CALIFORNIA SOLAR INITIATIVE LOW- INCOME SOLAR PROGRAM EVALUATION

Program Impacts and Cost-Benefit Report
PROGRAM YEARS 2009-2010

Prepared for:

California Public Utilities Commission

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Executive Summary

Navigant Consulting, Inc., (Navigant) conducted an evaluation of the Single-Family Affordable Solar Housing Program (SASH) and the Multifamily Affordable Solar Housing Program (MASH) for the Energy Division (ED) of the California Public Utilities Commission (CPUC). This report is the third in a set of reports delivered as part of the current program evaluation cycle and summarizes findings of the impacts and cost-benefit analyses for the SASH and MASH programs during the 2009 and 2010 program years.

The California Solar Initiative (CSI) provides solar rebates to customers of the investor-owned utilities (IOUs) in California to increase the adoption of solar energy in California. The CSI includes components for low-income single-family homeowners and multifamily affordable housing:

» The SASH program provides financial assistance for the installation of solar photovoltaic (PV) generating systems on qualifying affordable single-family housing. SASH is implemented statewide by GRID Alternatives, a nonprofit solar provider whose mission is to "empower communities in need by providing renewable energy and energy efficiency services, equipment and training."[1]

» The MASH program provides financial assistance for the installation of PV systems on low-income multifamily housing. MASH is implemented by three Program Administrators— Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and the California Center for Sustainable Energy (CCSE) in the service territory of San Diego Gas and Electric (SDG&E).

Key SASH Findings

» The SASH program installed 330 sites in 2009 and 2010, providing 840.6 kW of interconnected[2] capacity. The rate of new system installations is following a steadily increasing trend.

» Those 330 sites generated approximately 626 MWh of electricity through 2010.

» The weighted average annual capacity factor for SASH systems in 2010 was 16 percent.

» At the time of CAISO peak, Navigant models estimated a peak demand reduction of about 26 kW in 2009, with a capacity factor of 56 percent at the time of peak. In 2010, the 214 systems installed at the time of CAISO peak were responsible for an approximate 208 kW peak reduction, with a peak capacity factor of approximately 39 percent.

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[1] Grid Alternatives. 2010. "Grid Alternatives: Mission, History, and Future." Available: http://www.gridalternatives.org/mission-history

[2] An "interconnected" project is a PV system that has been installed, rebated, inspected by a third-party inspector, tied to the utility grid, and is expected to be producing power. A project that does not meet all of the requirements of an interconnected project is considered "in process".

» The SASH program solar systems are responsible for 300.6 tons of CO_2 emissions reductions in 2009 and 2010.

» A field evaluation of the SASH systems showed that systems are generally operating as expected, with the exception of a small number of sites with wiring issues.

» In 2010, SASH participants saw a typical annual bill reduction of approximately $336; participants who also participated in the LIEE program saw only modest bill reductions from LIEE as compared to the SASH program.

» The SASH program is cost effective from the participant perspective, but not from the societal, program administrator, ratepayer or total resource perspectives.

Key MASH Findings

» Although the MASH program took longer to deliver installed systems due to the size and complexity of projects, it has surpassed SASH projects in terms of the installed capacity and the capacity in process.

» There were no MASH projects interconnected in 2009. In 2010, there were 34 projects interconnected, while 291 projects were in process as of January 1, 2011.

» The 34 projects interconnected in 2010 are responsible for about 1,846 kW of installed capacity.

Recommendations

Navigant recommends that the centralized SASH and MASH data system (Salesforce.com and Power Clerk, respectively) be used more effectively as a data management tool to maximize transparency while minimizing the introduction of clerical errors, as well as significantly reducing evaluation labor.

Each project file and database records should provide a clear "paper" trail documenting the evolution of the project over the course of the program process and a clear process for the project documents resulting from third-party inspection findings should be developed and followed. Metrics reporting the inspection findings, including discrepancies at the individual line item level, should be easily identified and reported through program records.

To identify wiring and connectivity issues that develop after system installation and inspection, Navigant recommends that each SASH system owner be given a customized production target number to ensure the customer is aware when the system is not producing its target power.

The method for calculating the SASH design factor should be modified.

Navigant does not believe that is it necessary to subject SASH to a higher inspection rate than the general market CSI program, provided that certain modifications are made:

- The sample of inspections must be selected independently and a sampling protocol developed;
- The third-party inspection should feed directly to the SASH database without GRID intervention; and

- Finally, the third-party inspection findings and failure rate should be monitored on an ongoing basis.

Additional training should be conducted for the SASH third-party inspectors on the inspection protocols to ensure that they are followed consistently.

Introduction

Navigant Consulting, Inc., (Navigant) conducted an evaluation of the Single-Family Affordable Solar Housing Program (SASH) and the Multifamily Affordable Solar Housing Program (MASH) for the Energy Division (ED) of the California Public Utilities Commission (CPUC). This report is the third in a set of reports delivered as part of the current program evaluation cycle and summarizes findings of the impacts and cost-benefit analyses for the SASH and MASH programs during the 2009 and 2010 program years.

Program Background

The California Solar Initiative (CSI) provides solar rebates to customers of the investor-owned utilities (IOUs) in California to increase the adoption of solar energy in California. The CSI includes components for low-income single-family homeowners and multifamily affordable housing:

» The SASH program provides financial assistance for the installation of solar photovoltaic (PV) generating systems on qualifying affordable single-family housing. SASH is implemented statewide by GRID Alternatives, a nonprofit solar provider whose mission is to "empower communities in need by providing renewable energy and energy efficiency services, equipment and training."[3]

» The MASH program provides financial assistance for the installation of PV systems on low-income multifamily housing. MASH is implemented by three Program Administrators—the California Center for Sustainable Energy (CCSE) in the service territory of San Diego Gas and Electric (SDG&E), Pacific Gas and Electric (PG&E), and Southern California Edison (SCE).

The CPUC established the CSI in early 2006 in Decision 06-01-024[4]. Decision 06-01-024 included a provision to set aside a minimum of 10 percent of CSI program funds for projects installed by low-income residential customers and affordable housing projects. Later in 2006, the California Legislature codified this low-income funding requirement in Senate Bill (SB) 1(Murray, 2006) and Assembly Bill (AB) 2723 (Pavely, 2006). Subsequently, in Decision 06-12-033[5], the CPUC directed the PAs to conform the CSI program to the SB 1 and AB 2723 requirement that 10 percent of the CSI budget be reserved for the single-family and multifamily low-income residential solar incentive programs. On November 16, 2007, the CPUC established the $108.34 million SASH program. The administration of the SASH program was awarded to GRID Alternatives, and the program began accepting applications in May of 2009. On

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[3] GRID Alternatives. 2010. "GRID Alternatives: Mission, History, and Future." Available: http://www.gridalternatives.org/mission-history

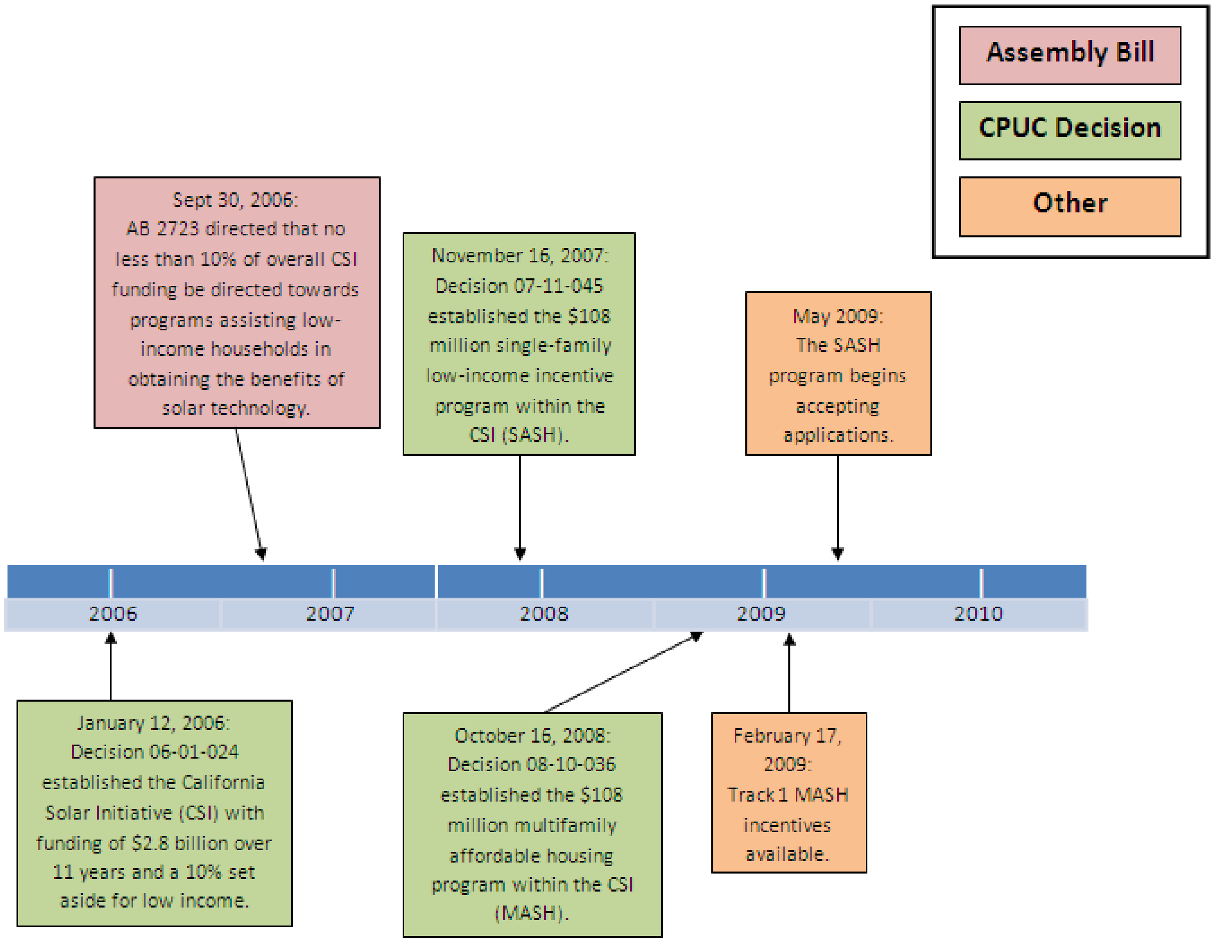
[4] CPUC Interim Order Adopting Policies and Funding for the California Solar Initiative, January 12, 2006.

