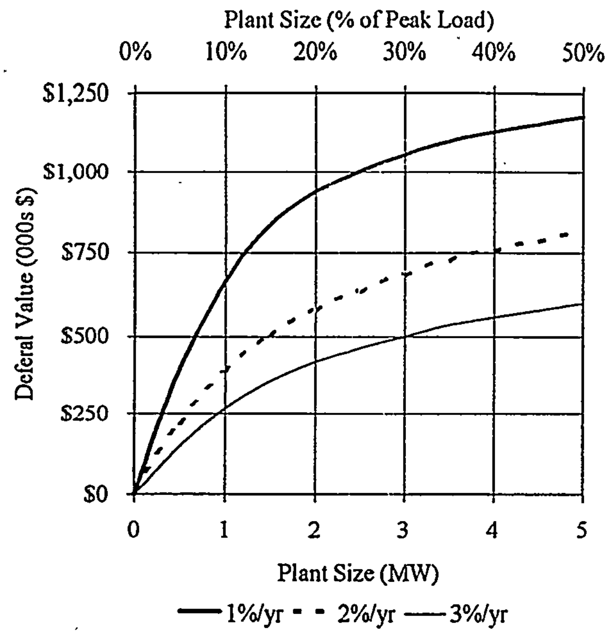

Fig. 7. Total deferral value (NPV) for three load growth scenarios.

Fig. 7 describes the transformer upgrade deferral value for three different rates of load growth. The figure suggests that the value of the 0.50 MW Kerman PV plant is estimated to be $398,000. This assumes that all available load transfers have been made, the transformer would have been replaced immediately if the PV had not been added, and that annual load growth was 1 percent.

VI. CONCLUSIONS AND FUTURE RESEARCH

This paper has attempted to identify and delineate one of the several cost-saving components of grid-support PV. It has demonstrated that strategically sited grid-support PV provides value to substation transformers. It showed that a 0.50 MW PV plant reduced the Kerman Substation transformer's hottest-spot temperature by 4 °C on a peak day in 1993. This converted to an allowable load increase of 4.6 percent or 0.46 MW on peak and a transformer upgrade deferral value of $398,000, assuming that the transformer needed upgrading and there was an annual load growth of 1 percent. It should be noted that the correlation between value and PV plant size is non-linear: for example, tripling plant size only doubles the value. Future work is needed to replicate model runs with a seasonal perspective and a multiple year data set. In addition, work is needed to deal with uncertainties in load growth, escalation rate, and cost of capital from an economic perspective.

VII. BIOGRAPHIES

Tom Hoff has a BS from California Lutheran College, Thousand Oaks, California, an MS from Washington University, St. Louis, Missouri, an MDiv from Trinity Evangelical Divinity School, and is pursuing a Ph.D. at Stanford University, Stanford, California. Mr. Hoff has equipped utilities with tools to value PV and other renewable technologies. His research includes developing methods to calculate the energy and generation capacity value of non-dispatchable resources, investigating PV as a demand side management option, and analyzing distributed generation and storage technologies.

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VIII. ACKNOWLEDGMENTS

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Appendix B

CONDUCTOR CAPACITY

CONDUCTOR CAPACITY

A PV plant that reduces a conductor's temperature may increase its available capacity. This appendix simplifies an existing IEEE model to an equation that can be used to calculate conductor capacity. Examples are then presented that use the model to estimate model parameters, calculate conductor time constants, and evaluate the effect of weather conditions on conductor capacity.

IEEE MODEL SIMPLIFICATION

Conductor temperature is affected by several factors, including current, wind speed (and direction), ambient temperature, and insolation. IEEE has developed a model to determine conductor temperature of bare overhead conductors that accounts for all of these factors [B-1]. The model uses a heat balance approach: there is heat gain from the sun and conductor current and heat loss from convection and radiation. The model is described in detail in [B-1].

Steady-state conductor temperature is determined by performing several iterations due to non-linearities in the model. That is, conductor temperature cannot be solved for directly. Likewise, conductor current cannot be solved for directly either. This makes it desirable to simplify the IEEE model.

The IEEE model is simplified as follows. First, as has been done by Black and Rehberg [B-2], the radiated heat loss is estimated to be a linear function of conductor temperature rise over ambient temperature.[1] Second, only the convective cooling calculation that is valid at low wind speeds is considered.[2] Third, wind direction is accounted for by a simpler term.[3] Fourth, material properties assume a 75°C conductor temperature so that resistance is linearly related to conductor diameter squared for a given conductor type.

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[1] Specifically, it is a linear function of conductor temperature rise over ambient temperature. $\left(\frac{T_c + 273}{100}\right)^4 - \left(\frac{T_a + 273}{100}\right)^4 \approx (0.012T_a + .89)(T_c - T_a)$.

This approximation is within ±2% for conductor temperature rise over ambient temperature of less than 30°C at an ambient temperature between 25° and 45°C.

[2] This calculation will exceed the natural convection heat loss for wind speeds greater than 0.5 ft/sec wind for conductors up to 1.5 inches in diameter.

[3] The wind direction factor is estimated to be $(\theta / 90)^{0.31}$. This approximation is within ±5% for wind directions between 15° and 90° (perpendicular to conductor).

