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CPUC Self-Generation Incentive Program

Solar PV Costs and Incentive Factors

Final Report

Submitted to:

The CPUC Energy Division

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Executive Summary

ES.1 Introduction

The tremendous growth worldwide in photovoltaic (PV) sales over the past decade testifies to the avid interest in solar technologies. Over 800 megawatts (MW) of PV systems were installed in 2005 in Germany alone.[1] Much of the growth in German PV sales can be attributed to generous feed-in tariffs that made it economically attractive for businesses and homeowners to install PV systems. Within the United States, a number of states are promoting more rapid development of PV. California, New Jersey, and Pennsylvania all have aggressive solar PV growth goals. Under the California Solar Initiative (CSI), $3.2 billion in incentives will be made available to support the growth of up to 3000 new MW of solar electricity generation capacity located at utility customer sites throughout the state by 2017. Recent changes to New Jersey's Renewable Portfolio Standard (RPS) targets a solar electric growth rate of nearly two million megawatt-hours per year. If successful, New Jersey's RPS will result in an installed solar capacity of nearly 1500 MW by 2021.

Establishing an effective incentive design is important to the long term success of PV market transformation. Incentives are a means of providing public support to help in market transformation of solar technologies that can deliver significant public benefits to California in the near-term and for decades to come. These incentives help to bridge the gap between the current costs of PV systems and the economic benefits received by their owners, thereby reducing risks to adopters of solar technologies. Incentives also encourage technology innovation that can accelerate the timeframe by which emerging technologies become cost-competitive and move into mainstream market products no longer needing public support. The California Public Utilities Commission (CPUC) has indicated its belief that "solar technologies can improve and become more cost-effective with a 'push' from an incentive program and the 'pull' of a program design that encourages technological improvements."[2] At the heart of this approach is the need to understand how changes in PV system performance and costs can impact incentive design.

The intent of this study is two-fold. First, it is intended to provide information on metered PV performance and reported PV system costs for PV systems implemented under the Self-Generation Incentive Program (SGIP); the single largest distributed generation program in the country. Second, it is meant to examine the relationships between PV performance, cost, and incentive design. Using actual PV performance information from the SGIP, the study

[1] Marketbuzz, 2006 World PV Industry Report Highlights, March 15, 2006

[2] California Public Utilities Commission, Decision D.06-01-024, January 12, 2006

results provide insights into how changes in PV system location and configuration impact not only PV performance and incentive levels, but also influence how geographical distribution of PV systems may affect system owners and utility ratepayers. The economic breakeven approach developed in the course of this study suggests ways of linking improvements in PV technologies with declining incentive levels that allow for a deliberate and reasonable transition to a fully competitive solar market.

ES.2 Approach

Our approach involves use of an economic lifecycle breakeven analysis, which sets incentive levels to the difference between PV system costs and realizable economic benefits to PV system owners. This approach ensures that owners are kept financially whole during the transition period to a competitive PV market. However, we limit economic benefits to those factors (i.e., value of displaced retail electricity rates and tax benefits) that can be tracked and easily updated. While based on actual measured PV performance and costs information, the approach uses well-established learning curves to project current PV component costs forward in time. When projected PV costs are used in combination with PV performance factors, the approach enables us to estimate incentive levels required in future years to achieve specified PV capacity goals. In turn, retail rates and solar resources can be used to make comparative evaluations of how well the incentive approach would work in other locations throughout the country. Among the advantages of this approach are the following:

- It connects incentive levels to the value of displaced retail electricity rates. Consequently, as retail rates increase, incentive levels decline. This feedback mechanism ensures incentive levels are maintained while PV costs and performance have the opportunity to develop.
- It provides forward-looking incentives that take into account the program “push” and the market “pull.”
- It is a transparent process and allows changes in assumptions or market conditions to be readily translated into results.
- It provides the CPUC, utilities and all other PV industry stakeholders with a means by which to examine longer-term impacts and benefits associated with incentive design decisions.

ES.3 Results

Based on the lifecycle breakeven approach described, we found the following results:

1. The use of metered data and reported costs from PV systems installed under the SGIP from 2001 through 2004 provide good baselines of PV system performance and costs for a solar incentive program.

   – An average annual statewide capacity factor of 17 percent is representative of PV systems that may be installed in California leading into 2007.

   – Representative-installed PV system costs for PV systems going into 2007 should be approximately \$8.50 per Watt $_{AC}$ (real 2006 dollars).

2. PV system location (which determines the amount of useable sunlight or the "available solar resource") and configuration (module tilt and orientation) have profound effects on PV performance and energy delivery.

   – Depending on location and configuration, PV capacity and electricity production can differ by as much as 20 percent.

   – Due to differences in climate and solar resources, utilities will have different abilities to optimize PV capacity and electricity delivery for the mix of PV systems installed in their service territories.

3. When combined with PV cost projections, PV system location and configuration strongly influence the required incentive levels under an economic lifecycle breakeven analysis.

   – Incentive levels calculated for the 2007 program year show required incentive levels under a five-year performance-based incentive (PBI) ranging from approximately \$1100 per kilowatt to nearly \$1750 per kilowatt; a differential of over 60 percent. Incentive level requirements are expected to grow increasingly different in later years.

4. The federal investment tax credit (ITC) and application of varying discount rates can strongly impact the incentive design.

   – Loss of the federal ITC may increase the required level of the incentive under a PBI structure by as much as a factor of two.

   – Excluding the discount rate tends to overestimate the required incentive level. Conversely, this exclusion of discount rate under net present value cash flow analyses does not enable the PV system owner to breakeven.

5. A forecast scenario that links PV performance levels and cost factors (e.g., displaced retail rates) to hypothetical 10-year PV program incentive levels illustrates the significant impacts of performance and cost factors on program goals and on the fundamental aspects of incentive design.

- Location and configuration of PV systems as well as retail rates were found to have a profound impact on cumulative program results. For example, for the same $1 billion investment in PV incentives, California may be able to install over 520 MW of new PV capacity; whereas New Jersey may only be able to install slightly over 300 MW and Oregon only 150 MW.
- A single statewide incentive would clearly be the simplest approach to implement a PV incentive program; however, it also most certainly does not provide an optimal use of ratepayer funds when compared to a utility service area-specific incentive that accounts for the differences in retail electric rates and average available solar energy resource, both of which drive the level of available system benefits to the participant.
- While a single statewide incentive would benefit the participating customers of Southern California Edison (SCE) the most, a utility-specific incentive produces the lowest mean participant benefit:cost ratio; in addition the overall benefit:cost ratio variability is lower for this structure than for a single statewide PBI.

1

Introduction

1.1 Purpose

The purpose of this study is to examine key relationships between solar photovoltaic (PV) performance, cost, and incentive levels. More specifically, this study is meant to provide insights into monitored performance of PV systems operating in California and ways in which changes in costs and performance of such systems can influence incentives paid out under a PV incentive program. The intent is for these insights to play a useful role in establishing PV incentive programs that fairly and transparently reward improved PV cost and performance while simultaneously providing a reasonable pathway for reducing PV incentive levels.

1.2 Background

Since the emergence of the first PV devices in the 1950s, PV technology has undergone tremendous changes in price and performance. Prices have dropped by over 33,000 percent.[1] During that same time, PV performance has improved by 375 to 500 percent.[2] Nonetheless, PV systems remain expensive relative to more conventional electricity generation technologies and often require financial incentives to help offset their high first-time costs. Incentive structures have been one method used to help promote development of PV technologies and accelerate market transformation.

This report grew out of discussions about an earlier study on the cost-effectiveness of distributed generation technologies implemented under the Self-Generation Incentive Program (SGIP).[3] One of the factors impacting PV cost effectiveness was the flatness in PV costs over the life of the SGIP. Lower capacity factors and performance of PV systems

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[1] In 1954, Hoffman Electronics was marketing a simple PV cell system at a price of $1,785 per Watt. As of March 2006, the average price of PV modules in the United States according to SolarBuzz.com was approximately $5.37 per Watt.

[2] In 1954, Bell Labs produced a PV cell with an efficiency of close to 4 percent. Today's commercially available solar PV cells have efficiencies ranging from 15 to 20 percent.

[3] Itron, "CPUC Self-Generation Incentive Program Preliminary Cost-Effectiveness Evaluation Report," prepared for the California Public Utilities Commission Energy Division, September 14, 2005

relative to other generation sources also impacted PV cost-effectiveness. As a result, the cost-effectiveness report contained a recommendation that the California Public Utilities Commission (CPUC) should investigate reasons for discrepancies between significant PV cost reductions observed in world markets over the past 20 years versus only slight PV cost reductions in the SGIP program. In addition, interest in assessing strategies for setting declining PV incentive levels developed from an earlier CPUC ruling in December 2004. Under CPUC Decision 04-12-045, the Working Group was directed to examine existing strategies based on declining incentive structures.[4] In late November 2005, the CPUC directed Itron to conduct a follow-up study focused specifically on PV system performance and costs. Among the items to be considered in the follow-up study were:

- Actual PV electricity generation and associated performance from PV systems implemented and monitored under the California Energy Commission (CEC)'s Emerging Renewable Program (ERP) and the SGIP;
- Comparison of costs of PV systems installed under the ERP and SGIP within the context of surrounding PV market costs; and
- Possible applications for development of incentive structures (such as performance-based incentives) that would take into account market forces and other major factors that could impact an incentive approach.

In December 2005, the SGIP Working Group approved a cost and time extension to the Southern California Edison (SCE) Monitoring and Evaluation Contract with Itron that included this study on PV Performance, Costs, and Incentive Factors.

1.3 Scope

This study is based on actual PV performance and reported system costs for PV systems implemented under the SGIP. The SGIP represents the single largest collection of monitored PV system performance data for any PV incentive program in the country. The results are representative of conditions in California and may be limited to commercial-size PV systems (i.e., PV systems larger than 30 kilowatts installed). However, we believe the relationships between cost and performance can be translated to other geographical regions and utility structures. While we include PV performance data from a variety of technologies, the data set was too incomplete at this time to allow us to discriminate between PV technologies (e.g., thin film versus polycrystalline silicon). The scope of the economic analysis is limited to taxable entities to facilitate more thorough examination of other factors influencing subsidy requirements (e.g., federal investment tax credit rates, retail electricity rate, and PV cost trends).

[4] California Public Utilities Commission, Decision 04-12-045, December 16, 2004

1.4 Approach

Our approach is based on the premise that an incentive should, at a minimum, make up the difference between the total costs borne by the PV system owner and the economic benefits accrued by the owner over the life of the PV system[5]. By setting the PV economic benefits equal to the PV system costs, we are able to estimate the required incentive level needed for participants to break even on their investment. We also assume that as PV costs decrease and PV system performance increases, the difference between costs and benefits will shrink, thereby reducing required incentive levels in the future. Lastly, by examining PV cost and performance trends and the factors that could influence them, we are able to conduct sensitivity analyses that show how changes in future cost and performance of PV systems could impact PV incentive levels, program funding levels, and the associated amount of installed PV capacity and generated electricity. The approach involves linking reported installed PV system costs and actual monitored PV system performance to incentive levels using a levelized cost model. Such an approach has been proposed by others, including Hoff and Starrs.[6]

We use an economic model previously developed by Itron in identifying the cost-effectiveness of distributed generation systems deployed under the SGIP to distribute costs and benefits on a 24-hour-day, 365-day-per-year-basis.[7] PV system costs are taken from Program Administrator reporting via the SGIP and represent total eligible installed cost estimates. PV performance data represent monitored PV generation typically collected in 15-minute intervals for PV systems installed under the SGIP.

As will be described later in more depth, PV system costs are broken into major components and projected forward using empirical "learning curves" developed by others.[8,9] PV economic benefits consist primarily of displaced retail rate electricity and tax benefits (to the PV system owners). We base retail electricity rates on time of use (TOU) tariffs established by the utilities.

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5 In this study, PV economic benefits are considered only to be those recognized by PV system owners and limited to immediately tangible benefits such as displaced retail electricity value and tax benefits. We recognize that PV systems may provide other benefits to their owners such as increased property value and increased control over their electricity costs. However, due to the difficulty in quantifying these other benefits, we have considered only displaced electricity value and tax benefits.

6 Hoff, T. and Margolis, R. "Economic Benefits of Performance-Based Incentives," July 2004 and Starrs,T. "Designing a Performance-Based Incentive for Photovoltaic Markets," Solar 2004 Conference Proceedings

7 Itron, "CPUC Self-Generation Incentive Program Preliminary Cost-Effectiveness Evaluation Report," September 14, 2005

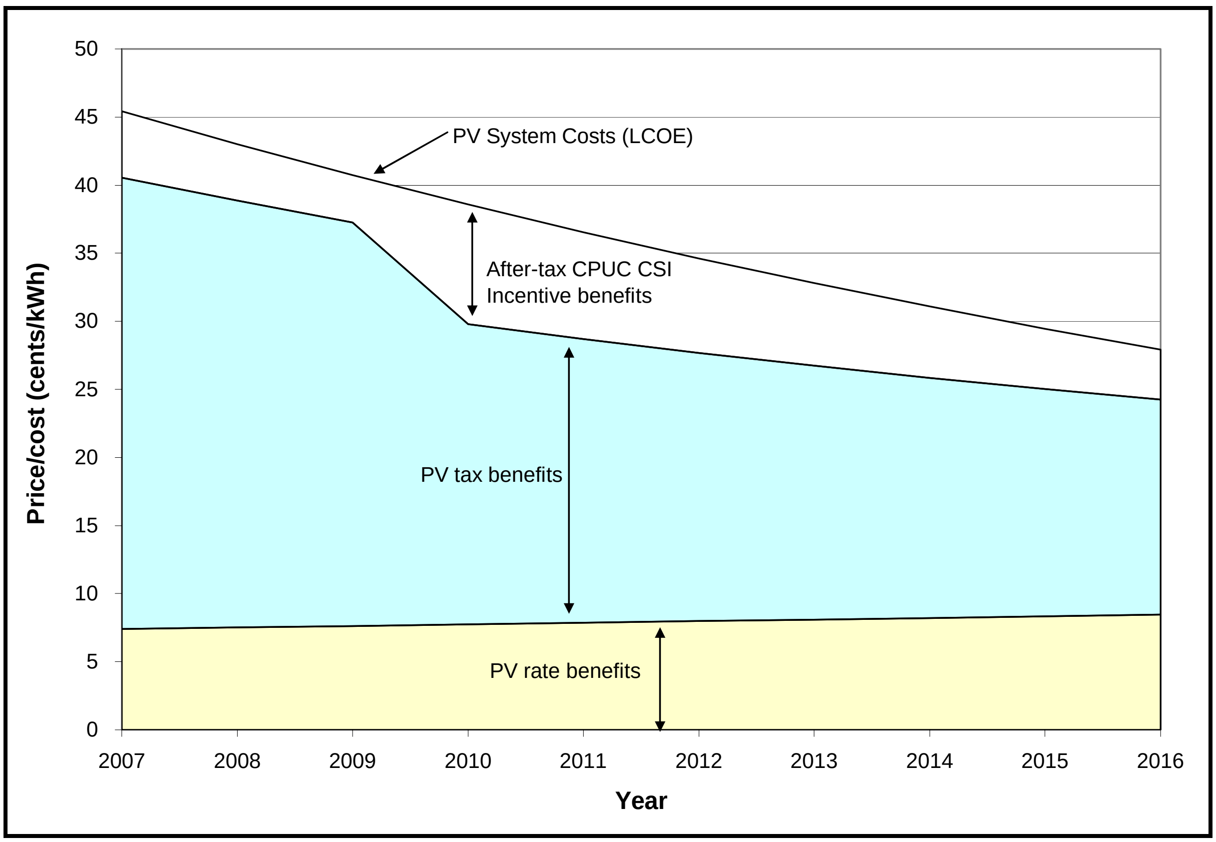
8 Maycock , *The World Photovoltaic Market*, Paul D. Maycock. PV Energy Systems. 2002.

9 Strategies Unlimited, *Five-year market forecast, 2002-2007.* Strategies Unlimited. Technical Report PM-52, 2003.

The primary strength of this approach is that it not only connects PV incentive level to cost and performance factors, but does so in a way that allows changes in PV performance and cost to adjust the estimated incentive levels accordingly. As such, the approach also enables pro forma incentive level scenarios to be developed based on projected improvements in PV costs and performance. Because the model incorporates monitored PV performance, we can also account for differences in location, PV system configuration (e.g., tilt and orientation), and specific utility rate structures.

A very simplified representation of the relationship between incentive levels, PV costs, and PV benefits is shown in Figure 1-1. In this idealized representation, incentive levels (in cents per kilowatt-hour of PV electricity generated) decline with declining PV costs. In later years, as retail costs increase and PV system costs decrease, the incremental amount of PV incentive required to make up the difference between cost and benefit decreases accordingly. For this illustration the 30 percent federal investment tax credit (ITC) rate is assumed through 2009 at which point it reverts back to 10 percent. This assumption is responsible for the drop in tax benefits (and corresponding increase in PV incentive rate) between 2009 and 2010.

Figure 1-1: Illustration of Relationship Between Incentive Levels, PV Costs, and PV Benefits



1.5 Report Organization

The report is organized into 10 sections.

The Executive Summary precedes all other sections.

- Section 1 is this Introduction.
- Section 2 provides the major findings of the study.
- Section 3 covers PV system performance for systems implemented under the SGIP and establishes a sound baseline for PV system performance going forward. This section also develops representative performance characteristics of PV systems that could be installed under future PV incentive programs. These representative systems demonstrate the impact of PV system location, configuration, and orientation on PV system performance.
- Section 4 identifies current PV system costs as reported under the SGIP to help establish baseline costs and indicates observed relationships between system performance and costs. This section also sets forth a basis for estimating future PV system costs, the various components making up the overall system costs, and the manner in which we have projected module and non-module PV costs into the future. Additionally, this chapter identifies PV costs that could possibly be influenced by California-specific policies.
- Section 5 delineates the various economic benefits that accrue to owners of PV systems, including the value obtained from displacement of retail rate electricity.
- Section 6 introduces PV incentive designs and summarizes the various capacity-based incentive (CBI) and performance-based incentive (PBI) approaches that can be used in structuring PV incentives.
- Section 7 presents the results of the breakeven incentive level analysis. It provides estimated CBI and PBI levels that would be required in 2007 under the breakeven approach. This section also shows how changes in location (relating to available solar resource and utility specific retail rates) and PV system configuration (tilt and orientation) impact incentive levels. Lastly, we identify the impacts of using a single statewide incentive level versus utility specific incentive levels on PV system owners.
- Section 8 discusses the impact of incentive levels on program results based on different funding levels. We specifically examine how the performance aspects that impacted incentive level further influence the amount of PV that could be installed and the associated amount of electricity delivered.
- Section 9 provides a limited look at how the PV incentives may impact others besides the PV owners, including ratepayers and society in general.

2

Findings

The purpose of this study is two-fold. First, it is intended to provide information on metered PV performance and reported PV system costs for PV systems implemented under the SGIP. Second, it is meant to examine the relationships between PV system performance, costs, and incentive levels. The intent has been to help provide insights into how PV performance and costs can influence PV incentive levels that may evolve under future PV support programs. To accomplish this goal, Itron employed a lifecycle breakeven economic analysis approach that combines existing measured PV system performance and cost information with future PV system costs projected over the expected lifetimes of various PV support programs. Our primary findings are summarized below:

1. The use of metered data and reported costs from PV systems installed under the SGIP from 2001 through 2004 provide good baselines of PV system performance and costs for future PV incentive programs.
   - An average annual statewide capacity factor of 17 percent is representative of PV systems that may be installed leading into 2007.
   - Representative installed PV system costs for PV systems going into 2007 should be approximately \$8.50 per Watt $_{AC}$ (real 2006 dollars).
2. PV system location (which determines the amount of useable sunlight or the "available solar resource") and configuration (module tilt and orientation) have profound effects on PV performance and energy delivery.
   - Depending on location and configuration, PV capacity and electricity production can differ by as much as 20 percent.
   - Due to differences in climate and solar resources, utilities will have different abilities to optimize PV capacity and electricity delivery for the mix of PV systems installed in their service territories.
3. When combined with PV cost projections, PV system location and configuration strongly influence the required incentive levels under a economic lifecycle breakeven analysis.
   - Incentive levels calculated for 2007 show required incentive levels under a five-year PBI ranging from approximately \$1100 per kilowatt to nearly \$1750 per kilowatt; a differential of over 60 percent. Incentive level requirements are expected to grow increasingly different in later years.

4. The federal ITC and application of varying discount rates can strongly impact the incentive design.
   - Loss of the federal ITC may increase the required level of the incentive under a PBI structure by as much as a factor of two.
   - Excluding discount rate tends to overestimate the required incentive level. Conversely, this exclusion of discount rate under net present value cash flow analyses does not enable the PV system owner to break even.
5. A forecast scenario that links PV performance levels and cost factors to hypothetical 10-year PV program incentive levels illustrates the significant impacts of performance and cost factors on program goals and on the fundamental aspects of incentive design.
   - Location and configuration of PV systems as well as retail rates were found to have a profound impact of cumulative program results. For example, for the same $1 billion investment in PV incentives, California may be able to install over 520 megawatts (MW) of new PV capacity; whereas New Jersey may be able to install slightly over 300 MW and Oregon approximately 150 MW.
   - A single statewide incentive would clearly be the simplest approach to implementing a PV incentive program. However, it may not provide an optimal use of ratepayer funds when compared to a utility service area-specific incentive that accounts for the differences in retail electric rates and average available solar energy resource, both of which drive the level of available system benefits to the participant.
   - Under this analysis, a single statewide incentive would benefit the participating customers of one utility the most, and provide the single highest cost-effectiveness to one group of participants. Conversely, a utility-specific incentive broadens the cost-effectiveness to participants in all of the utilities and lowers the variability in cost-effectiveness among PV owners.

3

PV System Performance

Performance of PV systems is critical in evaluating their cost-effectiveness and in structuring appropriate incentive designs. Obtaining actual performance data that are representative has been problematic. Various software tools, such as PV Watts, Clean Power Estimator, and Maui Solar's PV Design Pro are intended to simulate generation profiles that might be generated by a PV system under different conditions and configurations. These same tools generate cost and cost-saving estimates based on the simulated performance. While software tools are able to simulate PV performance under specified conditions, monitored data provides information on performance of PV systems under actual conditions.

This section provides information on actual electricity generation and performance of PV systems installed and monitored under the SGIP. It is intended to provide a baseline of PV system performance for California. This section also provides information on performance of prototypical PV systems that would be representative of PV systems installed under future PV incentive programs. The purpose is to show how system location, configuration, and orientation could impact PV systems installed under such programs.

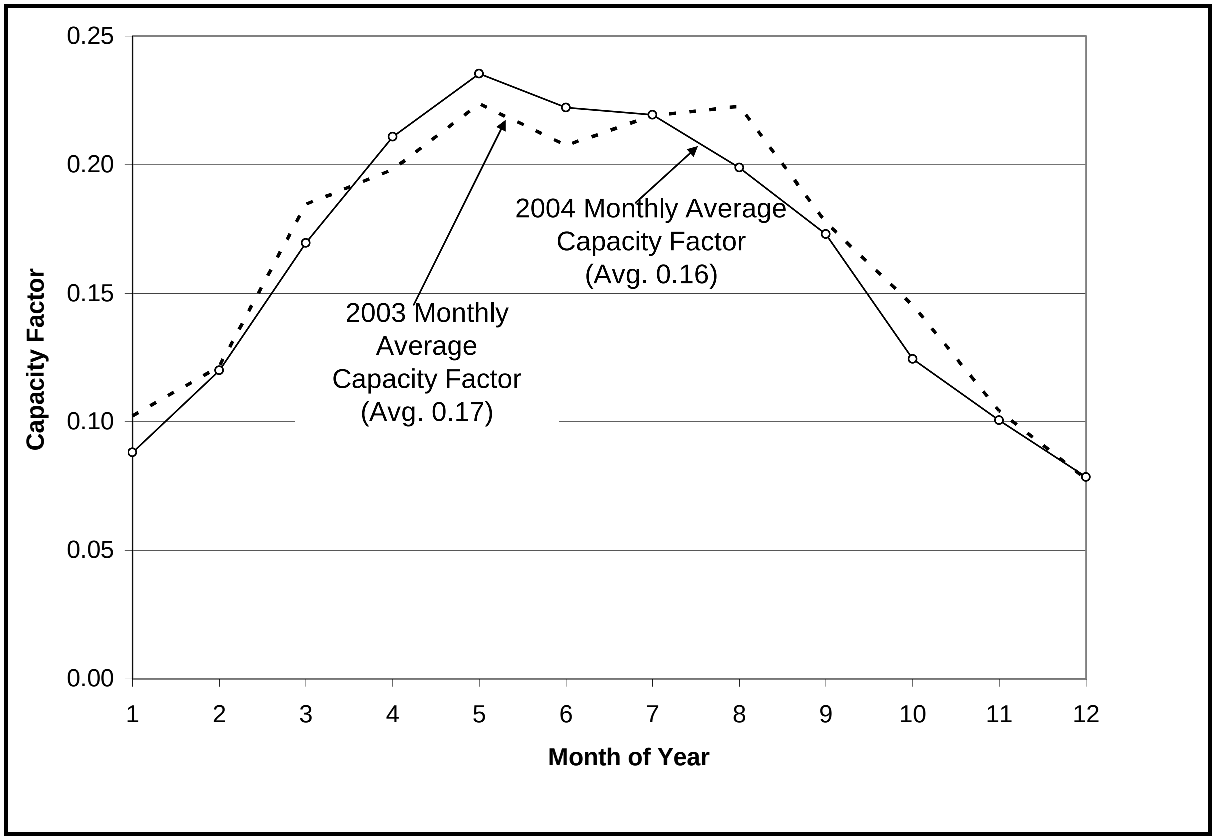
3.1 Current PV System Performance

Over 100 PV systems were metered for electricity generation during calendar years 2003 and 2004 under the SGIP. Generation data were typically reported at 15-minute intervals over 24 hours a day and 365 days per year. Generation profiles developed from the interval data to show impacts on annual and peak electricity demand have been reported previously in the SGIP Fourth Year Impact Report.[1] Performance of PV systems was based directly on the metered data and was also reported previously. Additional information on the distribution of PV system performance by location, configuration, and orientation has been developed for this report. Although an attempt was made to examine system performance by technology type, manufacturer, and size of installing company, data variability and availability are such that currently this level of breakdown is not feasible.

[1] Itron, "CPUC Self-Generation Incentive Program: Fourth-Year Impact Report," prepared for Southern California Edison and the Self-Generation Incentive Program Working Group, April 15, 2005

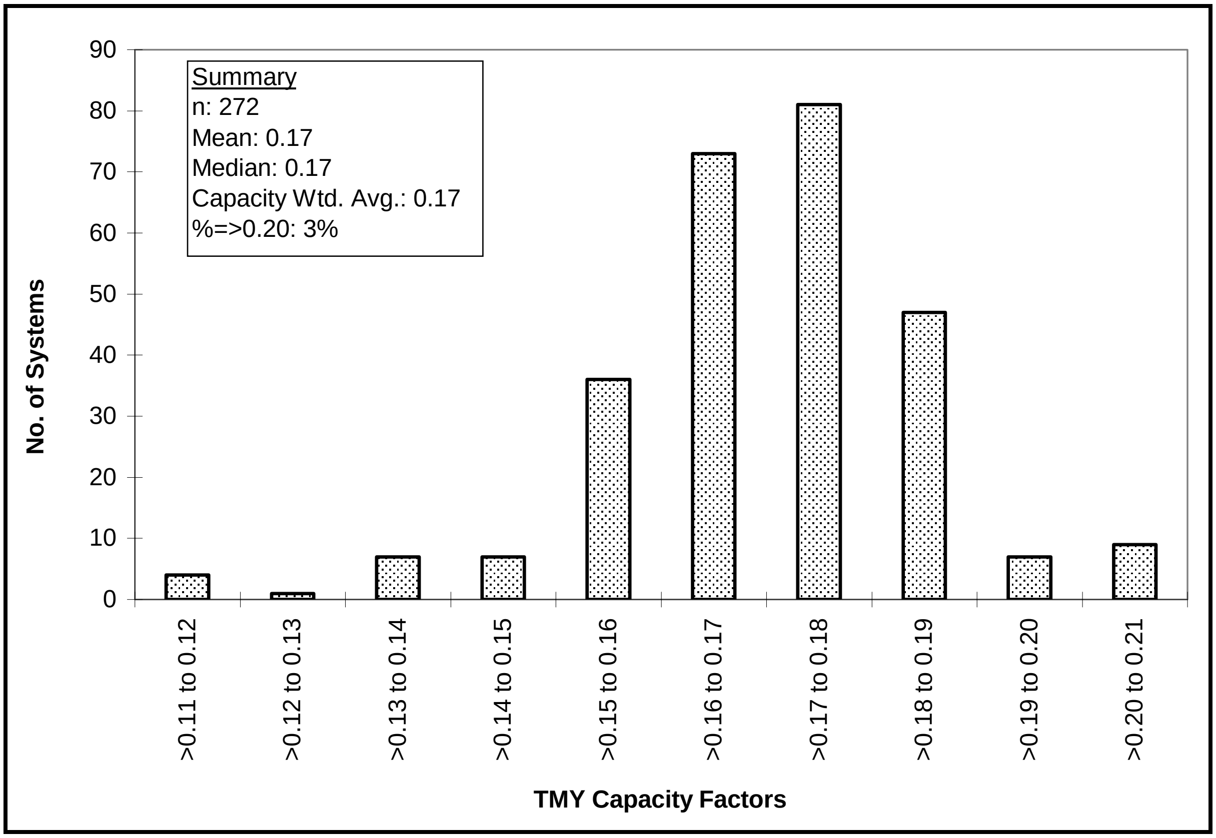
PV system average capacity factors for 2003 and 2004 are shown in Figure 3-1. Annual average capacity factors were found to be 16 percent in 2003 and 17 percent in 2004. As expected, PV systems show seasonal changes in capacity factor. During summer months the capacity factor reaches nearly twenty-five percent. During late fall through early spring, capacity factors can drop well below 15 percent. As a result, electricity generation during these time periods can be two to three times lower than during summer from the same system. PV contribution to addressing summer peak demand is a well established benefit. However, if left unidentified in an incentive program, the drop in PV performance during the fall and winter may result in high expectations and disappointment.

Figure 3-1: SGIP PV Capacity Factors for 2003 and 2004



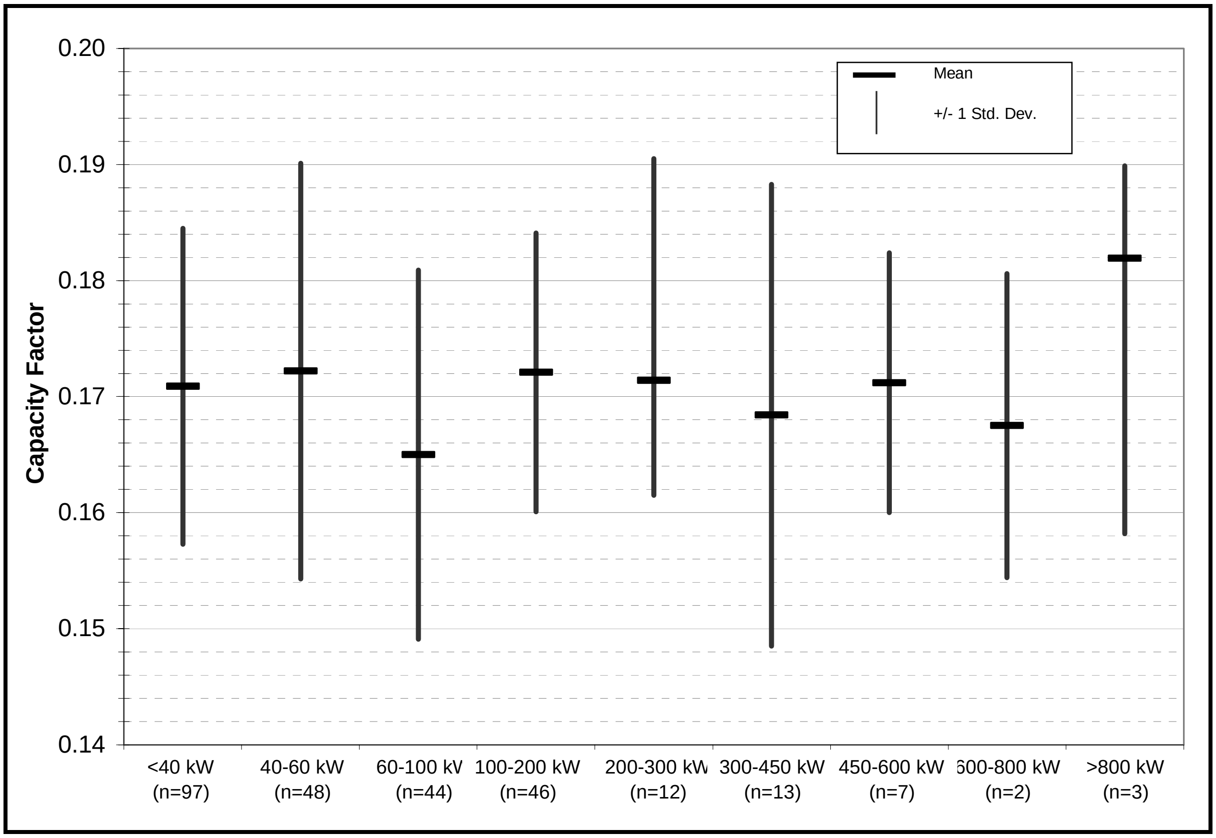
There is also significant variation in capacity factors between systems. Figure 3-2 shows the distribution of capacity factors for metered systems normalized to typical meteorological year (TMY) conditions. While the average annual capacity factor is 17 percent, nearly twenty percent of the monitored systems had capacity factors ranging from 12 to 16 percent. Less than 3 percent of the metered systems had capacity factors above 20 percent. Again, care in treating annual average capacity factors should be used to avoid unreasonable expectations.