[5] CPUC Opinion Modifying Decision 06-01-024 and Decision 06-08-028 in Response to Senate Bill 1, December 14, 2006.

October 16, 2008, in Decision 08-10-036[6], the CPUC established the $108.34 million MASH program. Track 1 incentives were first available on February 17, 2009.

Figure 1 below summarizes the key milestones in the SASH and MASH development.

Figure 1. CSI Low Income Program Timeline



Source: CPUC D. 06-01-024, 07-11-045, 08-10-036, AB 2723, and interviews with MASH and SASH Program Administrators.

Research Objectives

In addition to the overarching goal to identify opportunities to improve the SASH and MASH programs, the program impacts evaluation and cost benefit assessment objectives were to study the following:

[6] CPUC Decision Establishing Multifamily Affordable Solar Housing Program within the California Solar Initiative, October 16, 2008.

A. Develop realization rates from the field verifications for the following:
    i. Differences between general market program and low income;
    ii. Prevalence of theft or vandalism; and
    iii. Installed system performance and maintenance adequacy;
B. Determine the mean variation between the expected (simulated) first-year overall energy production (kWh) and actual kWh (realization rate, no degradation);
C. Determine customer bill impact due to:
    i. The PV system only; and
    ii. The PV system and installed LIEE measures;
D. Estimate peak (kW) reductions coincident with the CAISO system peak and IOU peaks;
E. Estimate greenhouse gas (GHG) reductions resulting from program impacts; and
F. Prepare a cost benefit analysis that conforms to CPUC Decision 09-08-026.[7]

At the time the evaluation scope was established, very few MASH projects were projected to be completed by the end of 2010. Therefore, the scope of the MASH evaluation was limited to high-level program summaries and an analysis of the MASH third-party inspection process. A more complete study of MASH impacts should be conducted in the future when a greater number of projects have been completed.

As the SASH study progressed and Navigant was able to review the available program information, the research objectives evolved to match available data and program complexity. As a result, the following changes were made to the research objectives:

» A comparison of SASH to the CSI general market program requires the 2010 CSI general market program report results, which were pending release at the time of this draft report. Navigant will include this comparison if the 2010 CSI general market program results are available at the time of the final report.

» A program-level realization rate was not calculated because a clear estimate of expected energy production was not available. Instead, using the verification rates from the field verifications along with 8760-hour modeled expected system production using actual weather and verified system conditions, Navigant estimated program energy impacts and associated program-level capacity factor.

» The original work plan specified estimates of CAISO and IOU peak reductions. Unfortunately, uncertainties around modeling assumptions did not allow for reliable IOU-specific system peak reduction estimates. Therefore, Navigant estimated only CAISO peak reduction in this report.

[7] California Public Utilities Commission Decision Adopting Cost Benefit Methodology for Distributed Generation, August 20, 2009.

Report Organization

Four sections follow this introduction:

- Section 2, Evaluation Methodology, described the methodologies used for the SASH field verifications, and impact and cost benefit analysis.
- Section 3, SASH Findings, describe the findings relevant to the SASH program.
- Section 4, MASH Findings, describe the findings relevant to the MASH program.
- Section 5, Recommendations, summarizes Navigant's recommendations for program modification.

Evaluation Methodology

This section describes the methodology used to conduct the SASH field verifications, and impact and cost benefit analysis.

SASH Field Verification

Sampling Approach

The goal of the field inspection sampling was to obtain a 90/10 confidence/precision on the ratio of the estimated design factor (as determined from modeling) after field inspection to the initial estimate—what we refer to below as the design factor verification rate, or "verification rate". To obtain the appropriate sample size, Navigant first obtained estimates of the coefficient of variation, or alternatively the mean and variance of this ratio in the population. To this end, Navigant drew on information from the CSI General Market Program. Figure 4.5 in the 2007-2008 CSI Impact Evaluation by Itron[8] (Itron Report) gives mean and confidence intervals for actual and estimated annual capacity factors. Navigant was mainly interested in the mean and variance of the ratio of these values, $C_{actual}/C_{estimated}$ because they bear on the mean and variance of the verification rate assumptions we make to recover these values:

- Errors in estimated are attributed entirely to site-related solar variation due to system installation characteristics.
- For a given system the capacity factor error due to solar variation is exactly the same for actual and estimated; the total actual capacity factor error is the sum of the error due to solar variation and the error due to behavioral/system unobservable variables, and this error is uncorrelated with the error due to solar variation.

The effect of these assumptions is that deviations from actual mean capacity factor can be specified as

$$\begin{aligned} &\varepsilon_{Actual} = \varepsilon^{SV} + \varepsilon^{Other}_{Actual} \\ &\varepsilon_{Est} = \varepsilon^{SV} \qquad , \\ &\Rightarrow \varepsilon_{Actual} = \varepsilon_{Est} + \varepsilon^{Other}_{Actual} \end{aligned} \tag{0.1}$$

And given the third assumption, the population standard deviation on actual and estimated annual capacity factor is,

$$\begin{aligned} &\sigma_{Est} = \sigma^{SV} \\ &\sigma_{Actual} = \sigma^{SV} + \sigma^{Other}_{Actual} \end{aligned} \tag{0.2}$$

[8] CPUC California Solar Initiative Final 2007-2008 Impact Evaluation. Itron, Inc., February 2010.

Navigant deduced σ^{SV}_{Error} from Figure 4.5 in the Itron Report. The figure generates a mean CF of .189 with a 90 percent confidence interval of .007. Dividing this CI by 1.65 gives an estimate of the standard error of the estimate, .0042. This standard error is related to the population standard deviation by,

$$\begin{aligned} SE^{SV} &= \frac{\sigma^{SV}}{\sqrt{N}} \\ \Rightarrow \sigma^{SV} &= SE^{SV} \cdot \sqrt{N} \end{aligned} \quad . \tag{0.3}$$

Given N=666 (from Table 3.1 of the Itron Report), $\sigma^{SV} = .108$.

Now consider the standard error for mean actual capacity factor; as reported in Figure 4.5 of the Itron report it is approximately .012/1.65=.0073. Multiplying this value by the square root of N=666 yields the estimate of the standard deviation of actual capacity factor within the population, $\sigma_{Actual} = .188$.

Subtracting from this value the estimated population standard deviation for solar variation, $\sigma^{SV} = .108$, yields the result $\sigma^{Other}_{Actual} = .08$.

Now consider the realization rate $R = {CF_{Actual}}/{CF_{Est}}$. As calculated from Figure 4.5 of the Itron Report the expected realization rate is $\bar{R} = \frac{\overline{CF}_{Actual}}{\overline{CF}_{Est}} = .952$.

