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CSI Program Impacts Peak Demand and Emissions

This section presents the results of the CSI program impact on the following areas: energy delivery; peak demand reduction; resource adequacy; expected performance of systems, and Green House Gas emissions reductions including CO_2, PM-10 and NOx.

5.1 Overall Program Energy Impacts

This section provides annual energy and non-coincident demand impacts for the overall program as well as for each PA. Electrical energy and demand impacts were estimated for projects completed or deemed to be active on-line prior to January 1, 2010. Impacts were estimated using available metered data and information on system characteristics. Information on system characteristics came from project tracking systems maintained by the PAs. Appendix E of this report provides a description of the data analysis, methodology and treatment of statistical uncertainty.

By the end of 2009, there were 24,938 complete or active on-line CSI solar systems providing nearly 285 MW of electric generating capacity. Table 5-1 provides the estimated quantity of electric energy (in megawatt-hours) delivered by CSI facilities for each quarter throughout calendar year 2009.

Table 5-1: Estimated CSI Statewide Energy Impact (PV Generation) in 2009 by Quarter*

Q1 (MWh)	Q2 (MWh)	Q3 (MWh)	Q4 (MWh)	Total (MWh)
60,486	118,021	130,614	81,630	390,750

*The uncertainty on all of these estimates is better than 90/10 confidence level.

The entire CSI program was broken up by similar groups or Strata to allow metered systems to estimate performance of unmetered systems. Strata used for estimation are Program Administrator, configuration (Near Flat, Titled, Tracking,) locale (Inland vs. Coastal,) program (Residential & Small Commercial vs. Large Commercial,) and incentive type

(EPBB vs. PBI.) Metered systems were used to estimate performance of unmetered systems that did not share all strata characteristics in only 1.1 percent of the total impact in 2009.

CSI projects generated over 390,000 MWh of electricity during 2009; over three times the amount generated in 2008[1]. That energy was enough to meet the electricity requirements of approximately 66,000 homes for a year.[2] CSI projects are located at utility customer sites where they help meet local electricity requirements. Consequently, the over 390,000 MWh of electricity provided by CSI facilities during 2009 represents electricity that did not have to be generated by central station power plants or delivered by the transmission and distribution system.

In addition to examining the amount of energy delivered annually by CSI PV systems, it's also valuable to know the variation in energy delivery during the course of the year. Weighted annual average capacity factors (CFs)[3] were developed for all systems by comparing annual generation to maximum possible generation (i.e., generation at full capacity for the time that the system was operational). For example if a 1 kW PV system provided 6 kWh of energy over a 24 hour period the capacity factor of that system would be 25 percent (i.e., 6 kWh / (1kW*24 hours)).

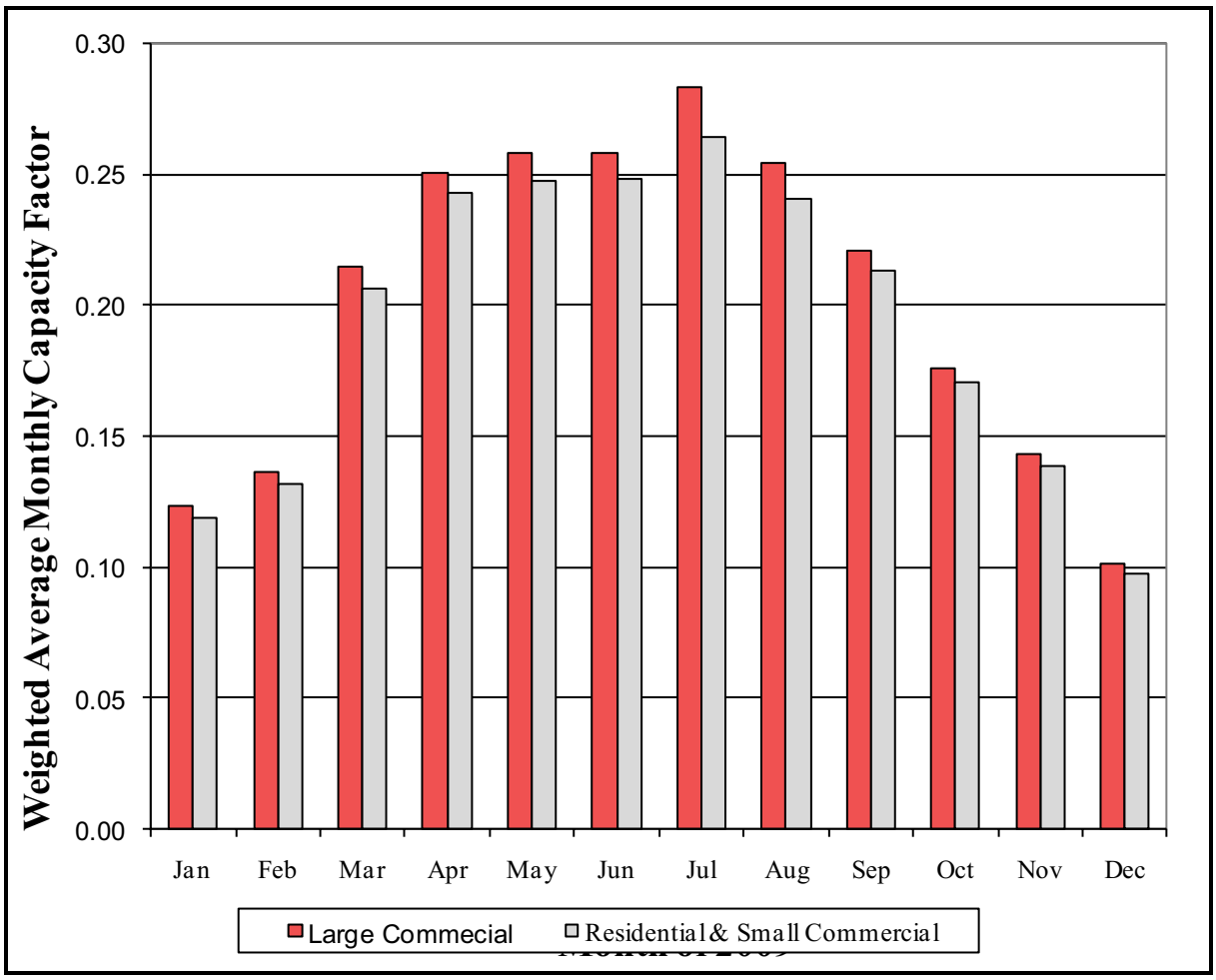
Consequently, capacity factor is useful in providing insights into the capability of a generating technology to provide power during a particular time period. For example, annual capacity factors indicate the fraction of energy that could, on average, be expected from that technology over the course of a year. Similarly, average monthly capacity factors represent the fraction available, on average, during any particular month. Weighted average monthly capacity factors for 2009 are shown in Figure 5-1.

1 118,489 MWh were estimated to be generated by CSI systems in 2008.

2 Assuming the typical home consumes approximately 5,914 kWh of electricity per year. From the California Statewide Residential Appliance Saturation Study Final Report, June 2004, www.energy.ca.gov/reports/400-04-009/2004-08-17_400-04-009ALL.PDF. Value derived from Figure 1 on page 3 of the Executive Summary.

3 Annual capacity factors are weighted by the capacity contribution from each facility

Figure 5-1: Weighted Average 2009 Estimated Capacity Factors by Month for All Systems



Note that capacity factors during the summer months peaked at over 0.25 in July and dropped below 0.1 in December. The weighted annual average estimated capacity factor for all installed CSI PV systems in 2009 was 0.20. The commercial systems have a higher capacity factor in part because systems included in these are more likely to be tracking systems which have a much higher capacity factor than a flat system.

PA-Specific Energy Impacts

Table 5-2 provides annual energy impacts for CSI projects by each PA for 2009, the corresponding number of PV systems installed by the end of 2009, and the estimated annual capacity factor.

Table 5-2: Estimated CSI Annual Energy Impacts by PA (MWh)

Program Administrator	PV Systems (n)	PV Systems (MW)	PV Generation (MWh)	Annual Capacity Factor (kWh/kWp)
PG&E	15,613	164.1	225,063	0.20
SCE	6,231	93.0	126,850	0.20
CCSE	3,139	27.4	38,837	0.21
Total	24,983	284.5	390,750	0.20

* The uncertainty on all of these estimates is better than 90/10 confidence
** CCSE is the program administrator of the CSI program in SDG&E's service area.

PV systems installed in the PG&E area are estimated to have supplied slightly over 58 percent of the total electricity delivered by the CSI in 2009, whereas SCE and CCSE systems are estimated to have supplied approximately 32 percent and 10 percent, respectively. The magnitude of electricity delivery in the PG&E territory is not surprising given that PG&E had over 15,600 PV systems representing 164.1 MW in 2009; over 62 percent of all systems and nearly 58 percent of the installed capacity.

The 2009 average annual capacity factors in Table 5-2 are somewhat higher than those seen in the Self Generation Incentive Program (SGIP,) where the statewide average annual capacity factor in 2009 was 0.175. This difference could be due to a number of factors:

- System Degradation; the average age of CSI systems is 1 year whereas the average of SGIP systems is approximately 4 years. Older systems tend to produce less energy due to module degradation and increased outages due to maintenance, and component failures.
- CSI systems are more likely to be tilted and more likely to be facing southwest. Near Flat and Tilted systems are in approximately a 1:1 ratio in the CSI program and a 3:1 ratio in SGIP. Tilted systems tend to have higher annual and peak capacity factors because the panels are pointed more directly at the sun.
- System technology and installation improvements may be resulting in more efficient systems.

5.2 Peak Electricity Demand Impacts

This section presents estimates of the CSI program as a whole on peak electricity demand. A program-wide examination of peak demand impact was based on the electricity produced by CSI projects coincident to the California Independent System Operator (CAISO) system peak for 2009.

Program Peak Demand Impacts

The ability of CSI projects to supply electricity during times of peak demand represents a critical impact. By providing electricity directly at the customer site during peak hours, CSI facilities potentially reduce the need for utilities to power up peaking units to supply electricity to these customers. As a result, the CSI may provide grid benefits by alleviating the need to dispatch potentially older, more polluting, and more expensive peaking generators as well as decreasing transmission and distribution line congestion. In addition, CSI projects provide potential cost savings to their host sites.

Peak loads and dates of the CAISO peaks for 2009 are listed in Table 5-3. The CAISO annual system load peaked for 2009 from 2:00 to 3:00 p.m. Pacific Standard Time (PST) (3:00 pm to 4:00 pm PDT).[4] The peak was slightly below 46,000 MW whereas the peak for both 2007 and 2008 was slightly above 46,000 MW.

Table 5-3: Loads and Dates of CAISO System Peak for 2009

Year	Peak Load (MW)	Date and Time
2009	45,994	September 3, 2:00 to 3:00 P.M. (PST)

[4] Unless otherwise stated, all time in this report are listed as Pacific Standard Time.

Table 5-4 shows the number of systems which were online during the CAISO peak in 2009.[5] This table also provides information on the overall CSI program impact on electricity demand coincident with the CAISO system peak loads in 2009. Hourly Capacity Factor (CF) is defined as the energy generated during that hour (kWh) divided by the nominal rated AC capacity during ideal conditions (kWp.)

Table 5-4: Estimated Demand Impact Coincident with CAISO System Peak*

Program Administrator	PV Systems (n)	PV Systems (MW)	PV Generation (MWh)	Hourly Capacity Factor (kWh/kWp)
PG&E	12939	139.5	87.2	0.62
SCE	5005	82.8	43.3	0.52
CCSE	2198	22.6	13.6	0.60
All	20142	245.0	144.0	0.59

* The uncertainty on all of these estimates is better than 90/10 confidence

In 2009, there were over 20,100 systems online at the time of the CAISO system peak. While these online systems had a CEC AC capacity of approximately 245MW (nearly 4x the capacity online during the 2008 peak), their generating output for that hour was estimated to be 144 MWh based on available metered data. Consequently, based on available metered data, CSI systems had a peak hour capacity factor of 0.59 at the time of the 2009 CAISO system peak. The peak hour capacity factor of SCE was somewhat lower than other areas for 2009. We believe this to be correlated with the wild fires in the Los Angeles metropolitan area at this time which included the Station Fire that was only partially contained at the time of this system peak.[6]

Figure 5-2 shows the estimated hourly impact of CSI projects on the 2009 CAISO system peak. Based on the available metered data, CSI system generating capacity increased steadily from 8 am to 11 am; remained fairly level from 11 am to1 pm and then declined steadily through the rest of the afternoon. This overall generation profile is typical of PV systems. The peak capacity factor at solar noon on the peak day in 2009 is approximately 0.72. This is less than 1 due to a number of possible reasons:

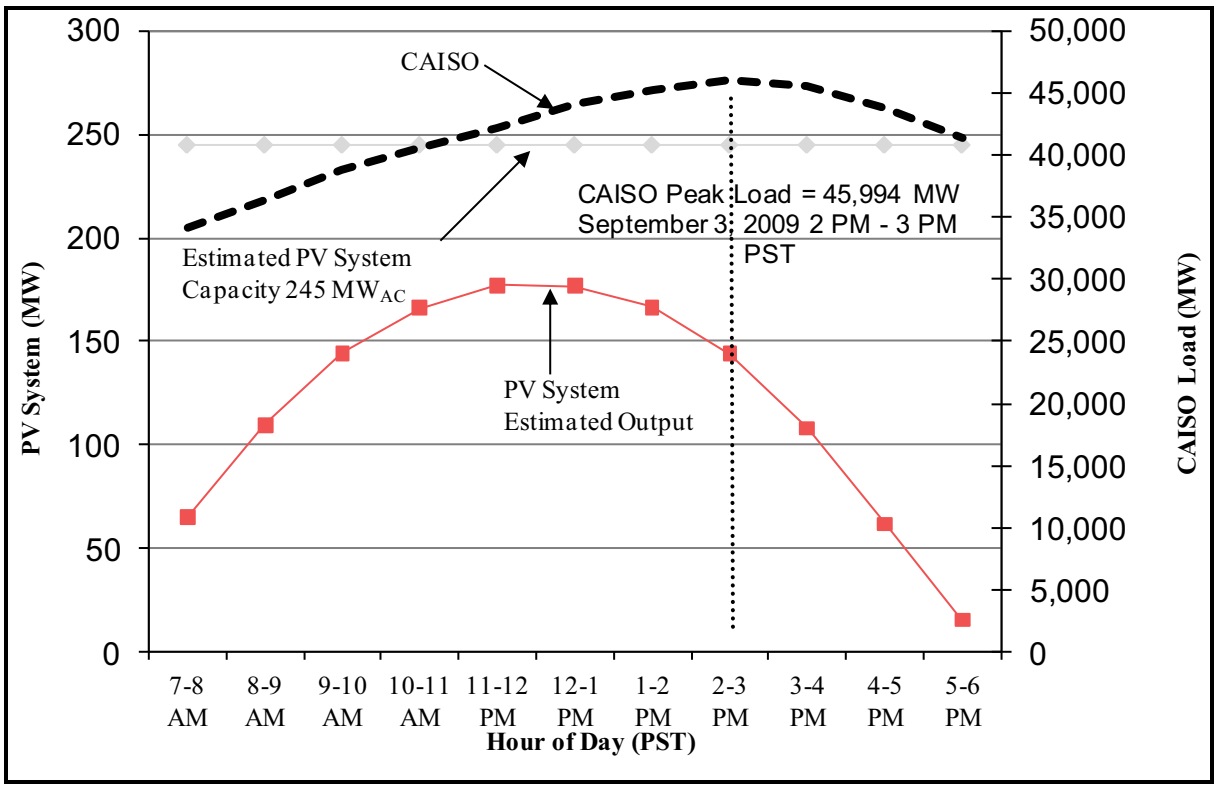
- The peak CAISO day load is usually driven by cooling demand on a hot day, when PV panels do not perform quite as efficiently as when tested at 20°C (68°F)

[5] The number of on-line systems for both years is lower than the on-line number for at the end of the year. Approximately 4,800 more systems were installed between September t 3, 2009 and December 31, 2009. See table 2-5 for quarterly details.

[6] The Station Fire burned 251 square miles in the Los Angeles metro area. It began August 26, 2009 and was 100% contained October 16, 2009.

- In 2009, the CAISO fell relatively late in the year after most of the summer when dust and dirt builds up on panels (also know as soiling) to reduce performance and before the winter rains wash those systems that are not cleaned during regular service.
- The estimated production includes metered data for some systems that are not generating due to maintenance or other problems.

Figure 5-2: Estimated Hourly CSI Impact on CAISO 2009 System Peak



A similar analysis was performed looking at the individual peaks of the three utility service areas. With the exception of PG&E, the other IOU peaks were on the same day and hour as the CASIO system wide peak, September 3, 2009 from 2 to 3 PM PST.

Table 5-5 shows the number and estimated capacity of PV systems online during the IOU system peaks by PA and the associated impact on the IOU peak

Table 5-5: Estimated PA-Specific IOU Peak Impacts*

Program Administrator	Date and Time (PST)	PV Systems (n)	PV Systems (MW)	PV Generation (MWh)	Capacity Factor
PG&E	July 14, 3:00 to 4:00 PM	12,003	131.7	79.2	0.60
SCE	September 3, 2:00 to 3:00 PM	5,005	82.8	43.3	0.52
CCSE	September 3, 2:00 to 3:00 PM	2,198	22.6	13.6	0.60

* The uncertainty on all of these estimates is better than 90/10 confidence

5.3 PV's Effective Capacity during the Top 100 hours of CAISO Demand

As noted earlier, the ability of distributed generation systems to provide electricity at the time of the CAISO or utility-specific peak demand is important. Electricity generated from CSI PV facilities means potentially less need for the utility to power up peaking facilities and transfer electricity through the T&D system. However, the CAISO peak or utility-specific peak represents only a single hour of the entire 8760 hours per year. Consequently, examining only the impact on peak hour demand, while helpful, does not indicate the extent to which the utilities can rely on obtaining electricity from the PV resource over the course of the year. In late 2004, the CPUC began investigating standardized definitions and procedures for quantifying resource adequacy. Resource adequacy is used for determining the amount of resources that must be procured by load-serving entities (LSEs) to ensure supplies are sufficient to meet anticipated demand and does not include distributed generation. Resource adequacy, however, is more amenable to large scale systems connected, by definition, to the utility side of the meter.

A more useful method to evaluate how effective distributed generation is at meeting demand during critical periods is to examine system performance during the top hours of demand. This was done by first determining the time and day of the top 100 hours of CAISO level demand and the statewide estimated CSI system generation during each of those hours. That estimated generation is then divided by the system capacity operational during each hour to

determine an hourly capacity factor. Capacity factor was used to account for program growth from 150 MW at the start of 2009 to nearly 285 MW at the end of 2009.

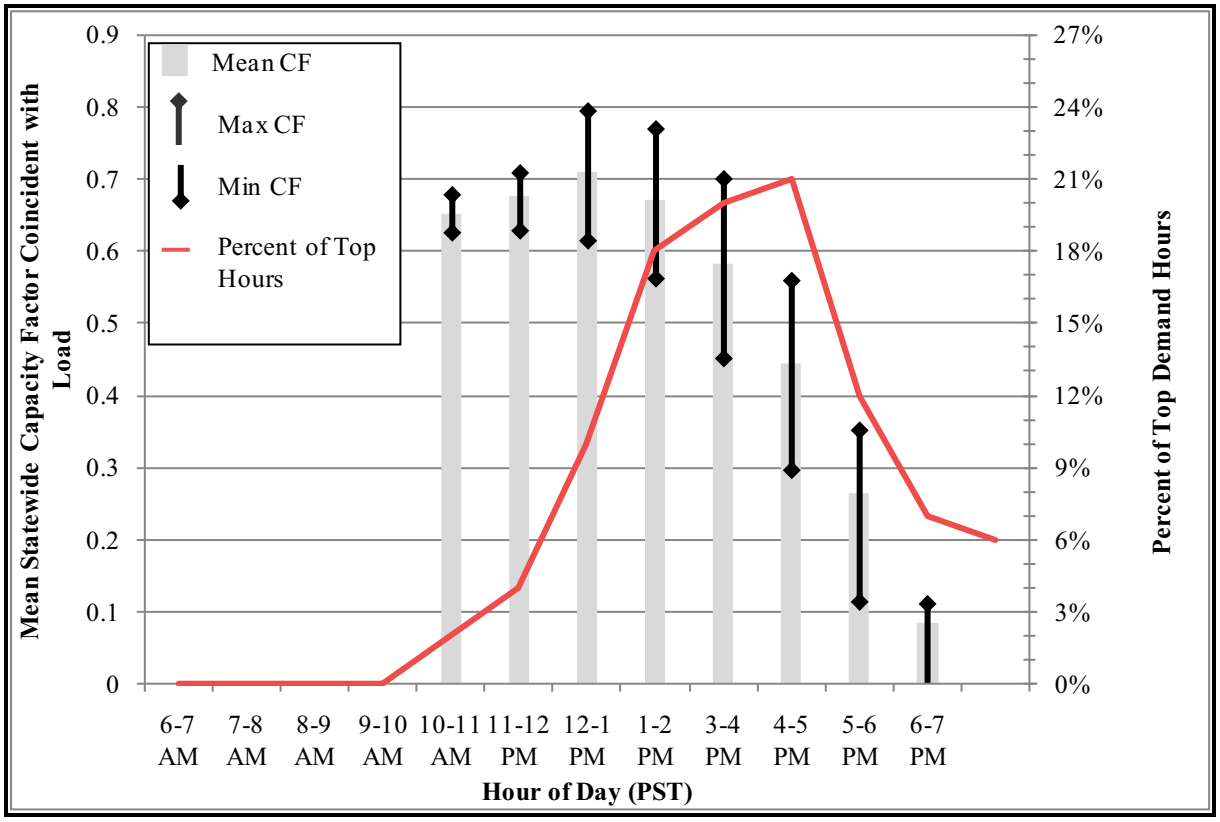
Effective Capacity Results

The mean statewide hourly capacity factor (CF, as defined in section 5.2 during the top 100 CAISO demand hours is shown by hour of the day in Figure 5-3. Also plotted (using a red line,) is the fraction of the top 100 hours that fall in that hour. Table 5-6 lists the months that the top 100 CAISO demand hours fall in.