Figure 3-2: Distribution of TMY PV Capacity Factors Estimated for SGIP PV Systems



Capacity factor results were based solely on PV systems metered under the SGIP, which tends to have larger capacity systems. As such, there may be questions of how representative the capacity factor results are for PV systems outside of the SGIP. However, Figure 3-3 shows the distribution of capacity factors by system size. This distribution suggests there is little correlation between system size and performance and that the SGIP capacity factor results may be indicative of PV systems in California in general.

Figure 3-3: Distribution of PV Capacity Factor by System Size



3.2 Prototype PV System Performance

Performance of PV systems implemented under the SGIP seems to provide a reasonable performance baseline for current PV systems in California. However, it represents a mix of PV systems at various locations, with various configurations and orientations at a particular slice in time. This mix will certainly change as new PV systems are deployed. To better understand the influence of location, configuration, and orientation on future PV system performance and on incentive designs, we defined 39 PV system prototypes. The PV system prototypes are listed in Table 3-1. Each prototype consists of a pairing of a location and one of three PV system configurations. The correspondence between locations and the three major investor-owned utilities (IOUs) is also presented in Table 3-1 on the following page.

Table 3-1: PV System Performance Prototypes

Location (Representative City)		Configurations
Santa Rosa Oakland Red Bluff Sacramento	(PG&E)	Horizontal Facing South, 15 tilt Facing Southwest, 30 tilt
Los Angeles Big Bear Pasadena Riverside China Lake El Centro	(SCE)	
San Diego Riverside	(SDG&E)	

Data Sources—Performance of PV System Prototypes

The four principal data sources listed below were used for the analysis of prototypical PV system performance. Each is discussed briefly.

- SGIP PV System Interval-Metered Performance Data
- California Irrigation Management Information System Observed Weather Data
- SGIP Project Files
- Typical Meteorological Year Weather Data

SGIP PV System Interval-Metered Performance Data

Metered 15-minute interval data were collected from a sample of PV systems participating in the SGIP and used in developing hourly electricity generation profiles for PV systems.

California Irrigation Management Information System (CIMIS)

The CIMIS system comprises over 120 automated weather stations throughout California. The purpose of the system is to provide California's irrigators with information that will help them manage water resources. Hourly data for global horizontal radiation and ambient temperature reported by the CIMIS system were used in this analysis to develop relationships between observed weather and observed PV system performance.

SGIP Project Files

Records provided by SGIP Program Administrators provided information regarding project size and system location.

Typical Meteorological Year (TMY) Weather Data

The CEC has developed hourly weather data files for 16 climate zones in California. These weather data reflect typical climatologic conditions for each of the 16 zones. The original purpose of these data was for use in assessing compliance with California's energy standards for buildings. Hourly data for global horizontal radiation and ambient temperature reported by the CEC climate zones were used in this analysis to provide a climatologic basis for estimates of TMY weather.

Analytic Methodology—Performance of PV System Prototypes

We developed estimates of prototype PV system performance and its possible impact on incentive design in three steps:

- Estimate Hourly Insolation for SGIP PV System Performance for Observed Weather.
- Estimate Hourly Insolation for PV Incentive Analysis Prototypes for Typical Weather.
- Estimate Hourly Performance of PV Incentive Analysis Prototypes for Typical Weather.

Estimate Hourly Insolation for SGIP PV System Performance for Observed Weather

Observed weather data from the nearest CIMIS station were downloaded for the period spanned by available SGIP PV system performance data. Performance data for 125 PV systems were included in the analysis. The CIMIS weather data include global horizontal solar radiation values. For the tilted prototypes, estimation of plane of array solar radiation involves application of standard solar geometry models.

- Input: Hourly CIMIS weather data, SGIP PV system configuration, size, and interval data.
- Output: Observed hourly energy production per kilowatt (kW) of PV system size. Each record was assigned to bins comprising ambient temperature and plane of array solar radiation.

Estimate Hourly Insolation for PV Incentive Analysis Prototypes for Typical Weather

Each of the PV incentive analysis prototypes corresponds to an 8,760-hour dataset of TMY weather data. These datasets include global horizontal solar radiation values. For the tilted prototypes, estimation of plane of array solar radiation involves application of standard solar geometry models.

- Input: Hourly TMY weather
- Output: Hourly TMY weather and plane of array solar radiation

Estimate Hourly Performance of PV Incentive Analysis Prototypes for Typical Weather

Results of the analysis of observed PV performance were merged into the TMY datasets. For each assignment bin there were many different hourly energy production values. This variability is partly explained by distances between SGIP PV systems and CIMIS weather stations. Additionally, there are many other factors contributing to system-to-system PV system performance variability. The examination of these factors is described later in this section under the heading *System-to-System Performance Variability*. Existing 8,760-hour TMY weather data sets for the 16 climate zones in California were used as a baseline. A TMY weather data set was assigned to each of the operational PV systems based on its location. These are the same 8,760-hour TMY data sets others have used as the basis for avoided cost data sets. PV energy production values were then estimated for each TMY weather data set record.

To estimate PV energy production for each of the 8,760 TMY hours we assign a value from the historical archive of actual production values observed during the period 2002-2004. The assignment is made based on a comparison of the TMY and observed solar radiation values. First, the historical observed data are divided into lists. Then, a separate list is created for each bin of observed solar radiation values (e.g., 751-800 W/m^2). The TMY solar radiation value dictates which list the PV energy production value is randomly selected from. This methodology produces TMY data sets containing PV production estimates that reflect hourly TMY solar radiation values. For instance, PV production values actually observed in summer during clear noontime hours are used to estimate PV production for clear noontime July TMY hours.

- Input: Hourly TMY weather data and plane of array solar radiation, bins containing observed hourly energy production per kW of PV system size.
- Output: Hourly TMY PV performance for 39 prototypes.

The analysis described above yielded estimated first-year TMY performance. Factors considered in developing TMY performance datasets for years 2 through 25 focused primarily on module degradation. We expect PV performance to increase with technology improvements. However, the rate of performance improvement is highly dependent on technology type, and market forces driving changes in the technology. In addition, we believe much of the economic benefits associated with improved performance may be captured in the PV learning curve characterizations described in Section 4.

Module Degradation: The conversion efficiency of all PV modules degrades slowly over time. Many modules are warranted by their manufacturers to maintain at least 80 percent of their initial output for 10 or even 20 years. Because the current generation of panels has been in use for only a few years, it is too early to accurately estimate the degradation rates. For the present analysis, a 0.5 percent per year degradation rate is assumed.

SGIP PV System-to-System Performance Variability

The above discussion of observed PV system performance described how the energy actually produced by similar 1 kW (nominal SGIP AC) PV systems varies from one PV system to another. Effects of PV system location and configuration were accounted for directly in the TMY analysis. Numerous other factors contribute to system-to-system performance variability, including:

+soiling	+PV racking design
+module mismatch	+inverter sensitivity to temperature and load
+wiring losses	+PV module sensitivity to temperature
+maintenance	+microclimate

These factors were accounted for in the TMY analysis; however, this was done statistically rather than directly. It was necessary to handle these factors statistically because information necessary to account for them directly is not readily available. The resulting TMY datasets for prototypes reflect the average performance of all metered SGIP PV systems.

For the recently completed Preliminary Cost-Effectiveness Evaluation it was necessary to develop TMY performance datasets for each of the 272 SGIP PV systems. System-to-system performance variability exhibited by these data was summarized in Section 3.1.

Performance of PV System Prototypes

Summary PV system performance statistics for the 39 prototypes are presented in Table 3-2 on the following page. The combined influences of climate, latitude, and configuration account for the highest energy production (1,788 kWh/yr) exceeding the lowest (1,373 kWh/yr) by 30 percent. A substantial portion of this variance is due to differences in solar resource.

Table 3-2: PV System Prototype Performance Summary

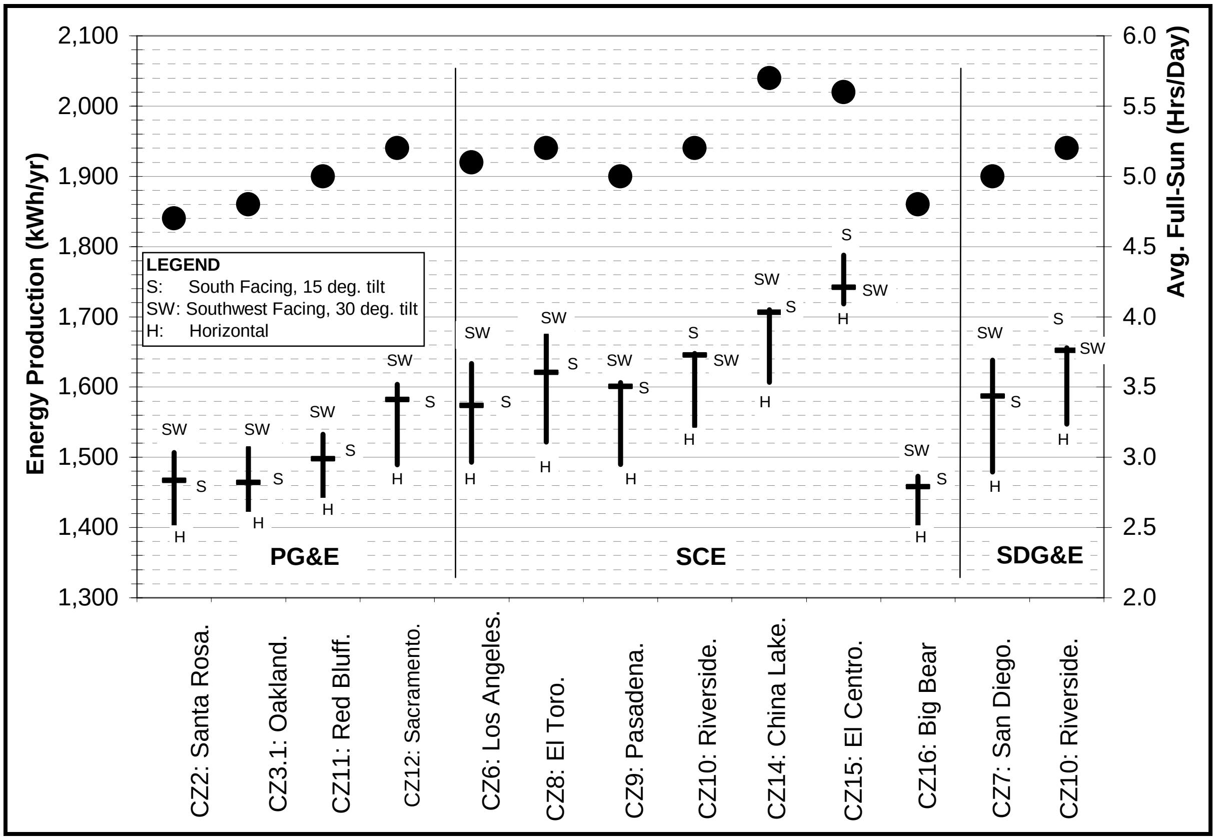
Summary Statistic	Full-Sun (Hrs/Day)	PV System Performance by Configuration kWh/yr & Capacity Factor (%)		
		Tilt: 0 Azimuth: 0	**Tilt: 15 Azimuth: S**	**Tilt: 30 Azimuth: SW**
Range	4.7 to 5.7	1,373 to 1,742 15.7% to 19.9%	1,458 to 1,788 16.6% to 20.4%	1,473 to 1,718 16.8% to 19.6%
Median	5.1	1,490 17.0%	1,587 18.1%	1,633 18.6%
Mean	5.1	1,498 17.1%	1,588 18.1%	1,609 18.4%
Std. Dev.	0.3	103 1.2%	99 1.1%	79 0.9%

The best solar resource (5.7 full sun hours per day (FSH/day) in the vicinity of China Lake) exceeds the poorest (4.7 FSH/day in the vicinity of Santa Rosa) by 21 percent. As compared to other countries aggressively pursuing PV development programs the California solar resource (5.1 FSH/day typical) is quite good. Values for Germany (3.1 FSH/day, Stuttgart) and Japan (3.8 FSH/day, Shimizu) are 39 percent and 25 percent lower, respectively.

Solar resource and PV system energy production results for all 39 prototypes are presented in Figure 3-4. Greater solar resource generally corresponds with higher PV system energy production but there are exceptions. For example, the solar resource in the vicinity of China Lake is approximately 2 percent more plentiful than in the vicinity of El Centro. However, the typical PV system energy production estimated for the China Lake area is approximately 6 percent *less* than for a similar system in the vicinity of El Centro. This example illustrates the influence of ambient temperature on PV performance. The annual average temperature in China Lake is 12˚F higher, and PV system power output diminishes at higher temperatures, all else equal.

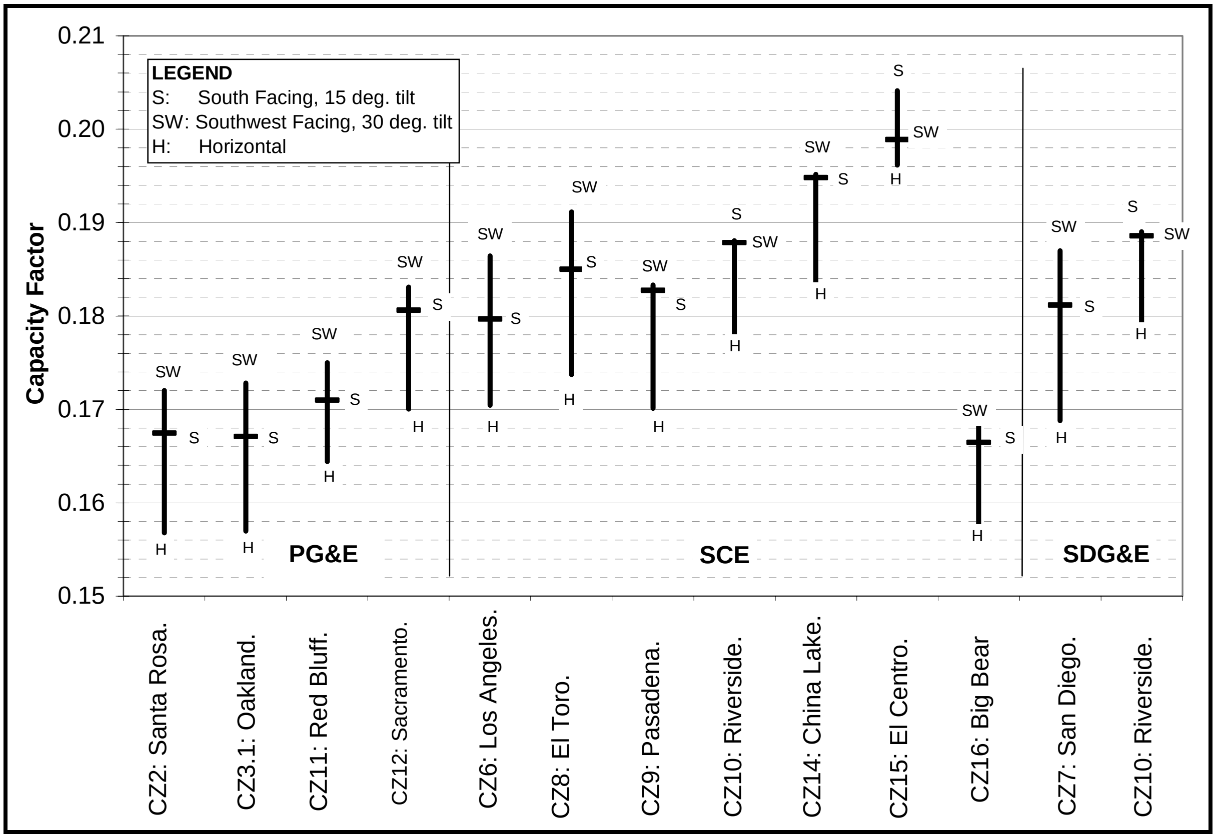
Three observations leap out from examining Figure 3-4. The first is the general dominance of a southwest orientation with a 30 degree tilt on PV generation. The second is the impact of location. Clearly, both configuration and location can play an important role in the performance of PV systems and, therefore, incentive levels. For example, PV systems located in climate zone 15, with a southwest orientation and 30 degree tilt could be expected to have greater annual electricity production than PV systems located in climate zone 16, with a horizontal and south-facing configuration. Lastly, Figure 3-5 indicates that PV performance may end up being substantially different from one utility to the next.

Figure 3-4: Typical Solar Resource and Energy Production (kWh/yr) for Prototypes



The energy production results from Figure 3-4 are presented again in Figure 3-5 in terms of annual average capacity factor rather than in units of kWh/year. As first noted in Table 3-2, the capacity factors range from 15.7 percent to 19.9 percent. As expected, the same impact of configuration and location shown with PV electricity generation shows up in the capacity factors.

Figure 3-5: Typical Energy Production (Capacity Factor, %) for Prototypes



3.3 Summary

Using SGIP metered PV data, we have found that a reasonable performance baseline for California PV systems is represented by a 17 percent capacity factor. Similarly, the same data show that a significant portion (i.e., 20 percent) of the systems may have capacity factors ranging from 12 to 16 percent if installed in comparable locations. We have also shown that location (due to available solar resource) and PV system configuration (tilt and orientation) can have a significant impact on PV system performance. Lastly, we have shown that PV performance between utilities can be substantially different depending on geographic development of PV within the utility service territory.

4

PV Costs

This section describes PV cost data used in the PV incentive design analysis. PV system costs are made up of a number of components, including hardware costs, labor for system design and installation, and other miscellaneous costs. Identifying the factors that could impact PV system costs and projecting PV system costs forward requires an understanding of the various PV cost components. In this section, we first establish a baseline of current PV system costs using cost data from SGIP project records. Because SGIP PV costs are reported only on a system basis, we use other sources to establish estimates of component costs. PV component and system costs are then projected for future years using well established experience curves that model relationships between unit costs and cumulative worldwide production.

4.1 Current PV Costs

Current PV system costs are based on total installed PV system cost data as reported by the program administrators for participants in the SGIP.

Total PV System Costs

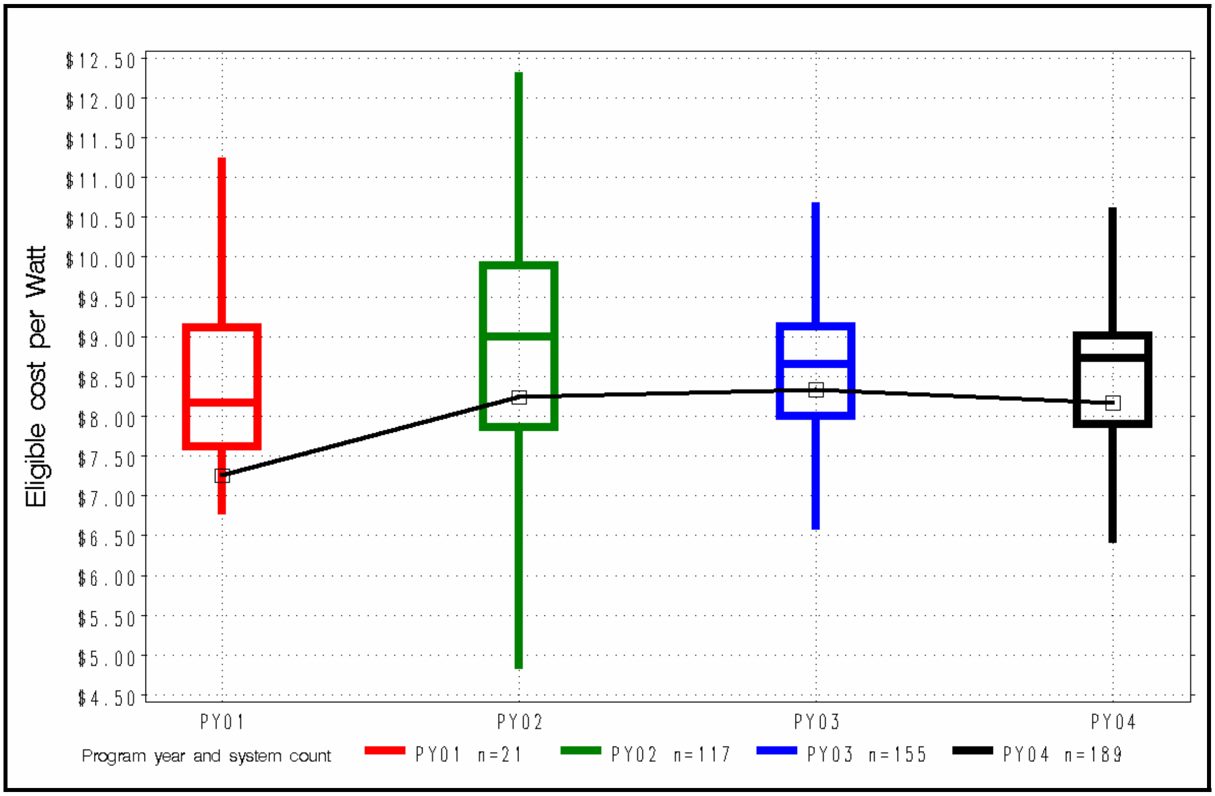
SGIP PV cost data are summarized in Table 4-1. Only completed projects for which a check has been issued are included in the analysis. Since startup of the program, mean costs have increased from $7.94 per Watt to $8.56 per Watt. Cost decreases were seen from Program Year (PY) 02 to PY 04. However, cost increases of over 10 percent that occurred from PY 01 to 02 had not been overcome by PY 04.

Table 4-1: Eligible Cost per Watt by Program Year (Nominal $)

Program Year	System Count	Mean Cost	Median Cost	Min. Cost	Max. Cost	Weighted Mean Cost
PY01	21	$7.94	$8.16	$4.51	$11.24	$7.26
PY02	117	$8.76	$9.00	$4.50	$16.19	$8.24
PY03	155	$8.78	$8.69	$4.29	$15.48	$8.34
PY04	189	$8.56	$8.74	$5.57	$12.57	$8.17

While unit costs have not fallen over the course of the SGIP, their range has narrowed. Although this is expected as installed system count increases, the range has become more consistent over time. This suggests some standardization and possibly learning effects. Box and whisker plots of unit costs for each program year are presented in Figure 4-1. System counts for each program year are shown in the legend. Each year's box has a center horizontal line at the median unit cost. Above and below the median are the middle quartiles. The vertical lines, or whiskers, connect the quartiles to the most extreme point observed within 1.5 interquartile ranges (an interquartile range is combined height of 25th and 75th percentiles.). The solid black line between years connects weighted mean unit costs. The low weighted mean of PY 01 is an artifact of a single very large and low unit cost system.

Figure 4-1: Eligible Cost per Watt by Program Year



The SGIP data do not demonstrate a systematic cost difference by module tilt. The four SGIP PV systems with tracking arrays also have unit costs per Watt within the range observed for fixed arrays whether horizontal or tilted. A 2001 study of 23 systems, nine with single-axis tracking, and capacities ranging from 72 to 437 kW also showed no distinct difference in unit costs by mounting type.[1] Although we do not adjust unit costs by module tilt, we do adjust PV performance by module tilt as discussed in Section 3.

1 Solar Electric Power Association. *Large Systems Cost Report 2001 Update, Cost Analysis for 70 kW and Larger TEAM-UP PV Installations.* Washington, D.C. September 2001.

Larger capacity systems do show a trend toward lower unit costs. Figure 4-2 shows box and whisker plots of unit costs for 9 kW-capacity bins. Each box has a center horizontal line at the median unit cost. Above and below the median are the two middle quartiles. The whiskers connect the quartiles to the most extreme point observed within 1.5 interquartile ranges.

Figure 4-2: Eligible Cost per Watt by kW Capacity Bin

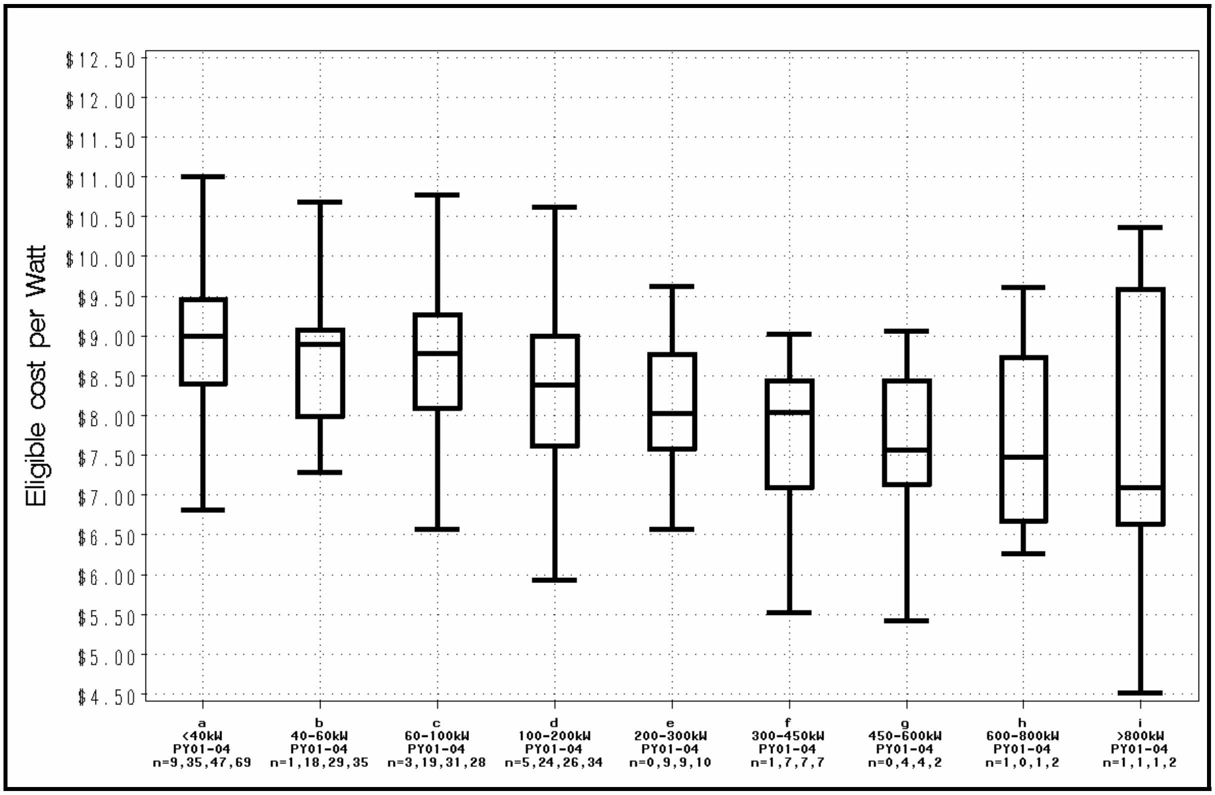


Figure 4-2 shows a decline in median unit cost as capacity increases. The median cost decline pauses at the 300-450 kW bin, then resumes. In ranges above 300 kW, the interquartile range grows taller. While partly a result of smaller system counts, this taller range may indicate that less experience with very large systems leads to more scattered unit costs. System installation activity in capacities above 200 kW has changed little since PY 02, with approximately two dozen such systems per year. The system counts of Figure 4-2 (n-values in horizontal axis labels) show marked increases from PY 02 to 03 only in bins below 100 kW.

A representative unit cost for 2004 would fall between $8.17 and $8.74 per Watt. For PV incentive analysis forecasting purposes a representative 2005 value of $8.25 per Watt is assumed ($8.50 in real 2006 dollars assuming 3 percent inflation). These values are close to those found by Ryan Wiser in his examination of SGIP PV system costs.[2] We use a basis of $8.50 (2006 real dollars) per Watt for forecasting future costs.

- PY2005 PV System Cost Basis: $8.50 (real 2006 dollars) per Watt

Component Costs

Readily available SGIP PV eligible installed cost data do not describe PV module or PV inverter costs separately. The available cost data contain only total eligible costs inclusive of labor. To enable separate estimation of module, inverter, and balance of system cost projections the total system cost data were disaggregated into the principal component costs presented in Table 4-2.

Table 4-2: Break-Out of PV System Costs

Principal Category	Sub-Category
Modules	None
Inverters	None
Balance of System (BOS)	▪ Electrical Balance of System (eBOS). Transformers, meters, switches, panels, conductors, raceways, and associated mounting structures, foundations, construction materials, and installation hardware. ▪ Mounting Balance of System (mBOS). Mounting structures, foundations, construction materials, and installation hardware for modules ▪ Labor for system design and engineering ▪ Labor for system installation ▪ Other ("catch-all" includes various fees and miscellaneous costs)

<u>Estimating PV Module Component Costs</u>

A 2001 study of 23 systems ranging from 72 to 437 kW gave partial breakouts of installed unit costs[3]. The costs were in nominal year dollars per Watt from 1996 to 2000. The study used only three component categories: modules, inverters, and installation and mounting. Not all cost components were broken out, but the three categories appear to have captured no less than 55 percent of total installed unit costs. The study showed average over the five-year period that module percentages of total cost per Watt fell from 78 to 63 percent. Another

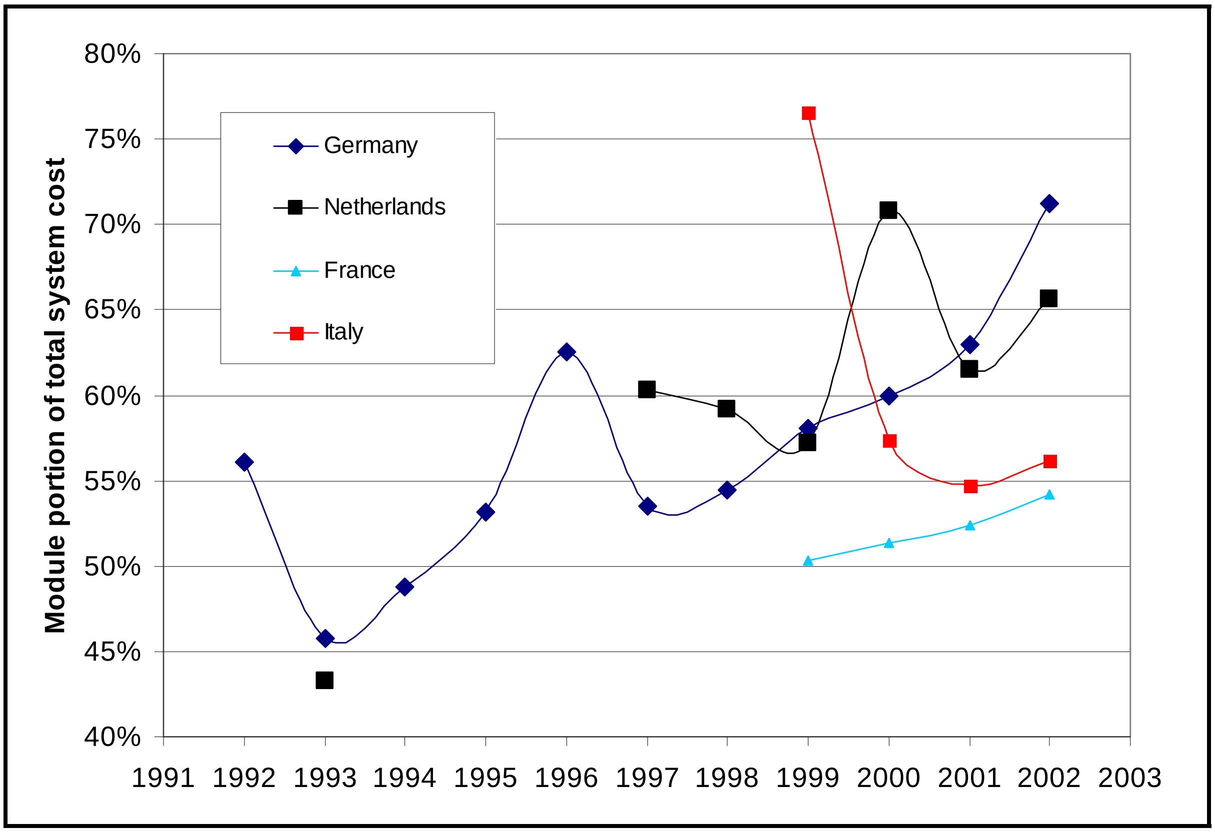
[2] Wiser, Ryan, M. Bolinger, P. Cappers, and R. Margolis. *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California.* Ernest Orlando Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division. LBNL-59282. January 2006.