The approximate population variance on this ratio is (this value is exact if the population is normally distributed),

$$\begin{aligned} VAR\left(\frac{CF_{Actual}}{CF_{Est}}\right) &= \left(\frac{\overline{CF}_{Actual}}{\overline{CF}_{Est}}\right)^2 \cdot \left(\frac{VAR\ \ CF_{Actual}}{\overline{CF}^2_{Actual}} + \frac{VAR\ \ CF_{Est}}{\overline{CF}^2_{Est}} - \frac{2COV\ \ CF_{Actual}, CF_{Est}}{\overline{CF}_{Actual} \cdot \overline{CF}_{Est}}\right) \\ &= \left(\frac{\overline{CF}_{Actual}}{\overline{CF}_{Est}}\right)^2 \cdot \left(\frac{\sigma^2_{Actual}}{\overline{CF}^2_{Actual}} + \frac{\sigma^{SV\ \ 2}}{\overline{CF}^2_{Est}} - \frac{2\ \ \sigma^{SV\ \ 2}}{\overline{CF}_{Actual} \cdot \overline{CF}_{Est}}\right) \end{aligned} \tag{0.4}$$

Given the values presented above, our best estimate on this variance is:

$$VAR\left(\frac{CF_{Actual}}{CF_{Est}}\right) = \left(\frac{.18}{.189}\right)^2 \cdot \left(\frac{.0353}{.0324} + \frac{.0117}{.0357} - \frac{.0233}{.034}\right) = .666 \tag{0.5}$$

Calculating the necessary sample size for the evaluation

To calculate the necessary sample size, Navigant proceeded on the assumption that the population mean and variance for the capacity factor realization rate in the CSI General Market Program, .952 and .666, are roughly the same as those for the design factor realization rate, i.e. the ratio of the *actual* design factor to the initial estimate of the design factor. (Please note the distinction between this value and what we call the verification rate, which is the ratio of the *re-modeled* design factor after inspection to the initial estimate of the design factor.) This assumption is reasonable because for any given household the ratio $CF_{actual}/CF_{estimated}$ is equal to the ratio of the *actual* design factor to the initial estimate of the design factor, and a priori, Navigant had no reason to believe that the population mean and variance of this ratio is any different for low-income households than it is for the general population.

For the purpose of sample size estimation, Navigant assumed that the design factor verification rate was unbiased. That is, Navigant assumed that the model estimate of system output using the information obtained upon inspection is correct on average, in which case the mean verification rate is equal to .952. We also assumed that site inspections will account for 2/3 of the variation in design factor realization rate; in other words, a considerable amount of the variation in the design factor realization rate is due to factors accounted for during the inspections. In this case our estimate of the variance for the verification rate is $.666 \cdot .666 = .443$. The implication is that the coefficient of variation is $\sqrt{.443} / .952 = .80$, implying a *target* 90/10 random sample size of 87. Note that the actual Navigant sample size for the field verification was 86, which was large enough to achieve the target 90/10 confidence/precision on design factor verification rate.

Stratification

Stratified random samples can produce estimates with smaller coefficients of variation than simple random samples. This characteristic makes them an efficient sample design since greater precision and reliability can be gained from a smaller sample size.

The stratification variables for the SASH field verification study were:

1. IOU territory
2. Rebated capacity (per application)
3. Climate

Table 1 shows the strata categories used in the verification.

Table 1. Verification Strata

	Investor Owned Utility					
Climate	PG&E		SCE		SDG&E	
Inland	< 2kW	> 2kW	< 2kW	> 2kW	< 2kW	> 2kW
Coastal	< 2kW	> 2kW	< 2kW	> 2kW	< 2kW	> 2kW

The final sample was pulled randomly within each stratum. This was accomplished by assigning a random number to each site, and sorting the sites in order of this random number from smallest to largest. The sites encompassed by the quantity specified in the sample design were be assigned a “1”. All others in the stratum will be assigned a “2”.

Recruiting

Recruiting sites for field data collection was conducted in the most convenient manner (i.e., logistics, scheduling, and geography will be taken into account) for all sites assigned a “1”. If a site was dropped from the sample for whatever reason, such as non-response or refusal to participate in EM&V, then the next site in the list that was assigned a "2"for that particular stratum was included in the primary sample.

To facilitate recruiting and minimize dropouts, a 50 dollar gift card was offered to each participant.

Data Collection Field Guide

The Data Collection Field Guide is included as an appendix (Appendix A) to this report. The field guide, or "protocol", indicates to the field personnel whether they should be collecting nameplate data, conducting spot measurements, or verifying system installation conditions. It also indicates how to fill out the forms, and what to do with the data once it has been collected. Quality control (QC) points were integrated into the onsite forms to ensure that field technicians do not overlook any data points. Wherever possible, the collection of existing forms, either currently being used by the CSI program or previously developed by Navigant staff, were leveraged to reduce cost for this study.

The following data were collected during the verification site visits. The field guide provides more specific information including site data collection forms and methods, a data collection system/warehouse specification, equipment needs, protocols for collecting/storing data, and quality control methods.

1. Verify that all assumptions that were used in the EPBB model (as documented in the site inspection report) are still intact:
    a. Nameplate PV module
    b. # modules
    c. Nameplate PV inverter
    d. # inverters
        i. Shading derate factors for each month
        ii. Follow protocols laid out in the field inspection protocol; average shading of four corners of array or other methods
    e. Tilt
    f. Azimuth
2. Note of any damage, evidence of tampering/theft/vandalism
3. Note residence characteristics
4. Note of levels of soiling on surface
5. Spot measurement at inverter, or read output off inverter (if available)
6. Note production-to-date (if available)
7. Note any other possible contributing factors to loss (or gain) of production

Data Management and Flow

Field activities were managed using Navigant's proprietary, web-enabled tool, Field Activity and Communications Tracker (FACT). FACT served as a central hub for all informational needs related to field data collection activities, including scheduling site visits, recording comments from customers, downloading the most up-to-date field forms, data entry, uploading pictures or other data files from the field, and reporting on progress.

Perhaps most importantly, the FACT system allows for data gathered from the field to be entered directly into the electronic database from any location with an Internet connection. This provided many quality control benefits, such as:

» Data collected in the field undergoes a near "real-time" QC process as reviewed by the project manager on a weekly basis. The project manager reviews data for incomplete data sets and values that are outside of expected ranges.
» Provides a web based data warehouse so that all EM&V staff are entering data into a single file, thus avoiding version problems associated with distributed tools, such as Access or Excel models.
» The most up-to-date data can be extracted at any time and used for various purposes, such as interim analysis to confirm evaluation results.

The screens making up the data entry system actually mimic the look and feel of the onsite forms so that data can easily be transferred by anyone with the proper access levels. All inputs to the data entry system are bounded and validated to ensure data integrity. For example, dropdown menus are used whenever there is a finite number of answers to a particular data point, thus ensuring that "data cleaning" activities are kept to a minimum.

The database itself is housed at a server farm with several backup mechanisms, and the FACT developer gets backups of the entire database daily. The system is password protected, and users can be assigned various levels of access. For example, a scheduler may only be allowed to access the scheduling screens of the system, thus ensuring a minimum of opportunities for data to be accidentally changed by anyone without the proper access.

This valuable tool has been used in many impact and process evaluations, as well as potential studies. It has been used to record both onsite data points, and data from telephone interviews.

Quality Control

Data entry occurred nightly by the field crew. The next business day, a Navigant analyst reviewed the data following a quality control procedure to ensure that the data was being collected and entered properly and to clarify any doubts and correct any issues while data collection is still ongoing. The QC team contacted the field crew promptly to discuss any issues.

Site Visits

Once the initial forms, procedures, and FACT system were drafted, the project team conducted preliminary site visits to pilot the proposed Data Collection Plan. A small number of pilot site visits bears great value over the course of full deployment. Preliminary site visits almost always reveal inefficiencies in the draft procedures, and by conducting these as part of a pilot, they can be quickly and easily remedied.

Once the procedures were piloted and fully vetted, Navigant trained its field technicians in the final data collection methods. Training ensures both quality and consistency of work across all staff conducting the field work. All personnel that collect data in the field were required to attend training. The finalized field protocols were provided in advance of the training so that staff could become familiar with procedures and come with informed questions. The training sessions covered everything the field technician must know in order to successfully complete the engagement, including appropriate customer interactions, how to fill out the forms, how to conduct spot measurements and use a SunEye™, and how to make sure the data collected in the field was transferred to the FACT system and the project managers.

After the pilot site visits and training, Navigant began full deployment of the site visits. Navigant utilized local resources familiar with local conditions wherever possible for the measurement and verification activities, which also served to reduce travel costs.

Final Disposition of Field Verifications

During July and August of 2010, Navigant-trained field crews completed field verifications of 86 SASH sites. These sites represent roughly a quarter of all SASH systems installed during 2009 and 2010. Figure 2 shows the breakdown of Navigant-visited sites in relation to the SASH participant population.