These assumptions results in a conductor temperature of

$$T_c = T_a + \frac{\alpha DH + b(I / D)^2}{1560(D\rho V / \mu)^{0.52} \kappa \theta^{0.31} + \varepsilon D(0.21T_a + 15.9)} \tag{B-1}$$

where T_a is ambient temperature (°C), D is conductor diameter (inches), H is global horizontal insolation (W/m^2), I is conductor current (amps), V is wind speed (meters/second), θ is wind direction in degrees relative to conductor, α is solar absorptivity, ε is emissivity, μ is air viscosity, κ is thermal conductivity of air, ρ is air density, and b is an empirically derived parameter based on conductor type and material. At a 75°C conductor temperature, b, which is empirically determined, equals 0.00166 for numbers 4, 6, and 8 copper conductors, 0.00220 for larger copper conductors, and 0.00353 for aluminum conductors.

It is further assumed that μ, κ, and ρ are based on a film temperature of 70°C so that conductor temperature equals

$$T_c = T_a + \frac{\alpha DH + b(I / D)^2}{16(DV)^{0.52} \theta^{0.31} + \varepsilon D(0.21T_a + 15.9)}. \tag{B-2}$$

Although the fraction in this equation appears to be complicated, its meaning is as follows. The numerator corresponds to heat gain (from the sun and conductor current) and the denominator to heat loss (from convection and radiation).

Conductor capacity at any given time is calculated by solving (B-2) for current

$$I = D\sqrt{\left\{(T_c - T_a)\left[16(DV)^{0.52} \theta^{0.31} + \varepsilon D(0.21T_a + 15.9)\right] - \alpha DH\right\} / b}\ , \tag{B-3}$$

substituting maximum allowable conductor temperature and measured weather conditions, and multiplying by three times line-to-neutral voltage.

SIMPLE MODEL VERIFICATION

It is of concern to ensure that the model simplifications do not have too large of an effect on accuracy. To address this issue, Figure B-1 compares 300 simulations using the IEEE's detailed heat balance model[4] to results from the simplified equation for conditions ranging from low to high current, 0° to 40°C ambient temperature, 0.5 to 5.0 meters/second wind speed, 15° to 90° wind directions, full sun to no sun, and a variety of conductor types. Although not perfect, the figure suggests that the simplified model is fairly accurate.