[3] SEPA. *Large Systems Cost Report 2001 Update, Cost Analysis for 70 kW and Larger TEAM-UP PV Installations.* Solar Electric Power Association, Washington, D.C. September 2001.

2001 report, on residential PV systems, indicated that module costs composed between 47 and 62 percent of total installed costs.[4]

A 2004 report describes cost component percentages in four European countries.[5] The total costs are broken out simply as modules and balance of system. Figure 4-3 shows that from 2001 to 2002, all four countries saw module cost percentages increase. The German figures represent a cumulative 83 MW in 2002, greater than 95 percent of which is grid-connected. The Netherlands follows with only 8 MW in 2002, and Italy is under half a MW. The French figures represent mostly off-grid systems, and for that reason may be excluded here. German systems had module percentages over 70 percent, while the Dutch were over 65 percent.

Figure 4-3: Module Cost Percentages in European Countries



4 Dunlop, James P., et al. *Reducing the Costs of Grid-Connected Photovoltaic Systems.* Proceedings of Solar Forum 200. Solar Energy: The Power to Choose. Washington, DC. April 2001.

5 Schaeffer, G.J.; A.J. Seebregts, L.W.M. Beurskens, H.H.C. de Moor, E.A. Alsema, W. Sark, M. Durstewicz, M. Perrin, P. Boulanger, H. Laukamp, C. Zuccaro. *Learning from the Sun; Analysis of the Use of Experience Curves for Energy Policy Purposes: The Case of Photovoltaic Power*. *Final Report of the Photex Project*. ECN Renewable Energy in the Built Environment. Report ECN DEGO: ECN-C--04-035, August 2004.

Based on these studies of component breakouts, it is plausible to estimate module cost portion of SGIP total system costs between 60 and 70 percent. A 60 to 70 percent module cost range combined with the SGIP total system installed cost basis of $8.50 (real 2006 dollars) per Watt would yield module costs of from $5.10 to $5.95 per Watt. By comparison, USA retail module prices from 2003 to 2005 went from $5.22 down to $4.99 and back to $5.17 (nominal year dollars).[6] Retail prices are based upon purchase of a single module exclusive of sales tax and delivery. Wholesale volume purchases would be discounted, but sales tax and delivery charges ultimately would be applicable. Given the German and Dutch experience, we use 65 percent as the module cost basis.

- 2005 PV Module Cost Basis: 65 percent of total installed cost of $8.50 per Watt in 2005, or module cost basis is $5.52 per Watt.

Estimating PV Inverter and BOS Component Costs

Turning to inverters and balance of system (BOS) generally, the 2001 SEPA and 2004 Photex[7] studies elaborate to different extents on BOS costs.[8] The 2001 study treated inverters separately, but did not provide information on all other cost components. The 2004 study broke total system cost into simply module and BOS components.

The 2001 SEPA report showed average inverter percentages of total cost per Watt staying steadily within a range of 5 to 10 percent. By comparison, USA retail inverter prices from 2003 to 2005 held steady at $0.83 (nominal year dollars) per Watt (SolarBuzz). This unit cost is approximately 10 percent of the estimated total installed cost of $8.50 per Watt in 2005.

Inclusion of total average cost per Watt information in the 2001 SEPA study allowed one to imply remaining, non-inverter BOS costs. After the first year, these non-inverter BOS costs remained steadily near 33 percent. Together these percentages suggest a total BOS cost percentage in a range around 40 percent.

A 2006 study indicates that inverter costs range from 10 to 20 percent of total installed costs.[9] This higher proportion may be due to a focus on residential inverter sizes that are generally smaller and cost more per Watt than units found on larger systems. Although this

[6] SolarBuzz. http://www.solarbuzz.com/ModulePrices.htm. April 2006.

[7] Photex. Learning from the Sun; Analysis of the use of experience curves for energy policy purposes: The case of photovoltaic power, Final report of the Photex project. Schaeffer, G.J.; Seebregts, A.J.; Beurskens, L.W.M.; Moor, H.H.C. de; Alsema, E.A.; Sark, W.; Durstewicz, M.; Perrin, M.; Boulanger, P.; Laukamp, H.; Zuccaro, C. ECN Renewable Energy in the Built Environment. Report ECN DEGO: ECN-C--04-035, August 2004.

[8] Balance of system typically refers to all PV system components other than the modules

[9] Navigant Consulting, Inc. *A Review of PV Inverter Technology Cost and Performance Projections.* NREL/SR-620-38771. January 2006.

percentage range is higher than the 2001 report's and supports a BOS range of perhaps over 40 percentage, we will assume a basis of a 35 percent BOS portion for consistency with the module portion.

Separation of inverter costs from non-inverter BOS costs pares into two parts the assumed basis of 35 percent of total installed costs. The 10 to 20 percent range of total installed costs of Navigant contrasts sharply with the 5 to 10 percent range of SEPA. Dunlop indicates an inverter mean of 10 percent, with non-inverter BOS composing 27 percent. We assume a basis of 10 percent for inverters and 25 percent for other BOS costs.

- 2005 Inverter Cost Basis: 10 percent of total installed cost of $8.50 per Watt in 2005, or the inverter cost basis is $0.85 per Watt.
- 2005 BOS Cost Basis: 25 percent of total installed cost of $8.50 per Watt in 2005, or the non-inverter BOS cost basis is $2.12 per Watt.

Annual Operations and Maintenance Costs

The treatment of annual operations and maintenance (O&M) costs first presented in the Preliminary Cost-Effectiveness Evaluation Report was retained in this PV incentives analysis. An O&M rate of 0.4 cents/kWh (real 2006 dollars) was applied to a basis energy production rate of 1,451 kWh/year to yield an estimate of annual O&M of $5.80/year per kW of PV capacity.[10]

[10] PV O&M costs were estimated based on maintenance cost data obtained from interviews with SGIP PV participants, and on annual PV production rates. As such, the O&M costs represent averages weighted by PV capacity. See page 3-3 of "Preliminary Cost-Effectiveness Evaluation Report," September 2005.

4.2 Projecting PV Costs

As technologies mature, unit costs generally decrease with increasing cumulative output. A log-linear relationship is found to exist between unit cost and cumulative output. This learning curve relationship is described in Equation 1.

$$\frac{c_t}{c_0} = \left(\frac{Q_t}{Q_0}\right)^{-b} \qquad (1)$$

where:

c_t = unit cost at time t,
c_0 = unit cost at time 0,
Q_0 = cumulative output at time 0,
Q_t = cumulative output at time 0,
b = the learning coefficient.

The learning coefficient, b, is used to describe a learning ratio as shown in Equation 2.

$$LR = 1 - 2^{-b} \qquad (2)$$

where:

LR = learning rate.

The learning curve is useful for estimating future unit costs given some knowledge of future growth in cumulative output. Several PV system components have demonstrated a learning curve relationship, namely PV modules (Strategies, 2003; Maycock, 2002) and PV inverters (Photex, 2004). These same components have shown trends in cumulative output that may be extrapolated to project future growth in cumulative output (Strategies, 2003; Maycock, 2002). Thus, future unit costs for modules and inverters may be projected easily, subject of course to the limitations of the learning curve methodology and all it presumes.

The following sections discuss application of learning curves for PV modules and PV inverters as well as BOS generally. The PY 04 total installed cost basis has been established above. That total cost is broken into three general cost component areas: PV modules, inverter, and non-inverter BOS. The breakout relies on earlier studies of data on component cost percentages. Learning rates and cumulative growth rates are separately applied to these components to project future PV costs. Three boundary cases of learning and growth rates are applied. A central basis and optimistic (high) and pessimistic (low) boundaries establish a range of future possible PV costs. Projected total installed unit costs are the sums of the three projected component unit costs.

Projecting PV Component Costs

Projecting PV Module Costs

PV module costs have fallen as cumulative output has risen, just as the learning curve suggests. The primary cause of this decline may have little to do with learning effects and more to do with manufacturing plant expansion.[11] Nevertheless, a learning curve approach remains a useful tool for projecting costs. Figure 4-4 shows world PV module unit costs and cumulative output and the log-linear fit of a learning curve.[12]

Figure 4-4: A PV Module Learning Curve

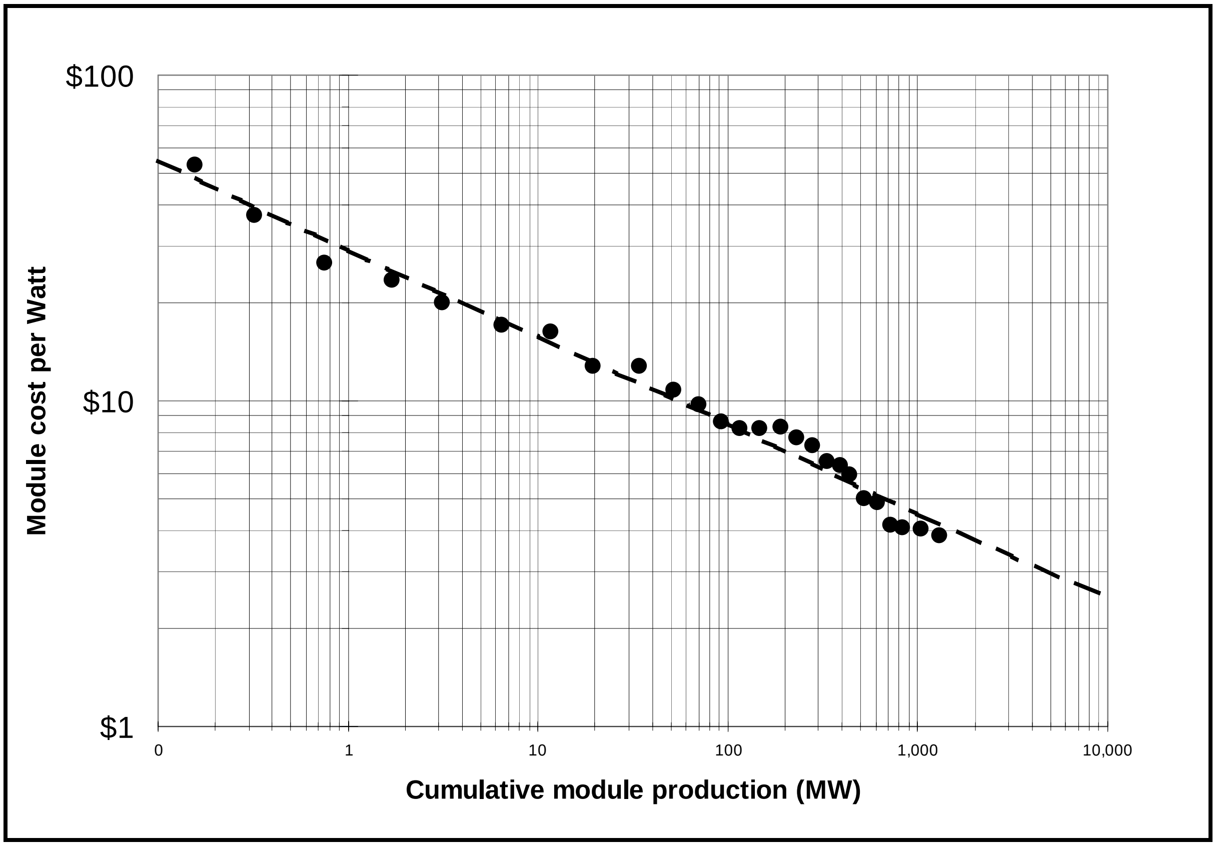


Figure 4-4 indicates a learning rate of 17 percent. Another study of world module unit costs shows a learning rate of 26 percent, with a higher starting point but a steeper decline in unit

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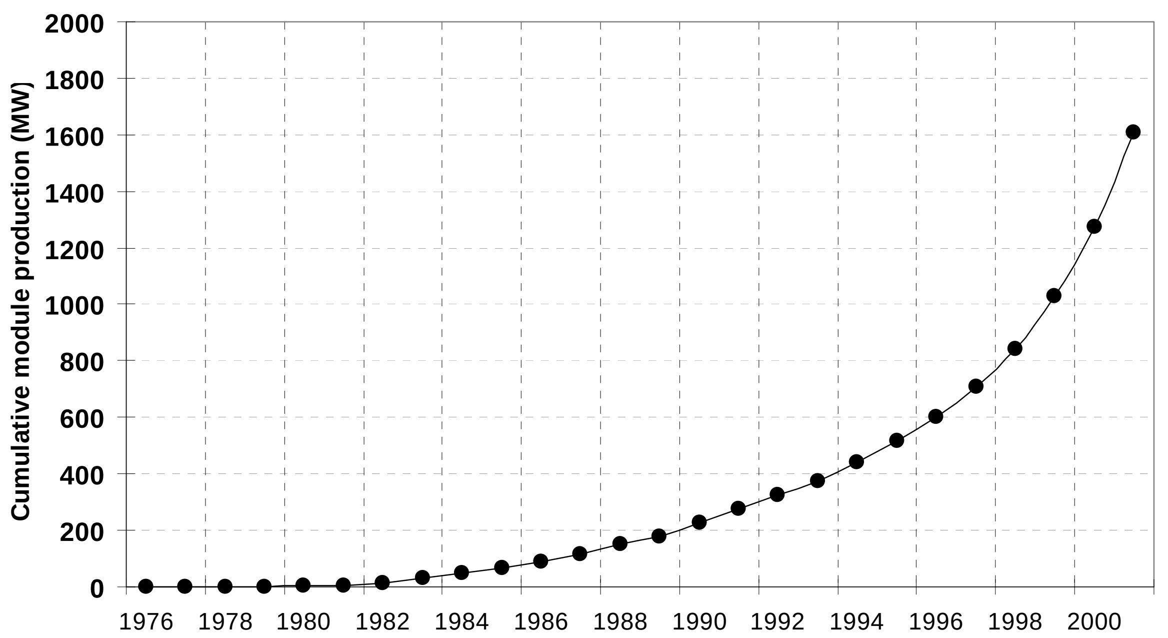
[11] Nemet, Gregory F. *Technical Change in Photovoltaics and the Applicability of the Learning Curve Model.* International Institute for Applied Systems Analysis. Laxenburg, Austria. Interim Report IR-05-029. April 2005.

[12] Strategies Unlimited. *Five-Year Market Forecast, 2002-2007.* Technical Report. PM-52. 2003.

costs.[13] We consider a range of learning rates to bracket future module unit costs. The central case has a learning rate used of 20 percent. An upper boundary case of 25 percent is the optimistic case. The lower boundary case is 15 percent.

For projecting future costs from a learning curve, an annual cumulative growth rate also must be defined. Figure 4-5 shows world PV module cumulative output.[14] The average growth rate from 1976 to 2001 is just over 40 percent, while the rate from 1995 to 2001 slows to just over 20 percent. Another study shows the 1995 to 2001 world rate to be 33 percent.[15]

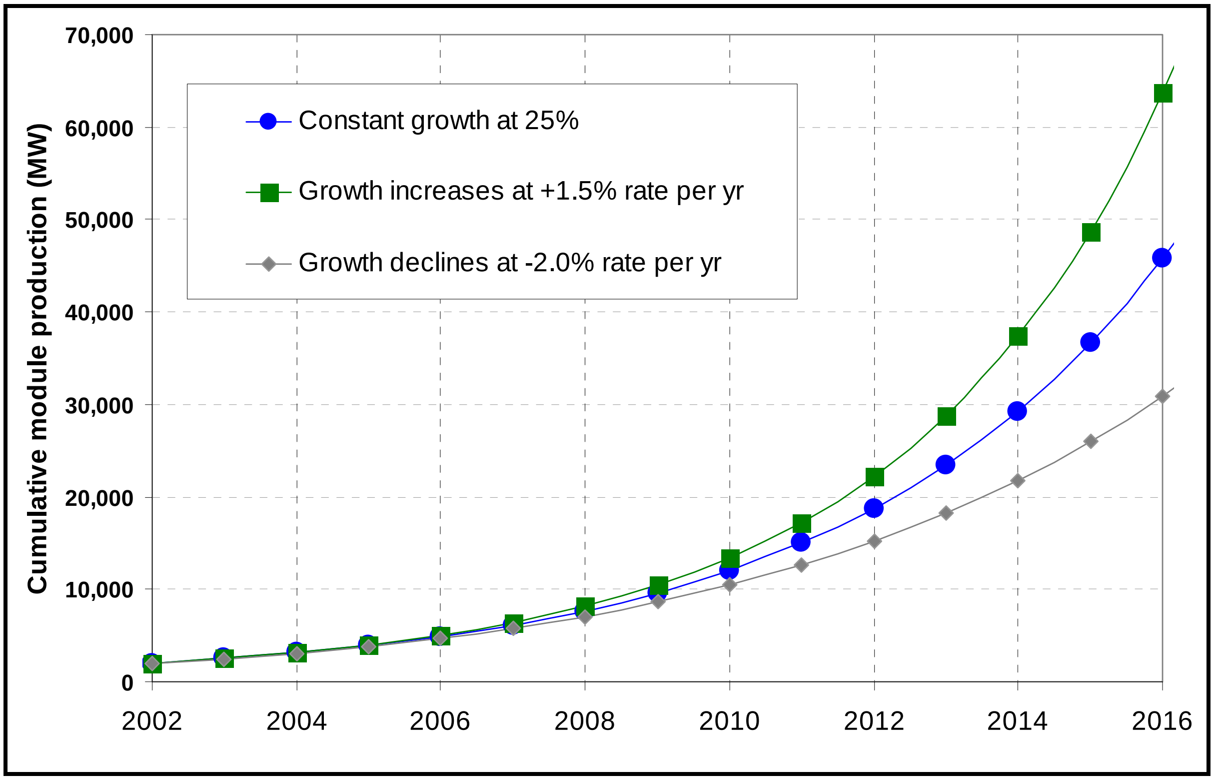
Figure 4-5: Historical PV Module Cumulative Output Curve



[13] Maycock, Paul D. *The World Photovoltaic Market.* PV Energy Systems. 2002.
[14] Strategies. *Five-year market forecast, 2002-2007*. Strategies Unlimited. Technical Report, PM-52, 2003.
[15] Maycock, Paul D. *PV News Annual Review of the PV Market 2004.* PV Energy Systems. 2004.

Given an observed range of 20 to 33 percent growth rates in recent years, we consider a range of growth rates to bracket future module unit costs. The central case is a constant annual growth rate of 25 percent from 2002. The high boundary case of optimistic growth increases that base rate by a relative 1.5 percent per year, reaching 33 percent by 2016. The low boundary case decreases that base rate by a relative 2 percent, reaching 17 percent by 2016. The three curves of central, high, and low boundary cases of projected cumulative output are presented in Figure 4-6.

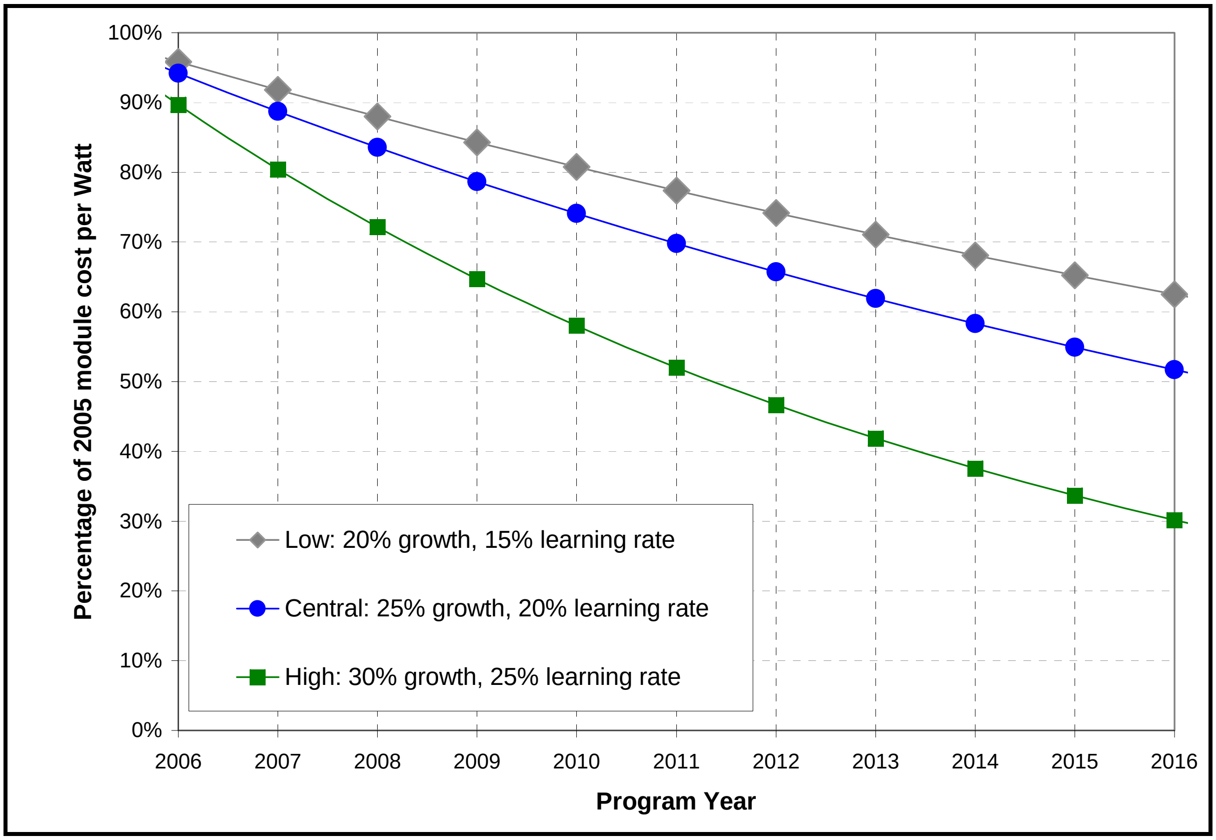
Figure 4-6: Projected PV Module Cumulative Global Output



- PV module learning and cumulative output growth rate boundary cases:
  - Central: learning rate = 20%, annual growth constant at 25%
  - High: learning rate = 25%; growth begins at 25% but increases 1.5% p/yr
  - Low: learning rate = 15%; growth begins at 25% but declines 2% p/yr

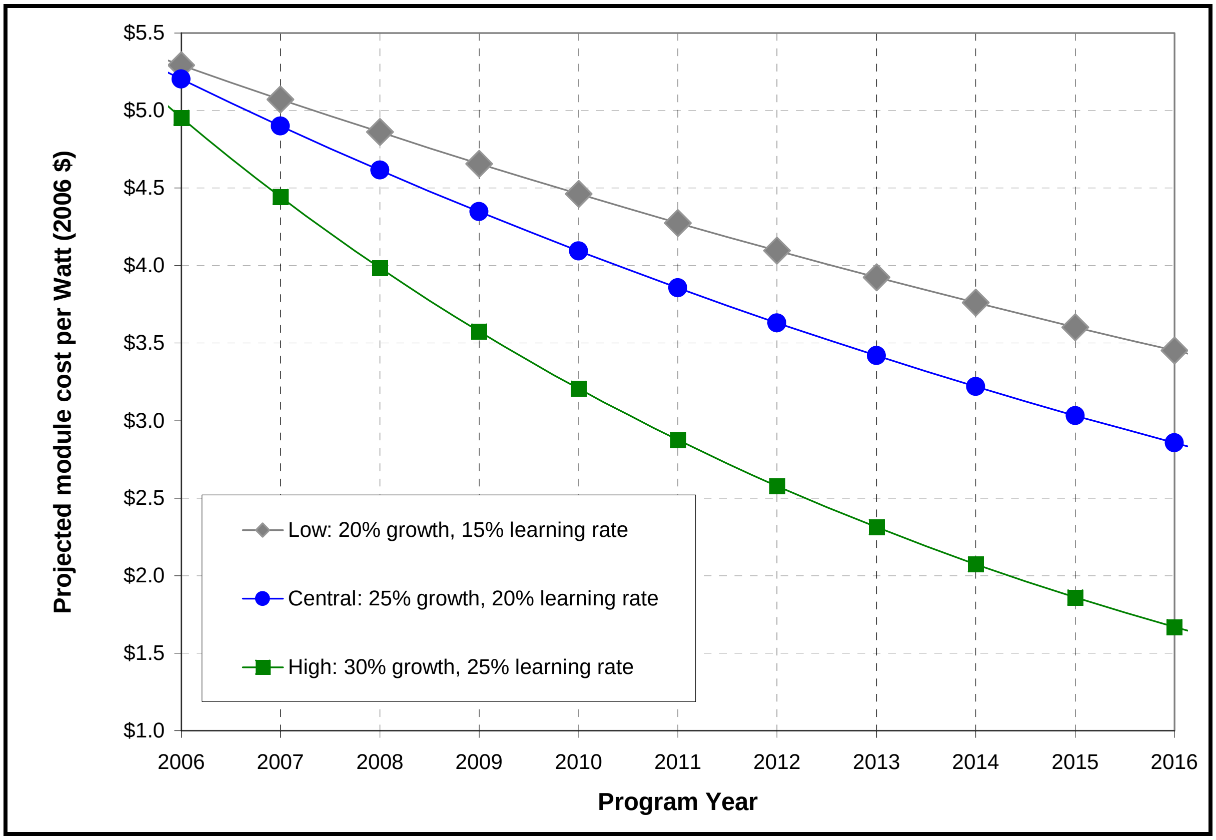
The percentages of 2005 module costs projected for the high, central, and low boundary cases are presented in Figure 4-7.

Figure 4-7: Projected Changes in Module Cost Basis



Module costs projected for three boundary cases are presented in Figure 4-8.

Figure 4-8: Projected Module Costs



Projecting PV Balance of System Costs

Application of a learning curve approach to project future unit costs of BOS faces disparate maturities in several technologies as well as in labor. Furthermore, recently stable inverter unit costs[16] do not reflect improvements in inverter modularity, functionality, and reliability.[17] Newly built-in features and accessories, such as disconnects and data acquisition systems, displace not only costs of otherwise non-inverter electric BOS hardware, but reduce labor costs for connecting circuit components.

A European study examined learning rates for BOS as a whole (distinct only from modules) as well as for inverters alone.[18] In the period from 1992 to 2001, Europe has shown BOS learning rates of 21 percent for four combined nations, 22 percent for Germany, and 18 percent for Netherlands.[19] The inverter learning rate for the combined-nations was 10

16 Solar Buzz, op. cit.

17 Navigant, op. cit.

18 Schaefer, op. cit.

19 Schaefer, ibid.

percent, that is, inverter unit costs did not fall as quickly as BOS as a whole. The implied non-inverter BOS learning rate for the period thus was roughly 24 percent.

The European study's learning rates for inverters are based on cumulative MW of installation. It has been noted that since the average capacities of inverters has been increasing over time, a historical learning rate based on count of inverter units would be higher than that based on MW.[20] Trends of increasing average inverter capacities will have to continue and costs not stabilize, for the projected costs to not be understated (or cost reductions to be overstated) by learning rate based either on MW or on count of units.

Analyses of world and national learning curves for PV inverters show nearly identical results, despite the U.S. having only 8 percent of installed world capacity in 2004.[21] Here then we will borrow from the European case and assume a central case for PV inverters with a learning rate of 10 percent and annual growth rate of 20 percent. For non-inverter BOS the central case will assume a learning rate of 20 percent. Inverter and non-inverter BOS boundary cases will have the same growth rates. The assumed parameters of the boundary cases are shown below. The projected changes in inverter and BOS costs are presented in Figure 4-9 to Figure 4-12.

- PV inverter learning and cumulative output growth rate boundary cases:
  - Central: learning rate = 10%, annual growth 20%
  - High: learning rate = 15%; annual growth 25%
  - Low: learning rate = 5%; annual growth 15%
- PV non-inverter BOS learning and cumulative output growth rate boundary cases:
  - Central: learning rate = 20%, annual growth 20%
  - High: learning rate = 30%; annual growth 25%
  - Low: learning rate = 10%; annual growth 15%

[20] Navigant, op. cit.

[21] Navigant, ibid.