Figure 2. Number and Percentage of SASH Sites Verified

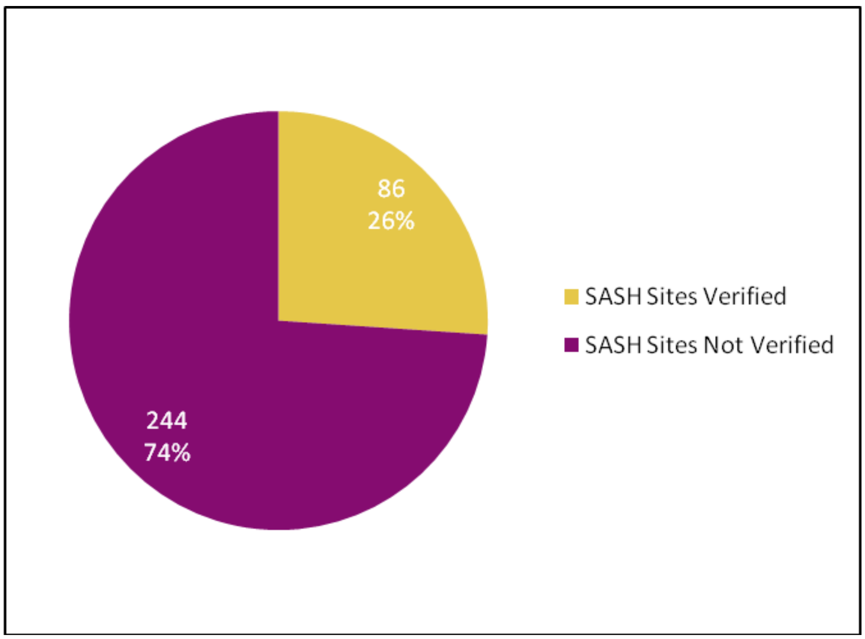


Table 2 and Table 3 show the breakdown of verified sites by IOU and relative system size, two characteristics used to stratify the random sample in an effort to reduce bias. A detailed discussion of the stratification used for sampling is presented below.

Table 2. Verified Number of Sites and Capacity as Compared to the Overall SASH Numbers by IOU

	Verified Sites		All SASH Sites	
System Size	# of Projects	Capacity (kW)	# of Projects	Capacity (kW)

PG&E	49	128.1	174	466.8
SCE	21	48.5	92	242.4
SDG&E	16	30.6	64	131.4
Total	86	207.2	330	840.6

Table 3. Verified Number of Sites and Capacity as Compared to the Overall SASH Numbers by System Size

	Verified Sites		All SASH sites	
System Size	**# of Projects**	**Capacity (kW)**	**# of Projects**	**Capacity (kW)**
<2 kW	36	56.6	141	220.5
>2kW	50	150.5	189	620.1
Total	86	207.2	330	840.6

SASH Impact Methodology

This section describes these analysis methodologies, data quality findings, and data processing methods that support the SASH impact analysis.

Data Processing

Analysis Software

With the exception of the hourly PV production modeling, all analysis was done using SAS statistical software. SAS has the ability to interface with Navigant's online FACT, facilitating real-time QA/QC of incoming data during the field study. Also, SAS has the ability to handle large data files of the size generated by the batch PV modeling software and hourly shading files generated by the handheld shading devices.

Field Data

The data collected from the field study went through an extensive QC process to assure that the inputs to the model and to the Design Factor verification calculations were valid and reasonable. The following list outlines the QC and data prep methodology used after the field work was complete.

1. QC and analyze the field collected data:
    a. Analyze failed spot measurements
        i. Sort out major issues (wiring, switches, interconnect, etc)
        ii. Summarize minor issues
            1. Time of spot measurement vs. azimuth
            2. Array shaded during measurement
            3. Soiling
            4. Power Factor
        iii. Didn't do spot measurement (roof unsafe)

   b. Check for discrepancies in reported values against verified values
      i. Equipment make/mfg reported incorrectly
      ii. Tilt off by >3 degrees
      iii. Azimuth off by >5 degrees
      iv. Monthly shading values off by >5 percent
      v. Number of arrays reported incorrectly
2. Manually verify all issues in 1(a) and 1(b) above
   a. Examine the data
      i. Go to Navigant forms/photos, look at notes
      ii. Go to original install data
      iii. Go to 3rd party verification forms
   b. For 2(a), track statistics for findings
   c. For 2(b), sort into:
      i. Sites without discrepancies
      ii. Sites with minor discrepancies in reported values
         1. run EPBB calculator with all original installer data except contested values
         2. Determine a per-site ΔDF
         3. Determine verification rate
            a. Per-site
            b. For sampled population

Weather data

Actual hourly weather data was downloaded from the California Irrigation Management Information System (CIMIS) for 2009 and 2010. The network has 120+ stations spread geographically across California in order to provide relevant meteorological data for making decisions about irrigation practices throughout the state. The data available at CIMIS weather stations contains most of the required inputs to the hourly solar PV model. Although the weather stations collect a wide range of data, the following list shows the data collected at each station that are relevant to the modeling effort:

- Total Horizontal Solar Radiation
- Dry Bulb Temperature
- Dew Point Temperature
- Relative Humidity
- Wind speed

After downloading hourly data for all active CIMIS weather stations, the analysis team cleaned the data with the following algorithm:

1. Values outside reasonable ranges expected for the California climates were set to missing.
   a. Solar radiation values greater than 1350 W/m^2 and less than 0 were discarded
   b. Temperatures below -50 and above 150 degrees F were discarded.
   c. RH values outside the range 0-100 percent were discarded.
2. Data interval between observations was checked.

   a. If more than one observation occurred in one hour, the values were averaged for that hour.
   b. If observations were more than an hour apart, data was interpolated according to step 3 below in order to create 8760 continuous values.
3. Missing data Interpolated/filled (missing data represented less than 1.2 percent of the data points).
   a. Data gaps of 3 hours or less were interpolated using the spline interpolation method.
   b. Data gaps of longer than 3 hours and less than 96 hours (4 days) were filled using the average of that particular hour, 2 days before and after the day in question.
   c. Data gaps of more than 4 days but less than 20 days were filled replacing the missing days with the nearest full day of data (forward or backwards).
   d. Stations with data gaps of 20 days or longer were thrown out.

All of the CIMIS data was directly input into the model without modification except solar radiation. Most PV solar models, including the model used for this study, require that the beam and diffuse components of solar radiation be separate inputs. Because the instrument necessary to collect beam solar radiation data separately (called a pyrheliometer) is much more expensive and difficult to maintain than a normal pyranometer, standard methods for decoupling the beam and diffuse components of the solar radiation exist. For this study, the Boland-Ridley-Lauret (BRL) model was used which, like many models, uses the clearness index to predict the diffuse component. However, the BRL uses dynamic predictors such as solar time and altitude angle, as well as a persistence factor to more accurately decouple the diffuse component from total horizontal radiation on shorter time intervals (hourly, for instance, which is required for the PV model used in this study).[9]

Once the weather data was cleaned, each SASH site was matched with the closest CIMIS weather station, using a database of latitude and longitude associated with U.S. zip codes. The formula used to calculate distance between two points is called the "great circle formula". The average distance from a modeled SASH site to the nearest weather station was 10 miles, with a standard deviation of 7 miles. The range of distances was 1 to 24 miles. The distance of a site from the nearest weather station is important because solar radiation varies geographically, especially on partly cloudy days. This primarily affects the peak demand impacts results, as the output of the system is required on a particular hour of a particular day. Estimating the uncertainty associated with this approach would be an involved and time-consuming process, beyond the budget and scope of this study. Therefore, energy, demand, greenhouse gas, and billing impacts are reported without estimated uncertainty.

8760 Hourly Model

The analysis team selected the National Renewable Energy Laboratory (NREL) System Advisor Model (SAM) to conduct the 8760 hourly PV production modeling. SAM has an advanced equipment-based modeling capability, which draws on a database of empirically determined PV and inverter characteristics in order to more accurately simulate PV system performance. SAM also has a scripting

[9] Ridley, B., Boland, J., and Lauret, Philippe. *Modeling of Diffuse Solar Fraction with Multiple Predictors.* Renewable Energy. Vol. 35 pp 478-483. 2010.

interface called SAMul (System Advisor Model User Language) which allowed the analysis team to set up batch model runs, facilitating a more coordinated modeling approach.[10]

Using system characteristics provided by GRID alternatives and verified by the field study, along with built-in Typical Meteorological Year (TMY) weather data and actual weather data from the CIMIS stations, the analysis team generated three hourly output shapes for the 86 sites from the field study:

1. TMY
2. 2009 (actual weather)
3. 2010 (actual weather)

Additionally, GRID Alternatives provided Navigant with the third-party inspection forms for those original 86 sites as well as 100 other sites in the SASH program at the time of the data request (June 2010). The third-party inspection form for each site has enough critical information—such as tilt, azimuth, shading, equipment make/model and quantities—to provide inputs for the 8760 SAM model. When the model was run in batch mode, the hourly kWh production results were automatically sent to text files which were in turn read into SAS for analysis.

Extrapolation of Hourly results to full SASH population

To enable a batch process of applying results from the field verification study to all sites, including those for which system characteristics data were unavailable, Navigant developed an 8760 hourly verification rate shape. By setting up separate runs for each case (Navigant-verified characteristics vs. GRID-reported characteristics), the analysis team was able to generate an hourly verification rate for each of the visited/verified SASH sites—86 of the 330 sites. By applying these hourly verification rates to the 100 sites modeled only with the provided third-party inspection forms, Navigant was able to obtain 8760 verified hourly production curves for each of the 186 sites for which site characteristics were available. In order to generate hourly data for the remainder of the SASH sites for which third-party inspection forms were not available (144 sites), a typical, normalized hourly production curve was generated for each California climate zone using actual weather data, and then applied and scaled to the unknown sites in those climate zones.