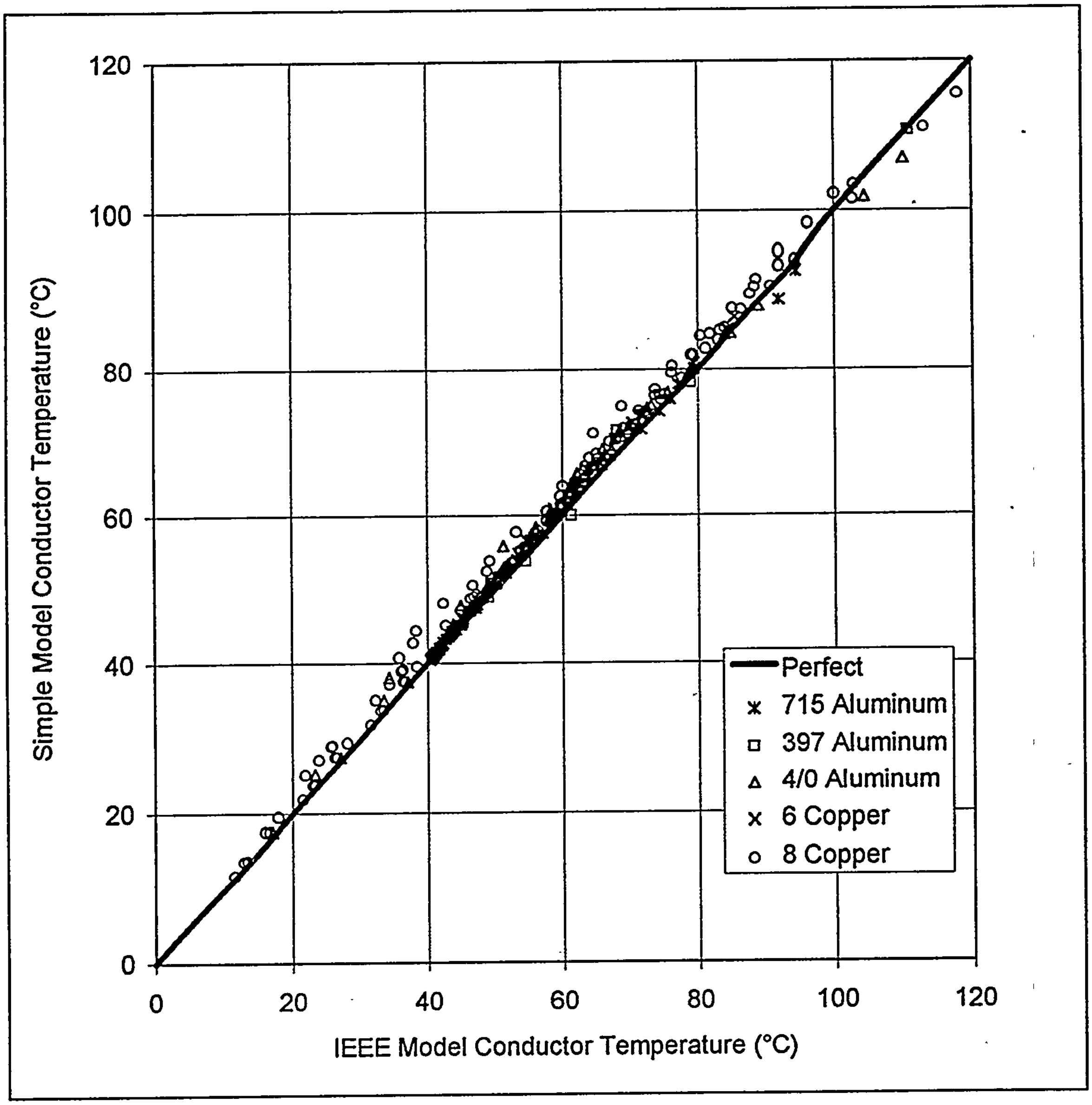

Figure B-1. Simple model verification.

[4] Model runs were performed using software provided with documentation in [B-1].

ESTIMATING ABSORPTIVITY

All inputs into both the detailed IEEE model and the simplified model are directly measurable except the conductor's absorptivity and emissivity. Equation (B-2) can be used to estimate absorptivity and emissivity by measuring weather and conductor data and then simulating conductor temperature with varying model parameters in order to minimize the error between measured and modeled values. This is particularly effective in determining the absorptivity parameter (as opposed to the emissivity parameter) for two reasons. First, there will be a richer data set for analysis purposes since insolation (and thus, the impact of absorptivity) varies throughout the day. Second, the emissivity parameter has a very small impact on model results compared to the absorptivity parameter.

A detailed analysis has been previously performed by other authors on the 4/0 aluminum conductor on the Kerman 1103 feeder [B-3]. The authors measured absolute line current and ambient and conductor temperatures using a device that had a temperature accuracy of ±2°C. The authors selected absorptivity and emissivity constants of 0.65 and 0.50 based on knowledge of conductor age and standard PG&E assumptions. Using a data set of 9 days in July 1993, and the detailed IEEE model, the authors concluded that the model had a root mean square error of 1.26°C during daylight hours and a definite absolute error of about 2°C during non-daylight hours.

Figure B-2 uses one day (July 6, 1993) from the same data set and plots modeled [using (B-2)] versus measured conductor temperature. The same absorptivity and emissivity parameters as assumed by the authors in the previous work are used. An error analysis indicates that there is a root mean square error of 1.25°C during hours where insolation exceeds 500 W/m^2. This is comparable to the result determined by the authors in [B-3].

An analysis of the errors in a plot in both [B-3] and Figure B-2 indicates that the errors differ between daylight and non-daylight hours. This suggests that the absorptivity constant might be different than the 0.65 value initially assumed and that there might be an absolute measurement error as well.

Due to the simplicity of (B-2), parameters can be varied to fit the IEEE model to the measured data. First, there is the potential for measurement error between ambient temperature and conductor temperature since the measurement device is accurate to only 2°C. Second, absorptivity and emissivity can be determined empirically. An optimization program, such as Solver in Microsoft Excel, can be used to determine the parameters.