Figure 4-9: Projected Changes in BOS Costs

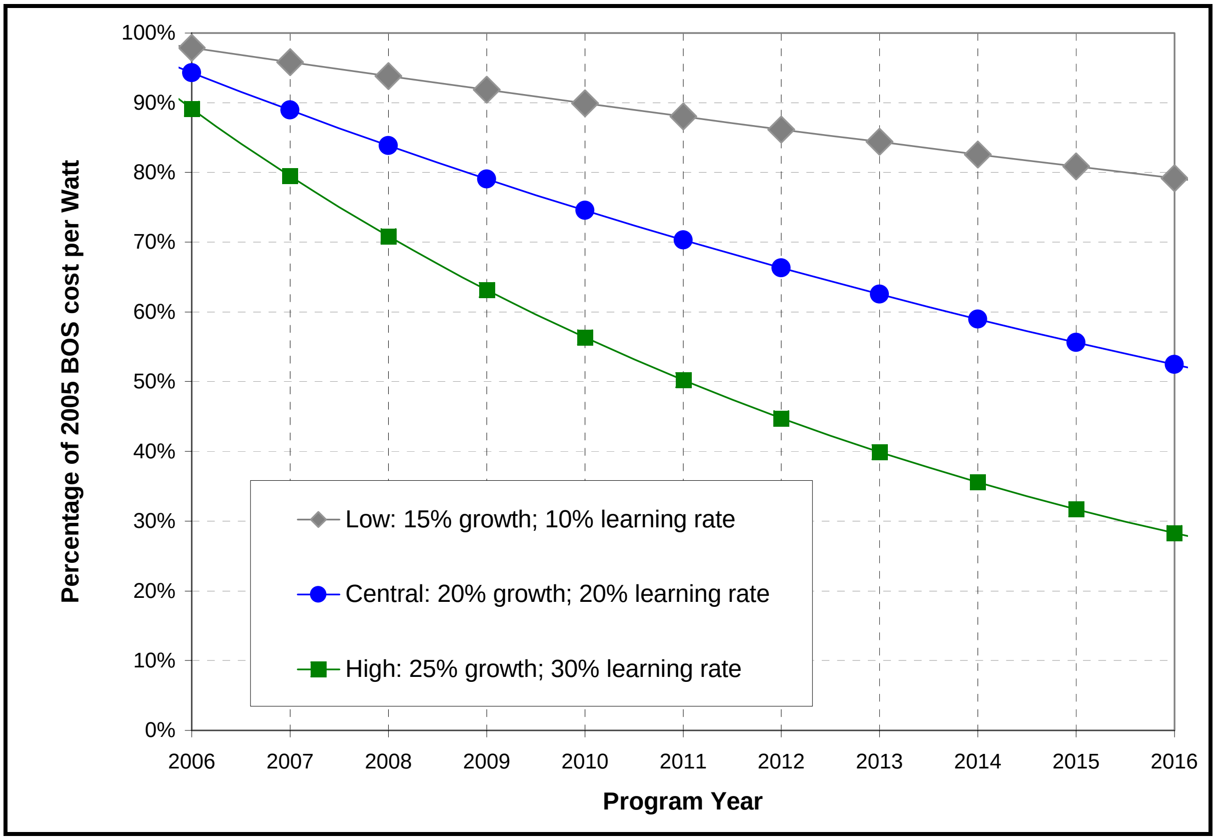


Figure 4-10: Projected BOS Costs

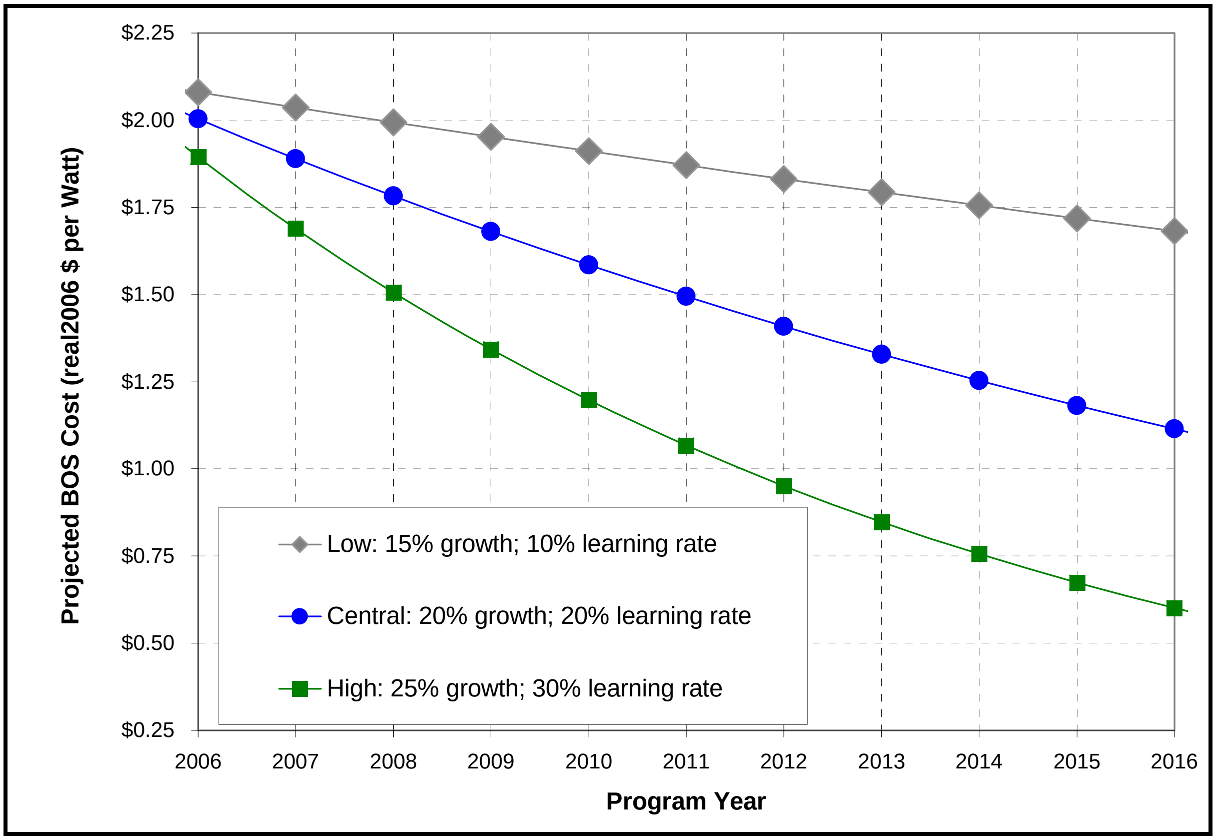


Figure 4-11: Projected Changes in Inverter Costs

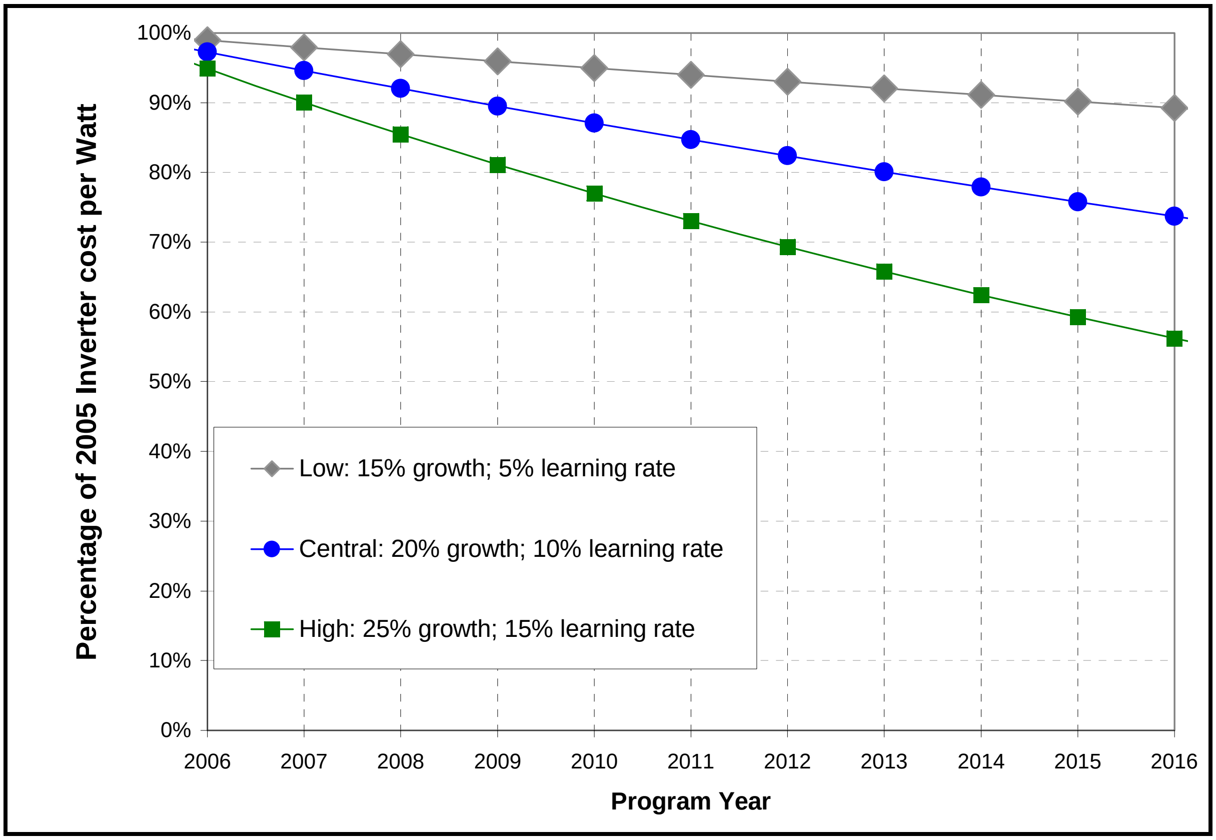
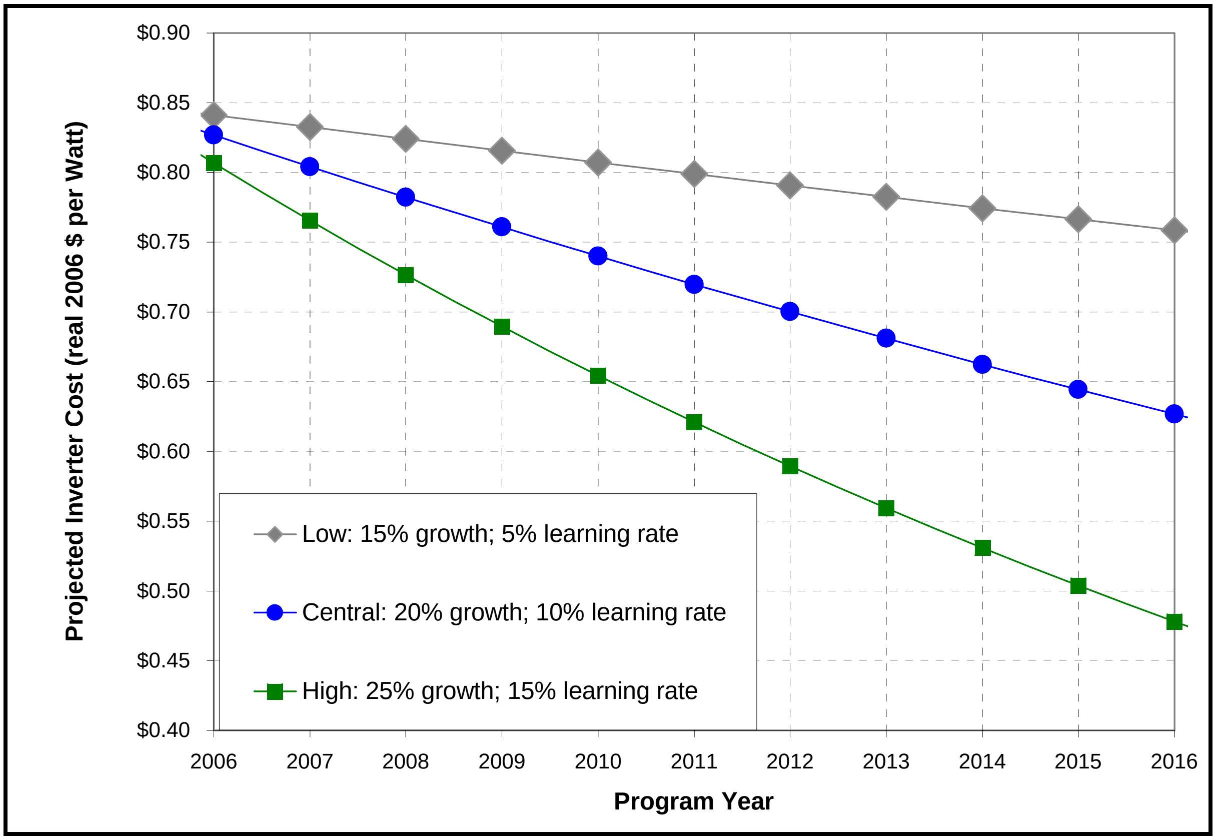


Figure 4-12: Projected Inverter Costs



Projecting Total PV System Costs

The learning rate, growth rate assumptions, and 2005 costs given the boundary cases allow projections of three cost components: modules, inverter, and non-inverter BOS. The projected total installed costs then are the sums by boundary case of these three component costs.

Figure 4-13: Projected Changes in Total Installed Costs

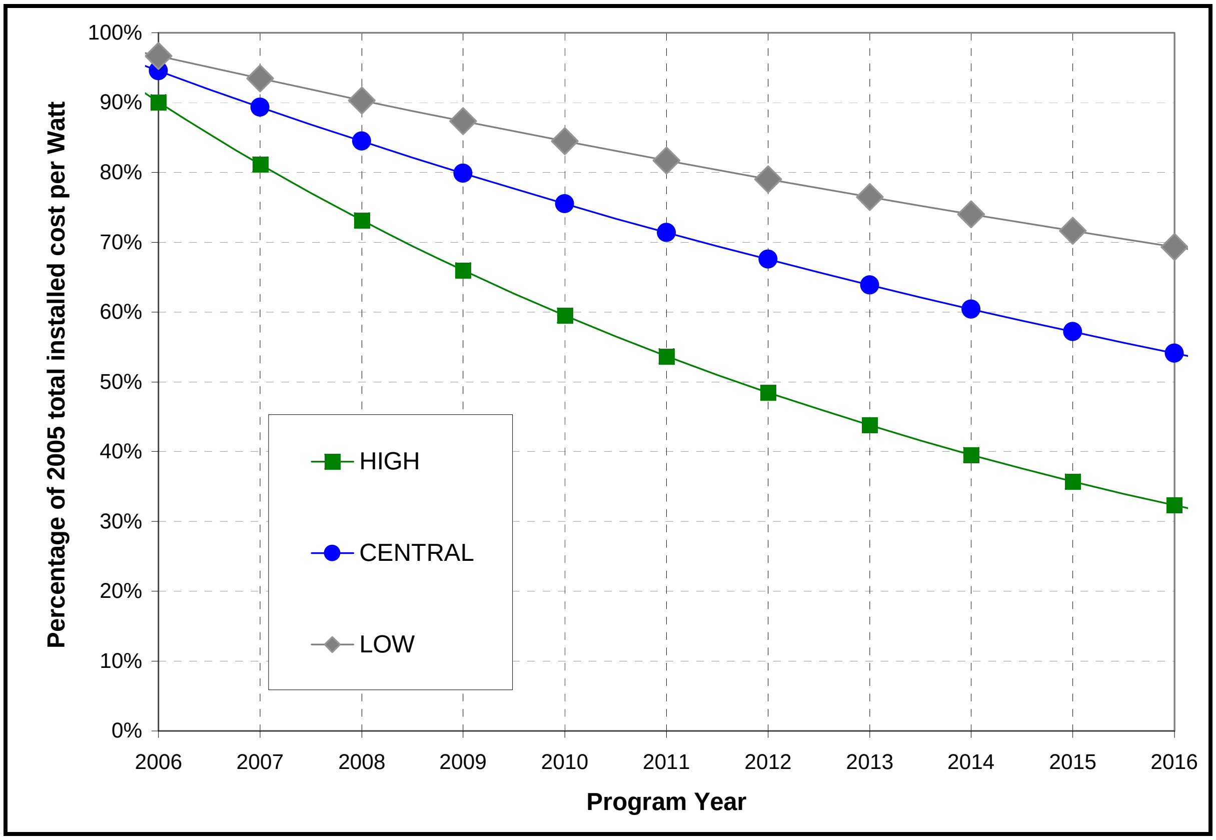
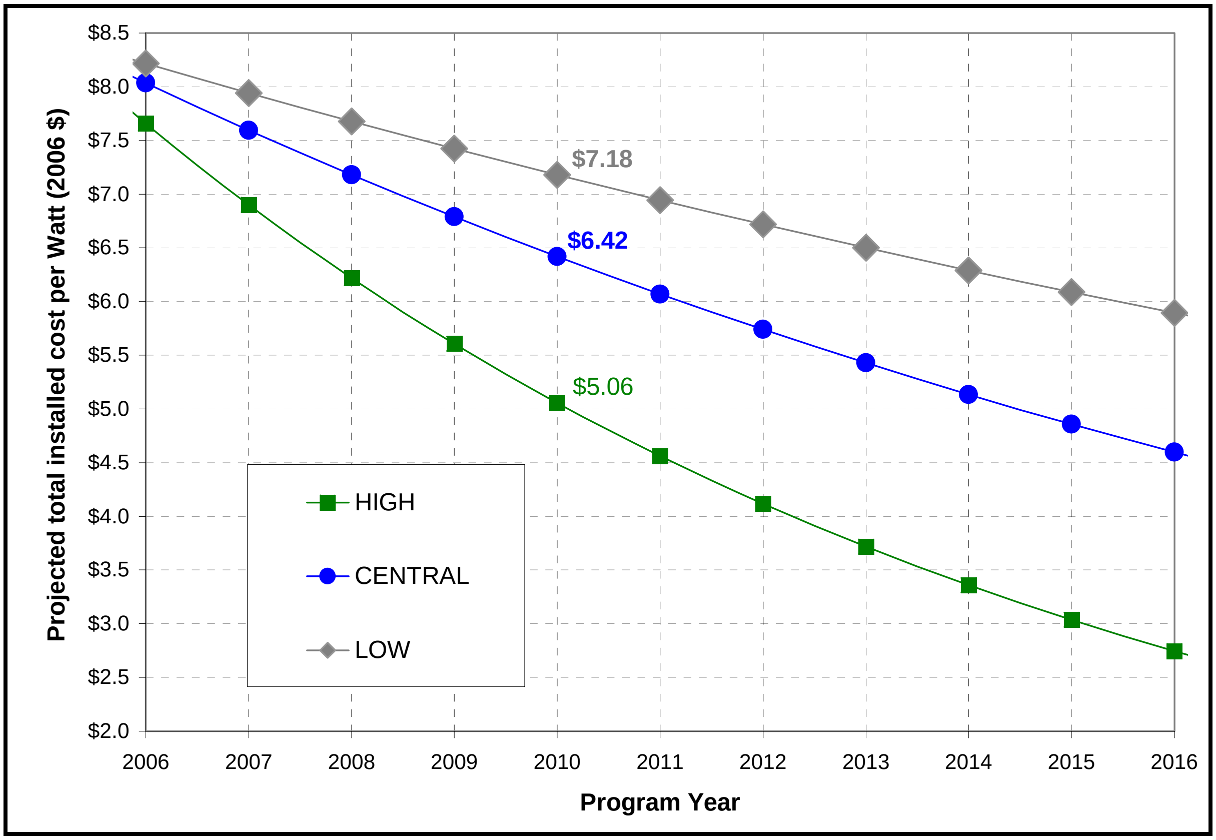


Figure 4-14: Projected Changes in Total Installed Costs



Component and total unit costs by year for the three boundary cases are presented in Table 4-3. The central case has total system cost reaching $6.42 in 2010, while the high case reaches $5.06 and low case reaches $7.18.

Table 4-3: Boundary Case Projected Costs

CENTRAL				
Year	**Module**	**Non-Inverter BOS**	**Inverter**	**Total Installed**
2005	$5.53	$2.13	$0.85	$8.50
2006	$5.20	$2.00	$0.83	$8.03
2007	$4.90	$1.89	$0.80	$7.59
2008	$4.62	$1.78	$0.78	$7.18
2009	$4.35	$1.68	$0.76	$6.79
2010	$4.09	$1.58	$0.74	$6.42
2011	$3.86	$1.49	$0.72	$6.07
2012	$3.63	$1.41	$0.70	$5.74
2013	$3.42	$1.33	$0.68	$5.43
2014	$3.22	$1.25	$0.66	$5.14
2015	$3.03	$1.18	$0.64	$4.86
2016	$2.86	$1.11	$0.63	$4.60
HIGH				
2005	$5.53	$2.13	$0.85	$8.50
2006	$4.95	$1.89	$0.81	$7.66
2007	$4.44	$1.69	$0.77	$6.90
2008	$3.99	$1.51	$0.73	$6.22
2009	$3.57	$1.34	$0.69	$5.61
2010	$3.21	$1.20	$0.65	$5.06
2011	$2.87	$1.07	$0.62	$4.56
2012	$2.58	$0.95	$0.59	$4.12
2013	$2.31	$0.85	$0.56	$3.72
2014	$2.07	$0.76	$0.53	$3.36
2015	$1.86	$0.67	$0.50	$3.04
2016	$1.67	$0.60	$0.48	$2.75
LOW				
2005	$5.53	$2.13	$0.85	$8.50
2006	$5.29	$2.08	$0.84	$8.22
2007	$5.07	$2.04	$0.83	$7.94
2008	$4.86	$1.99	$0.82	$7.68
2009	$4.66	$1.95	$0.82	$7.42
2010	$4.46	$1.91	$0.81	$7.18
2011	$4.28	$1.87	$0.80	$6.94
2012	$4.10	$1.83	$0.79	$6.72
2013	$3.92	$1.79	$0.78	$6.50
2014	$3.76	$1.76	$0.77	$6.29
2015	$3.60	$1.72	$0.77	$6.09
2016	$3.45	$1.68	$0.76	$5.89

<u>Comparisons to Industry PV Road Map</u>

For benchmark purposes, we compared our cost projections against projections developed by the National Center for Photovoltaics. The National Center for Photovoltaics targets an installed system price inclusive of operating and maintenance costs to be $3 to $4 per Watt by 2010 (presumably 2010 dollars).[22] Our central case does not break the $5 per Watt (2005 dollars) barrier until 2015, and would not reach the targeted range until 2019. The high case does reach the targeted range, but not until 2013. Consequently, we believe our projected costs represent a realistic, but somewhat more conservative set of costs.

Projecting O&M and Repair Costs

Operations and maintenance costs are assumed to remain unchanged in real terms. Inverters are assumed to require replacement after their eleventh year of use. Inverter replacement costs are based on results of inverter cost modeling discussed above. The central-boundary inverter costs from Table 4-3 were marked up 50 percent to account for installation costs and tax.

4.3 PV Costs that California May Influence

PV costs can be influenced by factors other than incentive structures. For example, improvements in technologies or disruptive technologies can play key roles in reducing PV costs. Similarly, changes in policies or requirements that tend to increase the costs of implementing PV systems could help lower PV costs. For instance, non-inverter BOS costs that might be influenced in California include interconnection material and labor costs. Streamlining and education of Rule 21 and statewide interconnection requirements may avoid costly delays that prevent system start-up.

SGIP process studies indicate applicant dissatisfaction with the expense, project delays, and frustration of the interconnection process. Utility interconnection representatives reported that delays in the interconnection process come from incorrect application information, subsequent turnaround back to the utility of requested information, supplemental reviews for larger projects, and obtaining permit approval from the local authority. Additional delays occur when initial inspection indicates the system electrical layout does not match the single-line drawing, a common problem being installation of system disconnect more than 10 feet from the utility's facility electric meter. Applicants countered there was uncertainty regarding interconnection requirements and differences between utilities, and delays and added equipment cost due to utility requirements to install more protection equipment and to perform testing.

[22] Department of Energy, National Center for Photovoltaics. *Solar-Electric Power: The U.S. Photovoltaic Industry Roadmap.* Reprinted January 2003.

Promulgation of streamlined and identical interconnection requirements across all utilities, and support for training of system developers, program applicants, utility interconnection representatives, and local inspectors in meeting these requirements would reduce the costs of these delays.

Other non-inverter BOS costs that might be influenced in California include labor costs to meet program requirement for provision of detailed cost estimates. Development of streamlined accounting worksheets that begin with standardization of project developers' cost categorizations and further allow applicants and hosts to categorize project costs will reduce the associated administrative labor costs. Furthermore, retention of electronic copies of such worksheets will allow far better capture of discrete program cost data useful to program evaluation.

In addition to development of cost standardization, development of another standard may reduce labor related to economic estimation. A PBI incentive approach will require a more concerted effort than a CBI approach to determine incentive value as part of financial planning. Thus a PBI approach may well benefit from a standard PV performance cost model available to all potential developers, applicants, and hosts. A standard performance cost model approved by the program, and credible to lenders, will lessen the additional difficulty and uncertainty related to this more concerted effort. Developed to include unexpected initial costs such as exit fees and future costs such as inverter replacement, such a model may reduce surprised dissatisfaction as well as delays and costs related to project financing.

California could also possibly influence PV installation costs by streamlining the permitting and sign-off processes associated with plan and inspection reviews. Use of template permitting requirements and increased training or certification of PV plan inspectors could significantly accelerate review time and result in cost savings that would impact overall PV system costs.

In addition, provisions for research and development of improved solar technologies can help reduce PV costs. One such effort could focus on improving inverter reliability and lifetime. Increasing the mean time between inverter failure would help improve PV system costs.

4.4 Summary

Based on cost data reported under the SGIP, we have found that a reasonable baseline for PV system costs is approximately \$8.50 per $Watt_{AC}$. Similarly, using learning curves established for the PV industry, we have projected PV costs over 10 years. Under a set of "central" case conditions, we expect PV system costs to decline by over a factor of two to approximately \$4.60 per $Watt_{AC}$ by 2016. Lastly, we have indicated that California can pursue several actions that may address cost reductions that go beyond those typically associated with module price reductions.

5

PV Economic Benefits

PV systems developed under incentive programs will reduce reliance on electricity from conventional sources. This results in economic benefits for owners of the PV systems, utility ratepayers and society. This study's principal focus is the impact of PV performance **and** cost on incentive design. It should be noted that costs should not be used by themselves as a means of trying to set incentive levels. As incentive payments will first affect PV system owners, we have focused primarily on looking at incentive structure impacts on PV system owners. This section specifically identifies economic benefits accruing to PV system owners. Ratepayer and societal benefits will be only briefly discussed in this report.

Our approach within this section is to develop a method for valuing benefits realizable by PV system owners based on displaced retail rate electricity and tax advantages. Values for displaced retail rate electricity are based on existing and projected electric tariffs. We then estimate tax benefits based on federal investment tax credits, state and federal depreciation benefits, and deductions on loan interest payments.

5.1 Valuing Displaced Retail Rate Electricity

PV system owners receive benefits by generating electricity which partially or completely offsets retail rate electricity that they would otherwise purchase from their utility. Under the net generation rules in effect in California, the before-tax (BT) value of these purchases is the full retail price the PV system owner would have paid for all energy[1] generated by their PV system. This value is a function of PV system performance and utility tariffs.

Utility Tariffs

Current Tariffs: The three IOU utilities modeled in this analysis each have distinct tariff structures and rates. Although numerous tariffs might be applicable to commercial and industrial PV system owners in each utility, the analysis was simplified by restricting

[1] Only energy costs are discussed in this draft. Our preliminary finding is that PV system owners would realize very little savings due to demand charge reduction because the demand charge depends on the maximum 15 or 30 monthly demand during the peak or partial peak periods. Because of the timing of these periods, even the occasional cloudy day will largely erase this benefit.

consideration to just one widely applicable tariff in each of the utility areas. Each of these tariffs is structured into seasonal and time of day periods, with differing energy rates for summer and winter periods and for peak, partial peak, and off-peak times of the day. The actual days and times when these rates apply and the actual 2006 rates for each of these tariffs are inputs into the valuation model.

Table 5-1: Electric Tariffs

Utility	Electric Tariff
PG&E	E-19: Medium General Demand-Metered Time-of-Use Service
SCE	TOU-8: Time-of-Use – General Service – Large
SDG&E	AL-TOU-DER: General Service – Time Metered – Distributed Energy Resources

Tariff Rate Escalation: Although the effects of inflation are neutralized in this analysis by expressing all costs and benefits in constant 2006 dollars, it was necessary to project how electric rates might change in real terms over the 25-year life of PV systems. Because of the difficulty in forecasting rates, two approaches were used in this analysis to determine the sensitivity of this factor.

In the Itron Cost-Effectiveness study, tariff rate escalation was based on the future revenue requirement projections submitted by the IOU to the CEC in 2005. These projections, documented in Itron 2005[2] result in real price escalations as shown in Table 5-2.

Table 5-2: Projected Electric Tariff Escalation Rates

Boundary	Electric Tariff Escalation Rate (%, Real)
Low	0.0%
Central	1.5%
High	3.0%

The second approach was to simply assume a 3 percent per year real rate escalation. This factor is based on the recent historic trend of electricity prices. It is also an assumption used in several prominent recent PV feasibility analyses.[3,4] Under this assumption, rates increase by 110 percent by the end of 25 years.

[2] Appendix C: Energy Price Forecasts, Cost-Effectiveness Report, September 14, 2005

[3] ASPv, 2005

[4] Wiser, 2006

Note that as opposed to the 3 percent real escalation assumption, the projected rates in Table 5-2 actually decrease slightly from their current levels. By using both of these escalation rates, we are able bracket the effects of utility rate changes.

These current and projected rates, combined with the TMY performance data, are integrated in the analysis to model the value of power generated in each of the 39 scenarios over the 25-year life cycle of PV systems in the SGIP. We believe this results in a well-rounded approach to estimating value of displaced retail rate electricity.

5.2 Tax Benefits

Federal and state tax benefits are likely to contribute heavily to the value received by participants in an incentive program. Tax benefit considerations include federal investment tax credits, state and federal depreciation benefits, and deductions on loan interest payments. These benefits are all used in the incentive modeling analysis. The assumptions and estimates of each of these tax benefit areas are briefly discussed below.

Tax Bracket: To model tax effects, it is first necessary to know the marginal tax bracket of the beneficiary. To simplify the analysis, it is assumed that all commercial-sized PV owners are in a 34 percent federal and an 8 percent California marginal tax bracket, for a combined effective tax rate of 39.3 percent. Thus, the after-tax (AT) value of tax deductions is 39.3 percent of the total of those deductions.

Investment Tax Credit (ITC): As opposed to deductions, tax credits such as the ITC reduce tax liabilities on a dollar-for-dollar basis. The Energy Policy Act of 2005 provides a 30 percent ITC for the cost of PV improvements. This 30 percent credit applies only to systems installed in 2006 and 2007. After 2007 the ITC rate currently is scheduled to drop to 10 percent. This amount applies to the gross capital investment for new PV systems. The present analysis assumes that PV owners are commercial operations with tax liabilities sufficiently high to utilize the entire tax credit.[5]

Depreciation: PV owners are able to claim the depreciation of their systems as a tax deduction. The federal MACRS (modified accelerated cost recovery schedule) allows owners to deduct the depreciation of the installed cost of their systems[6] over six years at a rate of 20, 32, 19.2, 11.5, 11.5, and 5.8 percent per year respectively. State depreciation

[5] In particular, we want to draw the distinction with residential PV systems that are capped at $2,000 or with tax-exempt operations.

[6] Current opinion, assumed in the present analysis, is that the entire cost of the system, without netting out incentive payments, is eligible for the ITC and depreciation basis, as long as the incentive payment is treated as taxable income. This has not yet been verified by the IRS.

deduction is straight line over 12 years. The depreciation basis is reduced by 50 percent of the ITC credit value.

Other Tax Considerations: The interest paid on loans for PV systems is deductible to the payee. Thus, the net cost of interest on capital borrowed to finance PV systems is reduced by the marginal effect tax rate, which is assumed to be 39.3 percent. The AT benefit of reduced retail electricity purchases must be discounted from its BT value by the marginal tax rate.[7]

5.3 Summary

We have developed a method for valuing benefits realizable by PV system owners based on displaced retail rate electricity and tax advantages. Current values for displaced retail rate electricity were based on existing electric tariffs. We projected future values of displaced retail rate electricity using a combination of real rate escalation factors and revenue requirement-based escalation factors. We used federal investment tax credits, state and federal depreciation benefits, and deductions on loan interest payments in estimating tax benefits.

[7] This is because had the PV system owner purchased retail power instead of self-generating, the BT purchase cost would have been a deductible business expense.

6

PV Incentive Analytic Methodology

PV incentives are only necessary when PV costs (Section 4) exceed PV benefits (Section 5). This section describes a lifecycle breakeven approach wherein PV benefits are set equal to PV costs. Under this breakeven approach, the difference between costs and benefits provides the required incentive level. When combined with projections of future PV costs and benefits and the factors that impact them, the approach allows for evaluation of possible incentive designs. Methods and key factors used to calculate the breakeven incentive levels are outlined. Next the development of several possible incentive designs is described. Finally, methods used to assess the likely impact of those incentive designs on the prospective PV owners are summarized.

6.1 PV Incentive Requirement

Benefits and costs of PV system prototypes were combined in pro forma[1] financial models to estimate required breakeven subsidy levels. A simplified summary of the calculations is described by the equation below.

Subsidy = Costs – Benefits

Benefit and cost components included in the calculations are listed in Table 6-1. A key aspect of the analysis was the incorporation of a discount rate. A discount rate is a quantitative measure of the preference to receive financial benefits immediately rather than at some time in the future. For example, the undiscounted sum of five annual performance based incentive (PBI) payments (under a five-year PBI) would be less than the sum of 20 annual PBI payments (under a 20-year PBI) for the identical level of discounted subsidy. PV system owners generally favor near-term payments to those accruing during later years.

The actual calculations are quite involved due to this discounting and also due to the variable nature of the components. Documentation of the calculations is included as Appendix A.

[1] The calculations are necessarily based on projections of future conditions. Such projections are subject to uncertainty. Financial analyses conducted in advance using projections of future conditions are termed “pro forma” to clearly differentiate them from analyses where actual values are known.

Table 6-1: Components of Breakeven Subsidy Analysis

Costs	Benefits
Loan Payments Operations & Maintenance Periodic Repair Lost tax advantage from deductible Purchased Retail Energy Value	Federal Tax Credit Federal Tax Depreciation State Tax Depreciation Net-Metered PV Retail Energy Value Loan Interest Tax Benefit Salvage

6.2 PV Incentive Design

PV incentives have several purposes that should be addressed in the design. Incentives are a means of providing public support to help in market transformation of a technology that can provide significant public benefits. Incentives are also used to help bridge the gap between the costs of installed PV systems and the economic benefits received from those installed systems, thereby reducing the risks to early PV adopters. Last, incentives can provide a means to encourage technology innovation that accelerates the timeframe under which an emerging technology transforms into a cost-competitive and mainstream market product.

Pro forma investment requirement modeling yields estimates of total net present value incentives for program participants willing to pay as much—but not more—for PV as they would have paid a utility company for electricity. While these data are necessary for incentive design, they are not sufficient. Additional information is required to establish incentive program structural elements such as duration and variability of payments. In this section an overview of the range of possible incentive structures is followed by discussion of select incentive structures included in the quantitative analysis. Lastly, the methods used to define specific incentive rates are presented.

Range of Possible Incentive Structures

The range of possible PV incentive structures is almost limitless. A general framework for classifying these innumerable incentive structures has been proposed by Hoff (2006).

Most PV incentive programs have focused on buying down the high cost of PV systems. Bollinger and Wiser have reported on buy-down approaches used in Japan and Germany.[2] Japan's PV industry was supported with a capital cost buydown approach that was initiated in 1994 and offset from 33 to 50 percent of the capital cost of the PV system. PV support in Germany started with a buydown approach in 1990 that covered up to 60 percent of the cost

[2] Bollinger, M., and Wiser, R. "Support for PV in Japan and Germany," Clean Energy Group and the Berkeley Lab, September 2002

of a PV system, and later added feed-in tariffs. Unlike Japan, Germany migrated to an incentive structure that tied PV incentives to performance.

California's support for PV has also followed a buy-down approach. The two largest PV incentive programs in California are the SGIP overseen by the CPUC and the ERP administered by the CEC. Both programs have typically used capacity-based incentive (CBI) approaches.[3] Under a CBI approach, incentives are based solely on the eligible installed PV capacity and are paid in full upon verification of a successful installation. While PV system performance may be monitored, the incentive level remains independent of the system's performance over time.