Table 5-6: Months of Top 100 CAISO Demand Hours

Month	Hours
July	10
August	36
September	54

Figure 5-3: Capacity Factor (CF) during High CAISO Demand Hours



The 100 hours with the highest CAISO demand levels occurred in three different summer months (July, August, and September), and during several different hours of the day (10 AM-

6 PM). Previously we saw that the annual peak occurred during the hour of 2-3 PM. In Figure 5-3 we see that a total of 20 of the 100 highest CAISO demand values occurred during that hour of the day and another 21 in the following hour (3-4 PM.). There was a steep decline from 3-4 PM to the next hour (4-5PM, 12 percent of the 100 highest-CAISO demand hours). Conversely, the hours of 1-2 (18 hours) and 2-3 (19 hours) accounted for relatively large portions of the highest-CAISO demand hours. Collectively, the three-hour period 1-4 PM accounted for more than 60 percent of the 100 highest-CAISO demand hours. CAISO high-demand hours and PV system high-generation hours are offset. PV system performance is around noon, whereas the highest CAISO demand values tend to occur later in the day.

Figure 5-4: Tracking System Capacity Factor (CF) during Top Demand Hours

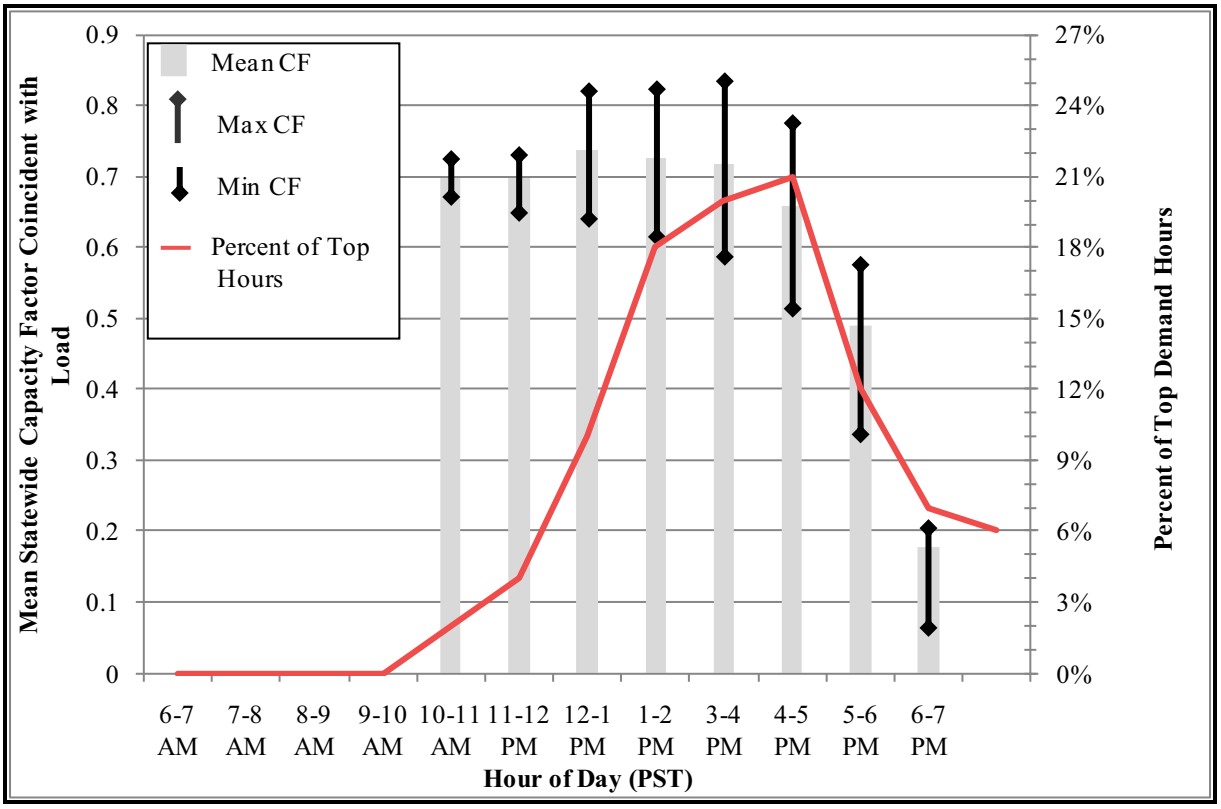


Figure 5-4 shows the weighted mean hourly capacity factor during the top 100 CAISO demand hours for tracking systems. Tracking systems significantly raise the hourly capacity factor later in the afternoon to better match production to periods of high demand. West facing systems shift the production peak towards the afternoon, better matching the demand curve at the expense of delivering slightly lower annual energy. In later sections on billing and profiles we can see how above generation and on-site usage can be combined.

5.4 Comparison of Estimated to Expected Performance

The expected annual average output of CSI systems is currently calculated during the incentive application process. These expected average outputs are used to calculate incentive payments for EPBB systems and allow Program Administrators to plan payments for PBI systems.

Section 3 compared measured to expected performance for metered systems with nearly a full year of data. This section compares the combined measured and estimated output for all of the systems installed under the CSI program to the expected performance for all systems installed. Also, this comparison includes all metered and estimated impacts for 2009.

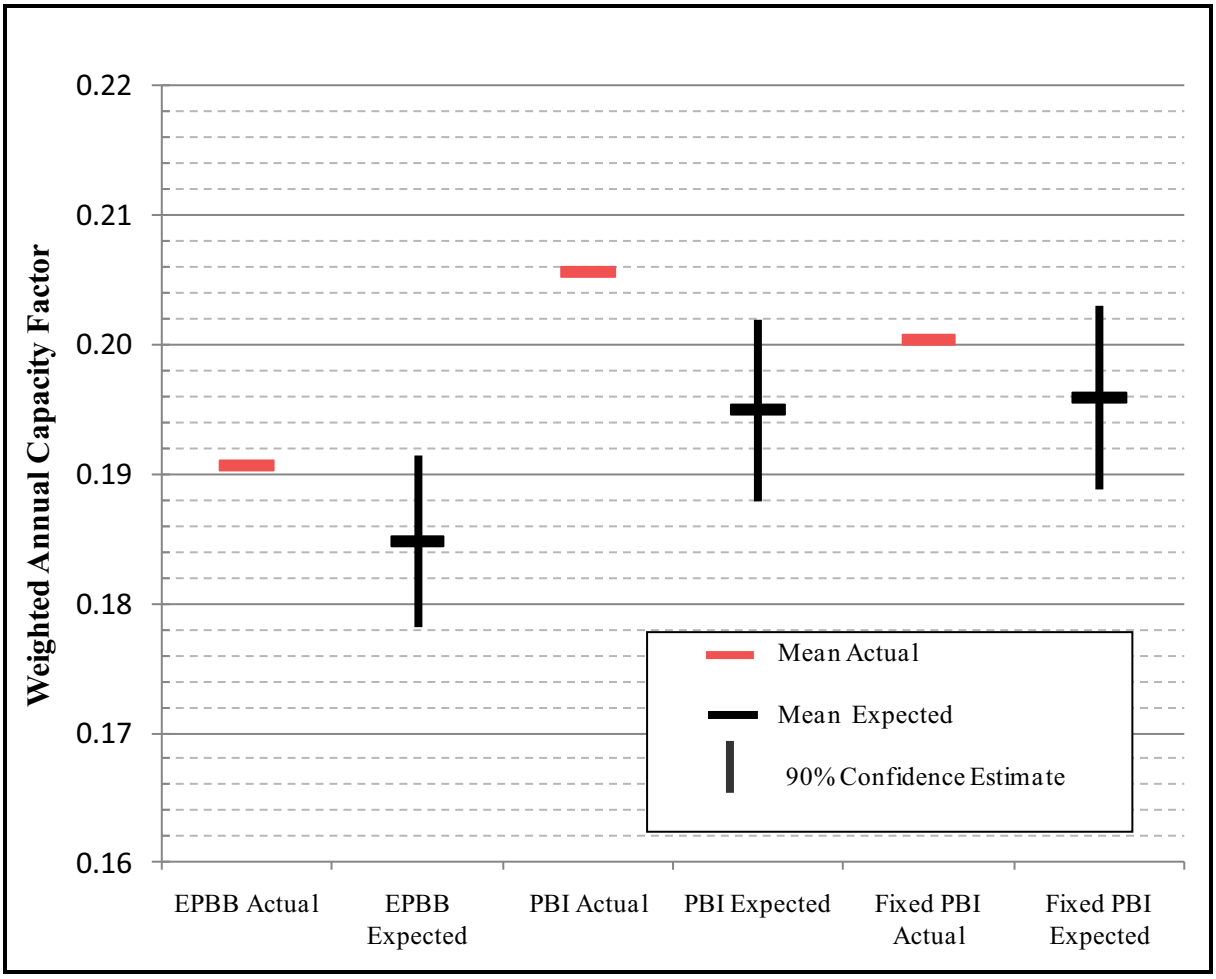
Comparisons of estimated annual capacity factor (as calculated in section 5-1) based on estimates of system wide generation to expected annual capacity factor provide one way to assess actual performance of installed systems. While this comparison is a meaningful cross-check, it is subject to at least three limitations. First, information regarding expected performance pertains to *average* performance. Information regarding expected performance during any individual year is not available. Second, estimates of actual impacts are subject to uncertainty due to sampling error. Third, the growth of installed capacity in late 2009, when energy production is somewhat lower, can lower the estimated actual performance slightly.

The expected annual capacity factor is calculated through the following steps:

1. Calculate an expected hourly capacity factor for each site by dividing the expected annual production reported by PowerClerk by installed capacity by 8760 (number of hours in one year.)
2. Calculate an overall average capacity factor weighted by the product of capacity and hours of operation.

The 90 percent confidence level error bounds for actual and expected performance for 2009 are depicted graphically in Figure 5-5 for all EPBB Systems, all PBI Systems (including tracking systems), and all Fixed PBI Systems. The 90 percent confidence level error bounds for the expected performance are based on historical solar resource variation. The methodology for estimating uncertainty for actual performance is described in Appendix E.

Figure 5-5: Comparison of Estimated Actual and Expected Annual Capacity Factors for 2009 by Incentive Type



Much like in Section 3, we can observe that the capacity factors for PBI systems are slightly above the uncertainty bounds in relation to the estimated annual capacity factor. When tracking systems are excluded, however, the annual performance of PBI systems is somewhat lower but is still better than expected. For EPBB systems, performance is above the expected average but still within the uncertainty bounds for the estimated annual capacity factor[7]. These differences could be due to a few reasons including:

- The solar insolation in 2009 may have been higher than the TMY2 (Typical Metrological Year Data) average used to estimate expected performance; or
- The metered systems used to estimate system wide performance currently are slightly out-performing their estimated annual capacity factors.

[7] EPBB systems are almost entirely fixed so excluding tracking systems from EPBB systems has no noticeable effect on annual capacity factors.

5.5 Emission Impacts Key Objectives

This section describes the impacts installation of CSI PV projects had on CO_2, NO_x, and PM_{10} emissions for 2009. The evaluation team estimated the avoided amounts of these three pollutants as they comprise the majority of the air and GHG pollutants associated with electrical generation. While the estimated emissions impacts are for 2009, the amount of CSI-related PV assessed is cumulative, and therefore includes capacity installed from 2007 to 2009.

A variety of approaches exist to estimating GHG emissions and air pollutant reductions from the installation of PV systems. Three approaches are noted here, each of which gauges what type of generation would likely have produced electricity in lieu of the installed PV.

The first approach, referred to here as the Avoided Cost approach, is derived from the Avoided Cost calculator developed by Energy and Environmental Economics (E3) and uses hourly price data. The second approach, referred to here as the Plant Schedule approach, was developed by KEMA, and uses plant schedule data from the California Independent System Operator (CAISO). The third approach, referred to here as the Generator Bid approach, was developed by KEMA, and uses real-time generator bid data from the CAISO. Each method has its drawbacks and benefits, which are detailed below. The intent of using multiple approaches to estimate the CSI emissions impact is to draw from the benefits of each and to assess the extent of the different limitations and their impact on the emission results.

The following sections outline the methodologies behind both approaches, present the results of each approach, and contrasts methodologies and results.

Analysis Approaches

To estimate emissions reductions the analyses approximate what types of generation would have produced electricity in lieu of the PV. Once generation types are identified, the analyses estimate emissions rates for the electricity produced by these types. All approaches assume that PV-based generation likely displaced centralized natural gas plants operating on the margin. The approach to identifying natural gas plant types varies, as described below.

Avoided Cost Approach

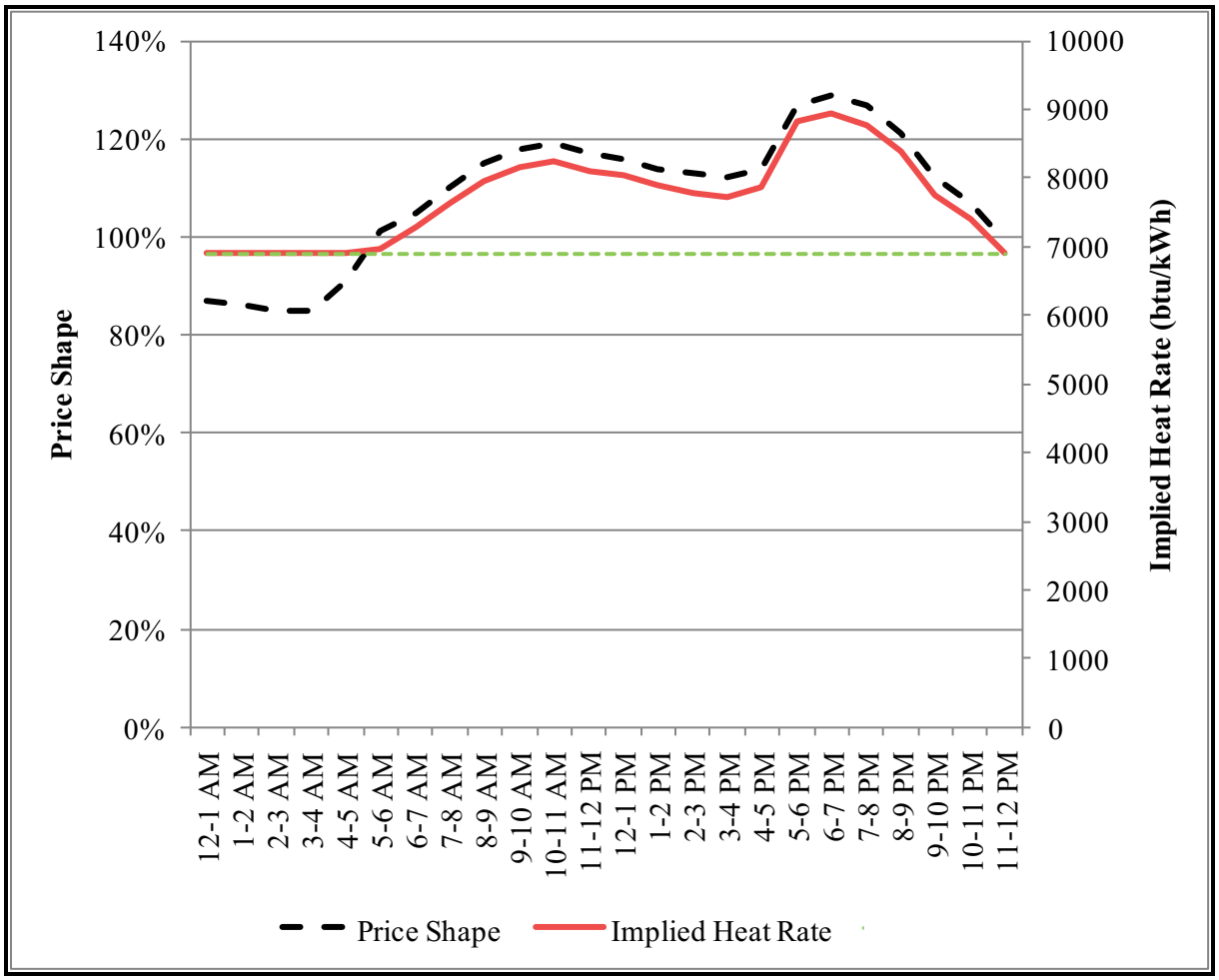
The Avoided Cost approach pairs an estimate of the hourly emissions rates from natural gas generation on the margin with estimates of PV production, throughout the course of a year. The hourly emissions estimates are derived from E3's Avoided Cost Calculator and the PV production estimates are derived by Itron from aggregating utility PV production data.

To estimate natural gas generation emissions, E3 assumes a mix of high-efficiency and low-efficiency plants in operation, with the mix varying over the course of a day. To indicate how the mix might vary by hour, E3 examines hourly market prices. As price increases, the model assumes that less efficient generation increases its contribution, increasing the weighted average heat rate. In particular, the model derives hourly heat rates from the hourly price shape by finding the average price over the year and developing a ratio to indicate how prices move from this point. Then, a heat rate of 6,924 Btu/kWh is associated with the average price or a price shape of 100 percent, and the hourly heat rate moves upward or downward as a multiple of the price shape. This average heat rate of 6,924 represents the average heat rate of a new combined cycle gas turbine.

The E3 calculation places bounds on the maximum and minimum heat rate for generation. E3 assumes a maximum heat rate, associated with low-efficiency plants, of 12,500 Btu/kWh. The minimum heat rate of 6,900 Btu/kWh is associated with high efficiency plants. E3 set minimum heat rate based on production simulation runs completed for California Public Utilities Commission and California Energy Commission joint proceedings on GHG emissions.[8] The simulations indicated that the best possible performance of natural gas generating units is about 6,900 Btu/kWh. E3 set the high range to reflect a typical heat rate of an older combustion turbine. Figure 5-6 illustrates how the heat rate changes over the hour as price shape changes, for a sample day of February 9, 2009. Because of the minimum and maximum boundaries placed on heat rate, the heat rate maintains its value between 6,900 and 12,500 Btu/kWh throughout the day, despite a drop in the price curve in the early hours.

[8] CPUC Rulemaking 06-04-009 and CEC Docket #07-OIIP-01

Figure 5-6 Sample Hourly Price Shape and Heat Rate (2-9-09)



Once heat rates are determined on an hourly basis, the hourly emissions rates are estimated using the minimum emissions rate (see emissions rates for the high efficiency plant) and a fixed ratio of emissions per implied heat rate. Table 5-7 illustrates the assumed emissions rates for the high and low efficiency plants.