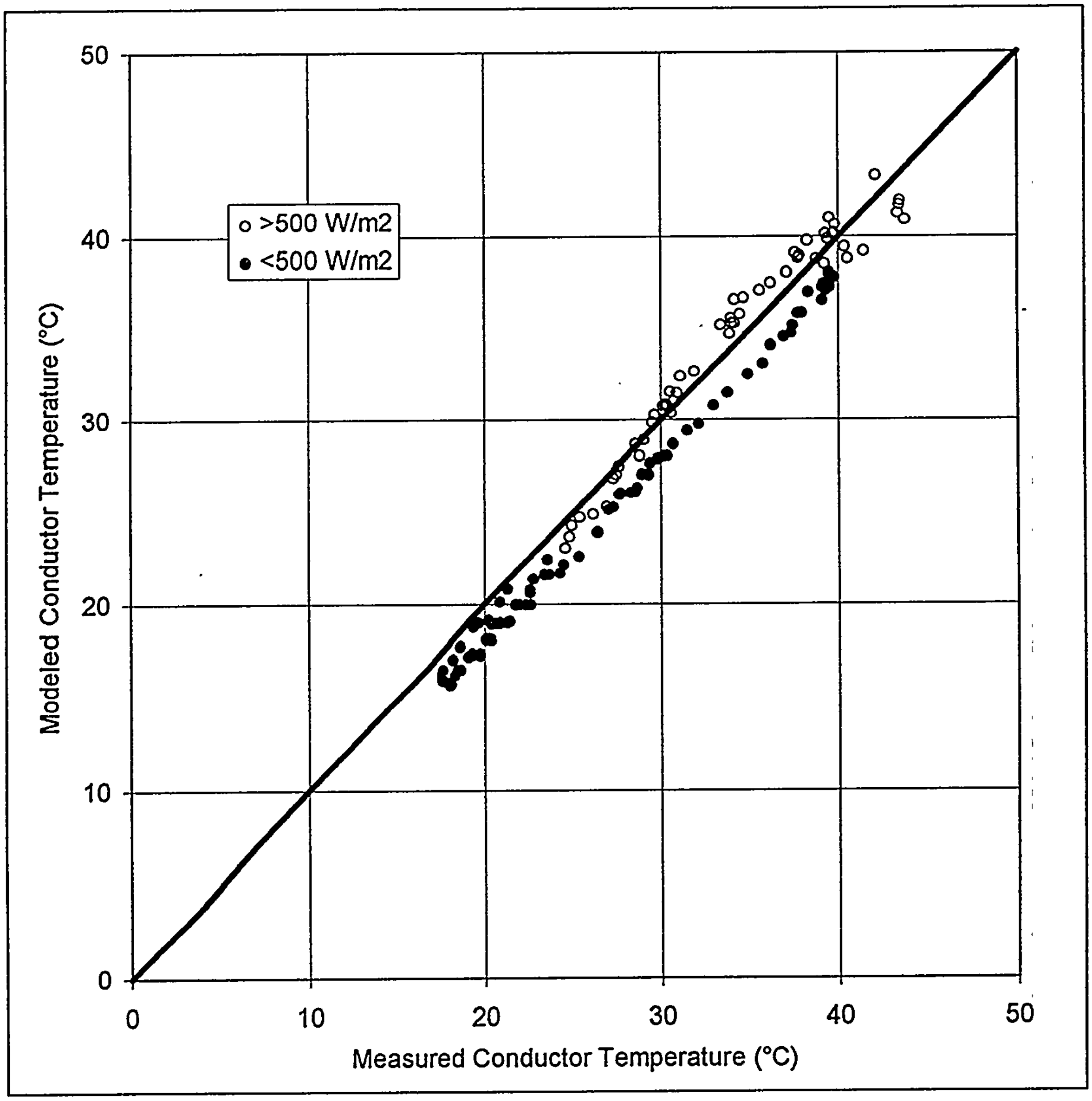

Figure B-2. Modeled versus measured conductor temperature with 0.65 absorptivity, 0.50 emissivity, and no temperature measurement error (July 6, 1993).

Figure B-3 presents modeled versus measured conductor temperature using (B-2) and assumptions of a 2°C temperature error, 0.2 absorptivity, and 0.2 emissivity.[5] An error analysis indicates that root mean square error is reduced from 1.25°C during daylight hours (before) to 0.58°C during all hours of the day (after). The simplified model is useful in parameter estimation because it does not require an iterative solution.