The attractiveness of a CBI approach is its relative simplicity and reduction in risk to buyers. However, the CBI approach has some important shortcomings. Because incentives are based solely on the eligible installed capacity, a CBI fails to account for PV system performance. As such, poorly installed or maintained systems receive the same incentive as properly installed and maintained systems. Moreover, the lack of clear connection between PV performance, cost, and incentive payments in a CBI program tend to restrict adjustments to PV incentive levels to the extent of participation within the program. Adjustments based on participation levels make it difficult to plan retirement of PV incentives that correspond to emergence of cost-competitive PV technologies.

A recent report by Lawrence Berkeley National Lab (LBNL) investigated incentive levels, installed costs, and relative costs of different PV applications implemented under the SGIP and ERP.[4] The LBNL report concluded that while PV costs have declined over the course of the two programs, it was difficult to tie causation of the decline to the incentive programs or to decreases in the incentives. The report also pointed out that PV module costs are set by world market prices and that non-module PV costs should be the primary focus of local PV incentive programs. Both findings are important in pointing to the need for a clear means for adjusting PV incentive levels and the local aspect by which adjustments can be influenced.

Concerns over limitations of CBI approaches have lead to increased interest in PV incentive structures that bring PV performance and cost more clearly into play. In a January 12, 2006 decision (Decision (D.) 06-01-024); the CPUC expressed its intention to explore performance-based incentive (PBI) options prior to a January 2007 initiation of the California Solar Initiative (CSI).[5] In that same decision, the CPUC indicated its belief that "solar

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[3] The CEC initiated a small $10 million pilot-scale performance based incentive approach in 2004. However, the remaining ERP incentive approach is based on a capacity buy down.

[4] Lawrence Berkeley National Laboratory, "Letting the Sun Shine on Solar Costs; An Empirical Investigation of Photovoltaic Cost Trends in California," January 26, 2006

[5] Discussed in Section VI (Structure of Incentives: Capacity-Based, Performance-Based and Auctions)

technologies can improve and become more cost-effective with a 'push' from an incentive program and the 'pull' of a program design that encourages technological improvements." Similarly, other entities are investigating or beginning to implement PBIs, including We Energies, the New Jersey Clean Energy Fund, North Carolina Green Power, etc. For these reasons, we have focused our evaluation of incentive design on a PBI framework.

Classification of a PBI framework is summarized in Figure 6-1. One additional key classification element concerns the grouping of program participants. A single PV incentive structure can be used statewide, utility-specific incentive rates can be used, or participant groups can be further broken down to the climate zone or PV system configuration level. Selection of an incentive structure suitable for a particular set of circumstances involves balancing the needs and desires of numerous stakeholders.

Figure 6-1: PBI Structure Classification Framework (Hoff, 2006)

<table>
<tr><td colspan="2" rowspan="2"></td><th colspan="2">Once a customer invests, the PBI rate:</th></tr>
<tr><th>Is fixed over time</th><th>Varies over time</th></tr>
<tr><th rowspan="2">The duration of PBI payments:</th><td>Is a fixed number of years independent of when the customer invests</td><td>Fixed duration
Fixed rate</td><td>Fixed duration
Variable rate</td></tr>
<tr><td>Varies depending upon when the customer invests</td><td>Variable duration
Fixed rate</td><td>Variable duration
Variable rate</td></tr>
</table>

Incentive Designs Included in Analysis

Both CBI and PBI designs were included in the analysis. The specific PBI structures included are listed in Table 6-2. As with the PBI modeling, CBI models were developed both for a statewide CBI rate and for the case where separate CBI rates are used for each electric utility service area.

Table 6-2: PBI Structures Included in Quantitative Modeling

PBI Structural Element	Quantitative Modeling Basis
Duration	Fixed (5 years)
Temporal variability	Fixed (same rate in each of 5 years)
Geographic/Utility variability	Fixed (statewide PBI) Variable (separate PBI for each IOU)

These specific quantitative modeling bases were selected for their representative and illustrative value. Omission of other structures is not intended to suggest that they are undesirable. A quantitative analysis like this is best suited for detailed analysis of select possibilities. More qualitative approaches are ideally suited for comprehensive summary analyses. Finally, it is important to note that this analysis is being used to explore the influence of other uncertain factors affecting subsidy requirements (e.g., federal Tax Credit variability, PV system cost variability, retail electricity price variability).

Development of Incentive Values

Just as there is a wide variety of possible incentive structures, there is a similarly wide variety of possible incentive rates for each structure. Consider the case of a statewide incentive. The subsidy requirement analysis shows that a single incentive rate would affect the various groups of prospective customers differently depending on factors such as utility tariffs and location, PV system configuration, and initial PV system cost. Adoption of a single statewide incentive rate would result in the subsidy being focused on those scenarios that have favorable climatic conditions and/or those whose utility retail energy rates are higher. Scenarios with higher than average incentive requirements would be less likely to develop PV projects.

In this analysis both statewide and utility-specific incentive rates were calculated. In both cases the incentive rates were determined as the median of the subsidy requirements for the applicable group. For the statewide incentives the medians of the 39 prototype-specific subsidy requirements was used as the statewide incentive rate. Minimum or maximum subsidy requirements within groups are other likely bases for incentive rates. Lastly, the incentive analysis could incorporate information about the distribution of performance observed among groups of similar PV systems. For example, identical PV system configurations at the same location would produce different quantities of energy if only one of them was cleaned regularly. If the incentive definition process were based on the performance of the cleaner array then poorer-performing PV systems could expect to achieve something less than breakeven financial performance. It is conceivable that this incentive definition approach could motivate PV system owners to implement operation and maintenance best practices.

6.3 Application of Program Incentive Designs

One goal of this study is to evaluate the cost:benefit aspects of PV incentives. The approach used to develop incentive rates for this study provided scenarios where most PV system owners received incentives that are either higher or lower than the breakeven requirement yielded by pro forma modeling. This result could be expected due to differences in location, solar resource, tariff rates, etc. but made it difficult to assess an overall cost:benefit ratio. Consequently, to gage the significance of the resulting variability in expected pro forma financial models, cost:benefit ratios were recalculated using the applicable statewide and utility-specific incentive rates in lieu of the breakeven subsidy requirement.

6.4 Summary

Within this section, we developed a lifecycle breakeven approach for estimating required PV incentive levels. Due to the relationship between the "push" of an incentive program and the "pull" of PV technological improvements, we focused our evaluation of incentive design to a PBI structure. This PBI structure became a basis upon which we could then apply PV performance characteristics developed in Section 3 to evaluate the economic impacts of PV performance on incentive levels.

7

PV Incentive Analysis Results

Results of the PV incentive analysis are presented in this section. We first provide estimates of PBI and CBI levels for 2007 based on representative PV systems developed in Section 3 and using the lifecycle breakeven approach. We then show the influence of PV system location and configuration on required PV incentive levels as well as impacts due to changes in retail rates and the federal ITC. Effects of these factors on the financial well-being of PV owners are described. Lastly, we examine the impact of PV performance and cost factors on a single statewide incentive versus utility-specific incentive levels.

7.1 Breakeven Incentive Requirements

The breakeven incentive requirement is the total net present value of the incentive that just provides a prospective PV owner an expectation that PV system costs will be offset by benefits (including the incentive). This balance marks a point of financial indifference where high costs no longer prevent decisions to purchase PV. Breakeven incentive requirements were calculated for thousands of unique combinations of factors (Program Year, discount rate, location-configuration-utility prototype, electricity price-PV cost scenario), each combination modeling the decision of a particular group of prospects. The scope of these calculations is summarized in Table 7-1.

Table 7-1: Scope of Breakeven Incentive Requirement Calculations

Factor	No.	Values
Location-Configuration-Utility Prototype	39	Utilities: PG&E-SCE-SDG&E Climate Zones: 12 PV Configurations: Flat, South @ 15˚, SW @ 30˚
Program Year (PY)	10	2007 - 2016
Electricity Price-PV Cost Scenario	3	Low: Low Retail Rate Increase & PV Cost Decrease Central: Central Retail Rate Increase & PV Cost Decrease High: High Retail Rate Increase & PV Cost Decrease
Federal Investment Tax Credit (ITC)	4	30% ITC: 2007, 2007-2009, 2007-2011 (reverting to 10% in all three scenarios)
Participant Discount Rate	5	0%, 3%, 6%, 9%, 12%

Modeling large combinations of factors allows bracketing of possible incentive outcomes and better identification of the factors that have the greatest impacts.

A partial set of the results of the breakeven incentive requirement calculations is illustrated in Table 7-2. This table reflects equivalent CBI and PBI levels using central electricity price-PV cost assumptions for customers purchasing PV systems in 2007. The results represent the NPV (net present-value) calculations of cash flows over the PV system's 25-year useful life. As shown in Table 7-2, representative CBI and PBI calculated values for 2007 are approximately \$1.39 per Watt and \$0.22 per kWh respectively. In comparison, the April 24, 2006 CPUC staff report includes a CBI value of \$1.50 per Watt and a PBI value of \$0.17 per kWh for small commercial taxable entities.

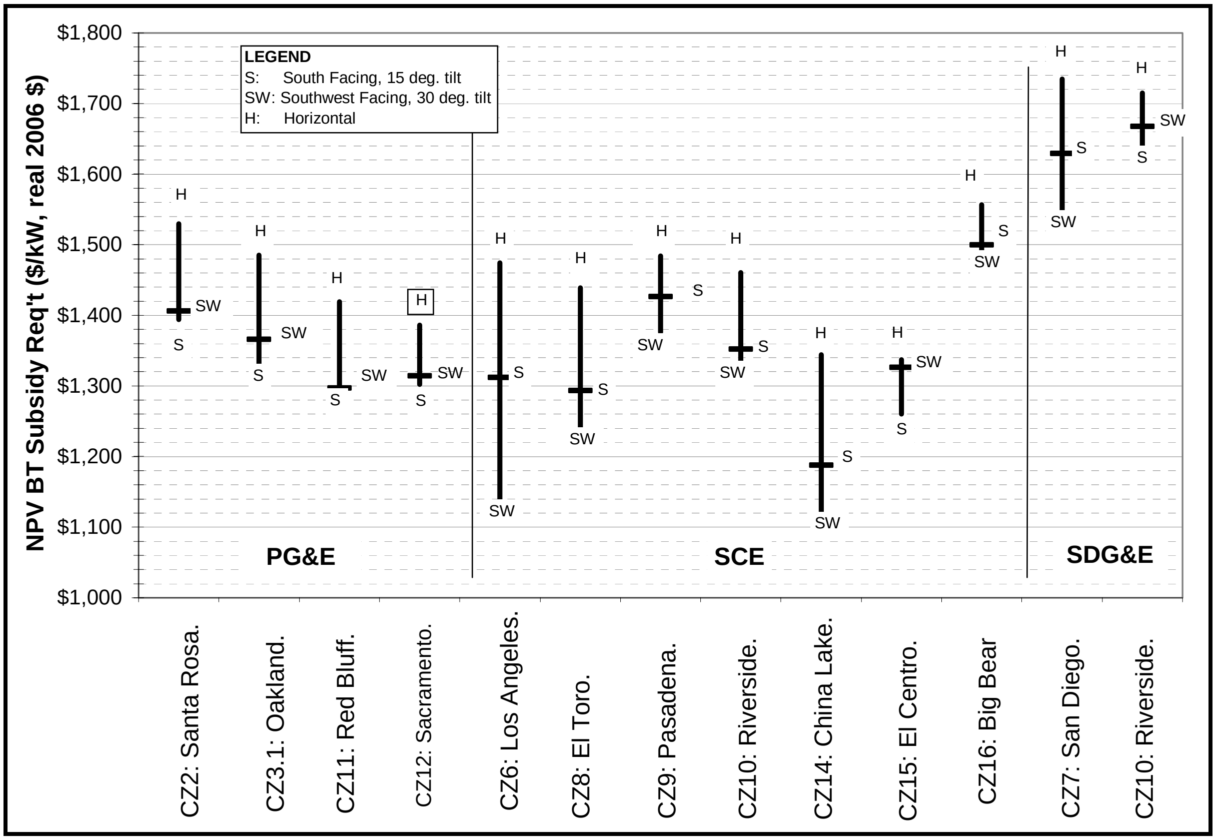
Table 7-2: CBI and PBI Results Overview and Comparison

Incentive Structure	Incentive Factors Study	CPUC Report
CBI	\$1.39/Watt	\$1.50/Watt
Five-year PBI	\$0.22/kWh	\$0.17/kWh

Incentive requirement results for 2007 broken out by PV system location and configuration are presented in Figure 7-1. Three values are reported for each climate zone; one for each of the three PV system configurations. In this graphic "H" indicates horizontal PV system, "SW" indicates southwestern-facing PV system tilted at 30˚, and "S" indicates south-facing PV system tilted at 15˚. Cases with the highest utility rates and those in the most favorable PV climate zones require the lowest incentive levels.

Incentive requirements are highest for prototypes subject to SDG&E electricity rates. Within climate zones the horizontal prototype always requires more incentive than the tilted prototypes. In general, PG&E and SDG&E scenarios have higher incentive requirements than do SCE prototypes. The very high peak energy rates faced by SCE customers are a non-Program incentive to utilize PV systems. The relatively lower peak energy rates faced by SDG&E customers have the reverse effect, necessitating higher PV incentives to achieve a balance between lifecycle costs and economic benefits faced by system owners.

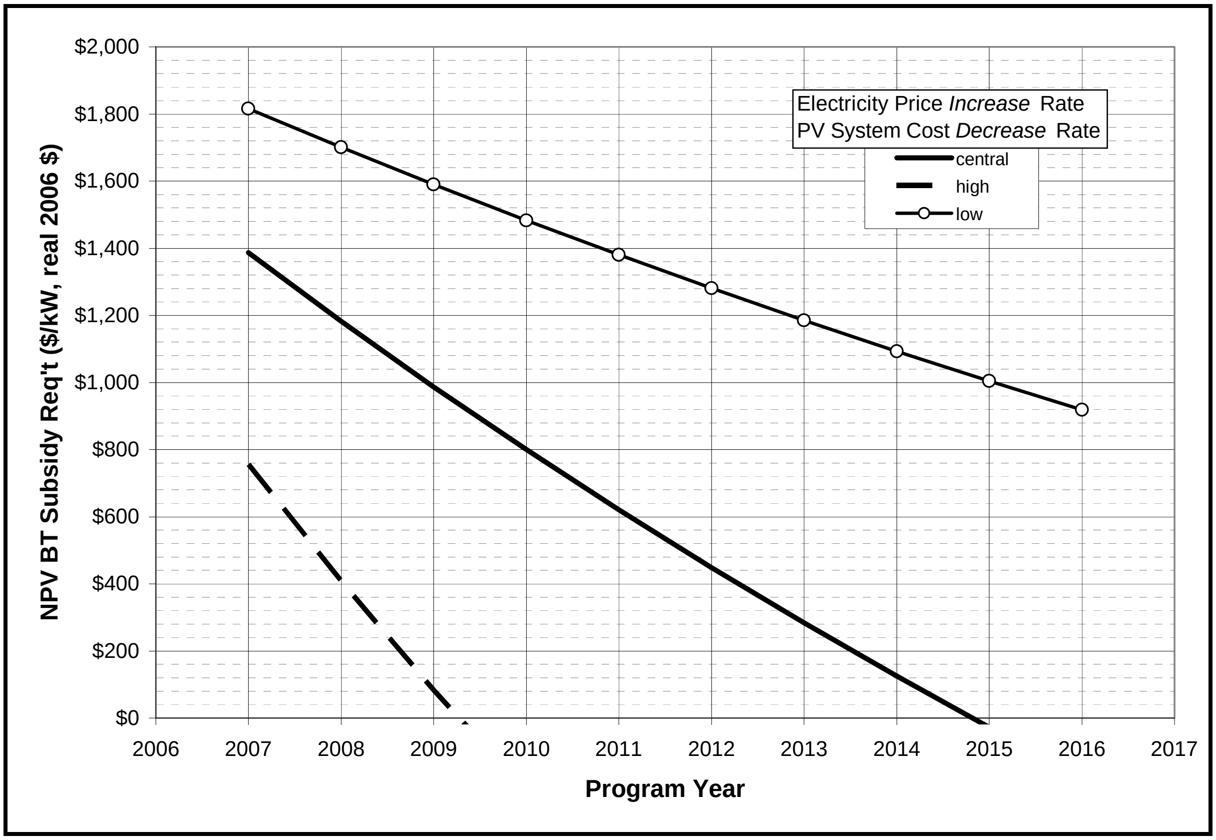
Figure 7-1: 2007 Incentive Requirement Distribution by Utility, Climate Zone, and PV System Configuration (Central Electricity Rates and PV Costs)



The above discussion summarized the influence of electric utility electricity rates, climate, and PV system configuration on 2007 incentive requirements. Incentive requirements for other years are likely to grow increasingly different. Several key influential factors that will drive incentive requirements include PV system costs, utility electricity rates, ITC availability and magnitude, and discount rate assumed to apply to PV system owners.

The influence of PV system costs and utility electricity rates is summarized in Figure 7-2. The results are not intended to be projections of likely incentive requirements in the future because investment tax credit regulations are expected to change. Rather, they are intended to illustrate the general trends introduced by just two of the many factors influencing PV markets: electric utility retail rates, and PV system costs. Under the low case trend (i.e., slowing rising electricity rates, slowly declining PV costs and equal distribution of PV systems among the various representative locations and configurations), the rate at which the required incentive declines over time is relatively low. Conversely, if electricity rates increase rapidly, and PV costs decrease rapidly (i.e., the high PV installation activity assumptions) then the need for PV incentives would disappear in 2012.[1]

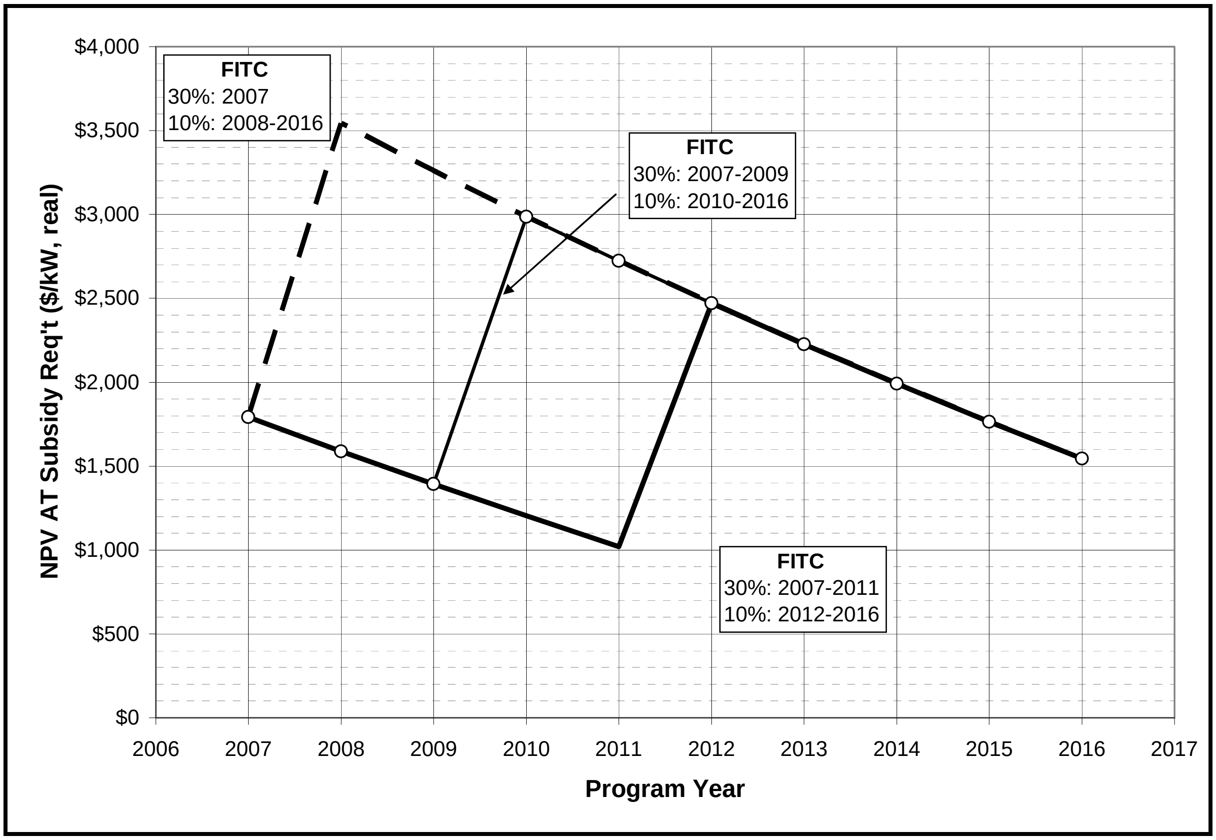
Figure 7-2: Representative NPV Incentive Requirement versus Program Year and Retail Electric Rate & PV Cost Scenario



[1] All subsidy requirement values are expressed in real terms using constant 2006 dollars to enable direct examination of trends caused by factors of principal interest (e.g., falling PV system costs). During implementation of an incentive designed in this manner these real values would require adjustment to account for actual, observed inflation rates.

The influence of the ITC on incentive requirement is illustrated in Figure 7-3. Again, the horizontal PV system in the vicinity of Sacramento and subject to PG&E rates is used for illustration purposes. In this example, the required incentive level at a 30 percent ITC in 2007 is approximately $1700 per kW. However, if the ITC was 10 percent in 2007, then the required incentive level would be approximately $3500 per kW, or nearly twice the incentive required with a 30 percent ITC.

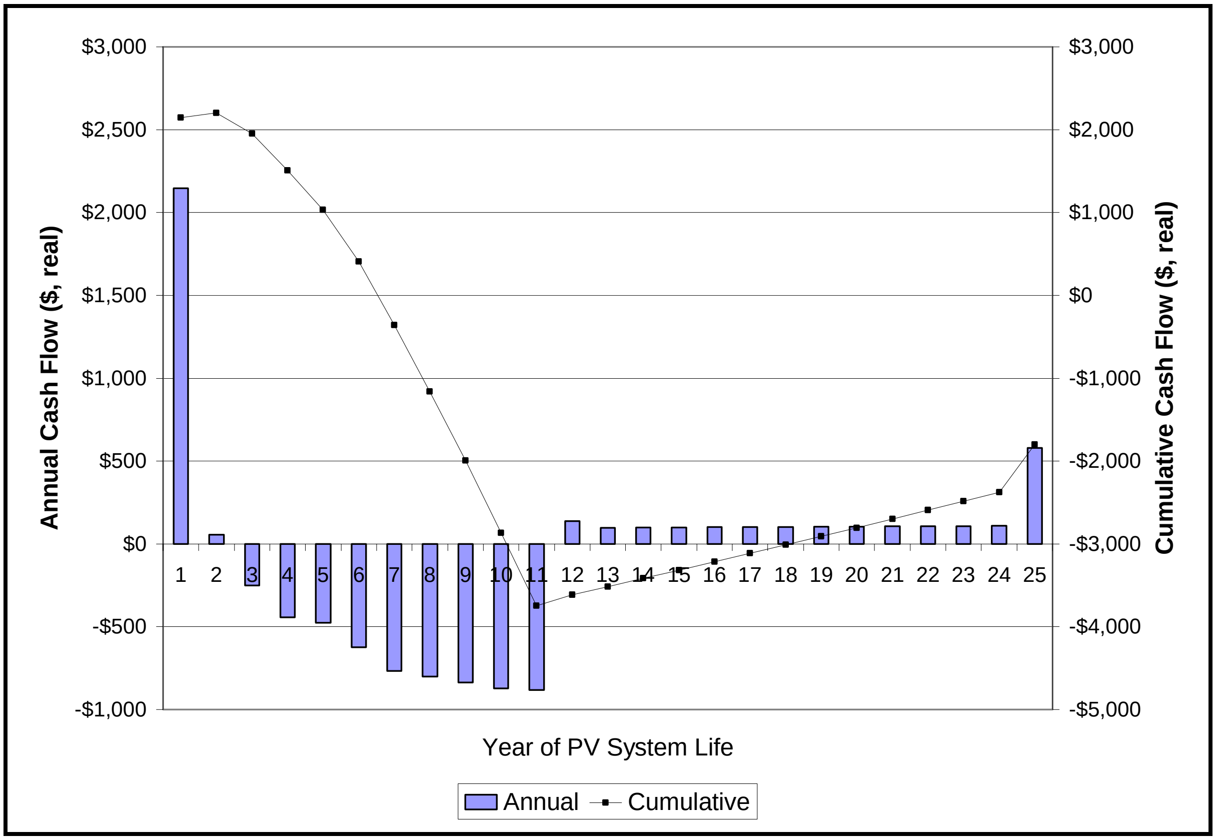
Figure 7-3: Representative NPV Incentive Requirement versus Program Year and Federal Investment Tax Credit



To illustrate some of the detail underlying the incentive requirement results summarized above, the prototype corresponding to the median incentive requirement is examined in more detail below. The median of the 39 incentive requirement results for individual PV system prototypes is $1,386. This corresponds to a horizontal PV system located in the vicinity of Sacramento and subject to PG&E electricity rates.

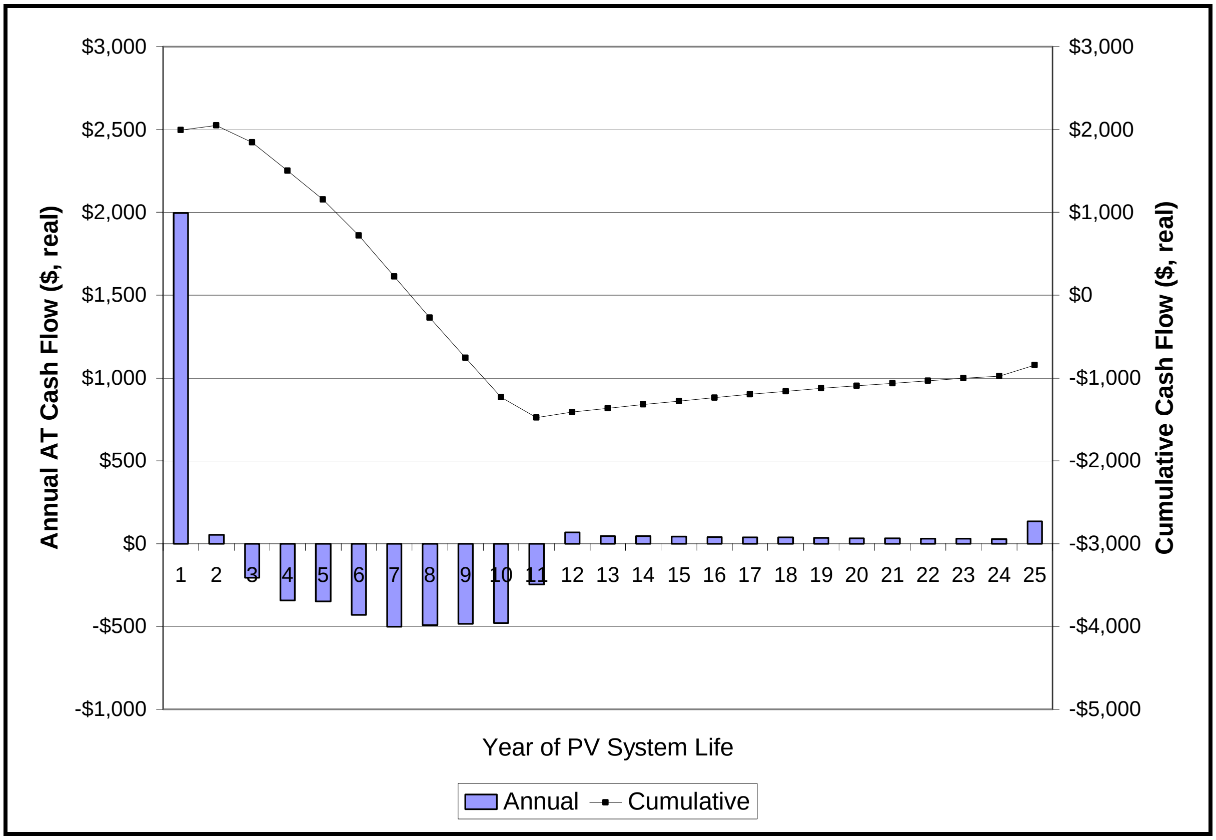
The undiscounted cash flows for this prototype are illustrated in Figure 7-4. The large positive cash flow in Year 1 corresponds to the 30 percent ITC. In Years 3 through 10 electricity bill savings are not sufficient to offset loan payments. In Year 11 electricity bill savings are not sufficient to offset the cost of inverter replacement. In Years 12 through 25 electricity bill savings are more than sufficient to offset annual O&M expenses. Finally, salvage value at the end of system life is reflected in the larger positive cash flow in Year 25.

Figure 7-4: Representative Undiscounted Cash Flow



The results presented in Figure 7-1 are based on an assumed discount rate equal to 6 percent (real). The impact of application of present worth factors is illustrated in Figure 7-5. The cumulative lifecycle cash flow without incentive level for the participant is -$842. The (taxable) incentive required to counter this potential loss is $1,386. This is the basis of the representative median incentive requirement result initially pointed out in Figure 7-1.

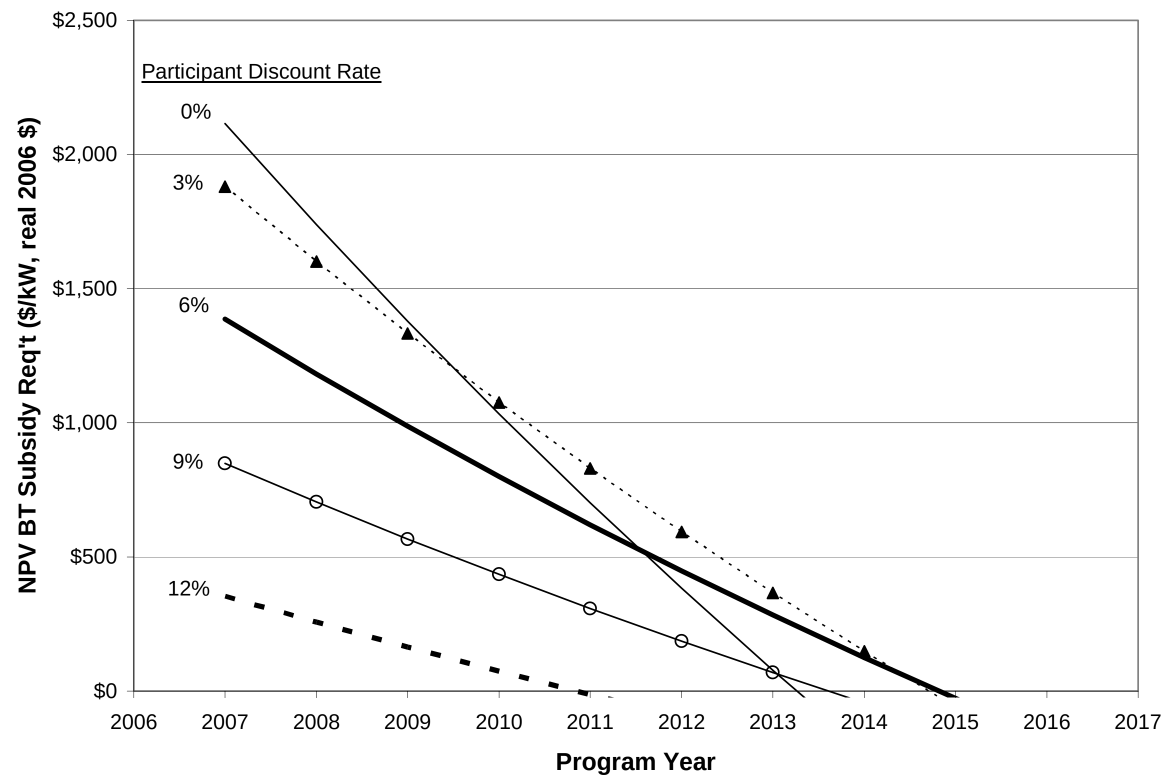
Figure 7-5: Representative Discounted Cash Flow



A critical aspect of this analysis concerns the timing of benefit receipt. A distinguishing characteristic of PV is that electricity rate benefit accrual occurs quite evenly throughout system life whereas other benefits and costs tend to occur during early years of system life. This complicates the incentive requirement analysis because prospective PV system owners value a dollar in benefits received today differently than a dollar of benefits received 20 to 25 years after installation of the PV system. This difference is referred to as the discount rate.

The results presented in Figure 7-1 are based on assumption of a 6 percent (real) discount rate. This is just that: an assumption. Previous research of discount rates for energy efficiency investments have suggested higher discount rates. On the other hand, purchasers of PV systems may adopt a longer than average perspective, in which case the discount rate could be lower.

Figure 7-6: Median NPV Incentive Requirement versus Program Year and Discount Rate (Central Electricity Rates and PV Costs)



7.2 Incentive Program Impacts

While the net present-value of breakeven incentive requirement modeling yields data necessary to design PBI structures, this information is not sufficient. A policy determination must be made regarding which incentive structure is preferred; CBI or PBI. Alternatively, a hybrid structure could be developed. In the case of PBI, design questions include how many years the payments will be spread over, and whether and how the payments might change over those years. In the remainder of this section, quantitative results are presented based on the specific PBI structures summarized in Table 7-3.