Table 5-7: Estimated Emissions Rates by Plant Type

	CO_2 (tons/MWh)	PM_{10} (lbs/MWh)	NO_x (lbs/MWh)
Low Efficiency Plant	0.731	0.090	0.2320
High Efficiency Plant	0.404	0.056	0.0729
Slope (Emissions/Implied Heat rate)	5.85E-05	5.93E-06	2.84E-05

E3 derived the relationship between heat rate and emissions rate, for PM_{10} and NO_x pollutants, from a 2004 report by E3 and the Rocky Mountain Institute which examined

publicly available permit data for California natural gas generating plants.[9] To estimate CO_2 emission rates, E3 multiplied the heat rate by a constant factor of 117 lbs/MWh, based on the carbon content of natural gas. Table 5-8 illustrates results from the E3 model, hourly emissions rates, for a sample day of February 9, 2009.

Table 5-8: Sample Hourly Emissions Rate Estimates (2-9-09)

Hour	Price Shape	Implied Heat Rate (btu/kWh)	CO_2 (tons/MWh)	PM_{10} (lb/MWh)	NO_x (lbs/MWh)
12-1 AM	87%	6900	0.4036	0.0564	0.0729
1-2 AM	86%	6900	0.4036	0.0564	0.0729
2-3 AM	85%	6900	0.4036	0.0564	0.0729
3-4 AM	85%	6900	0.4036	0.0564	0.0729
4-5 AM	91%	6900	0.4036	0.0564	0.0729
5-6 AM	101%	6973	0.4079	0.0568	0.0750
6-7 AM	105%	7292	0.4265	0.0587	0.0840
7-8 AM	110%	7642	0.4470	0.0608	0.0940
8-9 AM	115%	7962	0.4658	0.0627	0.1031
9-10 AM	118%	8156	0.4771	0.0639	0.1086
10-11 AM	119%	8231	0.4815	0.0643	0.1107
11-12 PM	117%	8113	0.4746	0.0636	0.1073
12-1 PM	116%	8035	0.4700	0.0631	0.1051
1-2 PM	114%	7893	0.4617	0.0623	0.1011
2-3 PM	113%	7790	0.4557	0.0617	0.0982
3-4 PM	112%	7726	0.4519	0.0613	0.0963
4-5 PM	114%	7871	0.4604	0.0622	0.1005
5-6 PM	127%	8821	0.5160	0.0678	0.1275
6-7 PM	129%	8956	0.5239	0.0686	0.1313
7-8 PM	127%	8779	0.5135	0.0675	0.1263
8-9 PM	121%	8398	0.4913	0.0653	0.1154
9-10 PM	112%	7757	0.4537	0.0615	0.0972
10-11 PM	107%	7406	0.4332	0.0594	0.0873
11-12 PM	99%	6900	0.4036	0.0564	0.0729

Once the emissions rates are determined, the analysis develops annual emissions estimates by region by aligning hourly PV data with the hourly mixed emission rates to calculate the offset emissions.

[9] E3 and RMI. Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs. October 2004. Available online at: http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf

Plant Schedule Approach

The Plant Schedule approach also pairs an estimate of the hourly emissions rates from natural gas generation on the margin with estimates of PV production. However, the selection of natural gas plants are based on plant schedules obtained from the CAISO rather than hourly price data. In addition, due to the limited availability of CAISO data, the Plant Schedule approach estimates emissions for a sample of 2009 days, and extrapolates them to the year.

To select days which represent average conditions over the course of the year, we examined factors such as relative load, relative PV amounts and relative hydropower amounts, along with other factors such as intermittency in wind (which would impact generator commitment). We also selected days across seasons. Table 5-9 outlines the days selected to represent the system over the course of the year.

Table 5-9: Plant Schedule Analysis Days

Date (2009)	Day	Relative Load	Relative PV	Relative Hydro
February 9	Monday	Low	Low	Low
May 16	Saturday	Low	High	Medium
July 13	Monday	High	High	High
November 12	Thursday	Medium	Low	Low

With these days selected, we examined the plants scheduled to run for each day and compared the schedules to the estimated hourly PV production. Based on the daily plant schedule, we observed which power plants were available for generation, not having already been scheduled. We then compared available plants' hourly capacities to the hourly PV production estimates and selected plants likely to produce in lieu of the PV.

As multiple units had available capacities, we selected units based on age and type. Plant age was used as an estimate of cost of generation, with newer plants units assuming to be more efficient and able to put in cheaper bids on the average. Regarding type, we selected combustion turbine and combined cycle gas turbine units only, allocating combined cycle unites to pre-peak periods and combustion turbines to peak and post-peak periods. The resulting heat rates ranged from 6,320 to 10,430 btu/kWh. The CO2 emissions rates ranged from 750 to 1,240 lb/MWh and the NOx emission rates ranged from 0.0480 to 0.120 lb/MWh.

Once we identified specific plants likely to 'make up' for the PV generation, we gathered information about select plants' emission rates from the Environmental Protection Agency's eGRID database. The eGRID database provides estimated heat rates and emission rates per plant. Using the eGRID emission rates and estimated production (based on PV production),

we developed hourly emissions estimates per day. We weighted these daily emissions up to a year by assuming the days represent their seasons. As eGRID does not contain information on plant PM_{10} emission rates, we used the same conversions from heat rate as the Avoided Cost approach.

Generator Bid Approach

The Generator Bid approach is similar to the Plant Schedule approach, except that it uses public bid data to select plants, rather than plant schedules. The calculation of emissions is the same once generation is selected. In addition, a similar constraint on data availability existed, resulting in a subset of days being used for the calculation. Because the CAISO market underwent a structural change in April 2009, only data after April 2009 was available. As such, the team used only the May, July and November days, and not the February day. The resulting heat rates ranged from 5,560 to 7,860 btu/kWh, the CO2 emissions rates ranged from 930 to 660 and the NOx emissions rates ranged from 0.0880 to 0.0400 lbs/MWh.

Results

Table 5-10 illustrates the estimated emissions savings by emission type and by approach. The CO2 reductions for the Avoided Cost Approach are 180,136 tons of CO_2, the equivalent of taking over 31,000 cars off of the road.[10] The Plant Schedule approach estimates emissions higher by 16 percent. For the PM_{10} and NO_x emissions estimates, the Plant Schedule estimates are lower by about 14 percent.

Table 5-10: Estimated Emissions Reductions by Approach

Approach	Energy Impact (MWh)	CO_2 Emissions Avoided (tons)	PM_{10} Emissions Avoided (lbs)	NO_x Emissions Avoided (lbs)
Avoided Cost	390,750	180,136	24,280	39,649
Plant Schedule	390,750	208,704	20,817	34,132
% Difference	0%	16%	-14%	-14%
Generator Bid	390,750	163,183	16,277	20,899
% Difference	0%	-9%	-33%	-47%

Table 5-11 details the average annual heat rates and emission rates by approach.

[10] Based on 5.23 metric tons (5.77 short tons) of CO2 /vehicle/year from http://www.epa.gov/grnpower/pubs/calcmeth.htm#vehicles

Table 5-11: Estimated Average Annual Emissions and Heat Rates by Approach

Approach	Average Heat Rate (btu/kWh)	Average CO_2 Emissions Rate (tons/MWh)	Average PM_{10} Emissions Rate (lbs/MWh)	Average NO_x Emissions Rate (lbs/MWh)
Avoided Cost	7,489	0.4381	0.0599	0.0896
Plant Schedule	8,337	0.4955	0.0494	0.0811
% Difference	-11%	13%	-17%	-10%
Generator Bid	6,652	0.3953	0.03943	0.0506
% Difference	11%	-10%	-34%	-43%

The results of the Avoided Cost approach are sensitive to the assumption about how emission rates change with heat rates. The Plant Schedule approach, in turn, is sensitive to the selection criteria used to identify plants that would generate in lieu of PV. The Generator Bid approach has fewer data points to extrapolate to the year, particularly the early part of the year. However, the linkage between generator selection and bid price are more direct than other approaches.

The differences between the Avoided Cost and other approaches results are likely attributable to a difference in the assumed relationship between CO_2, PM_{10} and NO_x emissions and heat rates, though the limited data to extrapolate the other approach results to a year is also a factor. A comparison of individual days gives some indication of the divergence between the two approaches, independent of the extrapolation. Table 5-12 provides a comparison of CO_2 estimates for the sample day of July 13, 2009. The overall emissions estimates vary by about 13 percent though variation between the two approaches change by hour.

Table 5-13 does the same for NO_x emissions. Here, the total estimates vary by about 54 percent, though the variation changes by hour.

Table 5-12: CO_2 Emissions per Hour for 7/13/2009 (tons)

Hr	Avoided Cost	Generator Bid	Difference
12-1 AM	0.086	0.095	*10%*
1-2 AM	0.095	0.105	*10%*
2-3 AM	0.104	0.115	*10%*
3-4 AM	0.115	0.127	*10%*
4-5 AM	0.132	0.145	*10%*
5-6 AM	2.798	3.153	*13%*
6-7 AM	15.501	17.089	*10%*
7-8 AM	34.536	37.716	*9%*
8-9 AM	54.848	55.606	*1%*
9-10 AM	72.609	74.835	*3%*
10-11 AM	86.275	77.400	*-10%*
11-12 PM	93.962	81.249	*-14%*
12-1 PM	98.512	81.960	*-17%*
1-2 PM	97.339	78.462	*-19%*
2-3 PM	91.126	71.458	*-22%*
3-4 PM	77.411	59.678	*-23%*
4-5 PM	54.676	41.906	*-23%*
5-6 PM	26.095	20.397	*-22%*
6-7 PM	5.495	4.463	*-19%*
7-8 PM	0.277	0.237	*-15%*
8-9 PM	0.013	0.011	*-14%*
9-10 PM	0.013	0.012	*-8%*
10-11 PM	0.012	0.012	*0%*
11-12 PM	0	0	*0%*
Total	812	706	*-13%*

Table 5-13: NO_x Emissions per Hour for 7/13/2009 (lbs)

Hr	Avoided Cost	Generator Bid	Difference
12-1 AM	0.02	0.01	-25%
1-2 AM	0.02	0.01	-25%
2-3 AM	0.02	0.01	-25%
3-4 AM	0.02	0.02	-25%
4-5 AM	0.02	0.02	-25%
5-6 AM	0.51	0.40	-21%
6-7 AM	2.80	2.11	-25%
7-8 AM	6.56	4.77	-27%
8-9 AM	11.58	7.03	-39%
9-10 AM	16.58	13.93	-16%
10-11 AM	20.94	9.78	-53%
11-12 PM	23.63	10.27	-57%
12-1 PM	25.65	10.36	-60%
1-2 PM	26.03	9.92	-62%
2-3 PM	24.90	9.03	-64%
3-4 PM	21.43	7.54	-65%
4-5 PM	15.21	5.30	-65%
5-6 PM	7.15	2.58	-64%
6-7 PM	1.46	0.56	-61%
7-8 PM	0.07	0.03	-58%
8-9 PM	0.00	0.00	-57%
9-10 PM	0.00	0.00	-51%
10-11 PM	0.00	0.00	-19%
11-12 PM	0.00	0.00	0%
Total	205	94	-54%

The difference between the Plant Selection and Generator Bid approaches is attributable to the use of different selection criteria. The Generator Bid results indicate a narrower range of heat rates and emissions rates are likely amongst the units likely to displace the PV generation.

Avoided Cost Approach

Results for the Avoided Cost Approach are provided in Table 5-14, Table 5-15, and Table 5-16. Results are provided by program administrator, Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and the California Center for Sustainable Energy (CCSE) who administers the CSI for San Diego Gas & Electric (SDG&E). Each table provides a

total emissions savings estimate, along with an average rate of emissions per megawatt-hour. Emissions savings rates are comparable across the programs.

Table 5-14: Avoided Cost Estimated CO_2 Impact

Program Administrator	Energy Impact (MWh)	CO_2 Emissions Avoided (tons)	CO_2 Eq Factor (tons/MWh)
PG&E	225,063	103,442	0.460
SCE	126,850	58,754	0.463
CCSE	38,837	17,940	0.462
Total	**390,750**	**180,136**	**0.461**

Table 5-15: Avoided Cost Estimated PM_{10} Impact

Program Administrator	Energy Impact (MWh)	PM_{10} Emissions Avoided (lbs)	PM_{10} Eq Factor (lbs/MWh)
PG&E	225,063	13,956	0.0620
SCE	126,850	7,908	0.0623
CCSE	38,837	2,416	0.0622
Total	**390,750**	**24,280**	**0.0621**

Table 5-16: Avoided Cost Estimated NO_x Impact

Program Administrator	Energy Impact (MWh)	NO_x Emissions Avoided (lbs)	NO_x Eq Factor (lbs/MWh)
PG&E	225,063	22,658	0.101
SCE	126,850	13,028	0.103
CCSE	38,837	3,968	0.102
Total	**390,750**	**39,649**	**0.101**

Plant Schedule Approach

Table 5-17 details the emissions savings estimates using the Plant Schedule approach. Here, emissions savings are estimated across the State, rather than by program administrator. Again, an emissions savings rate is estimated based on the energy impact and the emission avoided.

Table 5-17: Plant Schedule Estimated Emission Impact

Emissions Type	Energy Impact (MWh)	Emissions Avoided (Unit)	Eq Factor (Unit/MWh)
CO_2 (Unit in Tons)	390,750	208,704	0.534
PM_{10} (Unit in lbs)	390,750	20,817	0.053
NO_x (Unit in lbs)	390,750	34,132	0.087

Generator Bid Approach

Table 5-18 details the emissions savings estimates using the Generator Bid approach. Here, emissions savings are estimated across the State, rather than by program administrator. Again, an emissions savings rate is estimated based on the energy impact and the emission avoided.

Table 5-18: Generator Bid Estimated Emission Impact

Emissions Type	Energy Impact (MWh)	Emissions Avoided (Unit)	Eq Factor (Unit/MWh)
CO_2 (Unit in Tons)	390,750	163,182	0.418
PM_{10} (Unit in lbs)	390,750	16,277	0.042
NO_x (Unit in lbs)	390,750	20,899	0.053

Key Findings

The Plant Schedule approach generally aligns with the Avoided Cost approach, within a range of 16 percent, providing a reasonable confirmation of the Avoided Cost estimates. The Generator Bid emissions estimates imply lower emissions savings than both of the other approaches. With regard to CO2 emissions, it is in general agreement with the Avoided Cost approach and varies by 9 percent. The Generator Bid approach, however, implies a relatively large discrepancy from the Avoided Cost approach for PM10 and NOx emissions.

One benefit of the Plant Schedule approach is the ability to identify a subset of power plants with a high likelihood of production in place of PVs (e.g., eliminating those plants already scheduled to produce, without excess capacity). This allows the analysis to focus on select power plants. However, a drawback of the Plant Schedule approach is the high sensitivity to selection criteria for identifying plants within this set. In particular, the range of emissions profiles for the remaining plants is large enough that the criteria for selection amongst these plants are significant. For example, plant type and average age were used as criteria for the results noted above. Were plant type and heat rate to be used, the CO_2 savings estimates

would vary by 28 percent. As such, a key improvement for the Plant Schedule approach would be selection criteria that better identify a specific plant (rather than a range of plants as occurs with age) and which better approximate the actual selection process in the market.

A benefit of the Avoided Cost approach is the ability to use market price data as a direct input to the calculations, and to avoid the need to identify individual plants. However, the results are quite sensitive to the assumption about how emission rates change with heat rate (e.g., the lb/MWh per btu/kWh) and the emission rate boundaries (e.g., high and low efficiency plant emission rates and heat rates). In comparison to the Avoided Cost estimates, the Plant Schedule estimates a higher CO_2 savings and lower PM_{10} and NO_x savings. This indicates a difference in the assumed relationship between CO_2, PM_{10} and NO_x emissions and heat rates. The same difference is apparent with comparison to the Generator Bid approach, for the annual estimate as well as for comparison of individual days. The differences indicate that the three emissions may not vary with heat rate at the same ratios as indicated in the Avoided Cost Approach.

We recommend further research into the relationship between NOx and PM10 emissions with heat rate to update the 2004 estimates. Limitations in the data for the Plant Selection and the Generator Bid approaches make annualizing the estimates difficult. Nevertheless, they do point to a need to review how NOx and PM10 emissions rates vary with heat rate.

None of the approaches currently assesses the impact of PV on ancillary services, and the resulting impact on emissions.[11] The E3 Avoided Cost Calculator does address the impacts on ancillary savings but that is not currently included in this analysis. As the size of PV grows, the impact on ancillary services will grow. As such, emissions savings associated with ancillaries may also grow, making it worthwhile to study the potential impacts. Given the relative size of PV and the regional distribution of the assets for this period, the team believes that the impact of ancillary services is likely small for this period and the omission of this aspect is reasonable.

Overall, estimating the emissions savings of PV installation requires an assumption about the type of plants that would have been operating in place of PV. Given the limited availability of information on the direct criteria that are used to select plants in the market, alternative methods are required. Here, the Avoided Cost approach uses an assumption about the linkage between market prices, heat rates, and emission rates while the Plant Schedule approach uses schedules to identify a set potential of plants and uses other known

[11] Ancillary services are grid-based services provided by generation resources, separate from the provision of energy, used to maintain reliable grid operations. (In some electricity markets, demand response and energy storage may also provide ancillary services). The quick response time required by some ancillary services can result in the ramping of generation.

information (such as type, age, and heat rate) to select among these plants and the Generator Bid approach uses bid data to identify likely substitute. All methods have their limitations given the reality of limited information. However, despite the different methodologies, the CO2 results appear to approximate one another. The NOx and PM10 results show wider variation, and indicate further research may be necessary in this area.

6

CSI Impacts on Transmission and Distribution

6.1 Overview

In addition to providing electricity over the course of the year and during times of peak demand, CSI PV facilities impact the transmission and distribution (T&D) systems of California's electrical grid. CSI PV systems reduce loading on the distribution and transmission lines by displacing remote sources of electricity that would otherwise have to be delivered over the T&D systems to electricity customers. Reduced line loading at the time of peak demand potentially alleviates the need to expand or build new transmission and distribution infrastructure, thereby saving utility and ratepayer monies. Moreover, by reducing the amount of electricity that needs to be delivered by the grid, CSI PV facilities may potentially lower the risk of transmission overloads during many operating hours, which in turn may increase overall system reliability.

This section presents the impacts of CSI PV facilities on the IOU T&D system as estimated during 2009. Transmission system impacts are discussed first, followed by distribution system impacts. Additional data and information is provided in Appendices F and G. Table F-1 provides a spreadsheet or "look up table" for determining the estimated impact factors of distributed PV on any feeder, based on a set of key feeder characteristics. Appendix G includes a more details on the feeder modeling tools, methodology, feeder sampling, and peak day load profiles.

6.2 Glossary of Benefits Examined

The following table provides a high level summary of the types of T&D benefits that are addressed in this section.

Table 6-1: Benefits Glossary

Category	Acronym	Description
Transmission		
Transmission Capacity Benefit	TCB	The aggregate reduction in transmission facility loading (statewide and by IOU), at the time of annual service area peak demand, as a result of CSI generation.
Transmission Loss Savings	None	The aggregate reduction in transmission system electrical losses (statewide and by IOU) at the time of annual service area peak demand, as a result of CSI generation.
Distribution		
Peak Reduction Factor	PRF	A measure of the reduction in distribution feeder loading on a given feeder, at peak feeder demand, as a result of CSI generation.
Energy Reduction Factor	ERF	A measure of the effectiveness of the CSI generation on a given feeder in reducing the annual energy requirements of the feeder.
Loss Reduction Factor	LRF	A measure of the reduction in electrical losses on a given feeder, as a result of CSI generation.

6.3 Key T&D Findings

Key findings from the analysis (as discussed in more detail later in the section) include:

Transmission System Impacts[1]

The evaluation team has performed an independent analysis that shows the 2009 CSI impacts on the California transmission system. Section 6.4 details the approach and key findings. Depending on the dispatch adjustment method used in the modeling, the 2009 Transmission Capacity Benefit (TCB) on a statewide level is estimated to range between 500-900 MW. This is comparable to the delivery capability of a modern 230kV transmission line.

In the future when CSI penetration reaches twice the 2009 level, the modeling yields a projected 1000-1600 MW statewide TCB, which is comparable to the delivery capability of a

[1] Transmission system impacts were calculated using the best available estimates of CSI generation in

500kV transmission line. Furthermore, the analysis shows that when the CSI full capacity target (1,750 MW) is reached, the statewide TCB could grow to 4,000 MW or more. However, it is important to note that these capacity benefits are distributed statewide, rather than on any one 230kV or 500kV corridor. Thus, the incremental benefits on each individual transmission corridor within the state of California represent only a small percentage of the aggregate TCB. Even so, this represents a tangible benefit as discussed further in Section 6.4.