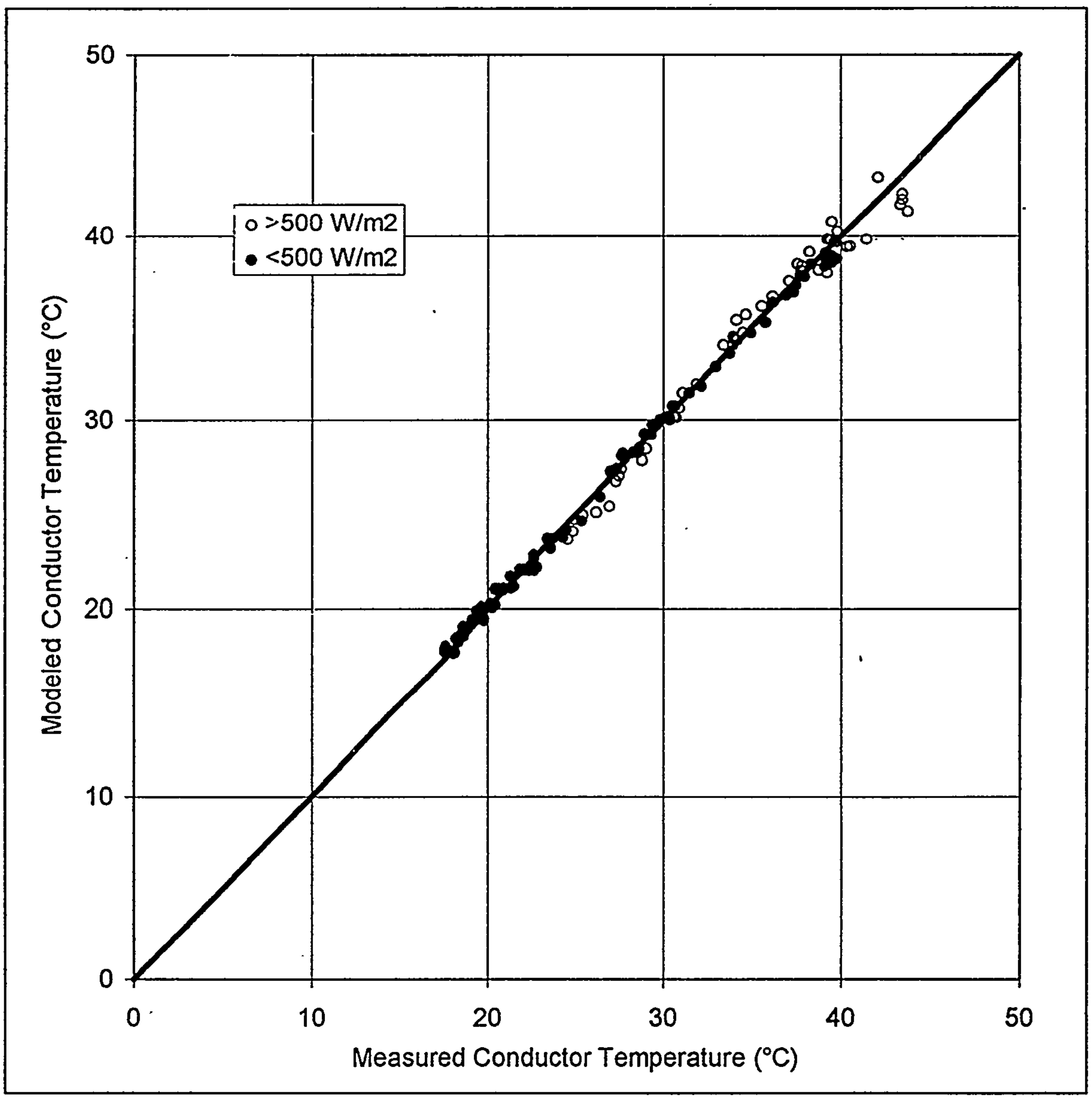

Figure B-3. Modeled versus measured conductor temperature with 0.2 absorptivity, 0.2 emissivity, and a 2°C temperature measurement error (July 6, 1993).

[5] These are within the range stated by the IEEE guide—absorptivity and emissivity can range from about 0.2 to about 0.9.

THERMAL TIME CONSTANT CALCULATION

A second item of interest is how quickly conductors respond to changes in current. The IEEE has developed an equation for the conductor's thermal time constant (see [B-1]). The equation is based on the initial and final conductor temperatures and currents, and conductor resistance and thermal capacity. Since the equation requires conductor temperature, several simulations must be performed to determine the time constant. The simplified model can be used to estimate a conductor's thermal time constant without iteration.

It can be shown that resistance and thermal capacity are proportional to squared conductor diameter.[6] Substituting these and the equation for conductor temperature, (B-2), into the IEEE thermal time constant equation results in a time constant formula of

$$\tau = \frac{650cD^2}{16(DV)^{0.52}\theta^{\ 0.31} + \varepsilon D(0.21T_a + 15.9)}. \qquad \text{(B-4)}$$

where c equals 1.0 for Aluminum conductors and 1.5 for copper conductors.

The most important variables in (B-4) are conductor material (Aluminum or Copper), conductor diameter, and wind speed and direction. Figure B-4 plots time constant versus conductor diameter for Aluminum conductors at various wind speeds; wind direction is perpendicular to the conductor.[7]

The figure suggests that small conductors (e.g., #6) have time constants less than a few minutes while large conductors (e.g., 715) have time constants less than 15 minutes. Since these time constants are so short (even for the large conductors), the implication for grid-support PV is that the PV must always be available during critical times. Since it is obvious that the PV is unavailable where there is no sun, the critical times must occur only when the PV is operating for PV to be of value.

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[6] Specifically, $R = \frac{b}{129D^2}$ and $130mC = 39{,}000D^2$ for Aluminum conductors and $130mC = 1.5(39{,}000D^2)$ for Copper conductors.

[7] The time constant plot for Copper conductors is Figure B-4 times 1.5.