The final step in generating realistic 8760 curves was to account for the utility interconnection dates of each system. This was accomplished by setting hourly production values to zero before for all hours before the installation date for the 2009 and 2010 modeled weather data. The modeled results using typical meteorological year (TMY) data were kept as full year production for use with calculating typical annual billing impacts. However, the abbreviated 2009 and 2010 production shapes were used for calculating the energy, demand, capacity factor, and greenhouse gas impacts.

Design Factor Verification Rate

Each SASH installation is required to have a calculated modified Design Factor of 0.95 or higher to be eligible for the SASH incentive. Navigant's verification rate of the Design Factor was based on field visits

[10] https://www.nrel.gov/analysis/sam/

to verify system characteristics, and subsequent Expected Performance-Based Buydown (EPBB) calculator runs to recalculate Design Factor. The hourly model designed above was not used in the calculation of program-wide Design Factor verification rates, as DF is a CSI-specific parameter used in qualifying CSI projects and is only available via the EPBB calculator. The following equation shows how the verification rate was calculated for each visited site:

$$VR_{site} = \frac{DF_{site,Navigant}}{DF_{site,3rd\ party}}$$

The IOU-wide and Program-wide Verification Rates were calculated by using a weighted average by system size (CEC-AC rating), so that larger systems contributed more to the overall average. The following equation shows the weighting process for the program level DF Verification Rate:

$$VR_{Program} = \frac{\sum_{i=1}^{\#\ of\ sites} VR_i \times CECAC_i}{\sum_{i=1}^{\#\ of\ sites} CECAC_i}$$

Where:

- VR_i is the site-level verification rate
- $CECAC_i$ is the site-level CEC-AC rating, in kW

Sampling precision for the field verification of the Design Factor was determined for the overall population using a 90 percent confidence interval. Precision values were calculated using ratio estimation. Variance for the precision calculations was based on the population's Coefficient of Variation of verification rates about the unweighted program mean.

Energy

Using the 8760 hourly energy production shapes, along with applied hourly verification rates detailed above, calculating the energy impacts for 2009 and 2010 involved summing up the hourly production curves by IOU and separately by quarter. Keep in mind that the annual production curves for 2009 and 2010 only contain values during the hours *after* the system was installed and interconnected. This represents the analysis team's best estimate of actual SASH system-wide production during the first two years of the program.

Capacity Factor

Capacity factor is a ratio of the actual output of a system during a specified time period to the theoretical rated capacity of that system during the same time frame. In simple terms, this is the equivalent fraction of the time the modules are producing the output rated at the Standard Testing Conditions (STC) of 1000 W/m^2 at 25° C. To calculate capacity factor, the CEC-AC rating of the system was used as the rated output for each hour, and summed over the desired time interval. The actual output was also summed over the same interval, and capacity factor was calculated as:

$$CF_{int} = \frac{\sum_{i=1}^{int} kWh_{prod,i}}{\sum_{i=1}^{int} CECAC_{site}}$$

Where:

- CF_{int} = Capacity factor calculated over a specific time interval

- kWh_{prod} = Actual kWh production during hour *i*
- $CECAC_{site}$ = CEC-AC Rating for the site

Demand

Peak demand events for 2009 and 2010 are in the table below.[11]

Table 4. CAISO Peak Definition for 2009 and 2010

Year	CAISO Peak
2009	September 3, 3:00 to 4:00 p.m. (PDT) [1]
2010	August 25, 4:00 to 5:00 p.m. (PDT) [2]

[1] *Source: Itron Report*
[2] *Source: CAISO website* (http://www.caiso.com/)

SASH demand reduction impacts during the CAISO peak hours were calculated by summing the modeled (actual weather) kWh energy production for those two hours by IOU and year. The model's 8760 results were all in PST (SAM does not account for daylight savings time), so this was accounted for before summing over the peak hour.

Greenhouse Gas

Greenhouse gas emissions impacts were based on the E3 CSI/SGIP Avoided Cost Calculator estimated CO_2 emissions curve (with units of tons CO_2/MWh) calculated from a mix of electricity generation sources across the state of California[12]. Navigant focused on CO_2 emissions. Those hourly CO_2 emissions values were overlaid with the kWh production curves for 2009 and 2010 and multiplied to get hourly CO_2 offsets, then summed by IOU for reporting.

Customer Bill Impacts

Navigant estimated SASH participant annual bill impacts in 2009 and 2010, attributable to participation in the SASH program only ("PV-only"), as well as participation in SASH and the LIEE program ("PV + LIEE").

Navigant's calculations for bill impacts take into account each site's installed PV capacity, typical local weather conditions, IOU-provided annual LIEE energy savings, and California Alternate Rates for Energy Program (CARE) status before and after upgrades. Navigant combined these site-specific conditions with calibrated residential Database of Energy-Efficient Resources (DEER) models' hourly energy loads, simulated hourly LIEE energy savings shapes, and hourly PV generation modeled through SAM. Navigant applied PG&E's residential CARE and non-CARE rates for tiered pricing for a base case, PV-only case, and PV+ LIEE upgrades case to every site. Navigant chose to apply PG&E rate schedules to

[11] For the 2009 CAISO peak hour definition, Navigant used the period defined in the Itron report to provide a basis of comparison for the SASH peak hour capacity factor. However, the CAISO indicates that the 2009 system peak occurred on September 3 at 16:17, PDT.
[12] E3 CSI/SGIP Avoided Cost Calculator, dated April 30, 2010.

reduce unnecessary levels of complexity. Additionally, the PG&E territory accounts for the majority of SASH participation. Finally, Navigant chose to base the analysis on a tiered residential rate structure, as SASH participants are not currently switching to a TOU structure as part of program participation.

Navigant then compared the PV only and PV+LIEE upgrades cases' annual energy costs to the base case annual energy costs for a site-specific typical weather year's energy consumption, PV generation, and energy savings shape.

Rate Schedules

Each IOU has a unique rate structure with its own definitions of baseline use, tiers, time-of-use, etc. Residential rate structures can quickly become complex; for example, baseline use definition can depend on many factors including HVAC type, zip code, elevation, and time of year. The SASH participation data contains data fields designed to represent the actual rate structure of each SASH participant before and after participation in the program; however, this data proved to be unreliable. Navigant made a simplifying assumption to use the PG&E residential rate structure to model SASH bill impacts. Navigant chose PG&E residential rate schedules to reduce unnecessary levels of complexity, and because the PG&E territory accounts for the vast majority of SASH participation.

PG&E's residential rate schedules use consistent rates and fees across their territory, but vary the baseline usage definition based on customers' location, the season and customers' heating fuel type (gas or electric). Navigant assumed that all customers have gas heat for this analysis. As climate zones 3 and 13 are prominent climate zones for SASH participants and well-represent both coastal and inland weather conditions, Navigant's analysis team used the appropriate PG&E baseline usage definitions for the CZ 3 and CZ 13 reference cities (San Francisco and Fresno respectively).

Table 5. PG&E Baseline Definitions for CZ 3 and CZ 13

	Summer Baseline (kWh/day)	Winter Baseline (kWh/day)
Climate Zone 3	8.3	9.8
Climate Zone 13	18.1	12.3

Source: PG&E Electric Schedule E-1, Residential Services, PG&E, San Francisco, CA.

Navigant's bill impact calculations account for several factors for each site:

- Installed PV capacity
- Typical year local weather conditions
- IOU-claimed annual LIEE energy savings
- California Alternate Rates for Energy Program (CARE) status before and after upgrades

Navigant combined these site-specific conditions with calibrated residential Database of Energy-Efficient Resources (DEER) model's hourly energy loads, DEER hourly LIEE energy savings shapes, and hourly PV generation modeled through SAM. Navigant applied PG&E's residential CARE and non-CARE rates for tiered pricing for a base case, PV-only case, and PV+ LIEE case to every site.

Hourly Base Load Simulation

Navigant obtained typical residential home load curves for CZ 3 (coastal) and CZ 13 (inland), courtesy of the Database for Energy-Efficient Resources (DEER) team. These curves are a product of calibrated typical residential hourly building simulations used to estimate energy savings associated with energy efficiency measures. For the purposes of this analysis, Navigant averaged residential consumption data from various home types within each climate zone based on an algorithm provided by the DEER modeler to reach a normalized typical load shape for the two climate zones. Each SASH site was associated with climate condition (coastal or inland) based on the site's zip code.