On a statewide basis, the current (2009) level of transmission loss savings attributable to CSI generation ranges from 7 MW to 25 MW depending on the generation redispatch method used (as discussed later in this section).

Overall, there was a 240 percent increase in both the statewide TCB and transmission loss savings (calculated at peak system load) between 2008 and 2009 (see Table 6-3). As distributed PV generation continues to increase in future years, transmission system impacts will become even greater, as indicated in projections shown in Section 6.4.

Distribution System Impacts

The precise impact of increasing levels of distributed PV generation on individual distribution feeders can only be determined through analysis of a specific feeder and its PV generation characteristics. Based on the 2009 feeder case studies performed, the greatest level of benefits is generally expected to occur on feeders with one of more of the following characteristics:

- Longer distribution feeders
- Feeders located in inland areas
- Feeders that have their summer peak demand in the mid-afternoon hours

The 2009 CSI Impact Evaluation shows that positive benefits are generally expected for a range of PV penetration levels, but also observes that there can be decreasing (or even negative) benefits above certain penetration levels as detailed below:

- Higher PV penetration levels and/or installation of a very large PV installation at a single point on a feeder can trigger a variety of negative impacts on feeder operation including increased risk of
  - Voltage flicker levels, at customer locations, outside of acceptable standards
  - Simultaneous PV unit trips and restarts causing sudden voltage drops and spikes, for which existing utility system voltage regulating equipment cannot fully compensate.

- Increased wear and tear on utility voltage regulating equipment, with a potential increase in maintenance and replacement costs for this equipment.

6.4 Transmission System Impact Analysis

Extensive work has been performed by the California Renewable Energy Transmission Initiative (RETI) in an effort to assess the impact of large scale renewable integration on statewide transmission planning requirements at RPS targets as high as 33 percent, which includes wholesale distributed generation.[2] RETI makes the following statement in regard to CSI generation:

> *"RETI intends to account for distributed resources in its determination of renewable resource requirements to meet the 33 percent goal. The distributed renewables that will be accounted for are: solar installations under the California Solar Initiative (CSI), the smaller renewables that will not be fully characterized in Phase 1B (anaerobic digestion, landfill gas, hydro, wave, and marine current), and renewable energy included in utility resource filings as "distributed renewables". While individual project sites will not be identified (as with the other renewables), the potential generation from the smaller resources will be used to determine the RETI "net short" – the additional amount of development necessary to meet the state's 33 percent RPS target."*[3]

In addition, the CPUC recently launched the Renewable Distributed Energy Collaborative (Re-DEC) process to assess issues related to large scale renewable DG integration (e.g., on the order of 15,000 MW) into California's distribution system(s).[4] However, the Re-DEC process is in its initial phase(s) and has not yet produced any results applicable to CSI impacts. Furthermore, Re-DEC is focused on renewable DG projects located on the utility side of the meter, and not on customer side generation such as CSI.

Even when combined with other categories of distributed solar generation, the 2009 CSI generation levels are at least an order of magnitude smaller than the renewable DG projects assumed in either RETI or Re-DEC. Given this large gap in the scale DG generation size assumptions it is not possible to determine the transmission impacts of the current level of CSI generation from the results of the RETI study work. Therefore, an independent assessment of transmission impacts was needed and has been performed by the CSI assessment team as discussed below.

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2 The RETI steering committee is comprised of the CPUC, CEC, CAISO, SCPPA, NCPA, and SMUD.

3 RETI Final Phase 1A Report, 5 August 2008, p 3-3.

4 RETI, Phase 2B Draft Report, 07 April 2010, pp 2-2 to 2-3.

Data Requirements

The following data were utilized in performing the 2009 transmission impact analysis:

- Transmission system "power flow" models for 2009 summer peak load conditions (one for each IOU with detailed transmission system representations, including expected generation dispatch in each area and power transactions between areas)
- CSI generation output values (i.e., best available estimates), by IOU service area, at the time of the 2009 system peak.

A substation by substation estimate of CSI output at 2009 system peak was not available for this analysis. Therefore, CSI generation was assumed to be distributed in a pro rata manner between all substations in each service area.

Detailed 2009 Models by Utility

Table 6-2 summarizes the utility by utility loads and resources from the 2009 summer peak power flow "base cases" that were used to conduct this analysis.[5] The models were provided by each IOU and represent their respective transmission systems (e.g., 500kV down to 115kV) and subtransmission systems (e.g., 66kV) in the 2009 summer timeframe.

Table 6-2: Detailed 2009 Summer Peak Power Flow Cases[6]

Service Area	Load (MW)	Losses (MW)	Interchange (MW)	Area Generation (MW)
PG&E	26,895.1	1,029.3	-861.2	27,063.3
SCE	21,506.7	616.7	-7,560.5	14,575.3
SDG&E	4,875.0	98.9	-1,171.2	3,802.6
Total	**53,276.8**	**1,744.9**	**-9,592.9**	**45,441.2**

Aggregated 2009 CSI Output

For this Impact Evaluation we utilized the aggregated CSI output coincident with the time of each utility's summer peak 2009 service area demand, as shown in Table 6-3 for the assessment of transmission system impacts.

[5] Table 6-2 shows modeling results, not metered values. This data format is familiar to utility system planners.

[6] A negative value of "Interchange" represents a power import into the service area (positive values represent an area export). "Area load" refers to the aggregate demand at load serving substations. "Area generation" refers to the generation running internal to each service area. "Area losses" refer to system transmission losses. Based on those definitions, the power flow model for each service area must balance the following equation: Area Generation = Area Load + Area Losses + Area Interchange.

Table 6-3: Aggregated PV Capacity Coincident to IOU Peak Loads

Service Area	Peak Date	Peak Hour (PST)	CSI Installed (MW)	Estimated CSI Output (MW)
PG&E	7/14/2009	16:00	131.7	79.2
SCE	9/3/2009	15:00	82.8	43.3
SDG&E	9/3/2009	15:00	22.6	13.6
Total	**NA**	**NA**	**237.1**	**136.1**

Methodology for Estimating Transmission Impacts

Distributed PV projects are not discretely modeled in the transmission power flow cases. Therefore, in order to evaluate the peak impact of CSI generation on the transmission system, the peak load power flow cases for each utility were adjusted by scaling their service area load and generation dispatch downward by the amount of the estimated CSI output level(s) shown in Table 6-3. The comparison of these scaled cases to the original base cases thus reflects the net change or impact on the transmission system. These revised cases assume a uniform distribution of PV geographically across all substations in the service area, which is a proxy for the actual distribution. However, resultant errors in transmission system impact calculations are not expected to be significant on an aggregate service area level.

Sensitivity cases were also run by several methods including pro rata generation redispatch by service area, reducing power imports for each service area in lieu of generator reduction, and lastly, by reducing generation at the "marginal" generating plant location(s) in each service area.[7] The following metrics were then used to evaluate the transmission impacts.

Transmission Capacity Benefit

Solar PV systems contribute to the deferral of transmission infrastructure investments by reducing net demand on the system, but the impacts from small PV penetration levels are hard to quantify in terms of specific capital deferrals. Nevertheless, in the 2008 CSI Impact Evaluation, the evaluation team defined TCB as a measure of this benefit as described below. In the 2009 analysis, the team also developed a proxy for the impact on 2009 transmission capital expenditures.

TCB equals the sum of the unused line capacities for every transmission circuit (i.e., transmission line and transformer) with PV generation modeled, minus the sum of unused circuit capacities without PV generation modeled. These values are computed using the respective IOU transmission system power flow models. Unused capacity is calculated as the "normal rating" (capacity) of the circuit element minus the actual flow on the same

[7] Lower efficiency units were selected as a proxy in the "marginal" adjustment redispatch option, rather than attempting to identify the true marginal cost unit(s) on the system. In actual operation, the California ISO would redispatch generation hourly based on locational market bids.

element in the power flow base case. The difference in unused circuit capacity with the installed CSI PV, versus without the installed CSI PV, determines the TCB benefit. This approach was retained for the 2009 CSI Impact Evaluation.

Figure 6-1 below illustrates the TCB calculation method for a sample 3-bus (substation) system. Results of the TCB example calculation are shown in Table 6-4 below. For simplicity, this example focuses on basic power flows only and ignores power "losses" (e.g., due to conductor heating) and capacitive/inductive flows (e.g., the component of electrical current associated with electromagnetic fields produced on every alternating current system). However, these components are included in the actual TCB calculations done for the CSI impact evaluation.

Figure 6-1: Sample 3-Bus (Substation) System Showing TCB Method

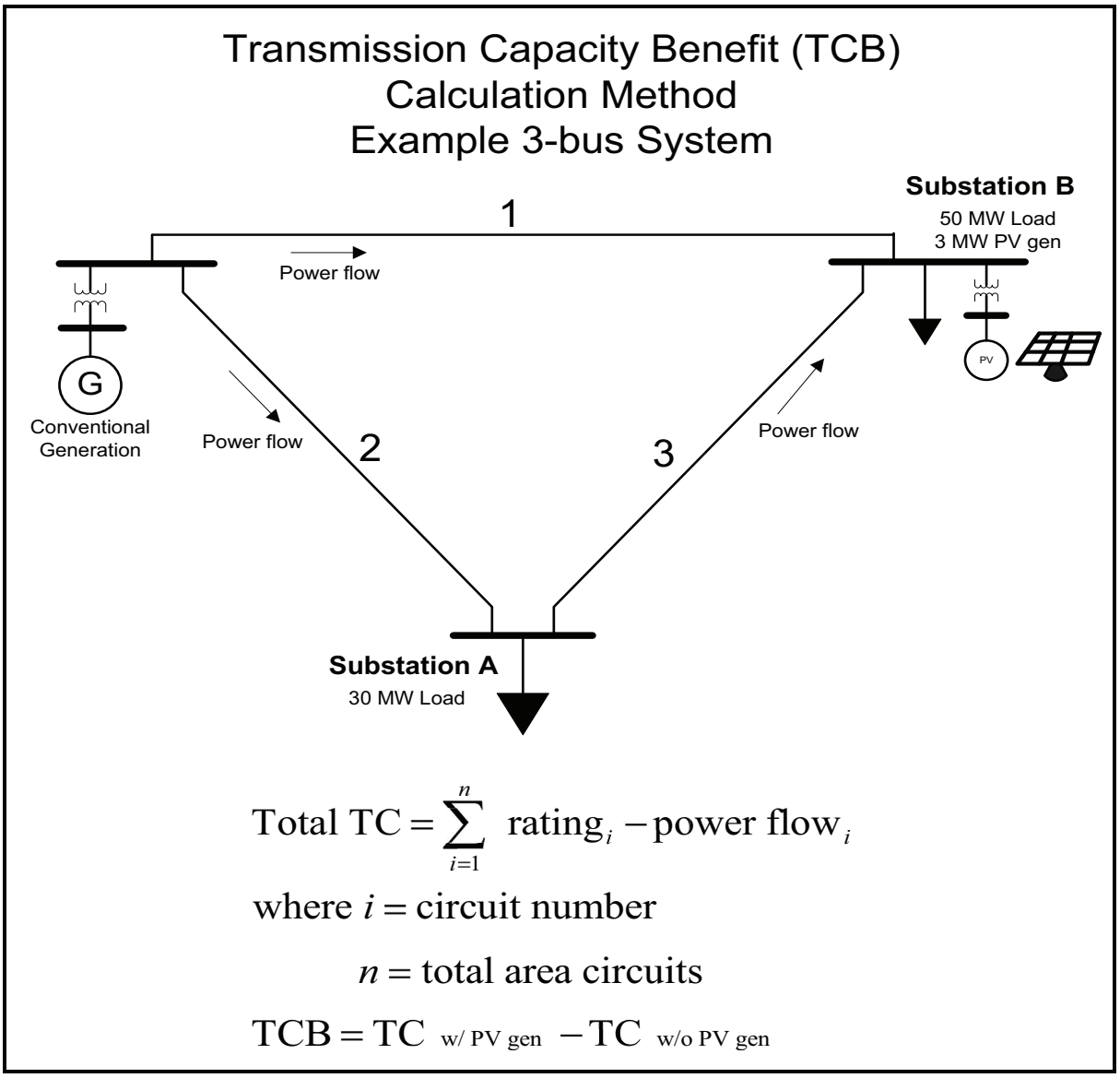


Table 6-4: Simplified Example of the TCB Calculation

Circuit Number	Rating (MW)	Without PV DG		With PV DG	
		Power Flow (MW)	Unused Capacity (MW)	Power Flow (MW)	Unused Capacity (MW)
1	100	35	65	34	66
2	100	45	55	43	57
3	50	15	35	13	37
Total			**155**		**160**

TCB (MW) = 160 - 155 = +5 MW

It should be noted that the value of the TCB in the example above (5 MW) actually exceeds the amount of PV generation added (3 MW), because the additive impact of the flow on the two lines (i.e., lines 2 and 3) that are connected in series between the generator and Substation B where the PV is located. This reflects real transmission capacity "released" on both lines. Thus, even a small addition of PV on the system can result in a cumulative TCB value that is larger than the amount of PV power output.

The TCB calculation provides a metric to determine the relative level of impact that small PV additions can have on the overall transmission system. The TCB represents the increase in transmission capacity made available by adding the distributed PV generation under normal system conditions, and does not address unused transmission capacity under the type of contingency conditions used for transmission system expansion planning. Therefore, the TCB is only a metric of deferred TCB and not directly useful for system planning purposes.

The 2009 TCB factors were calculated for each IOU service area based on the estimated CSI peak solar output levels, using the respective IOU transmission power flow models. These detailed power flow results included the affects of system losses and capacitive/inductive current flows.

Transmission Modeling Sensitivities

Every MW of CSI power output produced at system peak demand (See Section 5) displaces roughly an equivalent amount of MW of generation from other sources such as central station power plants.[8] This shift in generation impacts the power flows on the transmission grid. In

[8] The CSI analysis did not address the impact of this distributed generation on ancillary services that the CAISO requires to reliably operate the statewide grid. PV and other types of on-dispatchable generation can increase the level of certain ancillary services that must be acquired by the CAISO, which in some instances involves the incremental dispatch of conventional generation on the system to provide such services. Such ancillary services can also be provided by other means such as energy storage systems or aggregated demand side management (DSM) programs.

order to estimate the range of TCB factors for the 2009 CSI impact, the offset of "central station" generator dispatch was performed using three different approaches.

- One approach was to back off the dispatch of central station generating units in a pro rata manner to match the amount of CSI generation output in each IOU service area.
- The second approach was to reduce service area imports by the amount of CSI generation in each area.
- A third and final approach was to back off selected (e.g., marginal cost) units by the amount of CSI PV generation in that service area.

It is assumed that the dispatch actions taken by the CAISO in actual market operation, which account for the affects of distributed PV output on service area demand, can be approximated by a blend of these three modeling approaches.

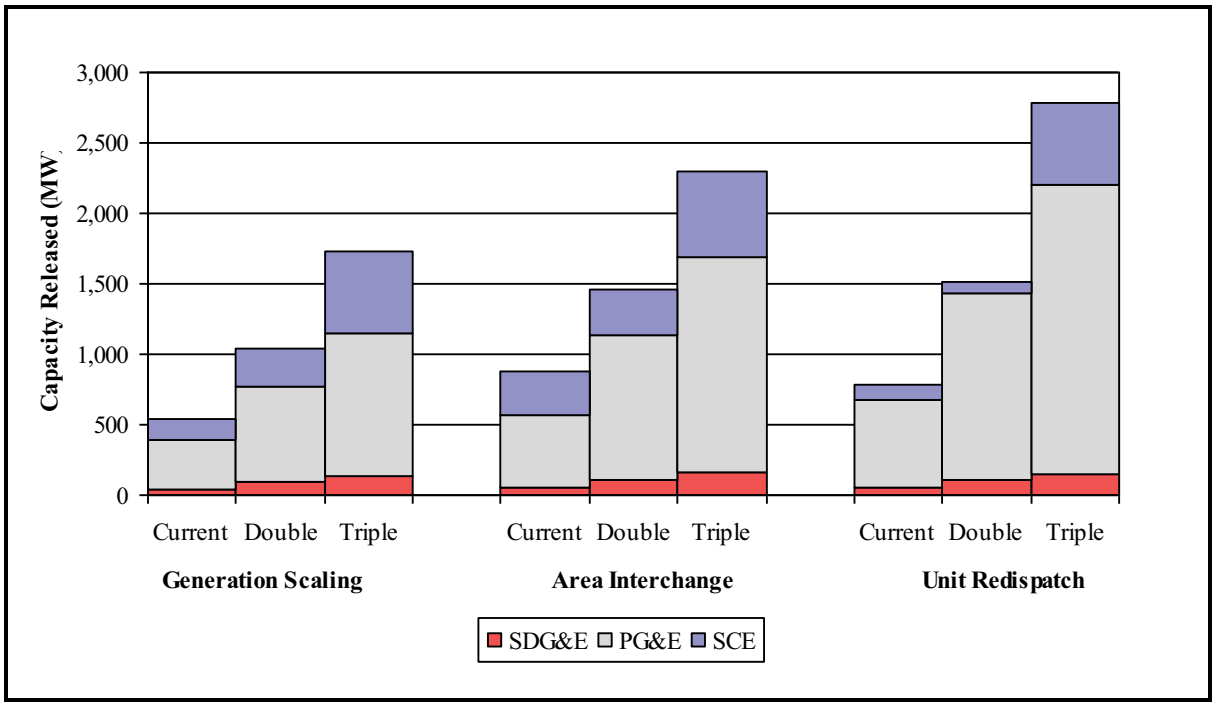
Table 6-5 is a summary of 2009 TCB results using the three different generation redispatch approaches in the power flow modeling. In addition to the "current" level of impacts based on the estimated 2009 CSI output levels, the analysis looked at potential future levels of TCB at double and triple the estimated 2009 CSI output level. These results are also shown graphically in Figure 6-2.

Table 6-5: Transmission Capacity Benefit Modeling Sensitivities at Peak

		Service Area (MW)		
CSI Production Level[9]	**Redispatch Option**	**PG&E**	**SCE**	**SDG&E**
Current (136.1 MW)	Pro Rata Generation Scaling	341.1	150.9	44.2
	Area Interchange Adjustment	514.0	312.9	52.5
	"Marginal" Unit Redispatch	616.9	107.0	53.3
	Average Impact	***490.7***	***190.3***	***50.0***
Double (272.1 MW)	Pro Rata Generation Scaling	680.8	270.5	88.2
	Area Interchange Adjustment	1,024.8	335.5	105.9
	"Marginal" Unit Redispatch	1,321.4	85.8	106.2
	Average Impact	***1,009.0***	***230.6***	***100.1***
Triple (408.3 MW)	Pro Rata Generation Scaling	1,019.8	576.8	133.0
	Area Interchange Adjustment	1,528.2	605.4	158.0
	"Marginal" Unit Redispatch	2,045.6	584.7	152.3
	Average Impact	***1,531.2***	***589.0***	***147.8***

9 Current CSI baseline MW equal the sum of estimated 2009 CSI outputs at IOU peak load(s), per Table 6-3.

Figure 6-2: 2009 Transmission Capacity Benefit Comparison at Peak



As shown in Figure 6-2, depending on the dispatch adjustment method chosen, the current (2009) TCB on a statewide level is on the order of 500-900 MW. This is comparable to the delivery capability of a modern 230kV transmission line. When the future CSI penetration reaches twice the 2009 level, these results project a 1000-1500MW statewide TCB, which is comparable to the delivery capability of a 500kV transmission line. The magnitude of the TCB is much larger than the CSI generation output metered in 2009 because the presence of this distributed PV on the distribution system reduces the loading on all of the "upstream" components of the statewide transmission system all the way back to the central generating stations, as demonstrated through Figure 6-1 and the associated example. Each decrement in line loading on all of these transmission elements in series with other upstream and downstream elements, adds to the aggregate capacity benefit captured in the TCB calculation. In other words, the TCB(s) are distributed statewide, rather than on any single transmission corridor. Thus, the incremental benefits on each individual transmission corridor within the state of California are just a small percentage of the aggregate statewide TCB(s).

Nevertheless, the TCB reflects a real deferral in capacity expansion needs. While actual data on related capital expansion deferrals is unavailable, a proxy for this economic benefit can be developed based on a set of hypothetical, distributed transmission project deferrals.

Given that objective, the most widely distributed transmission voltage class in California is 60-70kV.[10] All three of the IOUs operate 60-70kV facilities and there are more than 2,000 transmission lines in this voltage class spread across the state. Transmission lines in this voltage class typically range in length from several miles to over 50 miles and have capacity ratings from roughly 50-150 MW. Since the 60-70kV system is so widespread, it provides a good proxy to estimate transmission capital deferral from CSI deployment.