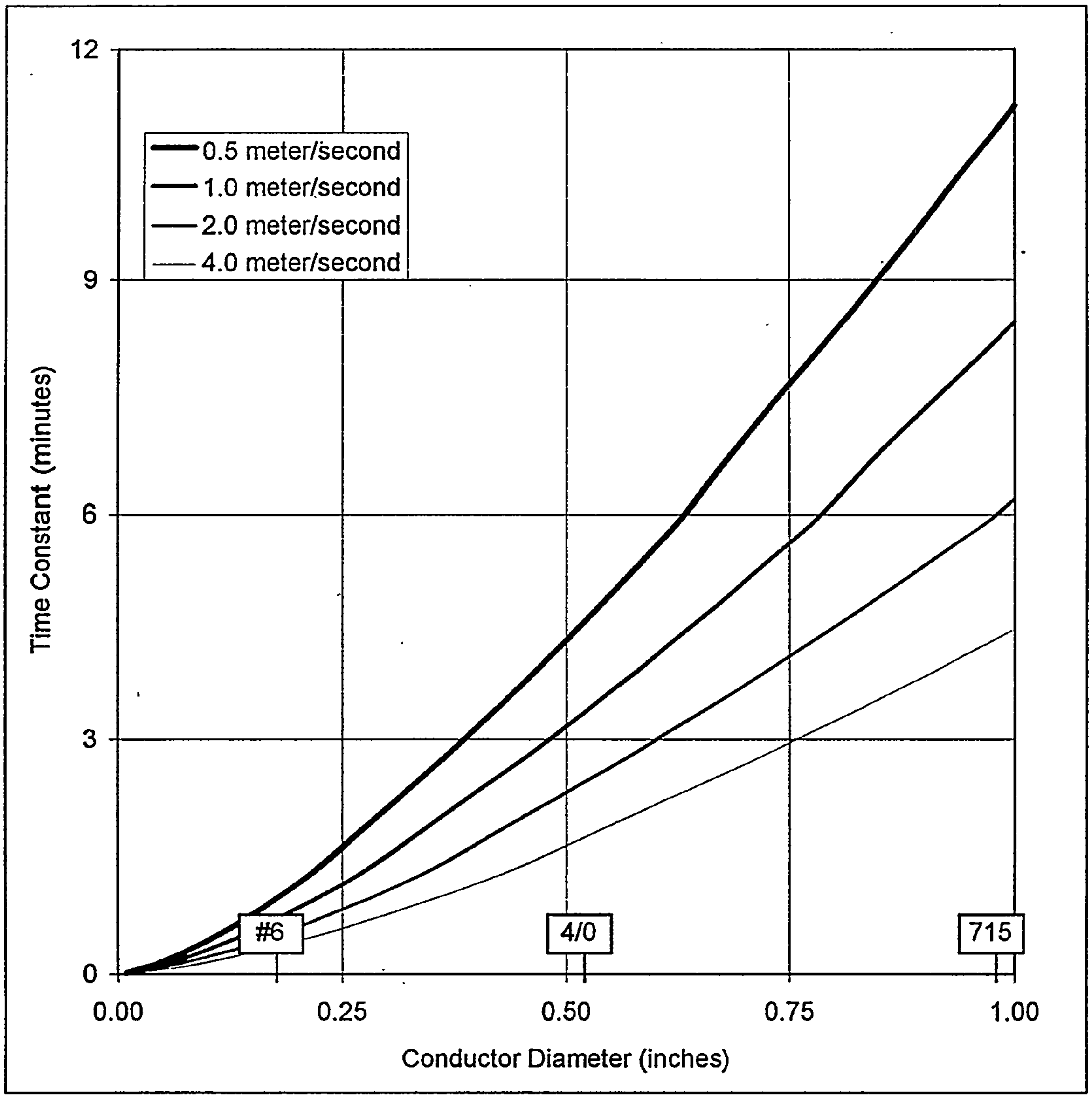

Figure B-4. Time constant versus aluminum conductor diameter at various wind speeds.

AVAILABLE CONDUCTOR CAPACITY

Equation (B-3) can be used to determine the effect of various parameter changes on rated conductor current in a general sense as well as using data specific to some conductor as described in the body of this report. Consider the general case where maximum conductor temperature is 85°C under emergency weather conditions [wind speed of 2 feet (or 0.6 meters) per second, wind direction of 90° (perpendicular to the conductor), ambient temperature of 43°C, and insolation of 1,000 W/m^2]. Absorptivity and emissivity are assumed to be 0.5. Figure B-5 presents the emergency conductor rating [the solution to (B-3) using emergency conditions] versus conductor diameter for copper and aluminum conductors.