Table 7-3: PBI Structures Included in Quantitative Modeling

PBI Structural Element	Quantitative Modeling Basis Alternatives
Duration	■ Fixed five-year PBI
Temporal variability	■ Fixed (same PBI rate in all five years)
Geographic/Utility variability	■ Single statewide PBI ■ Three PBI rates (one for each IOU)

The PBI structures examined in this study result in most participants' scenarios receiving subsidies that are either higher or lower than the breakeven incentive requirement suggested by pro forma modeling. The relative magnitude and distribution of this variability is an important measure of PBI structure suitability. This variability is described and summarized below.

Statewide Incentive

For both the CBI and the PBI, statewide incentive rates are based on the median of the breakeven incentive requirements calculated for the 39 prototypes. As noted above, for 2007 the governing prototype is a horizontal PV system located in the vicinity of Sacramento and subject to PG&E electricity prices. By definition the CBI incentive rate is equal to the NPV incentive requirement for this prototype: $1,386 per kW (real 2006 dollars).

Table 7-4: Statewide Incentive Rates for 2007

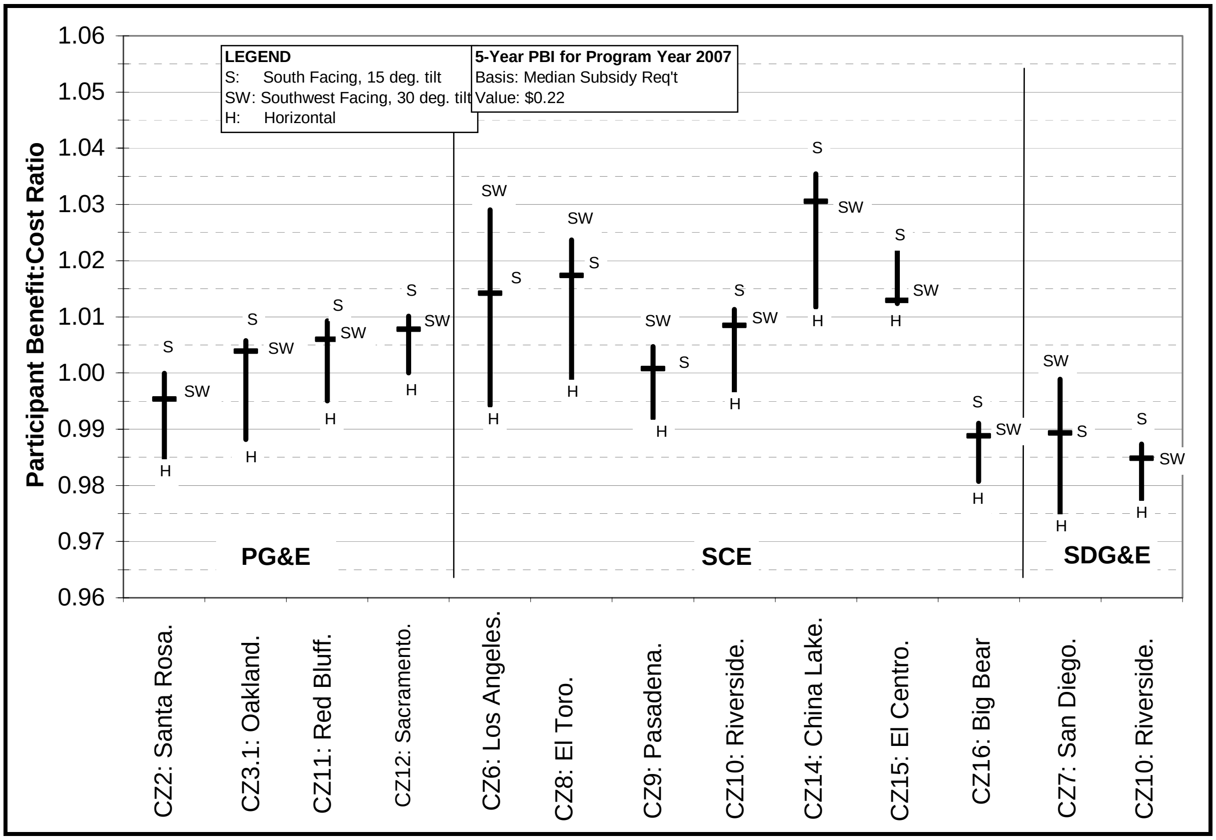
Incentive Structure	Rate & Disbursal
CBI	$1,386/kW one-time payment
PBI	22¢/kWh for five years
Reference	6.6¢/kWh for 25 years

Central-boundary statewide PBI values for each Program Year are presented in Figure 7-2. This PBI design will result in a participant cost:benefit ratio equal to exactly 1.0 for only one of the prospect scenarios. The remaining prospect scenarios will have cost:benefit ratios either higher or lower than 1.0.

The illustrations above are based on a five-year PBI structure. The differential impact on participant cost:benefit ratios using a 20-year fixed rate statewide PBI are illustrated in Figure 7-7.

The participant cost:benefit ratio results summarized in Figure 7-7 show that this single statewide PBI is based on the incentive requirement of the median scenario customer in climate zone 3.1 on a PG&E electricity tariff. Only three of the 12 (25 percent) PG&E prospective scenarios expect cost:benefit ratios exceeding 1.0, whereas 15 of the 21 (71 percent) SCE prospect scenarios can expect this level of financial performance. Consequently, this statewide PBI design would result in all but one of the six SDG&E prospect scenarios failing to achieve a participant cost:benefit ratio of at least 1.0. Thus, other factors held constant, we would expect few systems to be built in the SDG&E area under a PV support program if this incentive structure were employed.

Figure 7-7: Impact of Statewide PBI (PY2007—Central Retail Electric Rates and PV Costs)



Utility-Specific Incentives

Utility-specific PBI values are defined as the median of the breakeven incentive requirements calculated for the prospect scenarios corresponding to individual utility companies. This number of prospect scenarios varies depending on the number of climate zones.

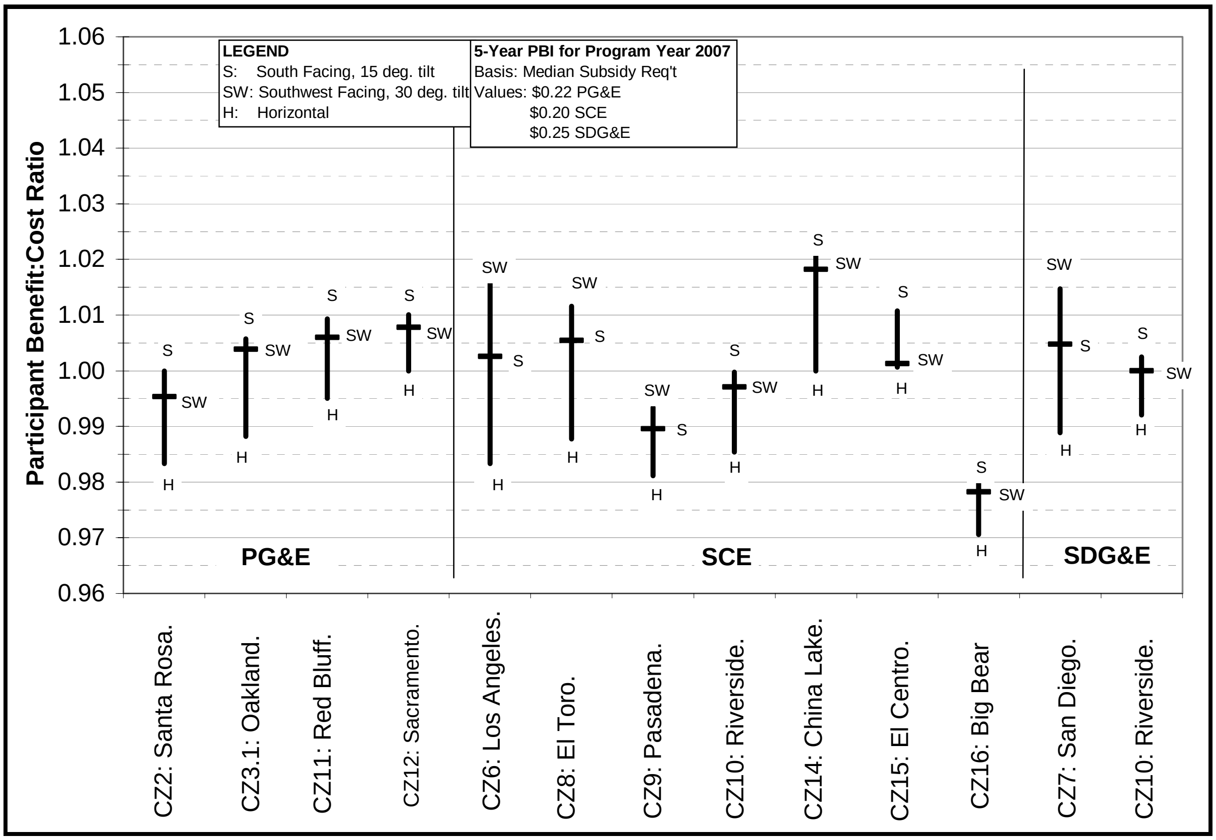
Table 7-5: Utility-Specific Incentive Rates for 2007 (Central Retail Electric Rates and PV Costs)

Incentive Structure	Disbursal	Electric Utility	Rate
CBI	One-time payment	PG&E	$1,386
		SCE	$1,344
		SDG&E	$1,667
PBI	Five years	PG&E	22¢
		SCE	20¢
		SDG&E	25¢
Reference	25 years	PG&E	6.6¢
		SCE	5.9¢
		SDG&E	7.5¢

Cost:benefit ratios for PV system owners resulting from application of utility-specific PBI values are shown in Figure 7-8.

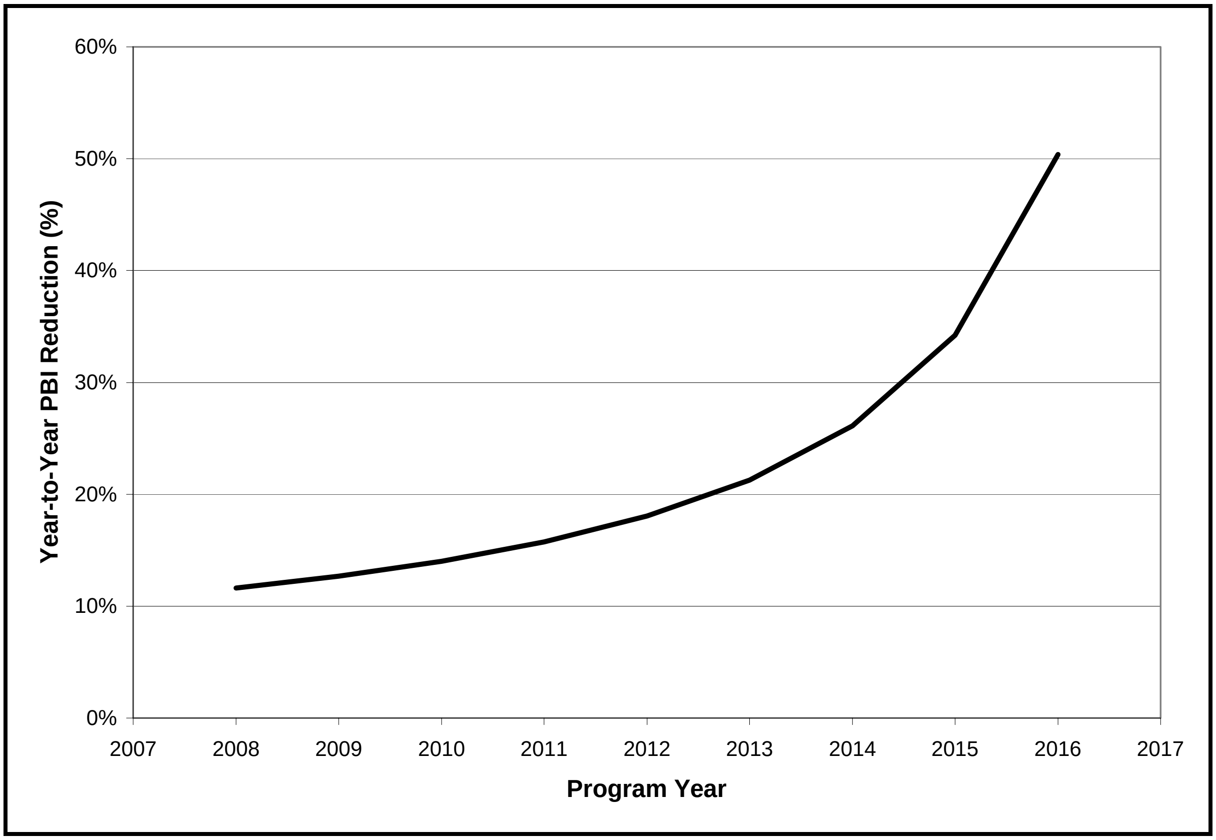
Comparison of the statewide and utility-specific cost:benefit ratios presented in Figure 7-7 and Figure 7-8 reveals at least two noteworthy observations. First, whereas the statewide PBI results in most of the "winners" being customers of SCE, the utility-specific PBI yields a more balanced distribution among utilities. Second, while the utility-specific PBI produces the lowest mean participant cost:benefit ratio, the overall level of variability is lower for this PBI structure than for the single statewide PBI.

Figure 7-8: Impact of Utility-Specific PBI (PY2007—Central Retail Electric Rates and PV Costs)



Lastly, we examined the effect of using a flat rate of decline in the PV incentive level over a 10-year timeframe. During the latter years incentives will play a smaller role in making PV systems cost-effective for their owners. Diminishing incentives will be offset by gains yielded by PV cost reductions and retail electricity rate increases. With each successive year, as the incentive becomes a smaller piece of the financial puzzle, a larger *percentage* of the remaining incentive will be eliminated by the offsetting gains described above. While the calculated percentage reduction is approximately 10 percent in the first years of a 10-year program, it increases from there on out as illustrated in Figure 7-9. As a result, it will be unlikely to maintain a flat rate of decline in incentive levels over the full course of the program.

Figure 7-9: Estimated Year-to-Year Incentive Rate Percentage Reduction



7.3 Summary

The significant impacts of PV system location and configuration on PV performance and electricity delivery are found to carry through to required incentive levels. However, the effects of PV performance and cost are compounded further when utility electricity retail rates are factored in. This creates a disparity in required incentive levels among the different utilities. In addition, the impacts of the federal ITC are found to have very significant impacts on required incentive levels, causing a near doubling of the required incentive level when the ITC drops from 30 percent to 10 percent. Similarly, the choice of assuming zero discount rate in setting incentive levels is likely to overestimate the required incentive level in order to avoid a cumulative net negative cash flow to system owners. In extending the analysis to incentive design, we found that use of a single statewide incentive level (versus utility-specific incentive levels) develops an isolated set of incentive "winners." While a utility-specific incentive approach produces a lower mean benefit:cost ratio for participants, it also provides a better balanced distribution of "winners" among the utilities. Lastly, in looking at how incentive rates should decline over the life of the 10-year PV support program, we found it unlikely that a flat declining incentive level could be maintained.

8

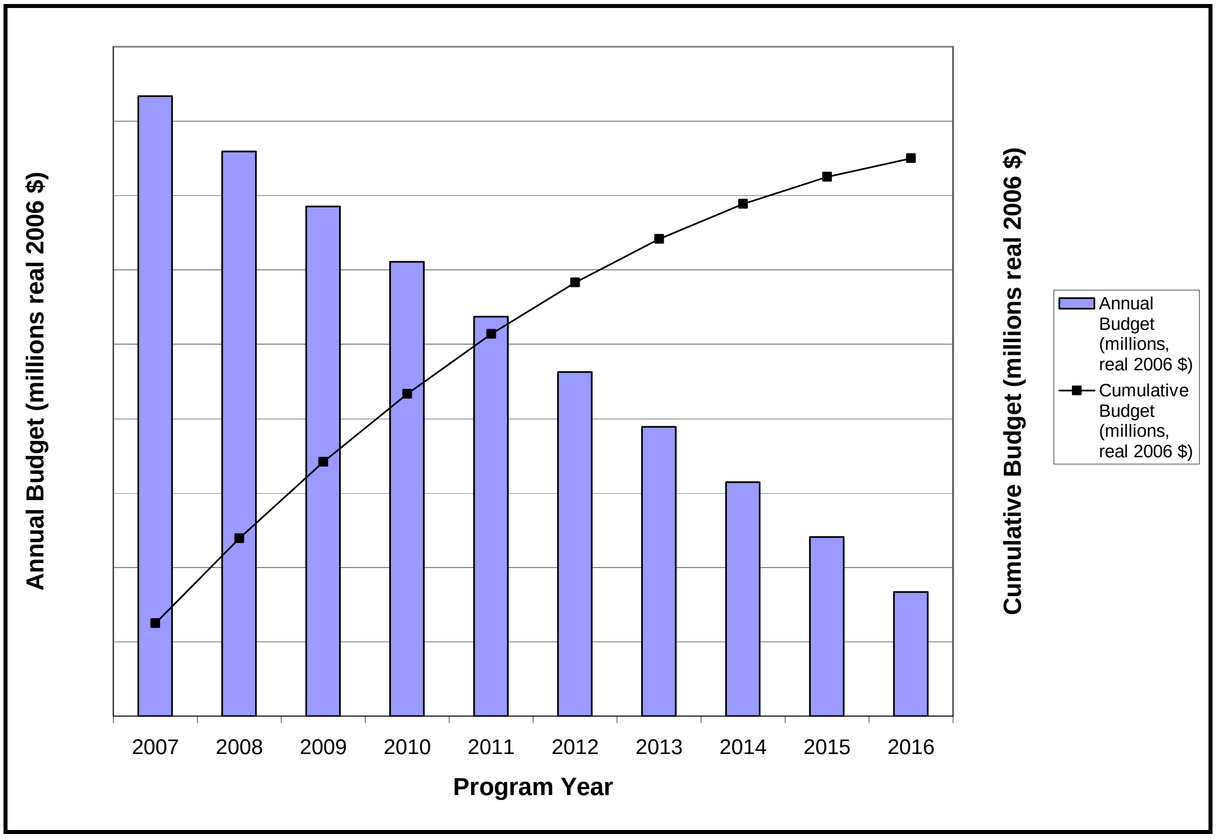
Program-Level Impacts

The analysis and results of Section 7 treated subsidy requirements, incentive levels, and project economics at the system prototype level. In Section 8 these results are extended to the program prototype level by applying an assumed 10-year program incentive budget profile to the system prototypes. Program-level budgetary and PV capacity installation impacts on both annual and cumulative bases are estimated for a hypothetical 10-year program comprising annual budgets totaling $1 billion. Results for California retail rates and solar resource are combined with information from secondary sources to summarize program impacts for other states. Finally, the possibility is raised that incentive structures could be used in the future to exert market pressures on PV capacity installation patterns in ways that most fully capture PV benefits.

8.1 Impacts on Budget

The annual and cumulative incentive budgets assumed for the hypothetical 10-year program are summarized in Figure 8-1. The budget in Program Year (PY) 10 is assumed equal to 20 percent of the PY 1 budget. The total incentives budget expressed in real 2006 dollars is $1 billion.

Figure 8-1: Ten-Year Program Budget—Annual and Cumulative



Depending on the basis of the incentives (e.g., capacity versus performance) the annual budgets may not be the amount of money actually paid out during each PY because incentive payments could extend five or more years beyond the year in which the PV system is installed. Rather, it is the amount of money reserved for participants in particular PYs.

8.2 Impacts on Installed PV Capacity

The impacts on installed PV capacity (or activity levels) of a 10-year, $1 billion program will depend on numerous factors. Of particular importance are availability of 30 percent federal ITC, solar resource and initial retail rates, and the combined effect of falling PV costs and rising electric utility prices. Impacts on PV capacity installed in California were calculated by combining annual incentive budgets from Figure 8-1 with central boundary case breakeven subsidy requirement results from Section 7. Breakeven subsidy requirements for the 39 system prototypes vary depending on location, configuration, and electric utility. Annual budgets were assumed to be distributed evenly across the 39 system prototypes. The federal ITC was assumed to revert to 10 percent in 2008 (as currently planned).

Other key elements of the central boundary case are summarized in Table 8-1.

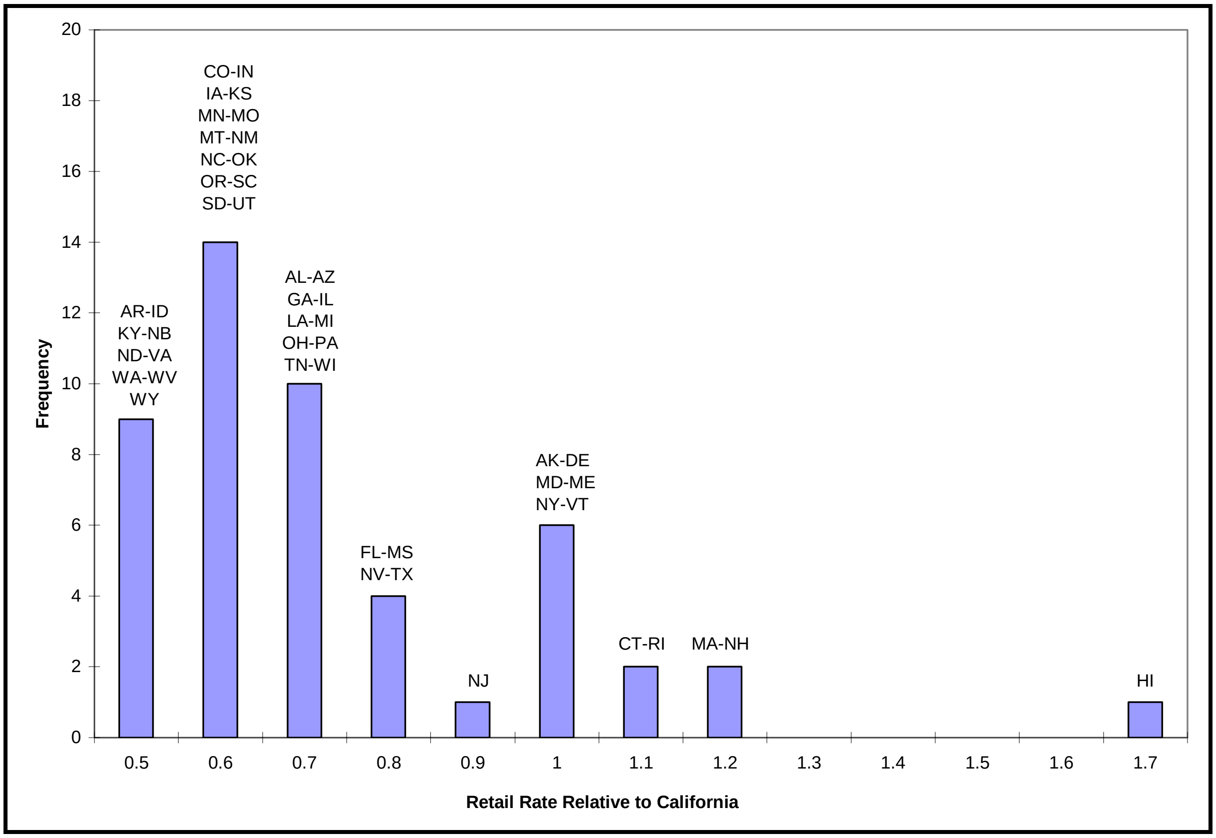
Table 8-1: Central Boundary Case Assumptions

Element	Basis
Solar Resource	TMY weather for 12 representative cities in California (Reference: Table 3-1)
PV System Cost	$7.59/Watt in 2007. -10%/yr thereafter. (Reference: Table 4-3)
Retail Electric Rates	Actual PG&E, SCE, and SDG&E tariffs in 2007. +1.5%/yr (real) thereafter. (Reference: Tables 5-1 and 5-2)

Impacts on PV capacity installed in other states were also estimated to lend additional perspective to the results calculated for California. Impacts for other states were calculated as the product of the statewide result for California and multipliers accounting for differences in retail electric rates and solar resources. For this simple illustrative comparison all other factors were assumed identical (e.g., state tax depreciation treatment, state tax credit provisions).

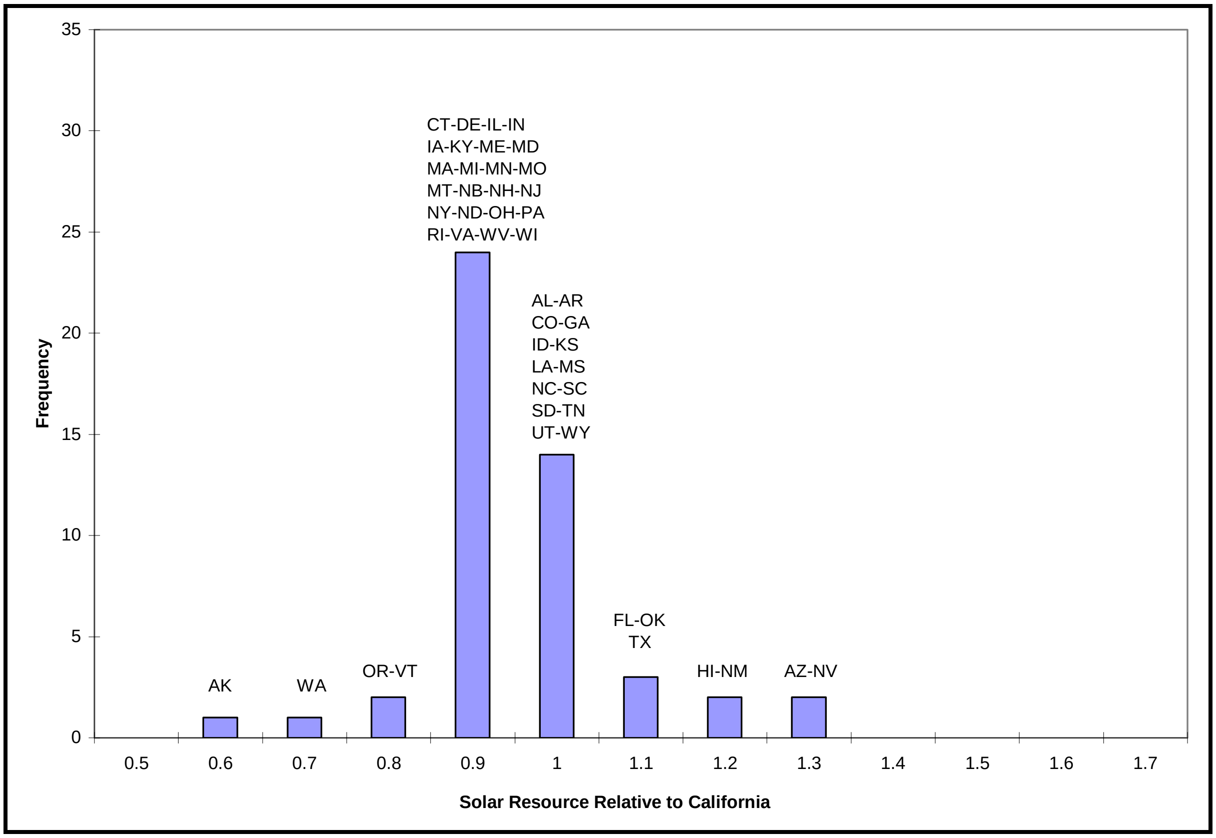
Data from the Energy Information Administration were used to explore the influence of initial retail rates. For each state a retail rate multiplier was calculated as the ratio of the average May 2006 commercial retail rate for the state to that for California. The distribution of resulting retail electricity rate multipliers is summarized in Figure 8-2. Only five states had retail rates higher than California. For the other 44 states retail electricity rates cause each PV program incentive dollar to yield less PV capacity than in California.

Figure 8-2: Retail Rate Multiplier by State



Data from the National Renewable Energy Laboratory were used to explore the influence of solar resource. For each state a solar resource multiplier was calculated as the ratio of the representative solar resource for the state to the solar resource for California. The solar resource in San Francisco was used to represent the solar resource for California. The distribution of resulting solar resource multipliers is summarized in Figure 8-3.

Figure 8-3: Solar Resource Multiplier by State



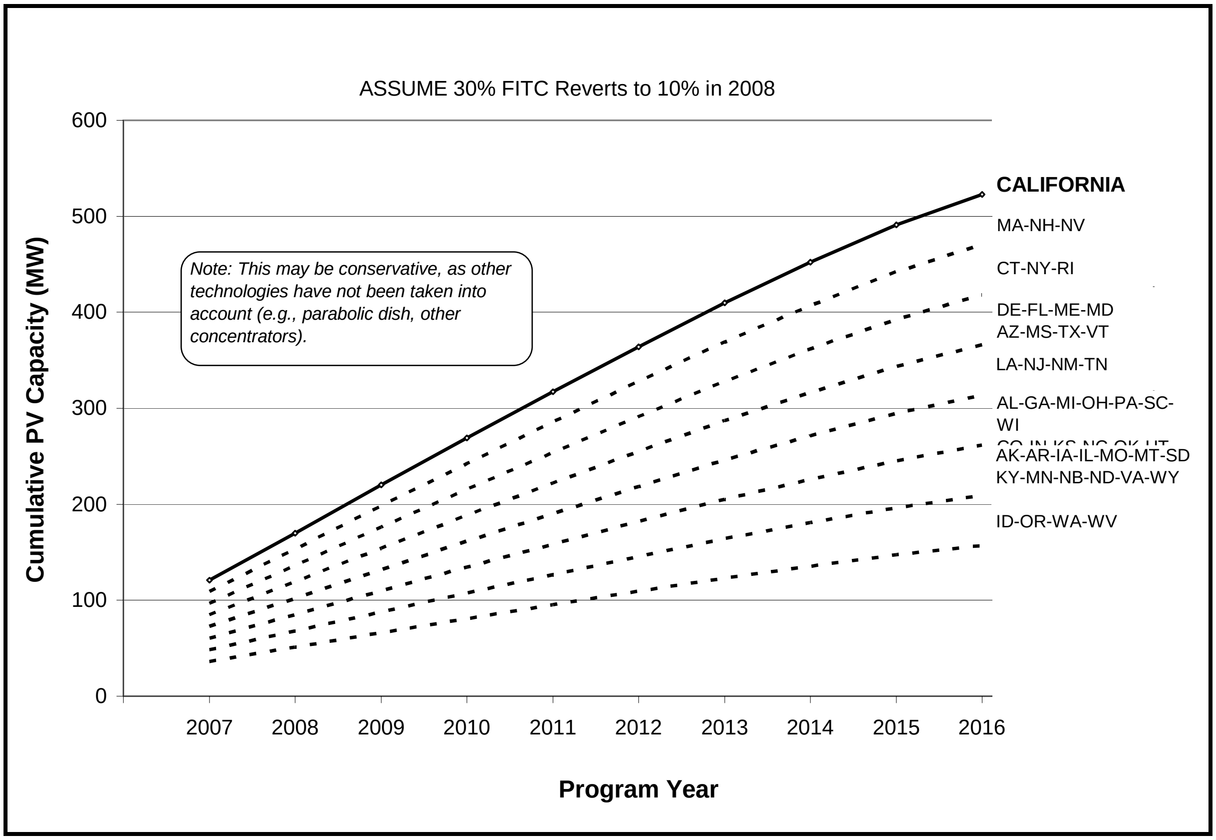
The solar resource multipliers exhibit substantially less variability than the retail electric rate multipliers. Standard deviations of the Retail Rate and Solar Resource Multipliers are presented in Table 8-2. Separate results are presented for the 48 states (excluding Hawaii) because determination of the point in time when PV becomes economic without subsidies depends on rate structures in Hawaii and analysis of rate structures in Hawaii is outside the scope of this study.

Table 8-2: Standard Deviations of Multipliers

Basis	Retail Rate Multiplier	Solar Resource Multiplier
All 49 states	0.24	0.12
48 states (Hawaii excluded)	0.20	0.12

The PV capacity impacts of a 10-year, $1 billion program are summarized by PY and state in Figure 8-4. For this hypothetical example the 30 percent ITC is assumed to revert to 10 percent in 2008.

Figure 8-4: Cumulative PV Capacity Impacts versus Program Year and State ($1 Billion Total Program – Hawaii Excluded)



The location and configuration of PV systems influences program-level results. In developing the program-level estimates for California, PV systems are assumed to be distributed evenly among the different PV prototypes. Consequently, this results in lower yields and so lower amounts of installed capacity going into the future.