Each decision for new capital investment in such facilities is made by the respective IOU based on reliability and economic criteria (e.g. cost effectiveness). The most common type of upgrade at 60-70kV would be to replace existing conductors with larger conductors. Depending on line design and terrain, such upgrades cost are approximately $50,000-100,000 per mile and typically increase 60-70kV line capacity by 50-100 percent. Assuming an average line capacity increase of 65 MW per project, roughly seven to fourteen 60-70kV line upgrades would equate to the current statewide TCB of 500-900 MW. Assuming an average reconductor cost of $75,000 per mile and an average line length of 25 miles, this yields a 2009 capital deferral of $13.13 to $26.26 million for the seven to fourteen upgrades respectively and provides a reasonable proxy for the impact of CSI on 2009 transmission capital deferrals. This proxy is based on overhead line costs only and ignores 60-70kV underground cable upgrades and substation upgrades, which would add to the economic benefit if included.

Peak System Loss Impacts

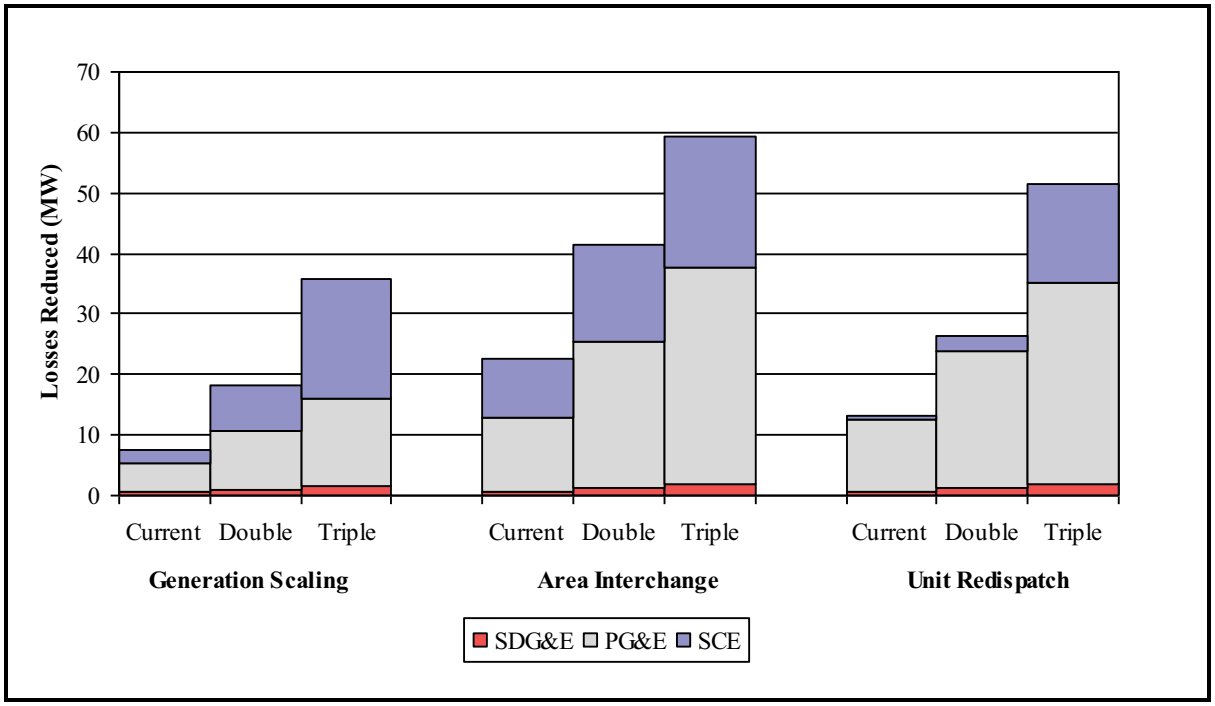
Distributed PV generation can reduce transmission system losses by lowering the power delivered over the transmission system. This is true both at peak demand as well as off peak. The resulting reduction in transmission losses translates directly into a further reduction of central station generation dispatch requirements, along with their related environmental impacts and emissions. Estimated reductions in transmission losses for each service area are shown in Table 6-6 and Figure 6-3 for 2009 summer peak conditions.

[10] This voltage class is sometimes referred to as “subtransmission”, but is included in the transmission model.

Table 6-6: 2009 Transmission Loss Sensitivities[11]

CSI Production Level	Redispatch Option	Service Area (MW)		
		PG&E	SCE	SDG&E
Current (136.1 MW)	Generation Scaling	4.89	2.28	0.51
	Area Interchange Adjustment	12.24	9.75	0.61
	"Marginal" Unit Redispatch	11.86	0.65	0.64
	Average Impact	***9.66***	***4.23***	***0.59***
Double (272.1 MW)	Generation Scaling	9.74	7.59	1.01
	Area Interchange Adjustment	24.24	16.09	1.23
	"Marginal" Unit Redispatch	22.45	2.66	1.26
	Average Impact	***18.81***	***8.78***	***1.17***
Triple (408.3 MW)	Generation Scaling	14.56	19.57	1.52
	Area Interchange Adjustment	35.91	21.70	1.83
	"Marginal" Unit Redispatch	33.17	16.50	1.84
	Average Impact	***27.88***	***19.26***	***1.73***

Figure 6-3: 2009 Transmission Loss Comparison vs. PV Deployment Level



The impact of CSI generation on statewide loss savings on the transmission system at summer peak load in 2009 was from 7.7 MW to 22.6 MW, depending on the dispatch adjustment method used. This loss savings roughly matches the aggregate of CSI generation

[11] Current CSI baseline MW equal the sum of estimated 2009 CSI outputs at IOU peak load(s), per Table 6-3.

currently installed in the SDG&E service area, and represents a real increase in the statewide generating capacity benefit realized from the presence of the CSI generation. Furthermore, these estimates address loss savings on the transmission system only and exclude loss savings that were realized on the distribution system.

System Reliability Impacts

Transmission system reliability is typically measured in terms of the system's ability to deliver power under both normal and contingency conditions. California IOUs, like other utilities across the United States, are required by FERC to adhere to NERC reliability standards. Those standards specify performance criteria for loss of individual components of the system such as a line or generator, as well as various overlapping outage events (e.g., common corridor outages, single contingencies in conjunction with a circuit breaker failure, substation bus outages, etc.). In actual operation, congestion constraints often occur on the transmission system and may require reductions in power deliveries in order to adhere to the reliability criteria. Distributed solar generation improves transmission reliability to the extent that it relieves congestion and helps the system to meet the NERC reliability criteria under both normal and contingency conditions. Transmission contingency analysis is a complex process and is outside the scope of this impact evaluation.

Other Observations and Conclusions—CSI Transmission Impacts

With increased distributed PV generation, there will continue to be increased savings in transmission losses and freeing of transmission capacity. There was a 240 percent increase in TCB and in statewide transmission loss savings between the 2008 study and 2009. As discussed above, these benefits will continue to grow year by year as additional CSI is installed. As regards a long-term projection, Figure 6-4 shows estimated TCB based on the projected statewide CSI installed capacity target of 1,750MW by 2017.[12] Similarly, Figure 6-5 shows the estimated projected benefits of the CSI on transmission loss reduction. These graphs show a projected 2017 statewide TCB of at least 4,000 MW and a projected 2017 statewide loss savings of nearly 70 MW.

[12] For developing the projected 2017 TCB value(s), the evaluation team assumed a ratio of 0.575 between CSI output at peak demand vs. CSI installed capacity (e.g., 0.575 x 1750 MW = 1,006 MW), based on the ratio between 2009 installed capacity and CSI output at peak demand from Table 6-3. The 2017 analysis was performed using the "generation scaling" redispatch method and the 2009 power flow base cases provided by the utilities. Similar results would be expected with a 2017 model. However, higher impacts might occur with other generation redispatch options, which were not tested in 2017.

Figure 6-4: Potential Transmission Capacity Benefit Due to CSI

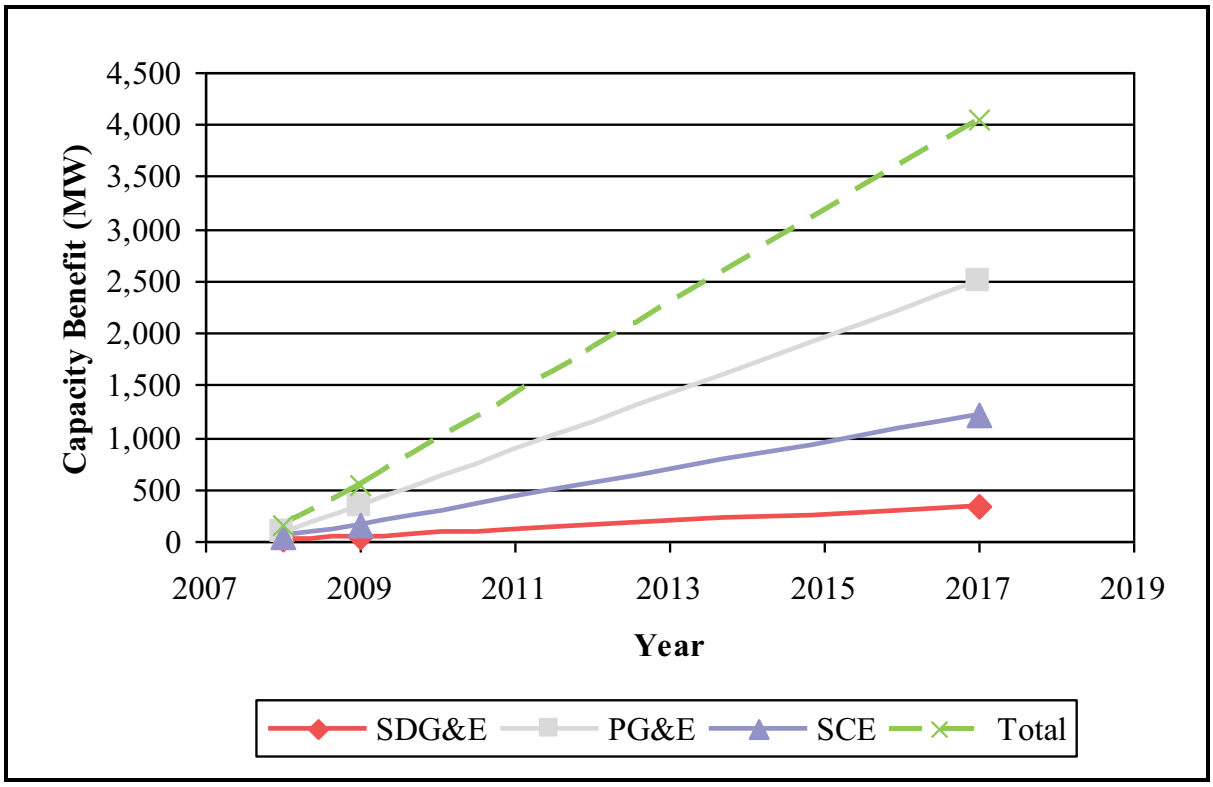
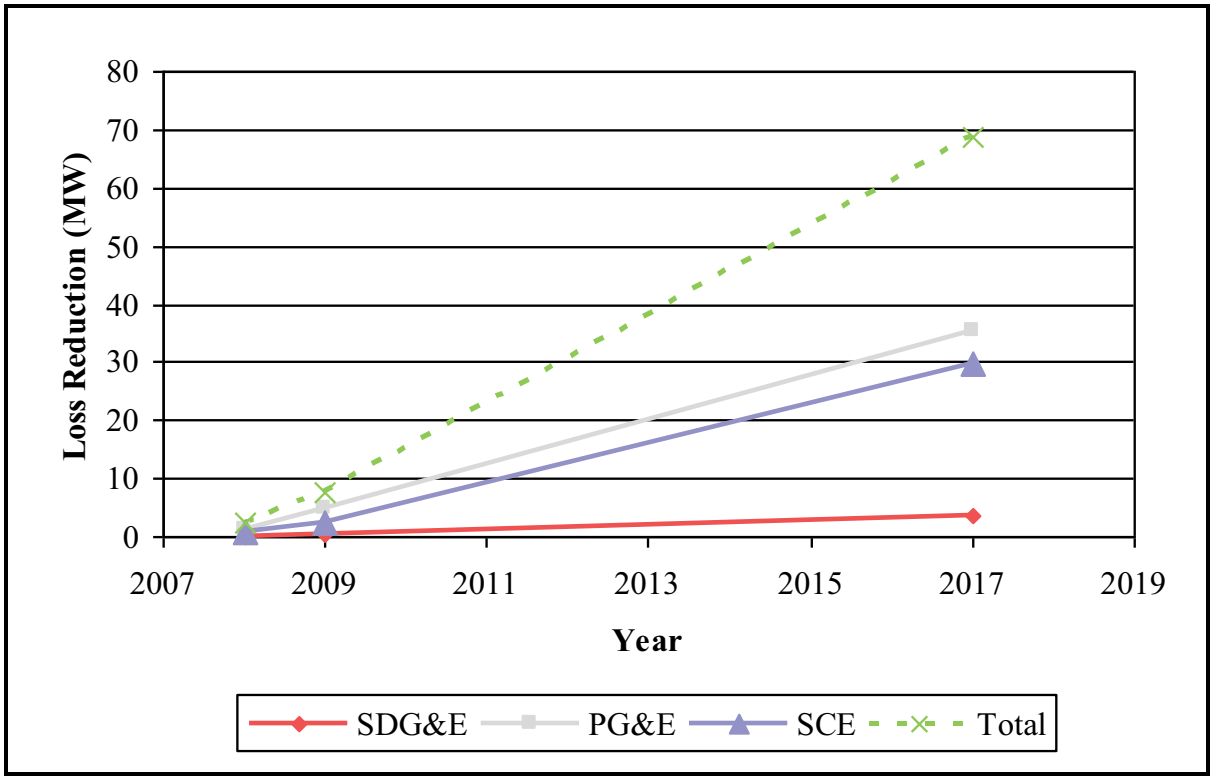


Figure 6-5: Projected Transmission Loss Reduction Due to CSI



6.5 Distribution System Impact Analysis

Distribution system impacts from distributed PV generation vary from feeder to feeder and depend on a variety of factors. These include PV output characteristics, the location of PV systems on the feeder, percent of penetration (defined here as PV Capacity/Peak Demand for the respective feeder), the electrical characteristics of the distribution substation supplying the feeder, and the characteristics of the feeder itself. Distribution feeder characteristics that can have a significant bearing on the impact(s) of PV are described below.

Climate Zone

The climate zone, Inland or Coastal, can alter the daily and seasonal load patterns, generation patterns, and output. It may also impact the level of coincidence between peaking of the PV generation and circuit demand.

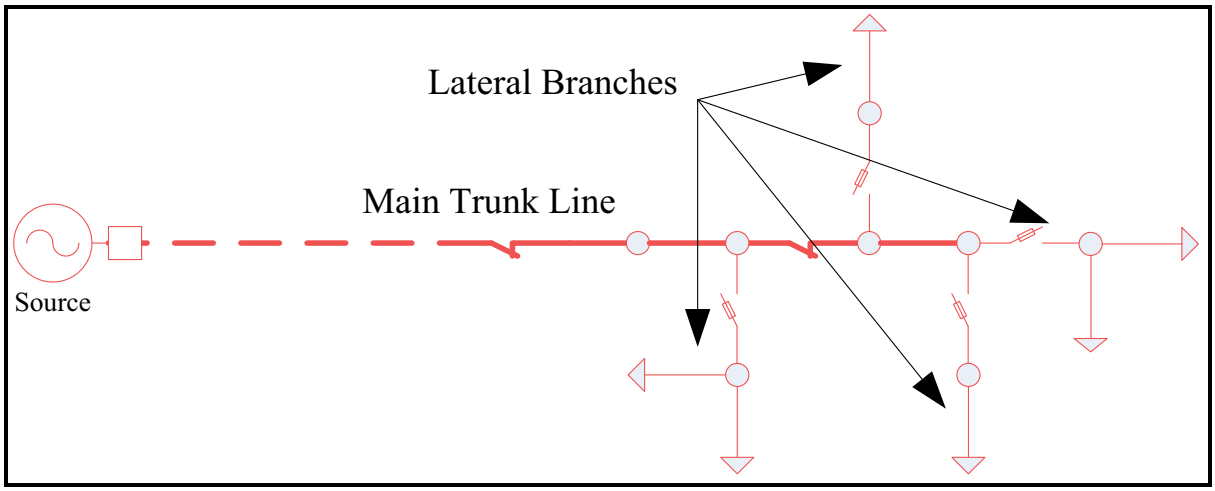
Customer Mix

The customer mix (e.g., whether the feeder is primarily residential or commercial customers) can greatly alter the load profile shape, feeder design and PV impacts. While almost all feeders have a blend of both load types, Table 6-7 shows how the sample set used by the evaluation team is distributed among feeders that are either predominately residential or commercial. It should be noted that in addition to commercial and residential customer types some feeders have additional sub customer types (e.g. industrial, agricultural load). However, the analysis did not explicitly address the latter subgroups.

Feeder Length

Feeder length can affect the impact that distributed PV has on feeder losses and voltages. For the purpose of this report, feeder length is defined as the total feeder "line-mileage", which includes the main trunk plus all branches supplied by that trunk, as shown in Figure 6-6. This mileage can vary a great deal between urban, suburban, and rural feeders. Both overhead and underground mileages are included when determining feeder length. Circuits included in the 2009 analysis range from less than 10 miles to over 150 miles in length.

Figure 6-6: Simplified Feeder



Peak Demand and Penetration Level

Penetration level is defined here as equal to the installed PV Capacity expressed as a percent of the Peak Demand for the feeder. It is expected that feeder impacts will be proportional to the level of PV penetration.

The feeders selected for analysis all have relatively high levels of PV penetration as compared to the general population of feeders in California. PV generation on a given feeder may consist of many small units (e.g. residential PV), a few large applications (e.g. commercial PV sites), or a mix of small and large PV.

Impacts

Key distribution system impacts investigated as part of the 2009 CSI impact analysis include:

- Reduction in overall feeder demand and energy requirements
  - During peak demand conditions
  - Off peak and seasonal variations
- Impact on feeder electrical losses (kW and kWh)
- The effect on voltages seen by customers on the feeder
- Impacts on utility voltage control equipment wear and tear

While the precise impact of PV on distribution feeders can only be determined on a case by case basis, one goal of the 2009 impact analysis was to determine if PV attributes and key feeder characteristics could be correlated in such a way that the results could be applied more generally to distribution circuits throughout the state. Documenting any such correlations

would be useful to IOU distribution system planners and operators in anticipating the impacts that increasing levels of PV penetration will have on a given distribution circuit or area of the system. With this goal in mind, the evaluation team, in conjunction with the utilities, chose a representative cross-section of 52 feeders statewide that fit a range of key characteristics. From this group, feeders with similar characteristics were then grouped into specific categories or "bins" in order to facilitate the process of correlating PV impacts to feeder traits. These bins are intended to capture feeders where the PV penetration levels were relatively high (compared to the overall feeder population), and to reflect a cross-section of PV customer types (e.g. residential vs. commercial). After further review of key characteristics of the 52 feeders, a subset of 23 of the feeders were selected for use as case studies. These 23 feeders were modeled in detail and used for analysis purposes, as discussed below.

Sample Feeder Characteristics

The characteristics of the 23 representative feeders chosen for the 2009 impact analysis are summarized in Figure 6-7. Feeder characteristics are grouped statewide and not separated by utility. The feeders selected were chosen in an effort to achieve a balanced distribution of the feeders across all of the key characteristics as summarized below.