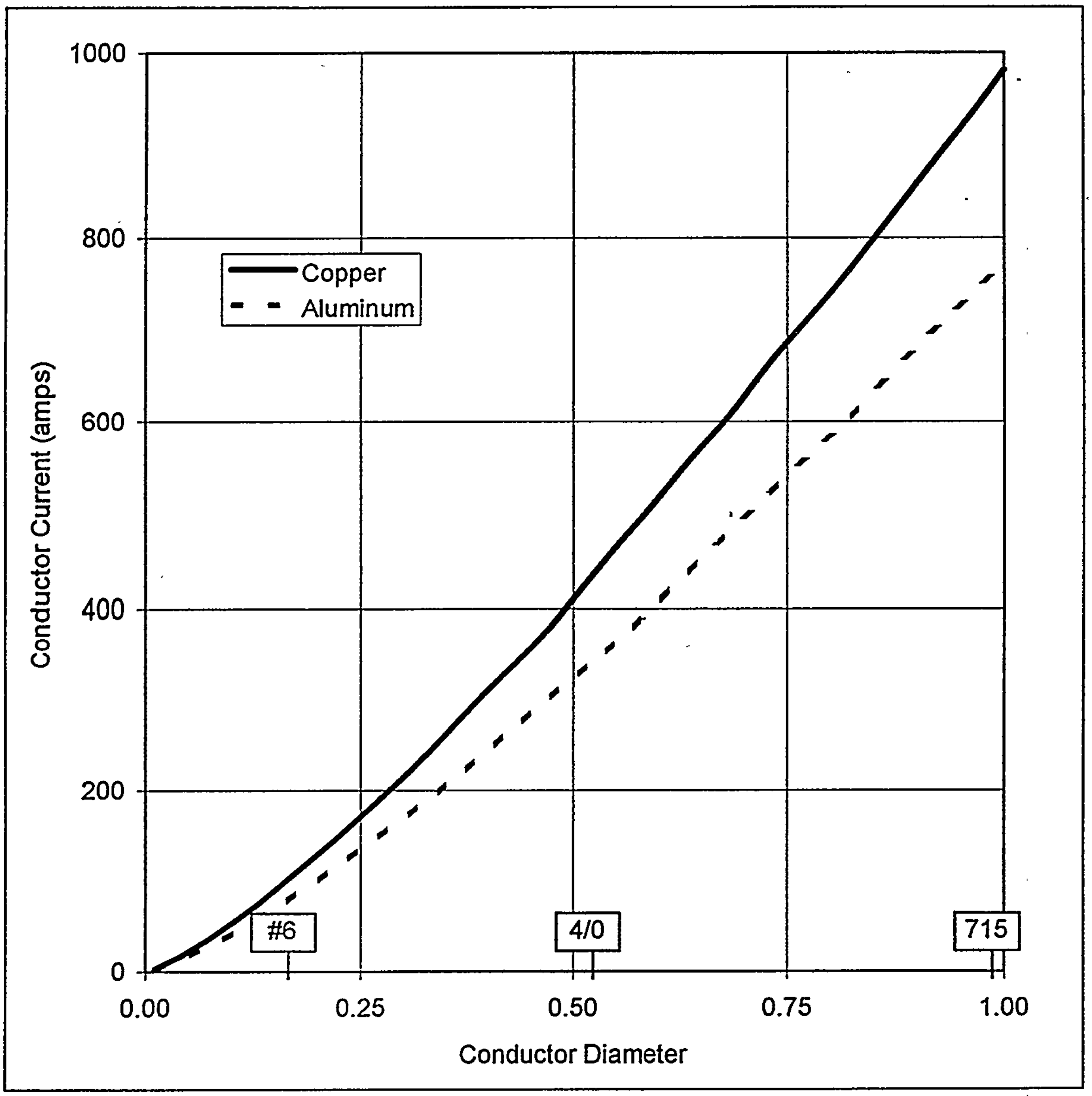

Figure B-5. Rated conductor current at emergency conditions.

Figure B-6 presents the relative change in current on aluminum conductors[8] at emergency conditions as a function of conductor diameter for a 1 ft/sec increase in wind speed, a 10°C decrease in ambient temperature, and elimination of sun. As is evident from the figure, a very small change in wind speed has a large effect. In addition, rated current changes corresponding to wind speed and ambient temperature changes are relatively independent of conductor size, whereas changes due to insolation are a function of projected collection area of the conductor.

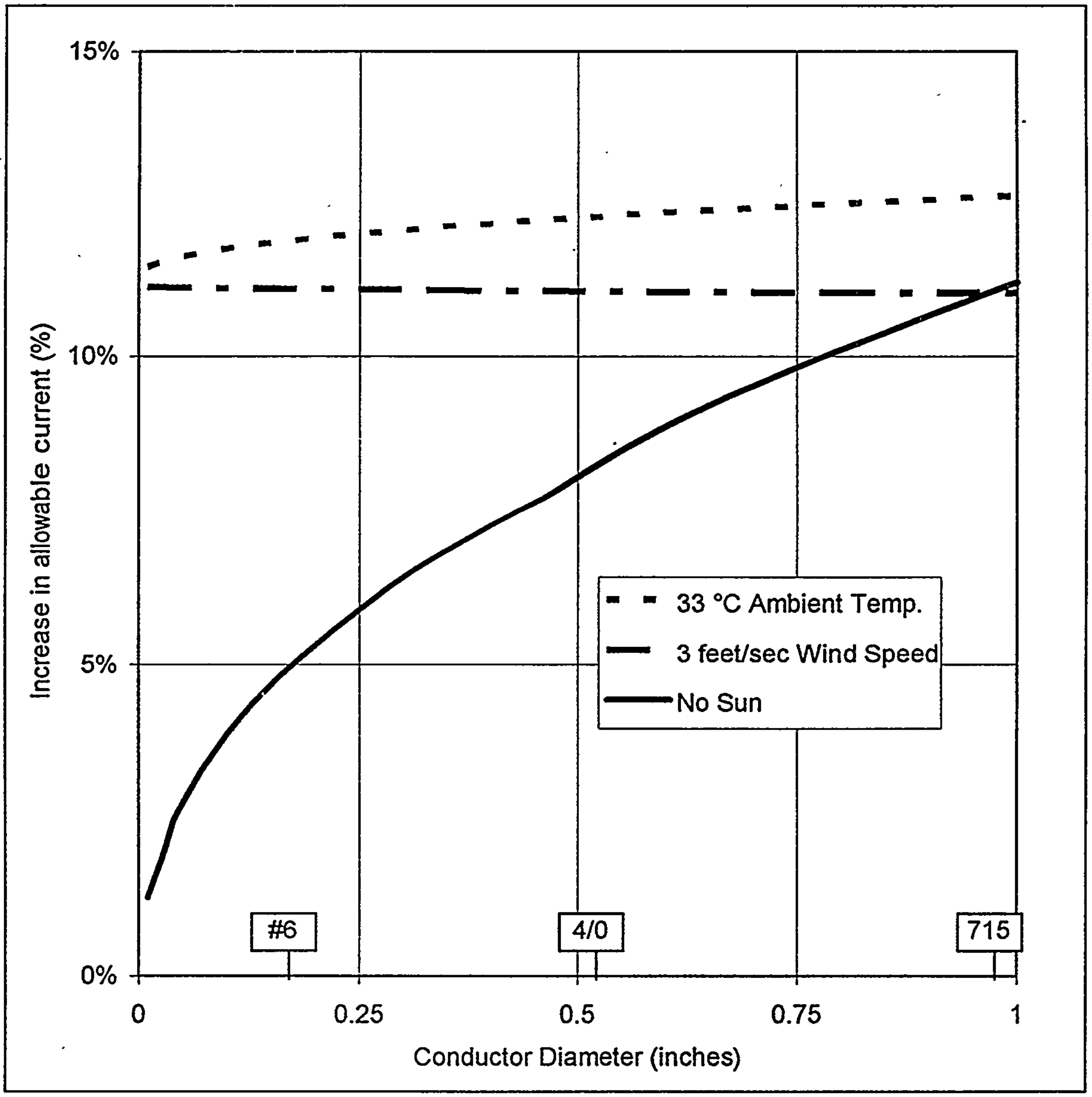

Figure B-6. Increase in current versus diameter for various weather changes (%).

[8]Copper conductors yield 20% higher results.