8.3 Impacts on PV Capacity Installation Patterns

In Section 7 the influence of incentive program design on participant benefit-cost ratio variability was described. Over time this variability could be expected to lead to disproportionate development of PV system prototypes with the highest participant benefit:cost ratios. This trend would be more pronounced with a statewide incentive rate as compared to utility-specific incentive rates. As more information about PV owner decision-making is developed these trends might be harnessed by program implementers to encourage development of PV capacity in particular areas or configurations (e.g., where anticipated load growth is expected to cause transmission or distribution system congestion in the future).

8.4 Summary

Based upon the PV market alone (e.g., ignoring other potential contributing technologies under solar programs) and without extension of the federal ITC beyond 2007, the installed capacity estimated for California is 523 MW. At the other end of the spectrum is the 10-year, $1 billion program assuming retail rates and solar resource for Olympia, Washington, where total cumulative PV capacity is only one-third of that estimated for California. Whether or not the ITC is extended will have an important effect on how much PV could actually be installed over the life of any 10-year program.

9

Benefits and Impacts from Other Perspectives

PV incentive programs are intended to influence decisions made by prospective PV system owners. As such, the PV incentive analysis emphasizes PV system economics from the customer perspective. However, design of such a program involves tradeoffs among numerous stakeholders. Two key stakeholders include society and utility customers opting not to install PV. Assessment of program economics from these perspectives is discussed in this section of the report.

9.1 Overview

To enable investigation of the influence of various factors on cost-effectiveness from the perspectives of society at large and non-participating ratepayers, benefit:cost ratios were estimated for 2007 assuming central electricity price and PV cost trends (i.e., $7.59 per Watt PV system cost). These results are based on avoided cost data covering the 25-year period of PV system economic life. Currently the readily available avoided cost data for California extend only through 2023. Avoided cost data through 2041 would be required to assess PV cost-effectiveness over the 25 years. Available data do, however, enable examination of general cost-effectiveness trends existing within a 10-year program.

9.2 Avoided Cost Value of Electricity

The avoided cost of generation provides benefits to society and ratepayers because every kilowatt hour of utility generation replaced by PV energy lowers the cost born by ratepayers or society as a whole. The actual cost to generate, transmit, and distribute electricity to customers in each utility varies minute by minute and year by year depending on which generation facilities are needed and how costly they are to run.

Tariff rates charged by utilities are based on an approximation of these avoided costs, so that customers each bear a fair share of the costs they impose on the utilities. Because generation during peak demand periods requires that capacity be present for only those periods, and because generation efficiency of these seldom-used resources is lower than average, the avoided costs are highest during these peak periods. Transmission and distribution costs are also much higher during peak periods. Because PV reduces the peak period demand, the avoided cost value of PV is considerably higher than the average cost of generation.

An avoided cost model was developed for the CPUC for use in rate cases. The E-3 model estimates the avoided generation and transmission and distribution (T&D) costs for each California IOU and climate zone. The E-3 model is used to evaluate the avoided cost benefits in the present analysis. This model was also used in the Itron Cost-Effectiveness analysis and is documented in that report[1]. In addition to generation and T&D costs, other benefits provided to society and electricity ratepayers result from PV avoided costs. These factors include reliability net benefits, reduced line losses, and price effects. These factors are treated the same way in the present analysis as they were in the Cost Effectiveness analysis. They are documented in that report.[2]

9.3 Societal Cost-Effectiveness

The societal cost-effectiveness estimated for PV systems installed during 2007 is summarized in Figure 9-1.[3] Societal net present value costs are identical for all of the prototypes: $8,404. All of the variability observed among these societal benefit:cost ratios originates from the benefit side of the equation. The source of the variability is illustrated in Table 9-1. Under these circumstances avoided T&D costs account for 61 percent of the difference in total net present value benefits.

Table 9-1: Societal Benefits Range for 2007

Societal Benefits and Costs	PV System: Horizontal Vicinity: Oakland Electric Utility: PG&E	PV System: SW @ 30˚ Tilt Vicinity: San Diego Electric Utility: SDG&E
Benefits	**$3414**	**$5162**
Avoided Costs – Energy	$2525	$3137
Avoided Costs – T&D	$217	$1277
Avoided Costs – CO_2	$309	$385
Costs	**$8,404**	**$8,404**
Benefit:Cost Ratio	**0.41**	**0.61**

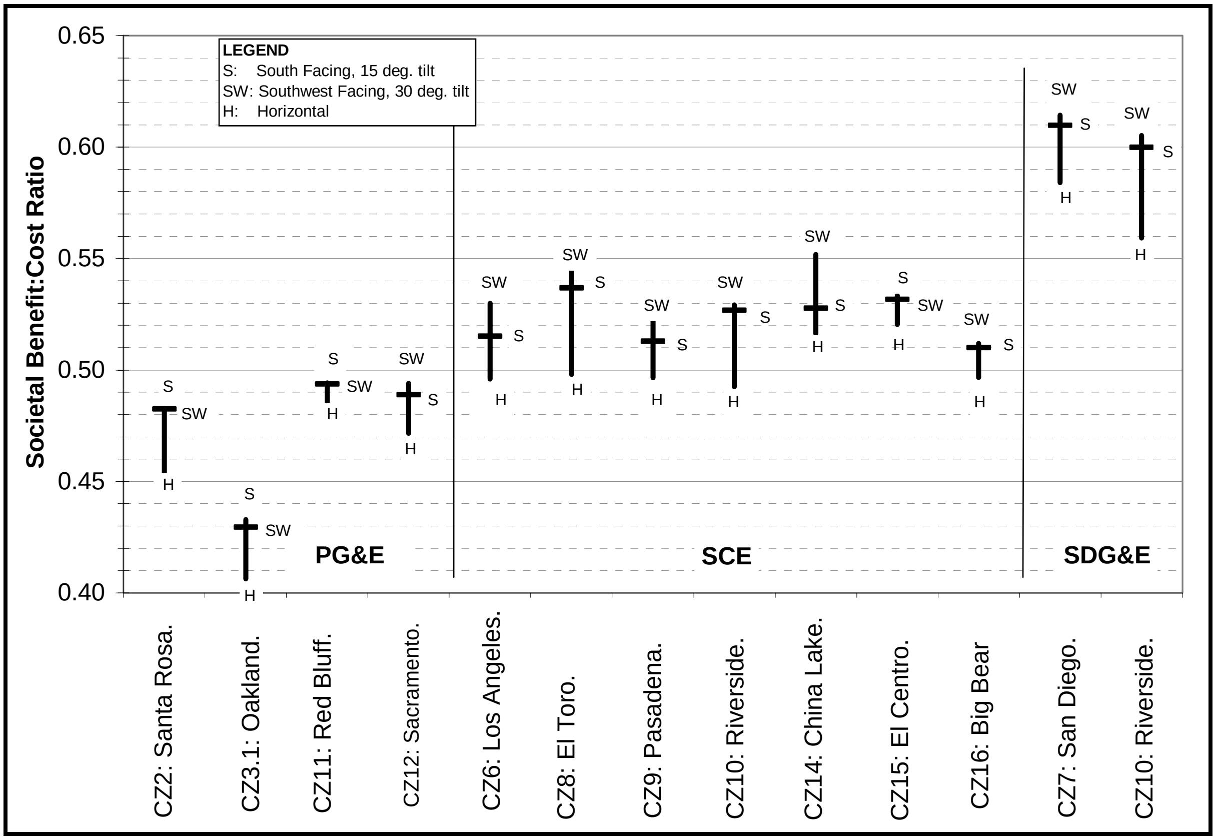
[1] Itron, 2005, Section 3.

[2] Ibid.

[3] As was the case in Section 5, three values are reported for each climate zone: one for each of the three PV system configurations. In this graphic "H" indicates horizontal PV system, "SW" indicates southwestern facing PV system tilted at 30˚, and "S" indicates south facing PV system tilted at 20˚.

General trends exist in the relationship between societal cost-effectiveness and PV system configuration. Horizontal was the least cost-effective PV system configuration for all electric utilities and climate zones. Southwestern-facing, 30˚ tilt PV systems achieved the highest societal benefit:cost ratios for all but one of the SCE and SDG&E prototypes. Southern-facing, 15˚ tilt PV systems achieved the highest societal benefit:cost ratio for three out of four PG&E climate zones.

Figure 9-1: Societal Cost-Effectiveness (PY2007 – Central Retail Electric Rates and PV Costs)

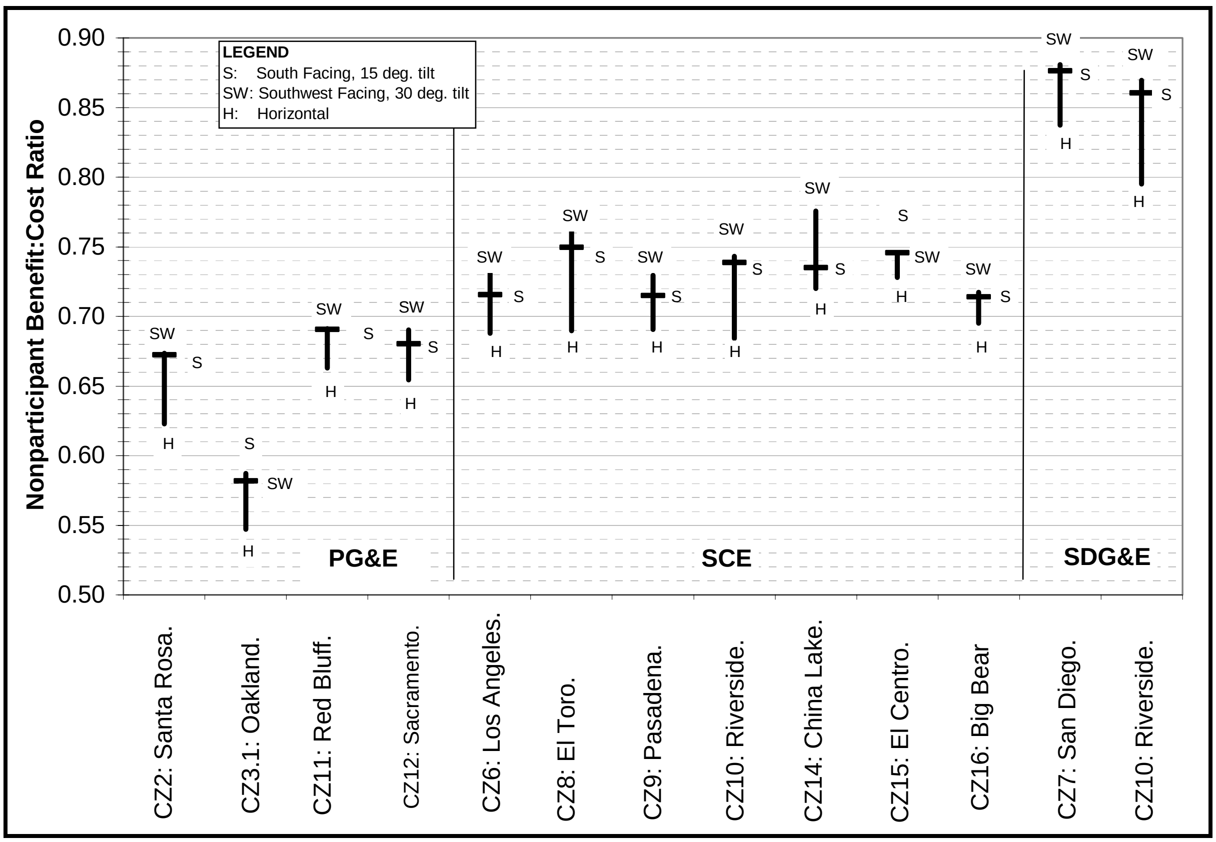


9.4 Ratepayer Cost-Effectiveness

The cost-effectiveness of PV systems installed during 2007 from the perspective of non-participating ratepayers is summarized in Figure 9-2. Ratepayer and societal cost-effectiveness share some common trends. In most (85 percent) cases southwestern-facing, 30˚ tilt PV systems yielded the highest benefit:cost ratios to non-participating ratepayers. As was the case with the societal perspective, a horizontal configuration was again the least cost-effective PV system configuration in all cases.

Prototypes subject to SDG&E electricity rates are responsible for the highest benefit:cost ratios. As with societal cost-effectiveness, this is again attributable in large part to benefits stemming from avoidance of transmission and distribution costs. This is an interesting result in light of the cost-effectiveness results presented in Figure 7-7. There the PV system owner benefit:cost ratios for prototypes subject to SDG&E electricity rates were shown to be quite low under the single statewide incentive rate. All else equal this lower cost-effectiveness would lead to PV investment in other areas. While avoided costs do not factor directly into participant investment decisions, designers and implementers of PV incentive programs may choose to take other perspectives into consideration when establishing incentive designs and rates.

Figure 9-2: Ratepayer Cost-Effectiveness (PY2007 – Central Retail Electric Rates and PV Costs)



9.5 Summary

Most decisions regarding incentive design focus on impacts to PV system owners. However, PV incentive design can also have significant impacts on ratepayers who are not using the incentive program and to society as a whole. By taking into account avoided electricity costs, we were able to calculate benefit/cost ratios for society at large and for ratepayers who are not participating in the PV incentive programs. We found that choices in PV location and configuration accounted for significant differences in benefit/cost ratios. In general, PV systems with south-facing horizontal configurations tended to yield the lowest benefit cost ratios to society and ratepayers. In addition, benefits associated with avoidance of transmission and distribution costs appeared to make up a majority of the benefits. Lastly, due to differences in avoided costs, climate, and solar resources, benefit:cost ratios for PV systems may vary considerably by utility.

Appendix A

PV Performance Analysis Detail

A.1 Introduction

Metered data collected from a sample of operational PV systems were used to create 8,760-hour performance data sets intended to represent expectations regarding long-run average performance. Whereas the monitored data collected during 2003 and 2004 were used directly to calculate summary statistics reported in the impact evaluation reports, these data were subject to several modifications prior to use in the incentive analysis. The methods used to translate monitored performance data collected from PV systems into typical-performance data sets used in the incentive analysis are described below.

A.2 Performance of PV System Prototypes

Metered power output data collected from 2002 to 2004 were combined with observed weather data to develop relationships between weather and PV system power output. These relationships were then combined with existing TMY weather data to estimate TMY power output. Steps in the process are listed below:

1. Estimate Hourly Insolation for SGIP PV System Performance for Observed Weather.
2. Estimate Hourly Insolation for PV Incentive Analysis Prototypes for Typical Weather.
3. Estimate Hourly Performance of PV Incentive Analysis Prototypes for Typical Weather.

1. Estimate Hourly Insolation for SGIP PV System Performance for Observed Weather.
The observed weather parameter of principal interest is plane of array solar radiation (POASOLRAD); however, only global horizontal solar radiation data were readily available. For tilted PV systems the ratio of POASOLRAD to global horizontal solar radiation is a function of PV system configuration, hour of year, and cloud cover. A solar radiation model was used to estimate POASOLRAD values coincident with each metered power output data point.

The result of the solar radiation modeling described above is a large lookup table containing pairs of POASOLRAD and ambient temperature values, and their corresponding PV system power output. The lookup tables were separated into groups based on season, hour of day, ambient temperature, and POASOLRAD level. Table A-1 indicates the three months that are assigned to each season.

Table A-1: Basis of Season Assignments

Season	**Months**
Spring	March, April, May
Summer	June, July, August
Fall	September, October, November
Winter	December, January, February

The general form of the PV performance modeling is illustrated in Table A-2. These are actual summer data for SGIP PV systems for the hour from noon to 1 P.M. (PDT). There are 539 PV system power output values, the median of which is 0.70.

Table A-2: General Form of PV Performance Models

(A) POASOLRAD (W/sq.m.)	**(B) TEMP (F)**	**(C) System Power Output (kW power output per kW of PV system size)**
901 - 950	71 - 80	0.67, 0.70, 0.74, 0.75, 0.74, 0.67, 0.67, 0.76, 0.51, 0.52, …..

2. Estimate Hourly Insolation for PV Incentive Analysis Prototypes for Typical Weather. The next step in the analysis entailed estimation of POASOLRAD for each hour of an average year representative of long-run average climate, as expressed by data for a TMY. Existing 8760-hr TMY weather data sets for 12 climate zones in California served as the starting point. Next, an 8760-hour TMY weather data set was created for each of the operational PV systems based on facility location. The orientation of each PV system was then used to translate global horizontal solar radiation into estimates of the corresponding POASOLRAD.

3. Estimate Hourly Performance of PV Incentive Analysis Prototypes for Typical Weather. Lastly, a PV system power output value was randomly selected (from Column C in Table A-2) based on TMY POASOLRAD and ambient temperature values. The data in Table A-2 are only meant to illustrate the general form of the model. The total number of actual SGIP PV metered power output values exceeds 640,000.

The methodology described above was used to estimate hourly PV system power output during Year One of the analysis. PV system power output for future years was estimated based on the assumption of a 0.5 percent per year PV system power output degradation. This factor roughly corresponds to degradation rates embedded in PV module warranties.

Appendix B

Economic Analysis Detail

B.1 Introduction

Note regarding suffix conventions used in the algorithms:

Suffix: *y*
Definition: Calendar Year
Values: 2007 through 2040

Suffix: *p*
Definition: Program Year
Values: 2007 through 2016

Suffix: *Y*
Definition: System Year
Values: 1 through 25

<u>Calculate PV impacts on energy bills during 2006</u>

Calculate hourly results

$$Y06BfTxEnergyRetailHr_{smdh} = Y06EnergyTrf_{smdh} \times \overline{ENGO}_{smdh}$$

Variable: $Y06BfTxEnergyRetailHr_{smdh}$
Definition: Net-metering value (before tax) of first-year energy production for scenario *s*, month *m*, day *d*, and hour *h*.
Units: $
Basis: Real 2006 $. End of year cash flow.

Variable: $Y2006EnergyTrf_{smdh}$
Definition: Price of electricity for scenario *s*, month *m*, day *d*, and hour *h*.
Value: Assigned as a function of utility, day of year, and time of day.

Table B-1: TOU Schedule and Tariffs

Tariff	Season	Peak	Y2006 EnergyTrf	start1	end1	start2	end2
PG&E E-19	summer May 1 to Oct. 31	On-Peak	0.145750	12	18		
		Part-Peak	0.108630	8.5	12	18	21.5
		Off-Peak	0.079680	0	8.5	21.5	24
	winter	Part-Peak	0.100360	8.5	21.5		
		Off-Peak	0.083100	0	8.5	21.5	24
SCE TOU-8	summer Jun. 1 to Sep. 30	On-Peak	0.157300	12	18		
		Part-Peak	0.094300	8	12	18	23
		Off-Peak	0.055100	0	8	23	24
	winter	Part-Peak	0.118570	8	21		
		Off-Peak	0.057166	0	8	21	24
SDG&E AL TOU DER	summer May 1 to Sep. 30	On-Peak	0.133930	11	18		
		Part-Peak	0.082900	6	11	18	22
		Off-Peak	0.061230	22	24	0	6
	winter	On-Peak	0.133040	17	20		
		Part-Peak	0.082920	6	17	20	22
		Off-Peak	0.061260	0	6	22	24

Units: $/kWh
Basis: Real 2006 $. 2006 electricity tariffs for PG&E, SCE, and SDG&E.

Variable: $\overline{ENGO}_{smdh}$
Definition: First-year PV system electric performance for scenario *s*, month *m*, day *d*, and hour *h*.
Units: kWh per kW of installed capacity.
Basis: Analysis of observed weather data, observed PV system electric performance data, and TMY weather files.

Roll hourly results up to months

$$Y06BfTxEnergyRetailMo_{sm} = \sum_{dh} Y06BfTxEnergyRetail_{smdh}$$

Variable: $Y06BfTxEnergyRetailMo_{sm}$
Definition: Net-metering value (before tax) of 2006 energy production for scenario *s* and month *m*.
Units: $.
Basis: Real 2006 $.

<u>Calculate PV impacts on energy bills during each year of CSI PV system life</u>

$$BfTxEnergyRetailMo_{spYm} = Y06BfTxEnergyRetailMo_{sm} \times TrfFrcstX_{spY} \times \left(1 - PVdegradRT\right)^{(y-1)}$$

Variable: $BfTxEnergyRetailMo_{spYm}$
Definition: Net-metering value (before tax) of energy production for scenario *s*, program year *p*, system year *Y*, and month *m*.
Units: $.
Basis: Real 2006 $.

Variable: $PVdegradRT$
Definition: PV system energy production degradation rate.
Value: 0.005
Units: 1/Year.
Basis: PV module manufacturer warranties.

Roll monthly results up to years

$$BfTxEnergyRetailYr_{spY} = \sum_{m} BfTxEnergyRetailMo_{spYm}$$

Variable: $BfTxEnergyRetailYr_{spY}$
Definition: Net-metering value (before tax) of energy production for scenario *s*, program year *p* and system year *Y*.
Units: $.
Basis: Real 2006 $.

$$EfctvMrgnlTxRT = FedTxRT + StTxRT \times \left(1 - FedTxRT\right)$$

Variable: $EfctvMrgnlTxRT$
Definition: Effective marginal tax rate
Value: 0.3928
Units: Fraction.

Variable: $FedTxRT$
Definition: Marginal federal tax rate
Value: 0.34
Units: Fraction.
Basis: ASSUMED

Variable: $StTxRT$
Definition: Marginal state tax rate
Value: 0.08
Units: Fraction.
Basis: ASSUMED

$$AfTxEnergyRetailYr_{spY} = BfTxEnergyRetailYr_{spY} \times \left(1 - EfctvMrgnlTxRT\right)$$

Variable: $AfTxEnergyRetailYr_{spY}$
Definition: Net-metering value (after tax) of energy production for scenario *s*, program year *p* and system year *Y*.
Units: $.
Basis: Real 2006 $.

Federal Tax Credit

$$FedTxCrdt_{p} = EligibleCost_{p} \times PvFedTxCrd\ tRT_{p}$$

Variable: $FedTxCrdt_{p}$
Definition: Federal tax credit for program year *p*.
Units: $.
Basis: Real 2006 $.

Variable: $PvFedTxCrd\ tRT_{p}$
Definition: Federal tax credit rate for PV
Value: Assigned as a function of program year *p*.

program year *p*	$PvFedTxCrdtRT_p$
2007	0.3
2008-2016	0.1

Units: Fraction.
Basis: 2005 Federal Energy Bill & US Tax Code.

Variable: $EligibleCost_{p}$
Definition: Eligible cost of PV system for program year *p*
Value: Assigned as a function of program year *p* and boundary case *b*.

Table B-2: Estimated Eligible PV Systems Costs under Different Scenarios

program year p	$EligibleCost_p$ Low	$EligibleCost_p$ Central	$EligibleCost_p$ High
2007	7,941	7,594	6,898
2008	7,678	7,179	6,218
2009	7,424	6,788	5,606
2010	7,180	6,418	5,057
2011	6,945	6,069	4,563
2012	6,718	5,740	4,119
2013	6,500	5,429	3,719
2014	6,290	5,136	3,360
2015	6,088	4,859	3,037
2016	5,893	4,597	2,747

Units: $

Basis: Real 2006 $. Experience curve projections. See Section 4, PV Costs.

<u>Federal Tax Depreciation</u>

$$FedTxDep_{pY} = FedTxRT \times \left(EligibleCost_p - 0.5 \times FedTxCrdt_p\right) \times FedTxDprcRT_Y \times \frac{1}{\left(1 + InflationRT\right)^Y}$$

Variable: $FedTxDep_{pY}$

Definition: Federal (after tax) depreciation benefit for program year *p* and system year *Y*.

Units: $.

Basis: Real 2006 $.

Variable: $FedTxDprcRT_Y$

Definition: Federal tax depreciation rate for system year *Y*.

Value: Assigned as a function of year *y*.

system year Y	$FedTxDprcRT_Y$
1	0.2000
2	0.3200
3	0.1920
4	0.1152
5	0.1152
6	0.0576
7 - 20	0.0000

Units: Fraction.

Basis: Federal Tax Code. MACRS depreciation, assumes that PV system is part of building.

Variable: $InflationRT$
Definition: General annual rate of inflation
Value: 0.02
Units: 1/Year
Basis: Precedent established by E-CUBE avoided cost work and Itron's cost-effectiveness evaluation work

State Tax Depreciation

$$StTxDep_{pY} = StTxRT \times EligibleCost_p \times StTxDprcRT_Y \times \frac{1}{(1 + InflationRT)^Y}$$

Variable: $StTxDep_{pY}$
Definition: State (after tax) depreciation benefit for program year p and system year Y.
Units: $.
Basis: Real 2006 $.

Variable: $StTxDprcRT_Y$
Definition: State tax depreciation rate for system year Y.
Value: Assigned as a function of system year Y.

system year Y	$StTxDprcRT_Y$
1 - 12	0.0833
13 - 20	0.0000

Units: Fraction.
Basis: California Tax Code.

Loan Amount

$$LoanAmt_p = EligibleCost_p$$

Variable: $LoanAmt_p$
Definition: Loan amount for program year p
Basis: Real 2006 $.

Loan Total Payments

$$LoanPmt_{pY} = LoanAmt_{p} \times \frac{InterestRT \times (1 + InterestRT)^{LoanTerm}}{(1 + InterestRT)^{LoanTerm} - 1} \times LoanFlag_{Y}$$

Variable: $LoanPmt_{pY}$
Definition: Loan payment for program year *p* and system year *Y*
Units: $.
Basis: Real 2006 $.

Variable: $InterestRT$
Definition: Loan interest rate
Value: 0.06
Units: 1/Year.
Basis: Real. ASSUMED.

Variable: $LoanTerm$
Definition: Loan term
Value: 10
Units: Years.
Basis: ASSUMED.

Variable: $LoanFlag_{Y}$
Definition: Flag used to effect loan term
Value: Assigned as a function of LoanTerm and system year *Y*.

system year *Y*	$LoanFlag_{Y}$
<=LoanTerm	1
>LoanTerm	0

Units: None.

Loan Interest Payments

$$Interest_{pY} = LoanPmt_{pY} \times \left(1 - \frac{(1 + InterestRT)^{y}}{(1 + InterestRT)^{(LoanTerm+1)}}\right)$$

Variable: $Interest_{pY}$
Definition: Interest portion of loan payment for program year *p* and system year *Y*
Units: $.
Basis: Real 2006 $.

Loan Interest Payment Tax Deduction Benefit

$$InterestTaxBen_{pY} = Interest_{pY} \times (1 - FedTxRT)$$

Variable: $InterestTaxBen_{pY}$
Definition: Tax deduction benefit resulting from interest portion of loan payment for program year p and system year Y
Units: $.
Basis: Real 2006 $.

Salvage Value

$$BfTxSalvage_{pY} = SalvageRT \times EligibleCost_p \times LifeFlag_Y$$
$$AfTxSalvage_{pY} = BfTxSalvage_{pY} \times (1 - EfctvMrgnlTxRT)$$

Variable: $BfTxSalvage_{pY}$
Definition: Salvage value (before tax) at end of useful life
Units: $.
Basis: Real 2006 $.

Variable: $AfTxSalvage_{pY}$
Definition: Salvage value (after tax) at end of useful life
Units: $.
Basis: Real 2006 $.

Variable: $SalvageRT$
Definition: Salvage rate expressed as a real portion of initial cost
Value: 0.1
Units: $/$
Basis: ASSUMED

Variable: $LifeFlag_Y$
Definition: Flag used to affect PV system life
Value: Assigned as a function of system year Y.

system year Y	$LifeFlag_Y$
1 – 19	0
20	1

Units: None.

Energy Production

$$\mathrm{ENGO}_{\mathrm{sY}} = \sum_{\mathrm{mdh}} \left(\overline{\mathrm{ENGO}}_{\mathrm{smdh}}\right) \times \left(1 - PV\mathrm{degradRT}\right)^{Y-1}$$

Variable: $\mathrm{ENGO}_{\mathrm{sY}}$
Definition: PV system energy production for scenario *s* and system year *Y*.
Units: kWh/Year.

Operations and Maintenance – Annual

$$BfTxOpMaint_Y = \overline{\overline{ENGO}} \times OpMaintRT$$
$$AfTxOpMaint_Y = BfTxOpMaint_Y \times \left(1 - EfctvMrgnlTxRT\right)$$

Variable: $BfTxOpMaint_Y$
Definition: Operations and maintenance costs (before tax)
Units: $/Year.
Basis: Real 2006 $.

Variable: $AfTxOpMaint_Y$
Definition: Operations and maintenance costs (after tax)
Units: $/Year.
Basis: Real 2006 $.

Variable: $\overline{\overline{ENGO}}$
Definition: Median first-year PV system electric performance for 39 scenarios included in analysis.
Value: 1,451
Units: kWh per kW of installed capacity.
Basis: Analysis of observed weather data, observed PV system electric performance data, and TMY weather files. ASSUMED PV system locations and configurations.

Variable: $OpMaintRT$
Definition: Operations and maintenance costs per unit of energy production
Value: 0.004
Units: $/kWh.
Basis: Real 2006 $.

Repair - Periodic

$$BfTxRepair_{pY} = Repair_{pY}$$
$$AfTxRepair_{pY} = BfTxRepair_{pY} \times \left(1 - EfctvMrgnlTxRT\right)$$

Variable: $BfTxRepair_{pY}$
Definition: Cost (before tax) for repairs (e.g., inverter replacement/rebuild) for program year *p* and system year *Y*.
Units: $
Basis: Real 2006 $.

Variable: $AfTxRepair_{pY}$
Definition: Cost (after tax) for repairs (e.g., inverter replacement/rebuild) for program year *p* and system year *Y*.
Units: $
Basis: Real 2006 $.

Variable: $Repair_{pY}$
Definition: Cost of periodic repairs (i.e., inverter replacement, other non-warranty repair)
Value: Assigned as a function of system year *Y* and program year *p*.

Table B-3: Estimated PV System Costs

System Year *Y*	Program Year *p*	Calendar Year	$Repair_{pY}$
11	2007	2017	$0.91
	2008	2018	$0.89
	2009	2019	$0.86
	2010	2020	$0.84
	2011	2021	$0.82
	2012	2022	$0.80
	2013	2023	$0.77
	2014	2024	$0.75
	2015	2025	$0.73
	2016	2026	$0.71
$\neq$11	2007-2016	2007-2040	$0.00

Units: $
Basis: Real 2006 $. Downward cost trend reflects forecast for inverter costs. Projected inverter costs marked up by 50% to account for re-engineering and other non-warranty repairs.

<u>Summary of Benefits and Costs</u>

Components

$$\begin{array}{ll}
\quad FedTxCrdt_{pY} & \\
+ FedTxDepBen_{pY} & \\
+ StTxDepBen_{pY} & \\
+ AfTxEnergyRetail_{spY} & \quad LoanPmt_{pY} \\
+ InterestTxBen_{pY} & + AfTxOpMaint_{spY} \\
+ AfTxSalvage_{pY} & + AfTxRepair_{pY} \\
\hline
\quad ParticipantBen_{spY} & \quad ParticipantCst_{spY}
\end{array}$$

Discount participant annual cash flows back to corresponding program year

$$NPVParticipantBen_{sp} = \sum_{Y} \frac{ParticipantBen_{spY}}{(1 + DiscRTpart)^{Y}}$$

$$NPVParticipantCst_{sp} = \sum_{Y} \frac{ParticipantCst_{spY}}{(1 + DiscRTpart)^{Y}}$$

Variable: $NPVParticipantBen_{sp}$

Definition: Net present value of annual benefit cash flows for scenario *s* and program year *p*.

Units: $.

Basis: Real 2006 $. Note that the net present values for different program years cannot simply be summed to arrive at a total for the entire 10-year program. These program year-specific net present values are being calculated in this manner to support modeling of participant decisions occurring during each individual program year.

Variable: $NPVParticipantCst_{sp}$

Definition: Net present value of annual cost cash flows for scenario *s* and program year *p*.

Units: $.

Basis: Real 2006 $. Note that the net present values for different program years cannot simply be summed to arrive at a total for the entire 10-year program. These program year-specific net present values are being calculated in this manner to support modeling of participant decisions occurring during each individual program year.

Variable: $DiscRTpart$
Definition: Discount rate for the Participant perspective
Value: 0.06
Units: 1/Year
Basis: Real.

Calculate required subsidy

$$NPVPBI_{sp} = NPVParticipantBen_{sp} - NPVParticipantCst_{sp}$$

Variable: $NPVPBI_{sp}$
Definition: Net present value of annual subsidy cash flows (after tax) for scenario *s* and program year *p*.
Units: $.
Basis: Real 2006 $, after taxes, for each program year. Note that the net present values for different program years cannot simply be summed to arrive at a total for the entire 10-year program. These program year-specific net present values are being calculated in this manner to support modeling of participant decisions occurring during each individual program year.

Calculate the $/kWh PBI corresponding to the NPV result

$$PBI5_{sp} = \frac{NPVPBI_{sp}}{\sum_{Y=1}^{5}\left(ENGO_{spY} \times \frac{1}{(1+DiscRTpart)^{Y}}\right)}$$

Variable: $PBI5_{sp}$
Definition: Five-year subsidy required to make participants whole for scenario *s* and program year *p*.
Units: $/kWh
Basis: Real 2006 $.