Table 6-7: Number of Feeder Case Studies by Key Characteristics

Characteristic	Category	Sample Feeders (n)
Geographic Location	Inland	14
	Coastal	9
Customer Mix	Commercial	12
	Residential	11
Length (mi)	Short (0-20)	6
	Medium (20-60)	11
	Long (60+)	6
Peak Load (kW)	Low (0-5,000)	5
	Medium (5,000-10,000)	10
	High (10,000+)	8
Penetration (Rated PV kW/Peak Load kW)	Low (0-5%)	10
	Medium (5-10%)	6
	High (10%+)	**7**

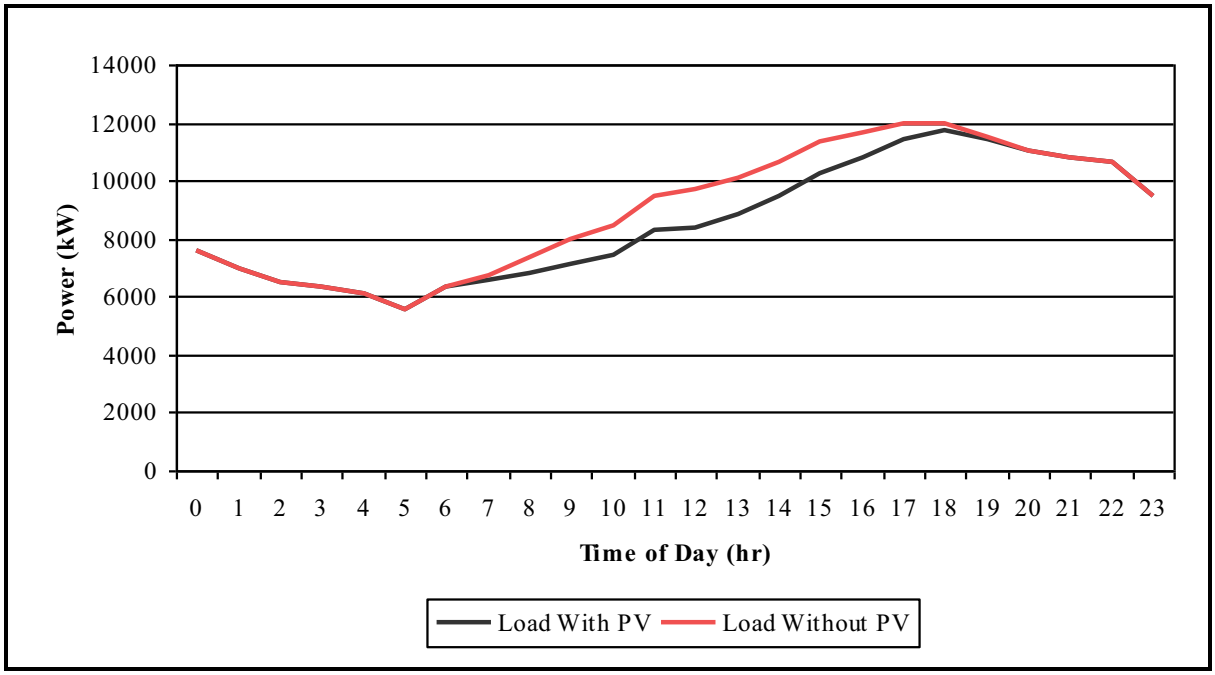
It should be noted that in the 2008 CSI Impact Evaluation, the focus was on a select group of feeders that had large CSI PV system installations. That approach may have resulted in a skewing of the analysis toward feeders that serve mostly commercial loads. The approach to selecting feeders for the 2009 impact analysis intentionally attempts to capture a much

broader cross section of feeder types, including feeders that have a significant penetration of residential CSI installations, the fastest growing segment of the CSI program.

Peak Demand Reduction

The impact of PV on reducing feeder peak demand depends on the degree of coincidence between PV output and feeder demand. The net hourly feeder demand with and without PV on the peak day as shown in the example of Figure 6-7. The PV contribution to hourly feeder demand is illustrated by the difference in the upper and lower curves. Although the PV on this feeder provided a significant energy reduction throughout the day, its impact on the feeder's peak demand at about 18:00 PST is fairly small due to this feeder peaking later in the day when solar output has declined.

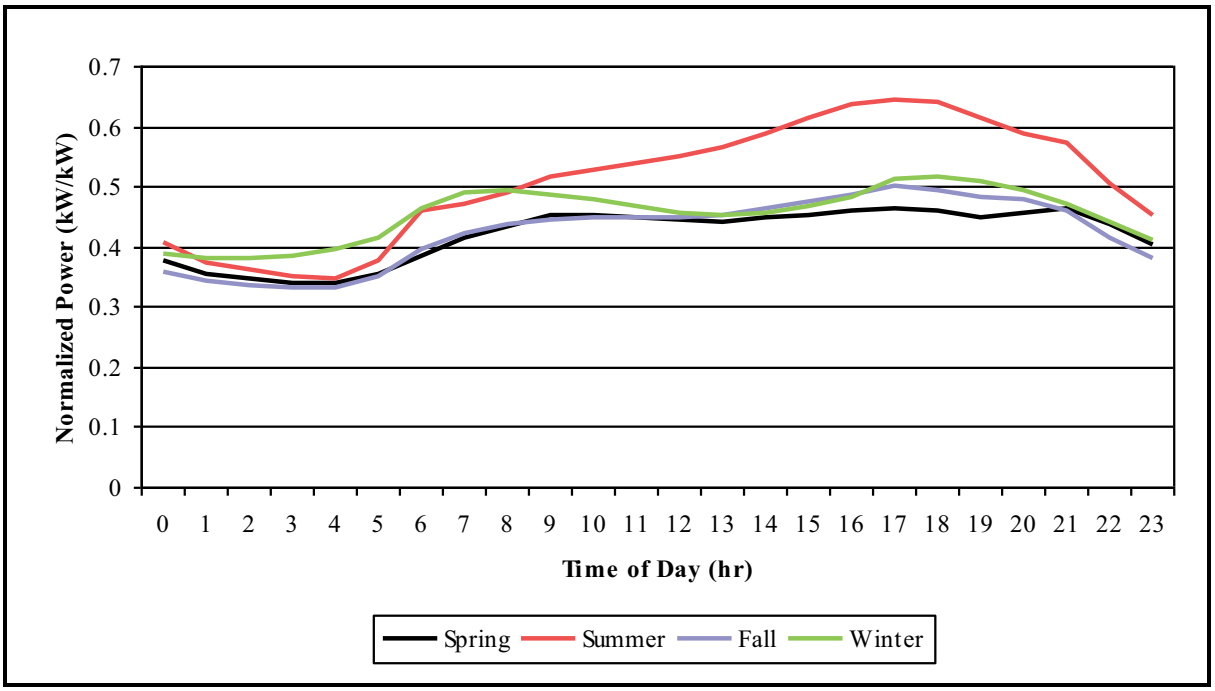
Figure 6-7: Peak Demand Reduction Example (Feeder 8)



One of the primary characteristics that impacts the PV generation shape is geographic location and physical orientation. As noted in Section 5, tracking systems can significantly raise the hourly capacity factor in the afternoon and west facing systems have a similar peak production shift towards the afternoon, thereby better matching the typical demand curve. The feeder demand curve will vary depending upon the customer mix and other factors. PV generation output and feeder demand curves both vary depending upon the time of year and a

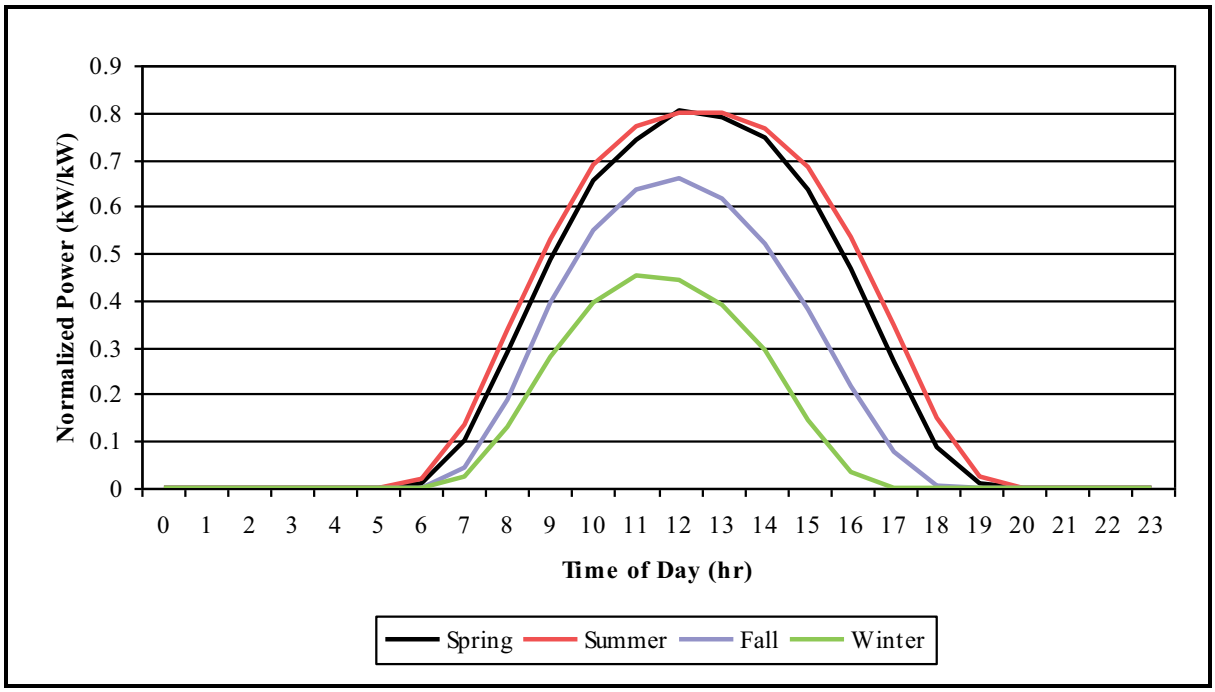
variety of local factors. Figure 6-8 illustrates how the feeder demand can vary by season[13]. This figure shows normalized demand (each point is divided by the annual peak demand) vs. time of day, by season. Likewise, Figure 6-9 illustrates how the PV output varies seasonally and is normalized by the total installed PV capacity.

Figure 6-8: Typical Daily Feeder Demand Curves vs. Season (Feeder 8)



[13] Seasons – Defined for this analysis as: Spring (March, April, May), Summer (June, July, August), Fall (September, October, November), Winter (December, January, February).

Figure 6-9: Typical Seasonal PV Output vs. Rated PV Capacity (Feeder 8)



The degree of coincidence between PV output and the peak of the feeder demand curve defines the "demand reduction" attribute to the PV on the feeder. In Figure 6-7 above, the peak feeder demand without PV generation occurs during the 18th hour and the demand with PV generation at this time is reduced by 228kW. This impact can be expressed as a Peak Reduction Factor (PRF) (defined as peak feeder demand reduction over total installed PV capacity).[14]

Table 6-8 provides the PRF calculated for each of the feeders analyzed for 2009 and shows the actual PRF values on the peak load day for the respective feeder. In an attempt to remove potential bias due to customer mix in the feeder sample, roughly an equal number of residential and commercial feeders was used for the case studies. More details on the feeder selection process are provided in Appendix G. Feeder numbers used in the left-most column of Table 6-8, and throughout this section of the report, were assigned by the evaluation team in order to mask the host utility and identity of the feeders.

[14] In the example shown in Figure 6-7, the installed PV capacity on the feeder is 1,596kW and the PRF is 0.14 (228/1596 = 0.14).

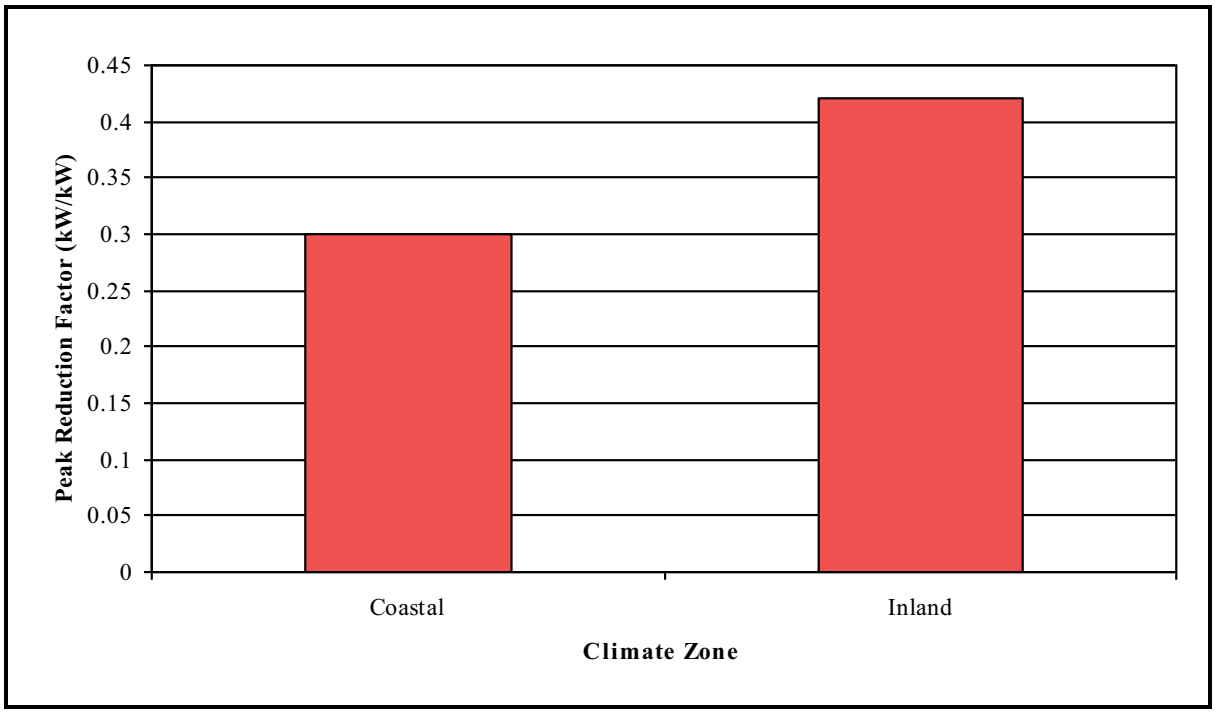
Table 6-8: Peak Reduction Factors

Feeder	Climate Zone	Customer Mix	PV Capacity (kW)	Peak Demand Hour	Peak Power Reduction (kW)	Peak Reduction Factor (kW/kW)
9	Coastal	Commercial	521	13	366	0.70
13	Coastal	Commercial	469	22	0	0.00
21	Coastal	Commercial	884	10	73	0.08
6	Coastal	Residential	388	12	274	0.71
15	Coastal	Residential	272	9	62	0.23
16	Coastal	Residential	1,087	19	82	0.08
17	Coastal	Residential	106	20	0	0.00
18	Coastal	Residential	400	19	0	0.00
22	Coastal	Residential	121	15	72	0.60
2	Inland	Commercial	307	17	158	0.51
3	Inland	Commercial	133	11	82	0.62
4	Inland	Commercial	999	14	210	0.21
8	Inland	Commercial	1,596	19	228	0.14
10	Inland	Commercial	364	15	295	0.81
12	Inland	Commercial	1,581	21	159	0.10
14	Inland	Commercial	104	18	20	0.19
19	Inland	Commercial	1,048	20	0	0.00
23	Inland	Commercial	1,045	13	687	0.66
1	Inland	Residential	20	16	10	0.50
5	Inland	Residential	39	14	34	0.87
7	Inland	Residential	615	19	59	0.10
11	Inland	Residential	111	17	46	0.41
20	Inland	Residential	1,976	19	50	0.03

The PRF was averaged by climate zone for comparison purposes. As shown in Figure 6-10 inland feeders have a significantly higher PRF on average as compared to coastal feeders. This implies that there is a higher coincidence between peak feeder demand and PV production on inland feeders.

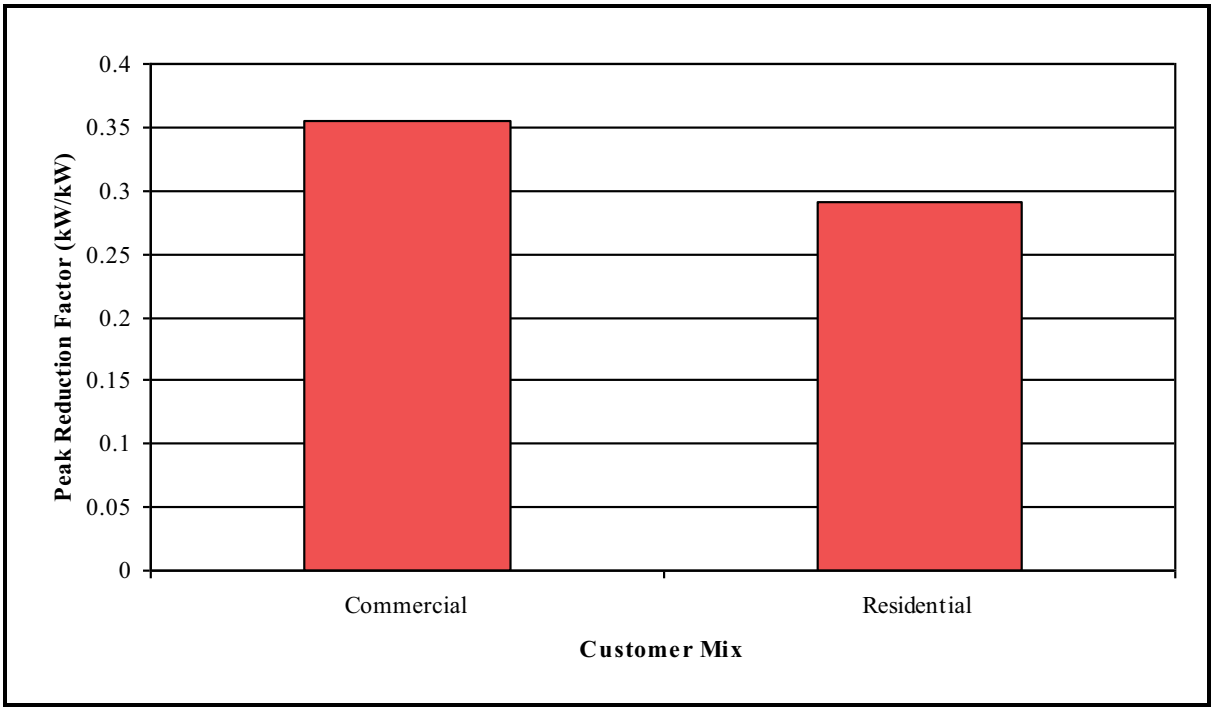
For the purpose of Figure 6-10, the team randomly chose an equal number of residential and commercial feeders in both the coastal zone and inland zone, to prevent any bias due to customer mix.

Figure 6-10: Average Peak Reduction Factor by Climate Zone



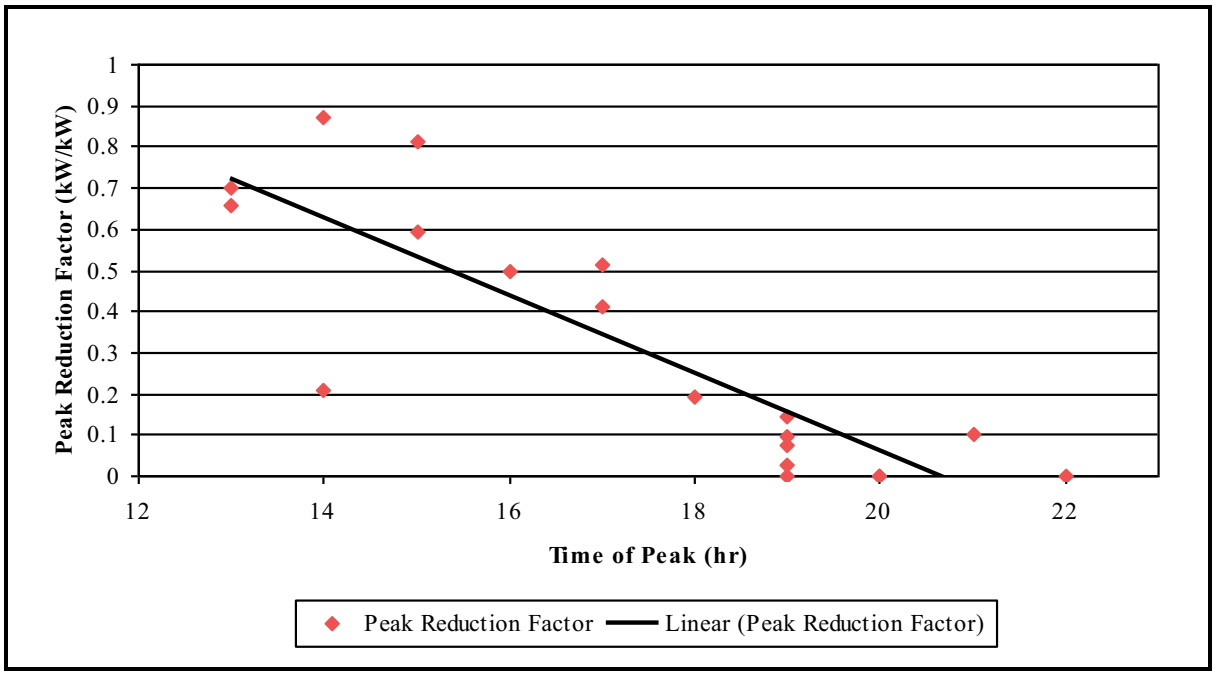
PRF was also averaged by residential versus commercial feeders for comparison purposes, as shown in Figure 6-11. In an effort to remove any bias effects related to climate zone, roughly equal subsets of inland feeders and coastal feeders were chosen at random from the overall 2009 sample set for use in developing Figure 6-11. Based on this result, the 2009 PRF value averaged approximately 0.32 with a plus and minus 10 percent range for commercial vs. industrial feeders. This deviation is quite small and suggests no significant correlation between PRF and customer mix on a statewide basis in 2009.