Figure B-7 presents the absolute current increase as a function of conductor size under no sun but otherwise emergency conditions. For comparison purposes, the output for two PV plants are included. The figure suggests that, at the distribution voltage (three phase, 12 kV), conductors bigger than 1/0 (0.4" diameter) can have a larger increase in current due to the lack of sun than the current produced by a 0.5 MW PV plant. At a transmission voltage (three phase, 70 kV), conductors bigger than 477 (0.8" diameter) can have a larger increase in current due to the lack of sun than the current produced by a 10 MW PV plant.

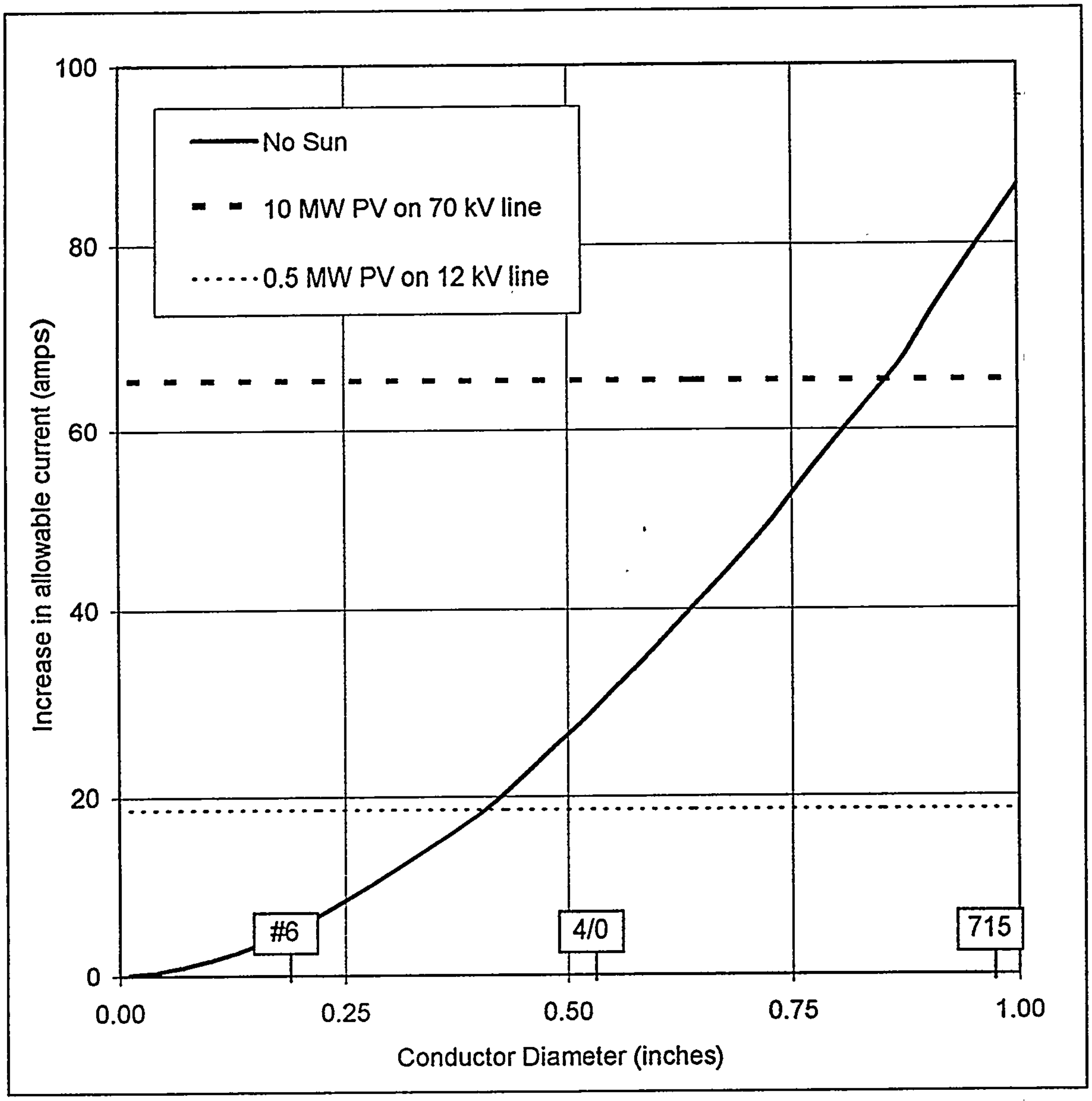

Figure B-7. Increase in current versus diameter with no sun (amps).

One implication of this is that PV may be a naturally dispatching technology. That is, although a significant penetration of PV into an area may shift daytime peak loads into the evening, if the conductor size is large enough (e.g., in the case of transmission lines and large amounts of PV), the thermal constraints of the line may still occur during the day when then PV is operating due to higher daytime ambient temperature and irradiance conditions.

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Appendix C

THE VALUE OF GRID-SUPPORT PHOTOVOLTAICS IN PROVIDING DISTRIBUTION SYSTEM VOLTAGE SUPPORT

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Appendix E

THE VALUE OF GRID-SUPPORT PHOTOVOLTAICS IN REDUCING DISTRIBUTION SYSTEM LOSSES

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Appendix F

THE VALUE OF DEFERRING ELECTRIC UTILITY CAPACITY INVESTMENTS WITH DISTRIBUTED GENERATION

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