Next, the normalized typical load shape was scaled to each site's expected annual energy consumption. Because actual consumption data was unavailable, Navigant estimated annual kWh using a method similar to that used by GRID when sizing SASH PV systems to each site. GRID sizes PV systems such that the expected annual energy output of the solar system equals the previous year's billed energy for that specific residence, minus assumed LIEE savings. Therefore, Navigant's analysis team used SAM's modeled annual energy production for each site and the average LIEE participant savings value to scale the normalized DEER hourly load shapes to each SASH site, as shown below.

$$X = \mathrm{Dh} * \frac{\mathrm{Sa} + \mathrm{Lc}}{\mathrm{Da}}$$

Where

- X = Hourly Energy Consumption (kWh/h)
- Dh = DEER Simulated Hourly Consumption (kWh/h)
- Da = DEER Simulated Annual Consumption (kWh/yr)
- Sa = SAM Simulated Annual PV Generation (kWh/yr)
- Lc = Average Annual LIEE Energy Savings (kWh/yr)

LIEE Hourly Savings Shape

Navigant standardized the PG&E LIEE data into DEER measure groups to make possible the mapping of LIEE measures to DEER load shapes. If a measure was not readily mappable to a DEER measure, Navigant used engineering judgment to assign an appropriate similar DEER load shape. The following table summarizes the DEER measure groups that were present in the PG&E LIEE data, along with the DEER Impact ID (used for load shape) assigned. Note that occupancy sensors were assigned a custom (non-DEER) load shape based on engineering judgment, as occupancy sensors are not currently addressed by DEER.

Table 6. Mapping of PG&E LIEE Measure Groups to DEER Impact IDs (CZ3)

LIEE Measure Group	DEER Impact ID
CFL	SFM-w03-vPGx-hAC-tWt-bCA-eMS-mRE-ILtg-Power-Prim
Refrigerator	SFM-w03-vPGx-hAC-tWt-bCA-eMS-mRE-Appl-RefgFrzrRef-Refg-900kWh-500kWh
Envelope	SFM-w03-vPGx-hAC-tWt-bCA-eMS-mRB-HV-SFDuctSeal-24pct-12pct
RCA	SFM-w03-vPGx-hAC-tWt-bCA-eMS-mRE-HV-RefChrg-Inc-typ
Faucet Aerator (Electric HW)	SFM-w03-vPGx-hAC-tWt-bCA-eMS-mRE-WtrHt-SmlInst-Elec-lte12kW-lt2G
Evap Cooler	SFM-w03-vPGx-hAC-tWt-bCA-eMS-mRE-HV-ResEvapAC-17p4S
Occupancy Sensor	Custom

Using the DEER Miser export function (Miser Version 1.10.07, DEER Version 2008.2.05), all applicable normalized DEER savings shapes listed in the table above were downloaded. Finally, using the relative savings from each DEER measure group listed in the LIEE data, Navigant developed a savings-weighted average aggregate normalized LIEE savings shape for each climate zone (CZ 3 and CZ 13). The normalized savings shape was finally applied to every LIEE participant, scaled to each site based on the LIEE kWh savings data provided by the IOUs, shown below.

$$Lh = Ln * La$$

» Lh = LIEE Hourly Energy Savings (kWh/h)
» Ln = Normalized LIEE Hourly Energy Savings (*unitless*)
» La = Annual LIEE Deemed Savings (kWh/year)

Key Assumptions

The following assumptions were used during the bill impacts analysis:

- All SASH participants have natural gas heating.
- SASH site annual energy consumption estimated using expected annual PV generation and average LIEE deemed savings.
- A typical LIEE savings shape is representative of all LIEE savings shapes.
- Minimum Energy Fees, included in some residential tariffs, are negligible.
- Tiered rate schedules across IOU's and regions within each IOU will yield similar annual bills.
- All SASH participants were on a residential tiered rate schedule before and after receiving the PV installation.

Assigning Rate Structures

The data on each SASH participant's rate schedule before and after the program contained many blanks and, more importantly, contained four rate schedules that were not immediately applicable to all IOUs. For instance, the actual residential rate schedules for PG&E include E-1, EL-1, E6 and EL-6. However, the SASH database includes the D-CARE rate schedule for PG&E, which is not a valid PG&E rate schedule.

This rate schedule mismatching led the Navigant analysis team to simplify the analysis to assume a tiered residential PG&E rate schedule for the billing impacts analysis.

For allocating CARE and non-CARE rate structures, Navigant took the percentage of participants that identified themselves as CARE participants before and after SASH participation and applied a weighted average of CARE and non-CARE savings. Most participants identified themselves as CARE (87 percent before and 96 percent after), although, again, the data required significant cleaning.

SASH Cost Benefit Methodology

Using the results from the impact analysis, Navigant prepared a cost benefit analysis that conforms to Decision 09-08-026[13] except for the inclusion of increased home value as an offset to the direct participant costs which is not anticipated in Decision 09-08-026. Decision 09-08-026 adopted a methodology for evaluating distributed generation, including costs and benefits from societal, participant, and non-participant perspectives, consistent with the California Standard Practice Manual and the current framework used by CPUC in evaluating other components of the CSI program. Under this task, Navigant determined the financial fitness of the programs determined by a cost benefit analysis, by collecting the positive (benefits to ratepayers) and negative (cost) factors and quantifying these costs.

This analysis reviewed the following categories of cost and benefits:

1. Administration costs, including labor and direct expenses
2. Equipment costs, including system installation and system inspection (subcontractor cost for SASH)
3. Incentive payouts
4. Direct cost to participants (including offsetting added value to the home)
5. Rate of return for participants (customer payback for direct cost)
6. Cost of sub-contracts with other agencies and affiliates (included in administration costs)
7. Invoice processing for program administrator/SCE[14]

The CPUC has outlined the cost benefit methodology for distributed generation in Decision 09-08-026. The decision calls for additional specificity, which Navigant provides in this analysis:

- Use both the Total Resource Cost (TRC) Test and the Societal Test to measure the impacts of distributed generation (DG) programs on the state's economy generally and to compare DG programs to other energy resource options;
- Use the Participant Test. [15]Use the Program Administrator (PA) Cost Test to evaluate the net costs of DG program budgets and expenditures;

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[13] California Public Utilities Commission, Decision Adopting Cost-Benefit Methodology for Distributed Generation, August 20, 2009.

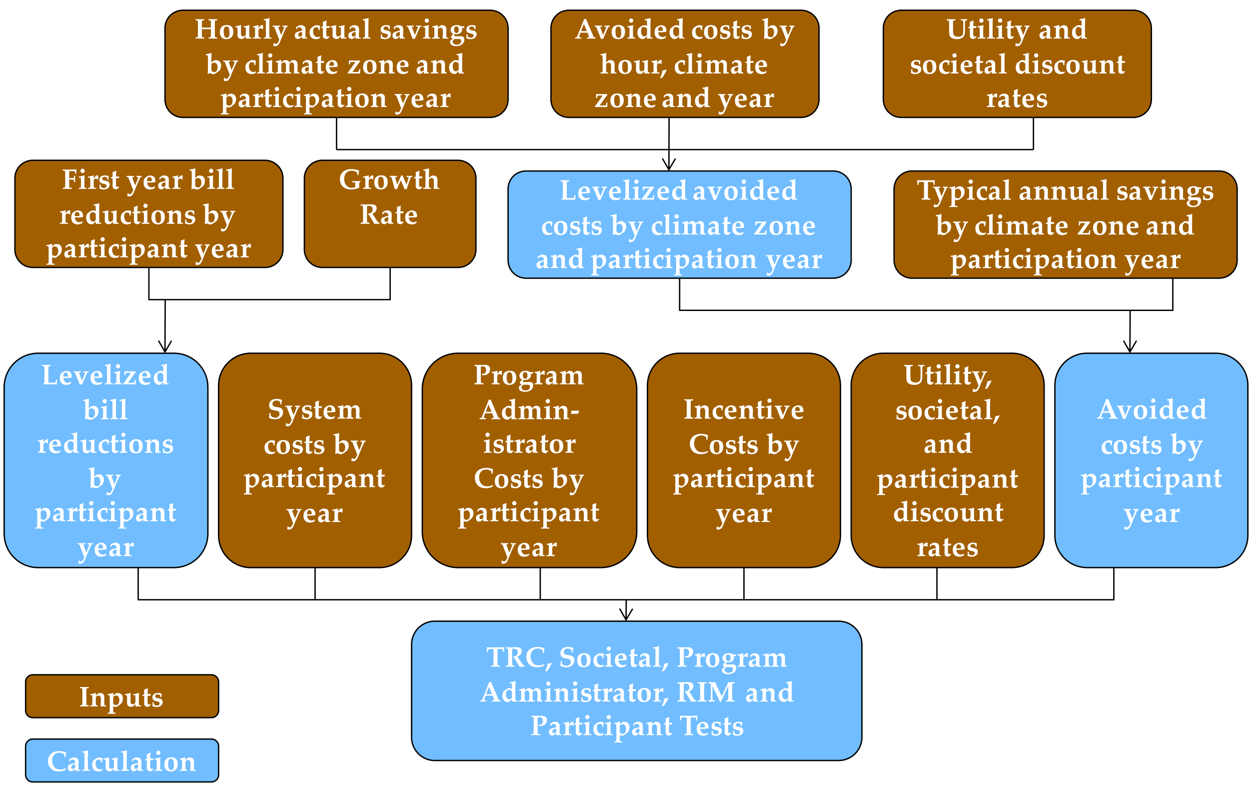
[14] The SASH administration costs were not provided and therefore are not included in the cost-benefit calculation.