Appendix C

Results Detail

C.1 Introduction

Detailed tables of results for Program Year 2007 for the range of prototypes are included as Appendix C.

Figure C-1: Representative NPV Break-Even Subsidy Requirement Results—PY 2007—Central Activity Boundary Rates and Costs—6% (Real) Participant Discount Rate

SYSTEMS					COSTS				BENEFITS (Excluding subsidy)							SUBSIDY				Year 1	
scenario	utility	climate zone	tilt	azimuth	LoanPmt	AfTx O_M	AfTx OtherCst	Total	AfTx Energy	Fed TxCrdt	Interest TaxBen	Fed TxDep	State TxDep	AfTx Salvage	Total	PBI AfTx	PBI BfTx	PBI 25-Yr	PBI 5-Yr	ENGO	BfTx GenVal
1	pge	2	0	--	$7,594	$45	$318	$7,957	$1,224	$2,149	$1,425	$1,775	$379	$107	$7,060	$929	$1,529	$0.08	$0.26	1337	$0.11
2	pge	2	15	S	$7,594	$45	$318	$7,957	$1,301	$2,149	$1,425	$1,775	$379	$107	$7,137	$846	$1,394	$0.07	$0.22	1420	$0.11
3	pge	2	30	SW	$7,594	$45	$318	$7,957	$1,274	$2,149	$1,425	$1,775	$379	$107	$7,110	$854	$1,406	$0.07	$0.23	1372	$0.11
4	pge	3.1	0	--	$7,594	$45	$318	$7,957	$1,240	$2,149	$1,425	$1,775	$379	$107	$7,076	$902	$1,485	$0.07	$0.25	1356	$0.11
5	pge	3.1	15	S	$7,594	$45	$318	$7,957	$1,321	$2,149	$1,425	$1,775	$379	$107	$7,157	$829	$1,366	$0.06	$0.21	1444	$0.11
6	pge	3.1	30	SW	$7,594	$45	$318	$7,957	$1,328	$2,149	$1,425	$1,775	$379	$107	$7,164	$808	$1,331	$0.06	$0.21	1434	$0.11
7	sce	6	0	--	$7,594	$45	$318	$7,957	$1,265	$2,149	$1,425	$1,775	$379	$107	$7,101	$895	$1,474	$0.07	$0.23	1426	$0.10
8	sce	6	15	S	$7,594	$45	$318	$7,957	$1,352	$2,149	$1,425	$1,775	$379	$107	$7,188	$797	$1,312	$0.06	$0.19	1528	$0.10
9	sce	6	30	SW	$7,594	$45	$318	$7,957	$1,390	$2,149	$1,425	$1,775	$379	$107	$7,226	$690	$1,136	$0.05	$0.17	1546	$0.11
10	sdge	7	0	--	$7,594	$45	$318	$7,957	$1,099	$2,149	$1,425	$1,775	$379	$107	$6,935	$1,053	$1,734	$0.08	$0.28	1426	$0.09
11	sdge	7	15	S	$7,594	$45	$318	$7,957	$1,158	$2,149	$1,425	$1,775	$379	$107	$6,994	$989	$1,629	$0.07	$0.24	1518	$0.09
12	sdge	7	30	SW	$7,594	$45	$318	$7,957	$1,202	$2,149	$1,425	$1,775	$379	$107	$7,038	$936	$1,541	$0.07	$0.22	1557	$0.09
13	sce	8	0	--	$7,594	$45	$318	$7,957	$1,285	$2,149	$1,425	$1,775	$379	$107	$7,121	$874	$1,439	$0.07	$0.22	1451	$0.10
14	sce	8	15	S	$7,594	$45	$318	$7,957	$1,373	$2,149	$1,425	$1,775	$379	$107	$7,209	$785	$1,293	$0.06	$0.19	1551	$0.10
15	sce	8	30	SW	$7,594	$45	$318	$7,957	$1,412	$2,149	$1,425	$1,775	$379	$107	$7,248	$751	$1,237	$0.05	$0.18	1577	$0.11
16	sce	9	0	--	$7,594	$45	$318	$7,957	$1,245	$2,149	$1,425	$1,775	$379	$107	$7,081	$901	$1,484	$0.07	$0.24	1404	$0.10
17	sce	9	15	S	$7,594	$45	$318	$7,957	$1,293	$2,149	$1,425	$1,775	$379	$107	$7,128	$866	$1,426	$0.07	$0.22	1465	$0.10
18	sce	9	30	SW	$7,594	$45	$318	$7,957	$1,317	$2,149	$1,425	$1,775	$379	$107	$7,153	$835	$1,376	$0.06	$0.21	1465	$0.11
19	sce	10	0	--	$7,594	$45	$318	$7,957	$1,268	$2,149	$1,425	$1,775	$379	$107	$7,104	$887	$1,461	$0.07	$0.23	1442	$0.10
20	sdge	10	0	--	$7,594	$45	$318	$7,957	$1,106	$2,149	$1,425	$1,775	$379	$107	$6,942	$1,041	$1,715	$0.08	$0.27	1446	$0.09
21	sce	10	15	S	$7,594	$45	$318	$7,957	$1,331	$2,149	$1,425	$1,775	$379	$107	$7,167	$811	$1,336	$0.06	$0.20	1513	$0.10
22	sdge	10	15	S	$7,594	$45	$318	$7,957	$1,141	$2,149	$1,425	$1,775	$379	$107	$6,977	$1,013	$1,668	$0.07	$0.25	1497	$0.09
23	sce	10	30	SW	$7,594	$45	$318	$7,957	$1,327	$2,149	$1,425	$1,775	$379	$107	$7,163	$821	$1,352	$0.06	$0.21	1492	$0.10
24	sdge	10	30	SW	$7,594	$45	$318	$7,957	$1,149	$2,149	$1,425	$1,775	$379	$107	$6,985	$986	$1,624	$0.07	$0.25	1488	$0.09
25	pge	11	0	--	$7,594	$45	$318	$7,957	$1,264	$2,149	$1,425	$1,775	$379	$107	$7,100	$862	$1,419	$0.07	$0.23	1381	$0.11
26	pge	11	15	S	$7,594	$45	$318	$7,957	$1,319	$2,149	$1,425	$1,775	$379	$107	$7,155	$787	$1,297	$0.06	$0.20	1447	$0.11
27	pge	11	30	SW	$7,594	$45	$318	$7,957	$1,298	$2,149	$1,425	$1,775	$379	$107	$7,134	$788	$1,297	$0.06	$0.21	1402	$0.11
28	pge	12	0	--	$7,594	$45	$318	$7,957	$1,290	$2,149	$1,425	$1,775	$379	$107	$7,126	$842	$1,386	$0.07	$0.22	1414	$0.11
29	pge	12	15	S	$7,594	$45	$318	$7,957	$1,339	$2,149	$1,425	$1,775	$379	$107	$7,175	$798	$1,314	$0.06	$0.20	1475	$0.11
30	pge	12	30	SW	$7,594	$45	$318	$7,957	$1,320	$2,149	$1,425	$1,775	$379	$107	$7,156	$791	$1,302	$0.06	$0.21	1432	$0.11
31	sce	14	0	--	$7,594	$45	$318	$7,957	$1,337	$2,149	$1,425	$1,775	$379	$107	$7,173	$816	$1,344	$0.06	$0.20	1527	$0.10
32	sce	14	15	S	$7,594	$45	$318	$7,957	$1,419	$2,149	$1,425	$1,775	$379	$107	$7,255	$721	$1,188	$0.05	$0.17	1620	$0.10
33	sce	14	30	SW	$7,594	$45	$318	$7,957	$1,431	$2,149	$1,425	$1,775	$379	$107	$7,266	$672	$1,107	$0.05	$0.16	1603	$0.10
34	sce	15	0	--	$7,594	$45	$318	$7,957	$1,330	$2,149	$1,425	$1,775	$379	$107	$7,166	$812	$1,337	$0.06	$0.20	1529	$0.10
35	sce	15	15	S	$7,594	$45	$318	$7,957	$1,381	$2,149	$1,425	$1,775	$379	$107	$7,217	$765	$1,260	$0.05	$0.18	1592	$0.10
36	sce	15	30	SW	$7,594	$45	$318	$7,957	$1,351	$2,149	$1,425	$1,775	$379	$107	$7,187	$805	$1,326	$0.06	$0.20	1525	$0.10
37	sce	16	0	--	$7,594	$45	$318	$7,957	$1,172	$2,149	$1,425	$1,775	$379	$107	$7,008	$945	$1,557	$0.08	$0.26	1330	$0.10
38	sce	16	15	S	$7,594	$45	$318	$7,957	$1,236	$2,149	$1,425	$1,775	$379	$107	$7,072	$905	$1,491	$0.07	$0.24	1401	$0.10
39	sce	16	30	SW	$7,594	$45	$318	$7,957	$1,238	$2,149	$1,425	$1,775	$379	$107	$7,074	$910	$1,499	$0.07	$0.25	1379	$0.11

Figure C-2: Representative NPV Break-Even Subsidy Requirement Results—PY 2007—Low Activity Boundary Rates and Costs—6% (Real) Participant Discount Rate

SYSTEMS					COSTS				BENEFITS (Excluding subsidy)								SUBSIDY				Year 1	
scenario	utility	climate zone	tilt	azimuth	LoanPmt	AfTx O_M	AfTx OtherCst	Total	AfTx Energy	Fed TxCrdt	Interest TaxBen	Fed TxDep	State TxDep	AfTx Salvage	Total	PBI AfTx	PBI BfTx	PBI 25-Yr	PBI 5-Yr	ENGO	BfTx GenVal
1	pge	2	0	--	$7,594	$45	$318	$7,957	$1,224	$2,149	$1,425	$1,775	$379	$107	$7,060	$929	$1,529	$0.08	$0.26	1337	$0.11
2	pge	2	15	S	$7,594	$45	$318	$7,957	$1,301	$2,149	$1,425	$1,775	$379	$107	$7,137	$846	$1,394	$0.07	$0.22	1420	$0.11
3	pge	2	30	SW	$7,594	$45	$318	$7,957	$1,274	$2,149	$1,425	$1,775	$379	$107	$7,110	$854	$1,406	$0.07	$0.23	1372	$0.11
4	pge	3.1	0	--	$7,594	$45	$318	$7,957	$1,240	$2,149	$1,425	$1,775	$379	$107	$7,076	$902	$1,485	$0.07	$0.25	1356	$0.11
5	pge	3.1	15	S	$7,594	$45	$318	$7,957	$1,321	$2,149	$1,425	$1,775	$379	$107	$7,157	$829	$1,366	$0.06	$0.21	1444	$0.11
6	pge	3.1	30	SW	$7,594	$45	$318	$7,957	$1,328	$2,149	$1,425	$1,775	$379	$107	$7,164	$808	$1,331	$0.06	$0.21	1434	$0.11
7	sce	6	0	--	$7,594	$45	$318	$7,957	$1,265	$2,149	$1,425	$1,775	$379	$107	$7,101	$895	$1,474	$0.07	$0.23	1426	$0.10
8	sce	6	15	S	$7,594	$45	$318	$7,957	$1,352	$2,149	$1,425	$1,775	$379	$107	$7,188	$797	$1,312	$0.06	$0.19	1528	$0.10
9	sce	6	30	SW	$7,594	$45	$318	$7,957	$1,390	$2,149	$1,425	$1,775	$379	$107	$7,226	$690	$1,136	$0.05	$0.17	1546	$0.11
10	sdge	7	0	--	$7,594	$45	$318	$7,957	$1,099	$2,149	$1,425	$1,775	$379	$107	$6,935	$1,053	$1,734	$0.08	$0.28	1426	$0.09
11	sdge	7	15	S	$7,594	$45	$318	$7,957	$1,158	$2,149	$1,425	$1,775	$379	$107	$6,994	$989	$1,629	$0.07	$0.24	1518	$0.09
12	sdge	7	30	SW	$7,594	$45	$318	$7,957	$1,202	$2,149	$1,425	$1,775	$379	$107	$7,038	$936	$1,541	$0.07	$0.22	1557	$0.09
13	sce	8	0	--	$7,594	$45	$318	$7,957	$1,285	$2,149	$1,425	$1,775	$379	$107	$7,121	$874	$1,439	$0.07	$0.22	1451	$0.10
14	sce	8	15	S	$7,594	$45	$318	$7,957	$1,373	$2,149	$1,425	$1,775	$379	$107	$7,209	$785	$1,293	$0.06	$0.19	1551	$0.10
15	sce	8	30	SW	$7,594	$45	$318	$7,957	$1,412	$2,149	$1,425	$1,775	$379	$107	$7,248	$751	$1,237	$0.05	$0.18	1577	$0.11
16	sce	9	0	--	$7,594	$45	$318	$7,957	$1,245	$2,149	$1,425	$1,775	$379	$107	$7,081	$901	$1,484	$0.07	$0.24	1404	$0.10
17	sce	9	15	S	$7,594	$45	$318	$7,957	$1,293	$2,149	$1,425	$1,775	$379	$107	$7,128	$866	$1,426	$0.07	$0.22	1465	$0.10
18	sce	9	30	SW	$7,594	$45	$318	$7,957	$1,317	$2,149	$1,425	$1,775	$379	$107	$7,153	$835	$1,376	$0.06	$0.21	1465	$0.11
19	sce	10	0	--	$7,594	$45	$318	$7,957	$1,268	$2,149	$1,425	$1,775	$379	$107	$7,104	$887	$1,461	$0.07	$0.23	1442	$0.10
20	sdge	10	0	--	$7,594	$45	$318	$7,957	$1,106	$2,149	$1,425	$1,775	$379	$107	$6,942	$1,041	$1,715	$0.08	$0.27	1446	$0.09
21	sce	10	15	S	$7,594	$45	$318	$7,957	$1,331	$2,149	$1,425	$1,775	$379	$107	$7,167	$811	$1,336	$0.06	$0.20	1513	$0.10
22	sdge	10	15	S	$7,594	$45	$318	$7,957	$1,141	$2,149	$1,425	$1,775	$379	$107	$6,977	$1,013	$1,668	$0.07	$0.25	1497	$0.09
23	sce	10	30	SW	$7,594	$45	$318	$7,957	$1,327	$2,149	$1,425	$1,775	$379	$107	$7,163	$821	$1,352	$0.06	$0.21	1492	$0.10
24	sdge	10	30	SW	$7,594	$45	$318	$7,957	$1,149	$2,149	$1,425	$1,775	$379	$107	$6,985	$986	$1,624	$0.07	$0.25	1488	$0.09
25	pge	11	0	--	$7,594	$45	$318	$7,957	$1,264	$2,149	$1,425	$1,775	$379	$107	$7,100	$862	$1,419	$0.07	$0.23	1381	$0.11
26	pge	11	15	S	$7,594	$45	$318	$7,957	$1,319	$2,149	$1,425	$1,775	$379	$107	$7,155	$787	$1,297	$0.06	$0.20	1447	$0.11
27	pge	11	30	SW	$7,594	$45	$318	$7,957	$1,298	$2,149	$1,425	$1,775	$379	$107	$7,134	$788	$1,297	$0.06	$0.21	1402	$0.11
28	pge	12	0	--	$7,594	$45	$318	$7,957	$1,290	$2,149	$1,425	$1,775	$379	$107	$7,126	$842	$1,386	$0.07	$0.22	1414	$0.11
29	pge	12	15	S	$7,594	$45	$318	$7,957	$1,339	$2,149	$1,425	$1,775	$379	$107	$7,175	$798	$1,314	$0.06	$0.20	1475	$0.11
30	pge	12	30	SW	$7,594	$45	$318	$7,957	$1,320	$2,149	$1,425	$1,775	$379	$107	$7,156	$791	$1,302	$0.06	$0.21	1432	$0.11
31	sce	14	0	--	$7,594	$45	$318	$7,957	$1,337	$2,149	$1,425	$1,775	$379	$107	$7,173	$816	$1,344	$0.06	$0.20	1527	$0.10
32	sce	14	15	S	$7,594	$45	$318	$7,957	$1,419	$2,149	$1,425	$1,775	$379	$107	$7,255	$721	$1,188	$0.05	$0.17	1620	$0.10
33	sce	14	30	SW	$7,594	$45	$318	$7,957	$1,431	$2,149	$1,425	$1,775	$379	$107	$7,266	$672	$1,107	$0.05	$0.16	1603	$0.10
34	sce	15	0	--	$7,594	$45	$318	$7,957	$1,330	$2,149	$1,425	$1,775	$379	$107	$7,166	$812	$1,337	$0.06	$0.20	1529	$0.10
35	sce	15	15	S	$7,594	$45	$318	$7,957	$1,381	$2,149	$1,425	$1,775	$379	$107	$7,217	$765	$1,260	$0.05	$0.18	1592	$0.10
36	sce	15	30	SW	$7,594	$45	$318	$7,957	$1,351	$2,149	$1,425	$1,775	$379	$107	$7,187	$805	$1,326	$0.06	$0.20	1525	$0.10
37	sce	16	0	--	$7,594	$45	$318	$7,957	$1,172	$2,149	$1,425	$1,775	$379	$107	$7,008	$945	$1,557	$0.08	$0.26	1330	$0.10
38	sce	16	15	S	$7,594	$45	$318	$7,957	$1,236	$2,149	$1,425	$1,775	$379	$107	$7,072	$905	$1,491	$0.07	$0.24	1401	$0.10
39	sce	16	30	SW	$7,594	$45	$318	$7,957	$1,238	$2,149	$1,425	$1,775	$379	$107	$7,074	$910	$1,499	$0.07	$0.25	1379	$0.11

Figure C-3: Representative NPV Break-Even Subsidy Requirement Results—PY 2007—High Activity Boundary Rates and Costs—6% (Real) Participant Discount Rate

SYSTEMS					COSTS				BENEFITS (Excluding subsidy)								SUBSIDY				Year 1	
scenario	utility	climate zone	tilt	azimuth	LoanPmt	AfTx O_M	AfTx OtherCst	Total	AfTx Energy	Fed TxCrdt	Interest TaxBen	Fed TxDep	State TxDep	AfTx Salvage	Total	PBI AfTx	PBI BfTx	PBI 25-Yr	PBI 5-Yr	ENGO	BfTx GenVal
1	pge	2	0	--	$6,898	$45	$318	$7,261	$1,437	$1,952	$1,294	$1,613	$344	$98	$6,738	$561	$923	$0.05	$0.16	1337	$0.11
2	pge	2	15	S	$6,898	$45	$318	$7,261	$1,526	$1,952	$1,294	$1,613	$344	$98	$6,827	$464	$764	$0.04	$0.12	1420	$0.11
3	pge	2	30	SW	$6,898	$45	$318	$7,261	$1,495	$1,952	$1,294	$1,613	$344	$98	$6,796	$473	$779	$0.04	$0.13	1372	$0.11
4	pge	3.1	0	--	$6,898	$45	$318	$7,261	$1,455	$1,952	$1,294	$1,613	$344	$98	$6,756	$529	$871	$0.04	$0.15	1356	$0.11
5	pge	3.1	15	S	$6,898	$45	$318	$7,261	$1,550	$1,952	$1,294	$1,613	$344	$98	$6,851	$444	$731	$0.03	$0.11	1444	$0.11
6	pge	3.1	30	SW	$6,898	$45	$318	$7,261	$1,558	$1,952	$1,294	$1,613	$344	$98	$6,859	$419	$691	$0.03	$0.11	1434	$0.11
7	sce	6	0	--	$6,898	$45	$318	$7,261	$1,485	$1,952	$1,294	$1,613	$344	$98	$6,786	$521	$858	$0.04	$0.14	1426	$0.11
8	sce	6	15	S	$6,898	$45	$318	$7,261	$1,586	$1,952	$1,294	$1,613	$344	$98	$6,887	$406	$668	$0.03	$0.10	1528	$0.11
9	sce	6	30	SW	$6,898	$45	$318	$7,261	$1,631	$1,952	$1,294	$1,613	$344	$98	$6,932	$281	$462	$0.02	$0.07	1546	$0.11
10	sdge	7	0	--	$6,898	$45	$318	$7,261	$1,290	$1,952	$1,294	$1,613	$344	$98	$6,591	$707	$1,164	$0.05	$0.18	1426	$0.09
11	sdge	7	15	S	$6,898	$45	$318	$7,261	$1,358	$1,952	$1,294	$1,613	$344	$98	$6,660	$632	$1,040	$0.05	$0.16	1518	$0.09
12	sdge	7	30	SW	$6,898	$45	$318	$7,261	$1,411	$1,952	$1,294	$1,613	$344	$98	$6,712	$569	$937	$0.04	$0.14	1557	$0.09
13	sce	8	0	--	$6,898	$45	$318	$7,261	$1,508	$1,952	$1,294	$1,613	$344	$98	$6,810	$496	$817	$0.04	$0.13	1451	$0.11
14	sce	8	15	S	$6,898	$45	$318	$7,261	$1,611	$1,952	$1,294	$1,613	$344	$98	$6,912	$393	$646	$0.03	$0.09	1551	$0.11
15	sce	8	30	SW	$6,898	$45	$318	$7,261	$1,657	$1,952	$1,294	$1,613	$344	$98	$6,959	$352	$580	$0.02	$0.08	1577	$0.11
16	sce	9	0	--	$6,898	$45	$318	$7,261	$1,460	$1,952	$1,294	$1,613	$344	$98	$6,762	$528	$870	$0.04	$0.14	1404	$0.11
17	sce	9	15	S	$6,898	$45	$318	$7,261	$1,517	$1,952	$1,294	$1,613	$344	$98	$6,818	$487	$802	$0.04	$0.12	1465	$0.11
18	sce	9	30	SW	$6,898	$45	$318	$7,261	$1,546	$1,952	$1,294	$1,613	$344	$98	$6,847	$451	$743	$0.03	$0.11	1465	$0.11
19	sce	10	0	--	$6,898	$45	$318	$7,261	$1,488	$1,952	$1,294	$1,613	$344	$98	$6,789	$512	$843	$0.04	$0.13	1442	$0.10
20	sdge	10	0	--	$6,898	$45	$318	$7,261	$1,298	$1,952	$1,294	$1,613	$344	$98	$6,599	$693	$1,141	$0.05	$0.18	1446	$0.09
21	sce	10	15	S	$6,898	$45	$318	$7,261	$1,562	$1,952	$1,294	$1,613	$344	$98	$6,863	$423	$696	$0.03	$0.10	1513	$0.10
22	sdge	10	15	S	$6,898	$45	$318	$7,261	$1,339	$1,952	$1,294	$1,613	$344	$98	$6,640	$659	$1,086	$0.05	$0.16	1497	$0.09
23	sce	10	30	SW	$6,898	$45	$318	$7,261	$1,557	$1,952	$1,294	$1,613	$344	$98	$6,858	$434	$715	$0.03	$0.11	1492	$0.11
24	sdge	10	30	SW	$6,898	$45	$318	$7,261	$1,348	$1,952	$1,294	$1,613	$344	$98	$6,649	$628	$1,035	$0.05	$0.16	1488	$0.09
25	pge	11	0	--	$6,898	$45	$318	$7,261	$1,483	$1,952	$1,294	$1,613	$344	$98	$6,785	$482	$794	$0.04	$0.13	1381	$0.11
26	pge	11	15	S	$6,898	$45	$318	$7,261	$1,548	$1,952	$1,294	$1,613	$344	$98	$6,849	$395	$651	$0.03	$0.10	1447	$0.11
27	pge	11	30	SW	$6,898	$45	$318	$7,261	$1,523	$1,952	$1,294	$1,613	$344	$98	$6,824	$395	$651	$0.03	$0.11	1402	$0.11
28	pge	12	0	--	$6,898	$45	$318	$7,261	$1,514	$1,952	$1,294	$1,613	$344	$98	$6,815	$459	$755	$0.04	$0.12	1414	$0.11
29	pge	12	15	S	$6,898	$45	$318	$7,261	$1,571	$1,952	$1,294	$1,613	$344	$98	$6,872	$407	$671	$0.03	$0.10	1475	$0.11
30	pge	12	30	SW	$6,898	$45	$318	$7,261	$1,548	$1,952	$1,294	$1,613	$344	$98	$6,850	$399	$657	$0.03	$0.10	1432	$0.11
31	sce	14	0	--	$6,898	$45	$318	$7,261	$1,569	$1,952	$1,294	$1,613	$344	$98	$6,871	$429	$706	$0.03	$0.10	1527	$0.10
32	sce	14	15	S	$6,898	$45	$318	$7,261	$1,665	$1,952	$1,294	$1,613	$344	$98	$6,967	$317	$522	$0.02	$0.07	1620	$0.10
33	sce	14	30	SW	$6,898	$45	$318	$7,261	$1,679	$1,952	$1,294	$1,613	$344	$98	$6,980	$260	$428	$0.02	$0.06	1603	$0.11
34	sce	15	0	--	$6,898	$45	$318	$7,261	$1,560	$1,952	$1,294	$1,613	$344	$98	$6,861	$424	$698	$0.03	$0.10	1529	$0.10
35	sce	15	15	S	$6,898	$45	$318	$7,261	$1,621	$1,952	$1,294	$1,613	$344	$98	$6,922	$369	$607	$0.03	$0.09	1592	$0.10
36	sce	15	30	SW	$6,898	$45	$318	$7,261	$1,585	$1,952	$1,294	$1,613	$344	$98	$6,886	$416	$685	$0.03	$0.10	1525	$0.11
37	sce	16	0	--	$6,898	$45	$318	$7,261	$1,376	$1,952	$1,294	$1,613	$344	$98	$6,677	$580	$955	$0.05	$0.16	1330	$0.11
38	sce	16	15	S	$6,898	$45	$318	$7,261	$1,450	$1,952	$1,294	$1,613	$344	$98	$6,751	$533	$878	$0.04	$0.14	1401	$0.11
39	sce	16	30	SW	$6,898	$45	$318	$7,261	$1,453	$1,952	$1,294	$1,613	$344	$98	$6,754	$539	$888	$0.04	$0.15	1379	$0.11

Appendix D

Program Prototype Results Detail

Detailed tables of program prototype results are included as Appendix D.

Annual and cumulative budgets summarized graphically in Figure 8-1 are presented in Table D-1. This assumed budget distribution is based on several assumptions:

- The total budget is $1 billion.
- The budget in Year 10 is 20 percent of the budget in Year One.
- Annual budgets decrease linearly from Year One through Year 10.

Table D-1: Annual and Cumulative Budgets for Hypothetical 10-Year Program

PY	Annual Budget (millions, real 2006 $)	Cumulative Budget (millions, real 2006 $)
2007	167	167
2008	152	319
2009	137	456
2010	122	578
2011	107	685
2012	93	778
2013	78	856
2014	63	919
2015	48	967
2016	33	1,000

PV capacity impacts for California summarized graphically in Figure 8-4 are presented in Table D-2. The large drop in annual PV capacity between 2007 and 2008 is attributable to the assumption that the federal ITC will revert to 10 percent from its current level of 30 percent. Whereas annual budgets fall 78 percent between 2008 and 2016, annual PV capacity falls only 33 percent during this same period. This trend is explained by the fact that PV costs are assumed to be falling, and retail electricity rates rising, throughout this timeframe. These two key trends enable each program incentive dollar to yield more PV capacity, as summarized in the Annual Incentive Costs column in Table D-2.

Table D-2: Annual and Cumulative PV Capacity Impacts and Program Incentive Costs for California

PY	PV Capacity Impacts Annual (MW)	Cumulative (MW)	Incentive Costs Annual ($/Watt)	Cumulative ($/Watt)
2007	121	121	$1.38	$1.38
2008	49	170	$3.10	$1.87
2009	50	220	$2.74	$2.07
2010	49	269	$2.49	$2.15
2011	48	317	$2.24	$2.16
2012	47	364	$1.97	$2.14
2013	46	410	$1.69	$2.09
2014	42	452	$1.50	$2.03
2015	39	491	$1.23	$1.97
2016	32	523	$1.04	$1.91

Retail Electric Rate[1] and Solar Resource[2] Multipliers summarized graphically in Figure 8-2 and Figure 8-3 are presented in Table D-3. The Total Multiplier is calculated as the product of the Retail Electric Rate and Solar Resource Multipliers. PV Capacity impacts for other states summarized graphically in Figure 8-4 were calculated as the product of the Total Multipliers and the PV impacts for California presented in Table D-2.

[1] Energy Information Administration, Electric Power Monthly with data for May 2006, Report Released August 11, 2006. Table 5.6.A. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, May 2006 and 2005.

[2] Solar Radiation Data Manual for Buildings, National Renewable Energy Laboratory, NREL/TP-463-7904, September 1995.

Table D-3: Retail Electric Price, Solar Resource, and Total Multipliers

State	Retail Electricity Price		Solar Resource			
	Avg. Retail Electricity Price (Cents/kWh)	Retail Electric Rate Multiplier	City	Avg. Incident Global Horiz. Solar Radiation (Btu/ft^2/day)	Solar Resource Multiplier	Total Multiplier
Hawaii	20.86	1.61	Honolulu	1,710	1.15	1.84
California	12.99	1.00	San Francisco	1,490	1.00	1.00
New Hampshire	14.96	1.15	Concord	1,240	0.83	0.96
Massachusetts	14.73	1.13	Boston	1,240	0.83	0.94
Nevada	10.07	0.78	Las Vegas	1,790	1.20	0.93
Rhode Island	14.15	1.09	Providence	1,230	0.83	0.90
Connecticut	13.56	1.04	Hartford	1,210	0.81	0.85
New York	12.83	0.99	New York City	1,260	0.85	0.84
Maine	12.41	0.96	Portland	1,230	0.83	0.79
Maryland	11.82	0.91	Maryland	1,280	0.86	0.78
Delaware	11.72	0.90	Wilmington	1,290	0.87	0.78
Florida	9.88	0.76	Miami	1,530	1.03	0.78
Arizona	8.28	0.64	Phoenix	1,810	1.21	0.77
Texas	9.47	0.73	Fort Worth	1,550	1.04	0.76
Vermont	11.99	0.92	Burlington	1,180	0.79	0.73
Mississippi	9.58	0.74	Meridian	1,420	0.95	0.70
New Jersey	10.76	0.83	Newark	1,230	0.83	0.68
New Mexico	7.49	0.58	Albuquerque	1,760	1.18	0.68
Tennessee	8.26	0.64	Memphis	1,430	0.96	0.61
Louisiana	8.20	0.63	New Orleans	1,440	0.97	0.61
Georgia	7.94	0.61	Atlanta	1,450	0.97	0.59
Pennsylvania	8.99	0.69	Philadelphia	1,260	0.85	0.59
Alabama	7.97	0.61	Birmingham	1,410	0.95	0.58
South Carolina	7.42	0.57	Charleston	1,460	0.98	0.56
Michigan	8.91	0.69	Detroit	1,200	0.81	0.55
Wisconsin	8.41	0.65	Madison	1,240	0.83	0.54
Ohio	8.51	0.66	Columbus	1,210	0.81	0.53
Kansas	7.12	0.55	Wichita	1,440	0.97	0.53
Oklahoma	6.77	0.52	Oklahoma City	1,510	1.01	0.53
North Carolina	7.13	0.55	Charlotte	1,410	0.95	0.52
Colorado	6.79	0.52	Boulder	1,450	0.97	0.51
Indiana	7.56	0.58	Indianapolis	1,300	0.87	0.51
Utah	6.72	0.52	Salt Lake City	1,450	0.97	0.50
Illinois	7.90	0.61	Chicago	1,220	0.82	0.50
Montana	7.35	0.57	Billings	1,310	0.88	0.50
Arkansas	6.49	0.50	Little Rock	1,430	0.96	0.48
Iowa	7.12	0.55	Des Moines	1,300	0.87	0.48
Alaska	12.07	0.93	Anchorage	760	0.51	0.47
Missouri	6.61	0.51	St. Louis	1,340	0.90	0.46
South Dakota	6.56	0.51	Rapid City	1,350	0.91	0.46
Wyoming	6.33	0.49	Casper	1,390	0.93	0.45
Minnesota	6.92	0.53	Minneapolis	1,230	0.83	0.44
Virginia	6.22	0.48	Richmond	1,340	0.90	0.43
Kentucky	6.36	0.49	Louisville	1,300	0.87	0.43
Nebraska	6.10	0.47	Omaha	1,330	0.89	0.42
North Dakota	6.10	0.47	Bismarck	1,270	0.85	0.40
Oregon	6.97	0.54	Portland	1,110	0.74	0.40
Idaho	5.51	0.42	Boise	1,400	0.94	0.40
West Virginia	5.62	0.43	Charleston	1,250	0.84	0.36
Washington	6.29	0.48	Olympia	1,030	0.69	0.33