Figure 6-11: Average Peak Reduction Factor by Customer Mix



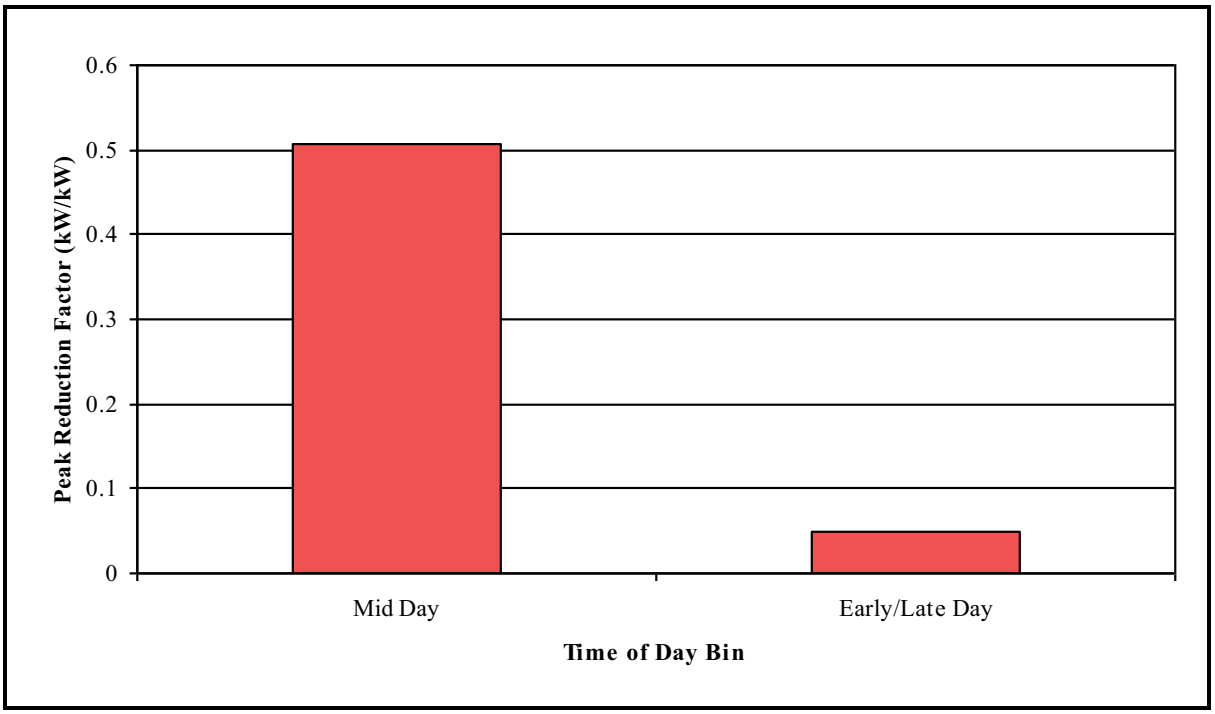
The time of day that each feeder experiences peak demand tends to vary as a function of customer mix, geographic location, and other factors. Since PV generation tends to peak in the afternoon, as shown in Figure 6-8 and Section 5, the degree of coincidence between feeder peak and peak PV output directly affects the PRF. Figure 6-12 shows a plot of PRF for feeders with peaks that occur at different times in the afternoon. It shows a strong negative linear relationship between time of day and PRF magnitude (e.g., a correlation coefficient of -0.86). A plot was not developed for feeders with morning peak demand since there were not many feeders in the 2009 case studies that had morning peaks. However, it is expected that there would be a similar but opposite relationship to that shown in Figure 6-12 (the closer to afternoon the more likely it will have a higher PRF). On average, the time of the maximum PV output on the peak day for the sample feeders was about 13:00 hrs (PST).

Figure 6-12: Peak Reduction Factor vs. Time of Feeder Peak Demand (Afternoon Peaking) PST



We can loosely characterize feeders by mid day and late day peaking (early day peaking feeders are grouped with late day because they are comparable for PV output) feeders as illustrated by Figure 6-13. Mid Day is defined here as between 9:00 and 18:00 hrs (PST) and all other hours are defined as Early/Late Day. Due to the tailing off of PV output in the late afternoon and early evening, essentially zero PRF is expected on feeders with demand that peaks after 18:00 hrs (PST) during the summer months.

Figure 6-13: Average Peak Reduction Factor vs. Peak Time of Day



Annual Energy Reduction

In addition to peak feeder demand impacts, the presence of PV on a feeder will reduce the overall amount of energy that must be supplied to the feeder from its source substation and remote generation over the course of the year. This is even true for feeders that have a PRF of zero. It should be noted that PV also has a direct effect on feeder losses (conductor heating due to electrical resistance in the conductor), which is addressed in a later section. The energy reductions discussed in this section include losses and are intended to show overall impacts on feeder energy requirements.

An Energy Reduction Factor (ERF) is defined here as the difference between annual feeder energy requirements with and without PV generation, normalized by the total PV capacity

and hours in a year (e.g., based on averaging 8,760 hourly values) [15] Table 6-9 shows the ERF for each of the feeders analyzed in the 2009 study. On average, ERF for all feeders in the sample set was 0.21 and varied only slightly from feeder to feeder. Based on Table 6-9, the annual energy production expected per kW of PV capacity in California can generally be expected to run about 20 percent of production capability regardless of feeder location.

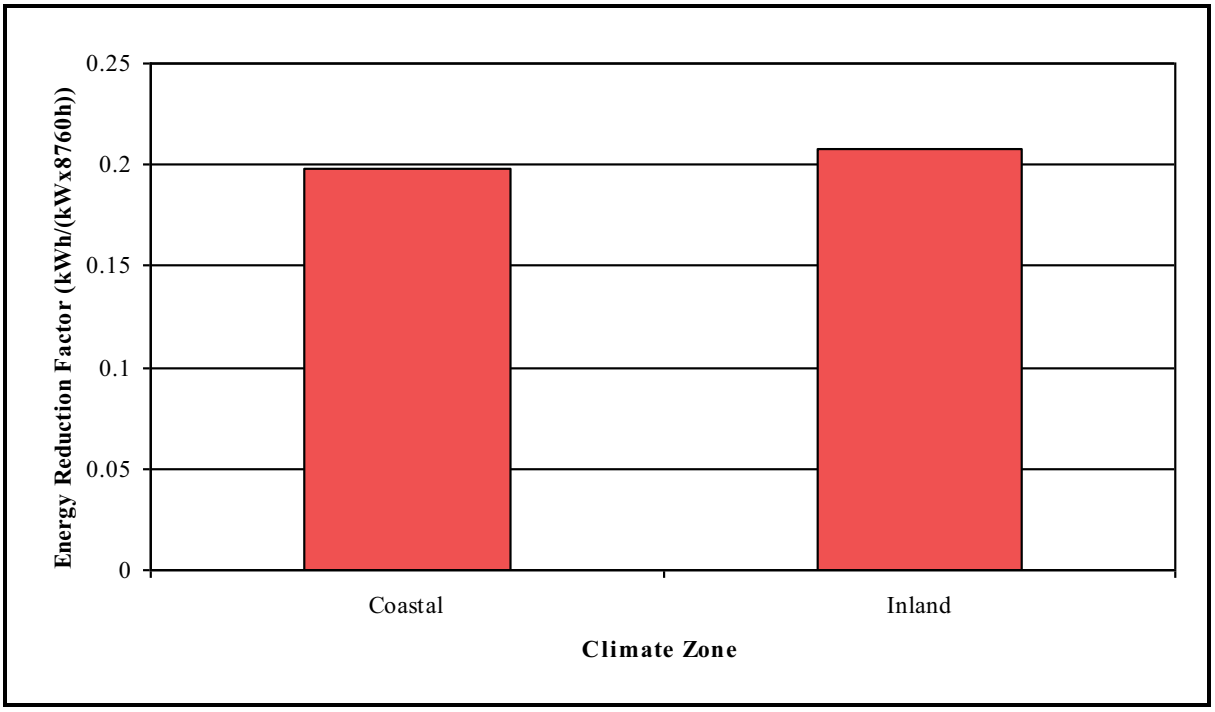
Table 6-9: Energy Reduction Factor (Annual)

Feeder	Climate Zone	PV Capacity (kW)	Annual Energy Reduction (kWh)	Energy Reduction Factor (kWh/(kWx8760h))
6	Coastal	388	673,233	0.20
9	Coastal	521	943,386	0.21
13	Coastal	469	798,880	0.19
15	Coastal	272	490,532	0.21
16	Coastal	1,087	1,727,608	0.18
17	Coastal	106	190,590	0.21
18	Coastal	400	651,568	0.19
21	Coastal	884	1,566,029	0.20
22	Coastal	121	209,325	0.20
1	Inland	20	38,811	0.22
2	Inland	307	587,739	0.22
3	Inland	133	262,591	0.23
4	Inland	999	1,997,815	0.23
5	Inland	39	77,155	0.23
7	Inland	615	1,088,449	0.20
8	Inland	1,596	2,781,336	0.20
10	Inland	364	643,184	0.20
11	Inland	111	205,091	0.21
12	Inland	1,581	3,349,699	0.24
14	Inland	104	190,395	0.21
19	Inland	1,048	1,961,335	0.21
20	Inland	1,976	2,579,701	0.15
23	Inland	1,045	2,009,773	0.22

[15] For example, the ERF for a feeder with 388kV of installed PV capacity that reduced combined energy requirements and losses on the feeder by 673,233 kWh, is (673,233 / (388 x 8760)) = 0.20.

As shown in Figure 6-14 the ERF was also fairly uniform across climates, with only a slight increase for inland circuits versus coastal.

Figure 6-14: Average Energy Reduction Factor by Climate Zone



Losses

Losses naturally occur on all feeders due to the electrical resistance of conductors. The amount of losses depends on:

- the feeder length,
- conductor sizes, and
- the location of load and PV along the feeder.

If PV generation at a given point on the feeder is less than the local load connected at that point, there is a loss reduction attributed to reducing the demand requirements. If the PV power generated is greater than the locally connected load then the excess power is being sent to other load along the feeder, but in many cases may still reduce overall feeder losses.

The losses considered in this section are only for the distribution system. The total system-wide loss savings will be greater than the feeder loss savings since the power transmitted to the distribution substation to supply the net feeder losses originates from remote generation

sources. The further energy has to travel across the transmission and distribution system to reach customer loads, the more it incurs additional losses on the delivery system.

The evaluation team defined a Loss Reduction Factor (LRF) to normalize the annual loss savings due to distributed PV on each of the feeders selected for analysis. To calculate the LRF, the feeder loss reduction (kWh) over a year is divided by the rated PV capacity and hours (e.g. at 39 kW capacity PV, with loss reduction of 1,135 kWh over a year has a LRF of 0.003 (1135 / (39 x 8760))). This factor can be used to determine the amount of losses a PV unit may reduce by using its rating and the duration of interest (e.g. a 1,000 kW capacity with a loss reduction factor of 0.005 operating over a year is, 1,000 kW x 0.005 x 8760 h or 43,800 kWh). Table 6-10 shows the LRF values for the 2009 sample feeder set

Table 6-10: Loss Reduction Factor (Annual)

Feeder	Length Bins	Customer Mix	PV Capacity (kW)	Loss Reduction (kWh)	Loss Reduction Factor (kWh/(kWx8760h))
4	Short	Commercial	999	19,178	0.002
9	Short	Commercial	521	3,468	0.001
10	Short	Commercial	364	3,679	0.001
13	Short	Commercial	469	2,047	0.000
21	Short	Commercial	884	10,432	0.001
5	Short	Residential	39	1,135	0.003
2	Medium	Commercial	307	3,795	0.001
3	Medium	Commercial	133	318	0.000
12	Medium	Commercial	1,581	31,618	0.002
14	Medium	Commercial	104	7,136	0.008
19	Medium	Commercial	1,048	20,609	0.002
23	Medium	Commercial	1,045	23,145	0.003
1	Medium	Residential	20	521	0.003
11	Medium	Residential	111	4,296	0.004
15	Medium	Residential	272	9,949	0.004
17	Medium	Residential	106	6,132	0.007
22	Medium	Residential	121	6,649	0.006
8	Long	Commercial	1,596	45,374	0.003
6	Long	Residential	388	12,077	0.004
7	Long	Residential	615	46,914	0.009
16	Long	Residential	1,087	38,082	0.004
18	Long	Residential	400	41,283	0.012
20	Long	Residential	1,976	-8,443[16]	0.000

[16] A negative value indicates that PV generation exceeds the local demand on the portion of the feeder near the PV, and therefore PV output has to travel further on the feeder to displace load. This causes an increase in annual losses on the feeder. This situation is discussed further in Figures 6-17 and 6-18.

Since the feeder losses are correlated closely with feeder length, PV loss impacts are also correlated to the length. Figure 6-15 shows how the average LRF varies according to feeder length. A longer feeder typically has greater losses and therefore a greater reduction of losses can be realized by adding PV on longer feeders. Figure 6-16 further illustrates the length and LRF relationship by a linear best fit. There is a moderate positive linear correlation between feeder length and LRF, with a correlation coefficient of 0.65.

Figure 6-15: Average Loss Reduction Factor by Feeder Length Bins

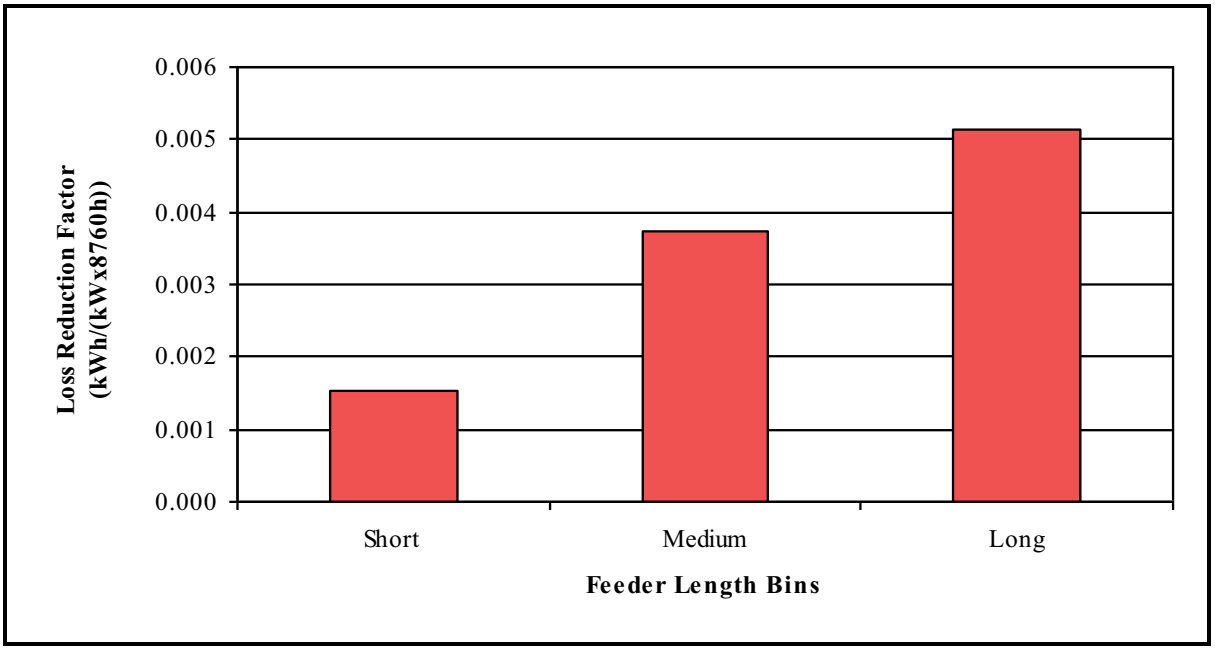
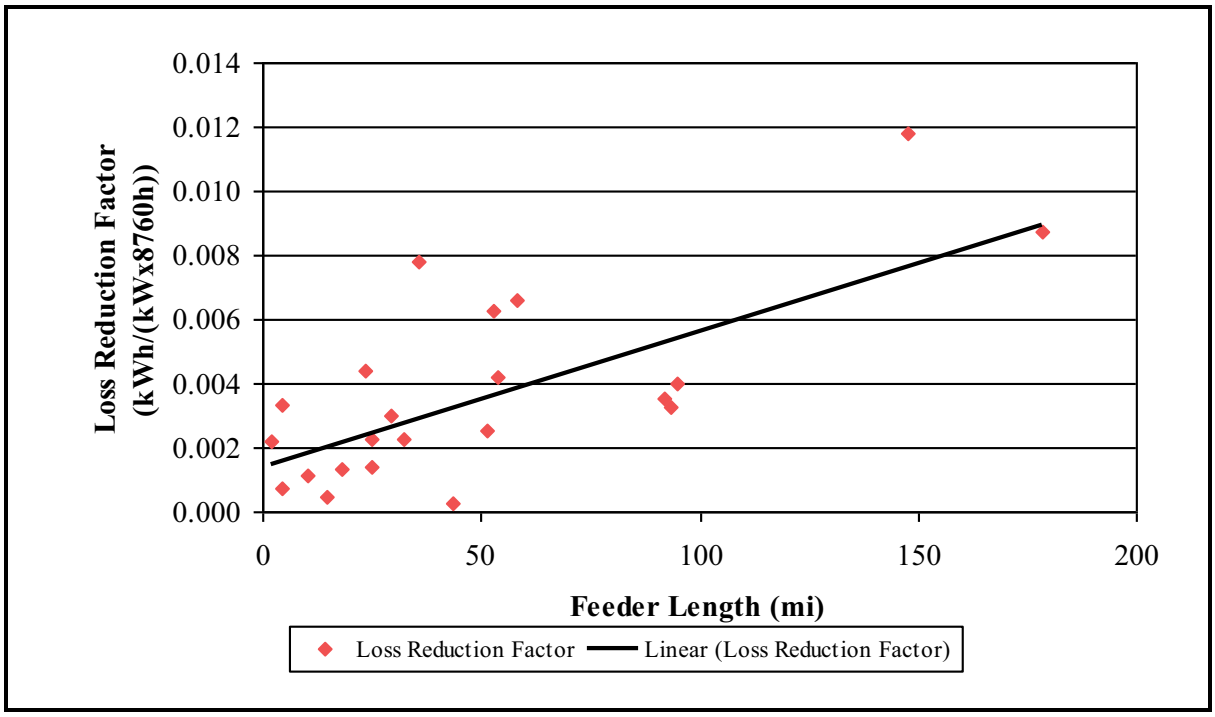


Figure 6-16: Loss Reduction Factor by Feeder Length



Intuitively, it might be assumed that the optimum distribution of PV units on a feeder would be one that matches the distribution of load on the feeder as closely as possible. In theory, this should minimize loading and losses on all sections of a feeder during those hours that the PV is generating. While it is impractical to achieve this in every case, feeders with a high percentage of residential CSI might tend to approach this optimum distribution more so than commercial feeders with a small number of large PV sites.

To illustrate how load and PV generator placement interact, consider Figure 6-17 as a representation of a typical feeder. This load in a simplistic sense can be represented by the equivalent feeder shown in Figure 6-18. The addition of PV generator sites in this example, show possible locations for PV placement (this is a simple case where there is only 1 PV unit that could be at Location 1, 2 or 3).

In the event that a PV generator is added at Location 1 between the load center and the substation, this will reduce losses from the source up to the PV generator location. If a PV generator is placed at Location 2, directly at the load center maximum loss reduction is achieved. If a PV generator is placed at Location 3, beyond the equivalent load center, losses will be reduced along the main trunk but will be increased beyond the load center. This may have an overall effect of increasing total feeder losses if the distance from the load center to the PV generator location is too great.

It should be noted that for the 2009 CSI distribution feeder case studies, feeder loads were modeled as close as possible to the actual location, based on the model data provided by the utilities.