- Estimate the collective transmission and distribution (T&D) deferral benefit of both grid-side and customer-side DG facilities using the E3 calculator; and
- Perform the SPM tests without any market transformation analysis.[16]

Cost Benefit Analysis Approach

Navigant used the E3 CSI calculator[17] to calculate the benefit cost tests. Each of the inputs and calculations is discussed below.

Figure 3. Approach to Calculating Benefit-Cost Tests



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[15] The decisions calls for the Participant test to be used to help identify free riders. However, for these low-income participants, the likelihood that they would acquire a capital intensive PV system without the program is quite low.
[16] The decision calls for a second set of the tests that incorporates a market transformation component, which includes an assessment of progress toward the goal of market transformation and how cost benefit test results might change as DG technologies evolve. Per discussions with CPUC staff, we did not assess this second set of tests.
[17] CSI Individual Installation Tool 8_04_2010.xls

Inputs

Hourly Actual Savings
Navigant used actual savings for calculation of levelized avoided costs to maintain the relationship between solar and weather patterns and avoided costs. Savings based on typical year data, while more representative of future impacts, do not have the range of values that actual data has – leading to underestimation of the avoided cost value. Navigant calculated hourly actual savings as described in the previous section on SASH Impact Methodology.

Avoided Costs
The E3 model "DERAvoidedCostModel_v3.9.xlsm" generated the avoided costs for each climate zone and each hour from 2010 through 2030. These costs include the T&D deferral benefit.

Discount Rates
Navigant used the default discount rates in the E3 model:

- Utility: 8.65%
- Societal: 5.06%
- Participant: 5.50%

Typical Annual Savings
Navigant used typical annual savings for the inputs to the avoided costs as typical savings are more likely to be realized in the future than first year actual savings. Navigant calculated typical annual savings as described in the previous section, SASH Impact Methodology.

Bill Reductions
Navigant assumed a tiered pricing structures, as well as CARE and non-CARE schemes which we think approximate typical rate structures experienced by SASH participants. We calculated customer billing costs before and after applying the PV load shape and subtracted to find the bill impacts. PV+LIEE bill impacts come from adding an 8760 savings shape for a typical LIEE installation (scaled at the site level to reported LIEE savings for that site) to the PV production curve at each site and again calculating the difference costs before and after PV/LIEE installation.

Growth Rate
The growth rate reflects the expected growth of the residential electricity prices. Navigant used the Department of Energy's projected nominal growth rate for residential electricity of 1.6%.[18]

System and Incentive Costs
Navigant obtained system and incentive costs from program tracking data. Table 7 shows the total installed system costs and SASH incentive amounts by utility and year. For eight sites, incentive information was not available in the database, so we assumed the incentive to be equal to the cost of the system. The system cost was missing for five of the sites, so we estimated the costs based on average cost

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[18] Energy Information Administration. 2011 *Annual Energy Outlook.* It should be noted that some low-income advocates say the recently created Tier 3 CARE rate will result in a 30% monthly bill increase for these CARE customers.

per kW of similar SASH systems. Generally, GRID Alternatives helps the homeowner find gap funding to make up the difference in system cost and SASH incentive amount.

A recent study has found strong evidence that California homes with PV systems have sold for a premium over comparable homes without PV systems.[19] This represents a benefit to the participant[20]. The analysis also found that sales price premiums decline as PV systems age: an average premium for PV systems that are one year or less in age of $8.3-9.3/watt, whereas those same models estimate an average premium of $4.1-6.1/W for systems that are five or more years old. This corresponds to the depreciation, or loss in value over time, of the PV systems. We used the mid-point of the first year value -- $8.8/watt, and assumed a linear depreciation cost over the 20 year life.

Table 7. Equipment and Incentive Costs

Electric Utility	Participation Year	Total Incentive Amount	Total System Cost
PG&E (Pacific Gas & Electric Company)	2009	$533,476	$580,467
San Diego Gas and Electric	2009	$232,146	$258,852
Southern California Edison	2009	$253,394	$268,158
Totals	2009	$1,019,017	$1,107,477
PG&E (Pacific Gas & Electric Company)	2010	$2,509,682	$2,742,442
San Diego Gas and Electric	2010	$655,408	$761,865
Southern California Edison	2010	$1,352,630	$1,458,087
Totals	2010	$4,517,721	$4,962,394

Program Administrator Costs

Navigant used program administrator costs from the CPUC Q4 2010 "Program Status Report." Values are:

- Program year 2009: $1,000,914
- Program year 2010: $1,596,259

[19] Hoen, B. R. Wiser, P. Cappers, M. Thayer. 2011. "An Analysis of the Effects of Residential Photovoltaic Energy Systems on Home Sales Prices in California." Ernest Orlando Lawrence Berkeley National Laboratory.

[20] Deed restrictions or other factors could mitigate this effect in the case of some SASH participants. Prior to June of 2010, the SASH program was only available to low-income residents with a documented deed restriction. These types of deed restrictions typically set a cap on the home's appreciation at resale, effectively preventing the homeowner from realizing an increase in their home value from the PV system.

Cost Benefit Calculations

Levelized Avoided Costs

Navigant combined the hourly avoided costs with the hourly actual energy savings using the formula shown below. This formula divides the net present value of the product of energy savings and avoided cost by the net present value of energy savings to produce a levelized value for each climate zone, participation year, and for a societal and utility discount rate.

$$AC_{cz,r,PY}\frac{\sum_{y=PY+1}^{PY+L+1}\frac{\sum_{h=1}^{8760} ES_{h,cz}AC_{h,y,cz}(1-d)^{(y-PY-1)}}{(1+r)^{(y-PY-1)}}}{\sum_{y=PY+1}^{PY+L+1}\frac{\sum_{h=1}^{8760} ES_{h,cz}(1-d)^{(y-PY-1)}}{(1+r)^{(y-PY-1)}}}$$

Where:

PY = year of participation (2009 and 2010)
y = year
h = hour
ES = energy savings
cz = climate zone (1 to 16)
AC = avoided costs
d = degradation factor (1.25% per year)
L = life (20 years)
r = discount rate (8.65% utility, 5.06 for societal, 5.50% for participant)

SASH Findings

SASH Program Status

This section provides the status of the CSI SASH program as of January 1, 2011, including all projects interconnected and in process during the years 2009 and 2010. The SASH program status is based on an extract of the SASH database, provided by GRID, dated January 7, 2011. Only interconnected projects as of December 31, 2010, were included in the scope of this evaluation, although in-process projects are summarized to show program ramp-up.

An "interconnected" project is a PV system that has been installed, rebated, inspected by a third-party inspector, tied to the utility grid, and is expected to be producing power. A project that does not meet all of the requirements of an interconnected project is considered "in process".

Summary of Installed Projects

The SASH program installed 330 sites in 2009 and 2010, providing 840.6 kW interconnected capacity. The rate of new system installations is following a steadily increasing trend. Table 8 summarizes the reported SASH kW installed/interconnected capacity, as well as the pending projects as of January 1, 2011, organized by IOU.

Table 8. Summary of Projects Interconnected and in Process as of January 1, 2011

	Interconnected		In Process	
IOU	**# Projects**	**Capacity (kW)**	**# Projects**	**Capacity (kW)**
PG&E	174	466.8	78	212.2
SCE	92	131.4	120	50.5
SDG&E	64	242.4	83	284.7
Total	330	840.6	181	547.4

Source: SASH Program Data

Figure 4 shows the relative distribution of SASH projects throughout the state. The systems are grouped by zip code. A larger circle means a greater capacity of systems were installed in a particular zip code. Often, low-income homes are grouped in neighborhoods; thus, there are several zip codes with a high number of SASH installations, shown by the larger circles on the map. The vast majority of projects are located in four regions: San Francisco Bay area, Los Angeles area, Central Valley, and San Diego area, with some installations in Lake and Monterey counties.

Figure 4. Map of Installed Capacity for the SASH Program

The SASH program has been steadily increasing its rate of installations throughout the life of the program, as presented in Table 9 and Figure 5 below. In the spring of 2010, GRID began contracting with installation contractors through the Subcontractor Partnership Program (SPP) "to bring in additional resources to increase the number of SASH projects than can be completed through GRID alone"[21].

Table 9. Installed SASH Projects by Quarter During 2009 and 2010

Year	Quarter	# of Projects	Capacity (kW)	New Capacity Since Prev. Quarter (kW)
2009	1	0	0	
	2	3	6.4	6.4
	3	19	36.2	29.8
	4	71	156.5	120.3
2010	1	118	262.0	106.4
	2	171	412.2	149.2
	3	251	647.0	234.9
	4	330	840.6	193.6

Source: SASH Program Data

Viewed as a line graph on a monthly basis (see Figure 5), the growth appears fairly steady. As of the end of year 2010, there were 330 interconnected projects equaling in 840.6 kW installed capacity.

[21] *California Solar Initiative SASH and MASH Program Administrator Performance Assessment Report*, Navigant Consulting, April 5, 2011, page 72.