Figure 6-17: Typical Distribution Feeder

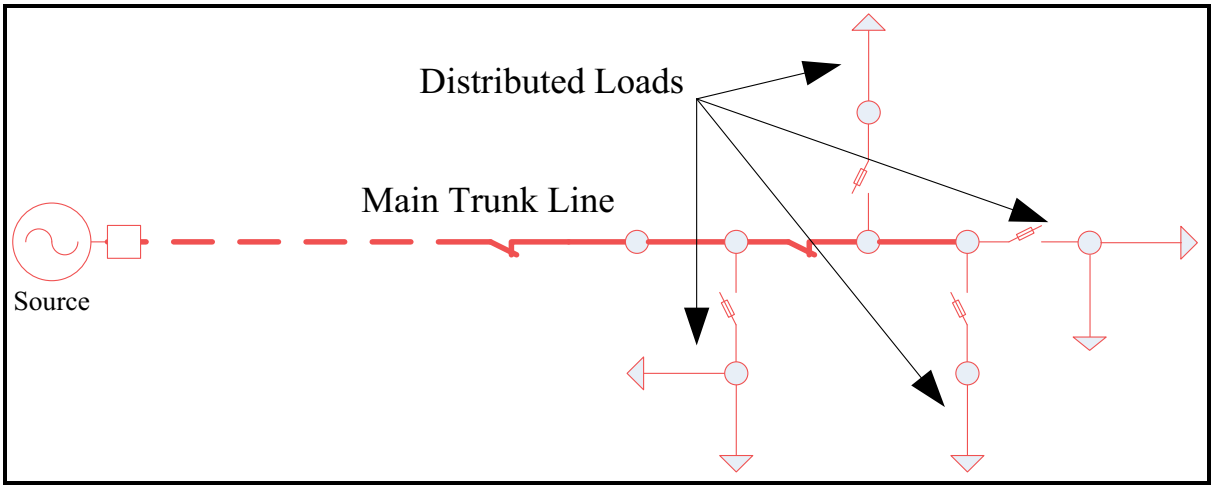
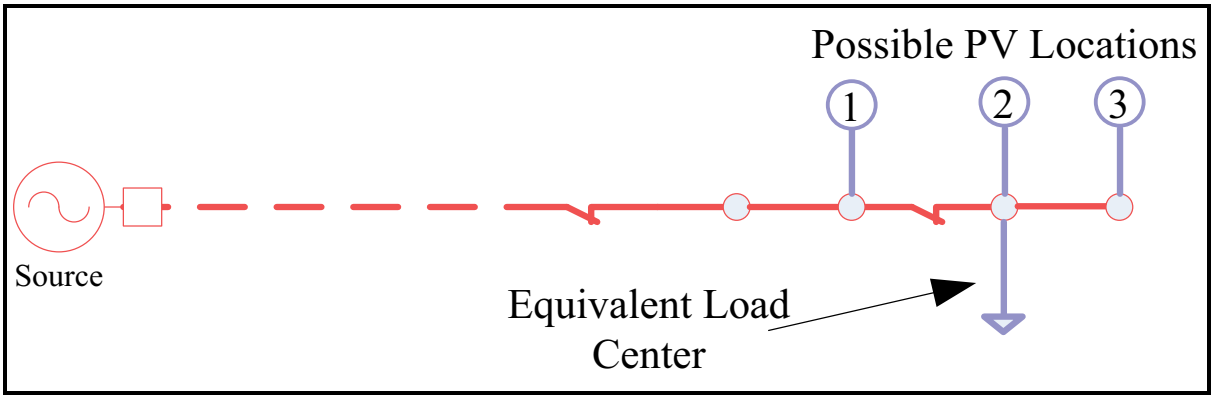
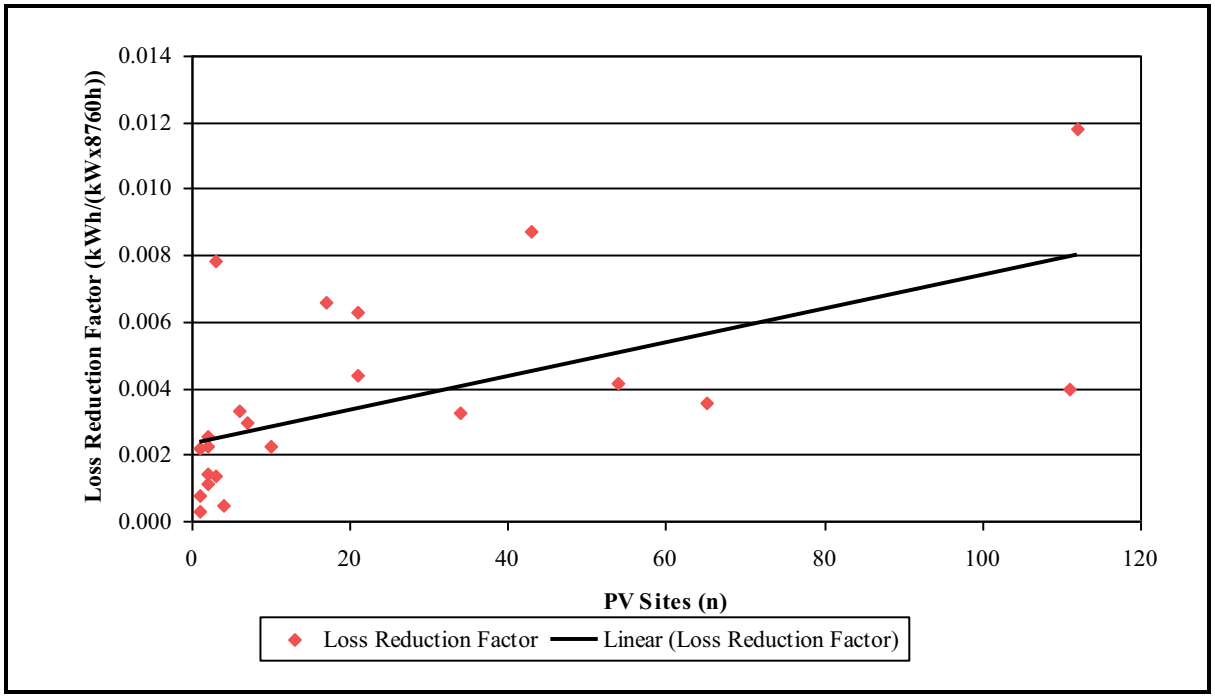


Figure 6-18: Equivalent Distribution Feeder



As previously noted, there is also a relationship between the number of PV units/locations on a feeder and the level of feeder loss savings. Figure 6-19 attempts to capture the relationship between number of PV sites and LRF for the feeders analyzed in the 2009 CSI. For detailed feeder characteristics (quantity and size of PV), please refer to tables in Appendix G. The quantity of PV sites on the feeders within the study group ranged from 1 to 115 with varying installed PV capacity. The figure indicates a weak positive linear relationship (correlation coefficient of 0.56).

Figure 6-19: Loss Reduction Factor vs. Number of PV Sites on a Feeder

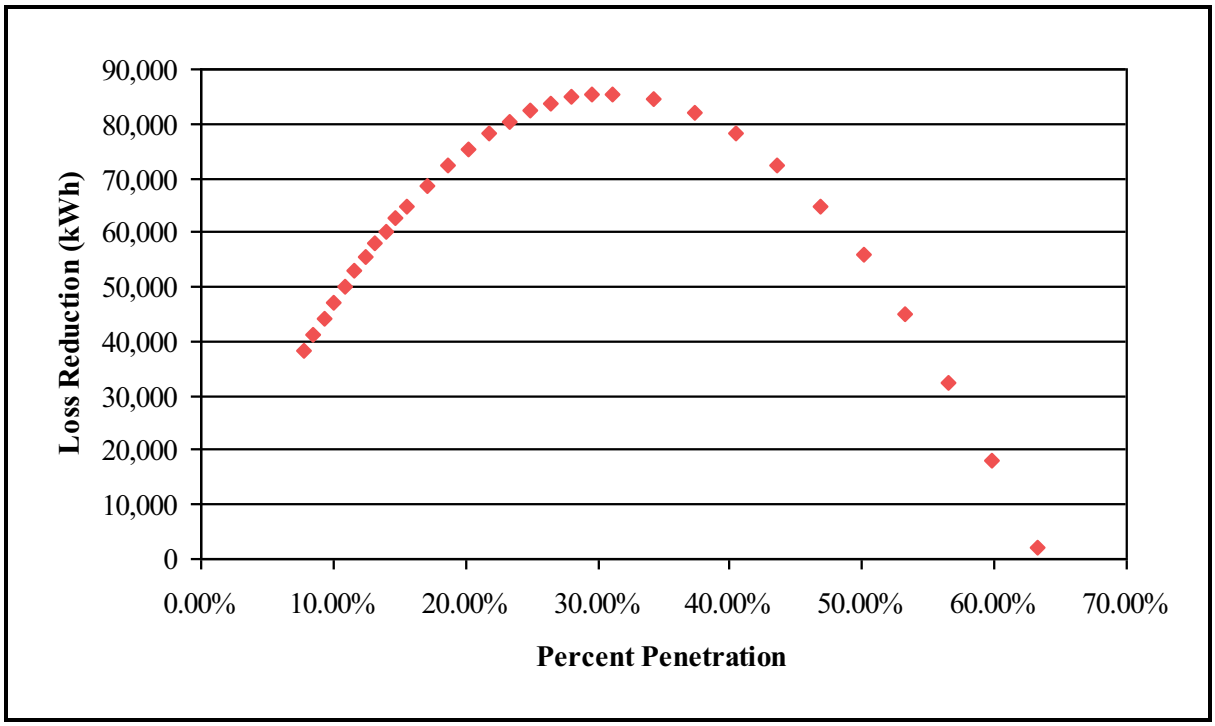


On the other hand, as the percent penetration level of distributed PV on a given feeder increases it becomes more and more likely that power will be exported to the rest of the system from PV generation. This does not pose an upper limit for PV penetration but does start to show a reduced efficiency in terms of feeder losses. Figure 6-20 shows an example of how increasing PV penetration level can affect feeder losses, based on an actual feeder from the CSI study group. This feeder has highly distributed PV installations (111 actual PV sites distributed throughout the feeder). As previously mentioned, the greatest loss savings are generally be expected on feeders with more highly distributed PV installations like this.

To develop Figure 6-20, the capacity of the actual PV sites on the feeder was varied over a wide range (in percentage point steps) and the impact on feeder loss savings graphed as shown. For this particular feeder the loss savings peak at around 30 percent PV penetration.[17] Above 30 percent the feeder loss savings begin to trail off. Some savings continue to occur until a little above 60 percent penetration, at which point the loss "savings" starts to go negative (i.e., this feeder would actually begin to see increased losses). The point at which this occurs will vary by feeder and depends on the relative positioning of the PV generation and loads on the feeder, and other factors described above in Figure 6-17 and Figure 6-18. Furthermore, it should be noted that Figure 6-20 only addresses feeder losses and not the impact on system-wide losses (including substation and transmission), which could continue to improve even at the higher PV penetration levels.

[17] Penetration level is defined here as equal to the installed PV Capacity expressed as a percent of the Peak Demand for the feeder.

Figure 6-20: Annual Loss Reduction by Percent Penetration (Feeder 16)



Composite Summary of Distribution Feeder Impact Factors

Based on the 2009 CSI feeder case studies, the team developed the table shown in Appendix F to provide a quick reference guide ("look up table") that can be used to estimate the capacity, energy, and loss impacts of distributed PV generation on any distribution feeder in California that has one of the combinations of attributes shown. The chart provides an easy way to estimate these impacts on the feeder, for essentially any amount of installed PV generation, as long as a feeder matches one of the combinations of feeder characteristics shown in the chart.

While detailed analysis of a feeder and its specific PV sites is needed to confirm the precise impacts, this chart provides utility planners and policy makers with a convenient tool for estimating and/or ranking such impacts. However, in cases where there is a very high PV penetration level (e.g., over 50-60 percent of feeder demand), unique impacts are likely to occur and should be studied in more detail.

Impact of PV during Electrical Faults

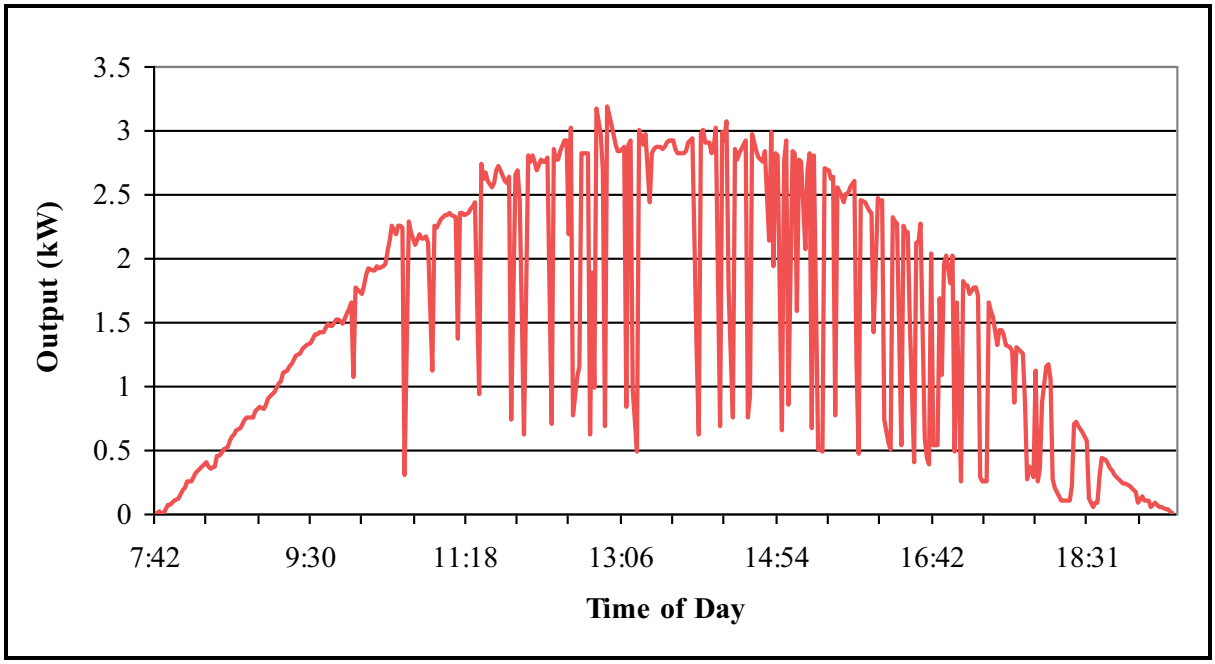
It is not uncommon for PV generation to trip instantaneously when a remote system fault (e.g., short circuit) or other types of system disturbances occur. In particular, faults on both the transmission or distribution system are common and result in voltage sags that can cause

distributed PV units to trip. Once tripped, the PV site would generally stay off-line for some period of time before being allowed to restart. Depending on the penetration level, the loss of the PV generation could create significant impacts on the distribution feeder since the loss of the PV generation might cause a further voltage drop on the feeder. This in turn may trigger response by automated feeder voltage control systems, or manual actions by system operators. Thus additional voltage adjustment actions may occur during both the initial loss of PV generation, as well as during the subsequent restarting of the distributed PV units. These impacts may be further amplified by the collective response of PV units over a larger area (e.g., an entire substation or a collection of substations), depending on the location and magnitude of the initiating fault. However, analysis of the risks and impacts of such widespread events is beyond the scope of the current study.

Voltage Regulation

PV generation is also subject to rapid output variations due to cloud cover.[18] The generator output can modulate from 100 percent of capacity down to 30-40 percent of capacity within a minute, dependent on the size of the PV site and the type of cloud cover conditions. Figure 6-21 shows an example of how high and fast moving cloud cover may create variation in output for a sample PV location.[19]

Figure 6-21: PV High Sample Rate Output Curve



[18] E.C. Kern, E.M. Gulachenski, G.A. Kern, "Cloud Effects on Distributed Photovoltaic Generation: Slow Transients at the Gardner, Massachusetts Photovoltaic Experiment", IEEE Transactions on Energy Conversion, Vol. 4, No. 2, June 1989, pp. 184-190.

[19] Note that data are not currently available at this high sampling rate for actual CSI units.

Such rapid swings in PV power output can have a negative impact on the distribution system. This type of event was simulated for a representative California feeder. In order to perform an analysis of these impacts, the random PV output curve of Figure 6-21 was replaced by a more uniform PV Duty Curve as shown in Figure 6-22. This assumption greatly simplified the modeling process, but still provides a reasonable proxy for the random curve. The curve assumes the PV site is generating 100 percent power at the start of the simulation (5 minutes). Then for 5 minutes, the PV site output is transient in nature swinging from 100 percent to 40 percent for 4.5 cycles. The site then outputs 40 percent power for 10 minutes and then goes into the transient period again for 5 minutes—ending up at 100 percent power for 5 minutes. This is a hypothetical example to show how the variation impacts feeder voltage regulation.

Figure 6-22: PV Duty Curve

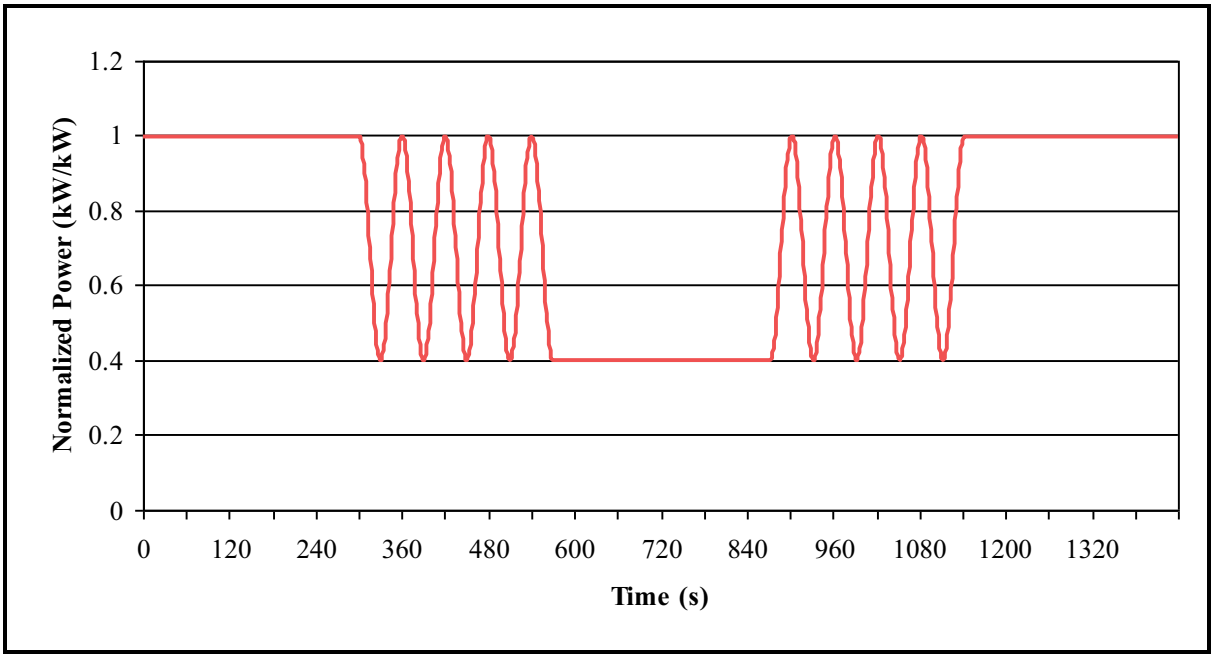


Table 6-11 shows estimates of the number of distribution voltage regulator tap changes per day based on simulation of the cloud cover conditions described above. Tap changes were calculated based on power flow simulation models using a typical load curve and a typical PV generation curve, with two voltage regulators on the given circuit based on modeling obtained from the California utility.

From the results shown in Table 6-11, it appears that the PV site could cause at least a 50 percent increase in regulator tap changes on the analyzed feeder. Such increases in the frequency of voltage regulator tap changes will accelerate the maintenance and replacement schedules for such distribution equipment.

Table 6-11: Estimated Tap Changes Per Day Example (Feeder 12)

		Phase A	Phase B	Phase C	Total
Regulator 1	Without PV	22	16	10	**48**
	With PV	36	28	22	**86**
Regulator 2	Without PV	8	4	6	**18**
	With PV	10	4	6	**20**

Feeder Selection and Modeling

Additional background on CSI 2009 feeder selection and modeling methodology is provided in Appendix G.