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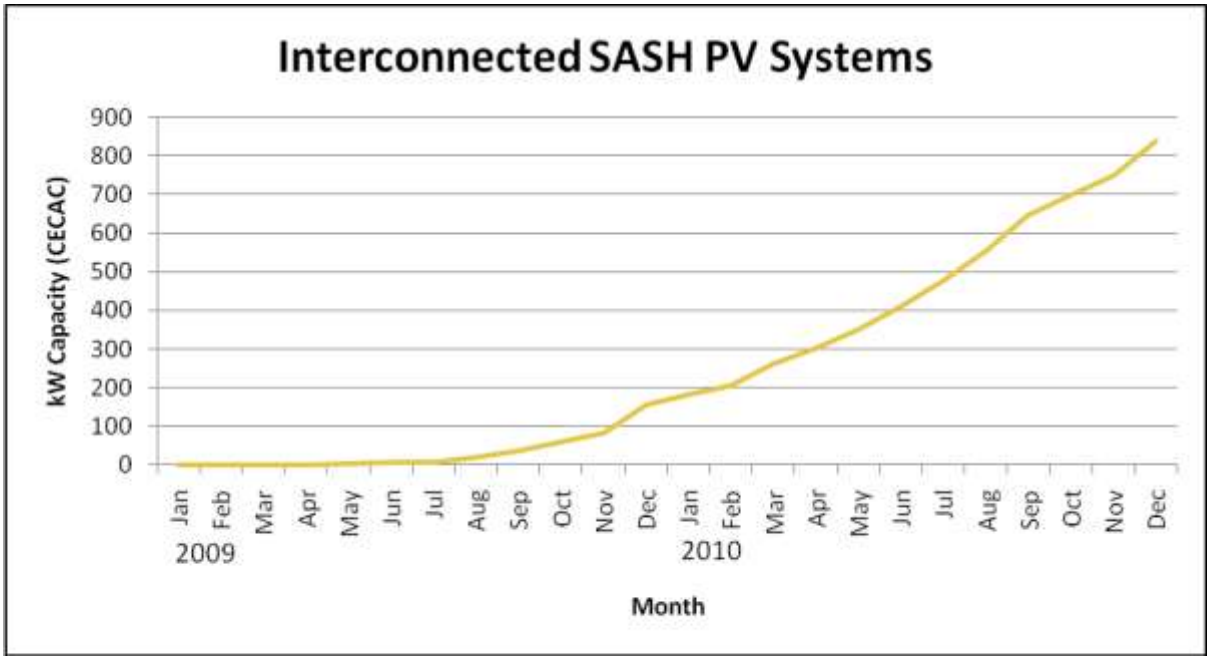
Figure 5. SASH Installed Capacity by Month During 2009 and 2010



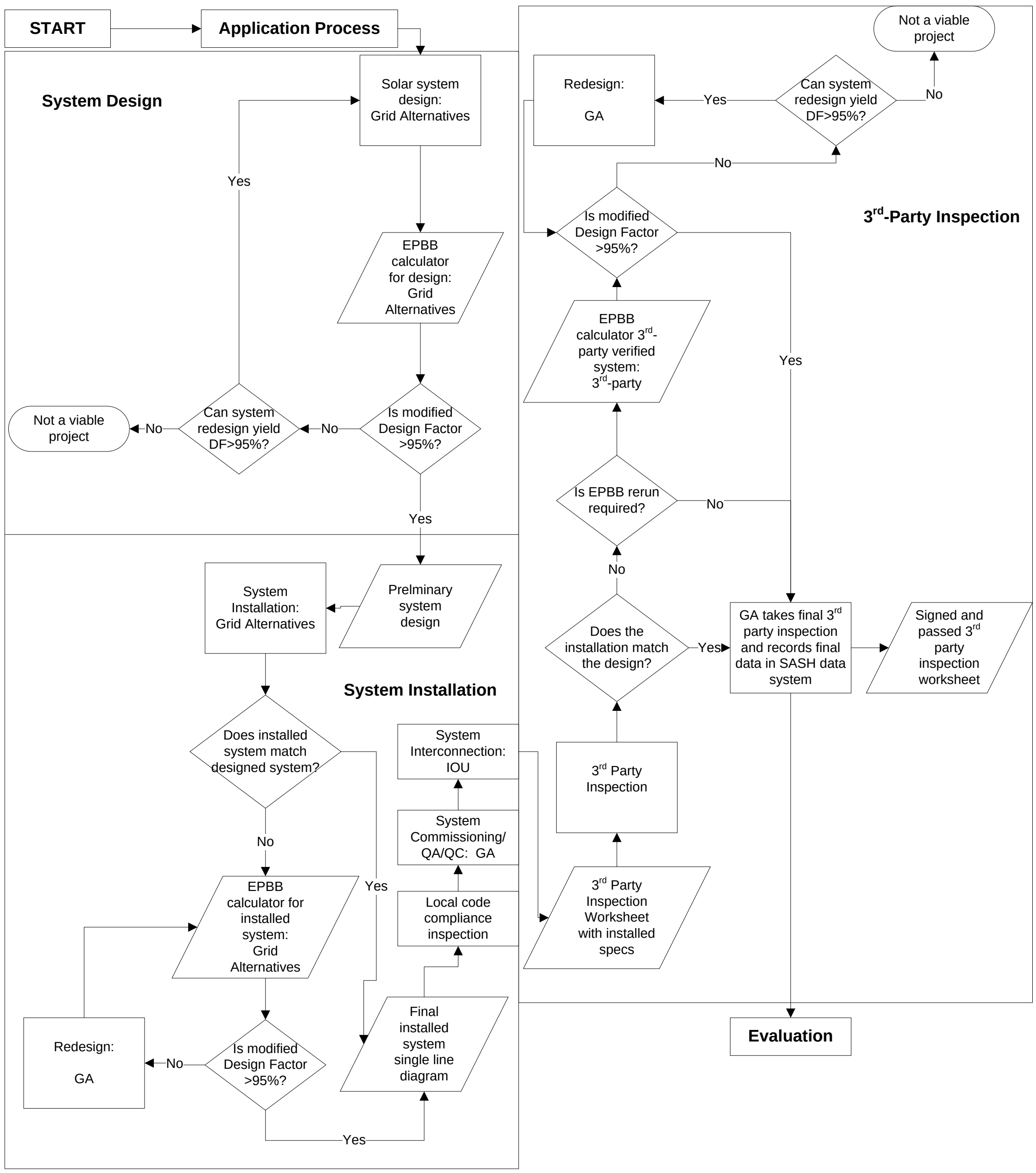
SASH Program Process

The flowchart shown in Figure 6 illustrates the current SASH design/installation/inspection process. The scope of the flow chart starts at system design (after application processing and preliminary approval) and ends at the final claimed system rebated size and design being reported to the SASH data system. At a high level, the inspection process involves three phases:

1. Solar system design (conducted by GRID or subcontractor).
2. Solar system installation (conducted by GRID or subcontractor).
3. Inspection (conducted by third-party inspector).

Each phase is described below in Figure 6.

Figure 6. SASH Project Process



NOTE: In the diagram above, "GA" refers to either GRID Alternatives or the SPP subcontractor, if applicable.

System Design

After a SASH application has been preliminarily approved, a project enters the system design phase. GRID or the SPP subcontractor develops a preliminary design of the proposed solar system and performs an initial Expected Performance-Based Buydown (EPBB) calculator run. If the proposed system has a modified SASH design factor (DF) (excluding geographic correction) of greater than 0.95, the project enters the system installation phase shown on flowchart. When a system does not meet the DF requirement, GRID or the subcontractor can iteratively redesign to meet the DF requirement. This process adds additional time to the project and could add cost in the form of additional required materials (such as racks for flat roofs). If the DF requirement cannot be met by the redesign process, the project cannot move forward. The result of the system design process is a preliminary system design, as well as the preliminary EPBB calculator run. These files are stored in a standalone file structure at GRID.

System Installation

The SASH system is installed by GRID or a subcontractor per the preliminary system design. Sometimes it is necessary for changes to the design to be made on site during installation. These changes can include system component changes (e.g., rack, panel model, etc.), installation changes (e.g., tilt, azimuth, etc.), or wiring changes (e.g., Number of strings, disconnects, j-boxes, etc.). Some changes, such as wiring changes, do not require an EPBB calculator re-run; however, other changes, such as some system component and installation changes, do require a revised EPBB calculator run. It would be unlikely that on-site design changes would push the DF below 0.95; however, if this were to occur, the flow chart reflects that the system would need to be modified.

Upon completion, the installed system is inspected by the local authority for code compliance and is scheduled for interconnection by the utility. The result of the system installation process is the final installed system single line diagram and final GRID EPBB calculator run. These documents are also stored in the GRID file structure mentioned above and the third-party inspection phase is initiated with the appropriate inspection firm.

Third-Party Inspection

GRID (or the subcontractor) produces a SASH Inspection Worksheet for each installation (because of the 100 percent inspection requirement), populating the "reserved" column of the worksheet, and sends it to the inspection firm. The form contains system parameters for the installed system that affect the EPBB calculator estimates, including items such as shading factors, system components, tilt, and azimuth.

The third-party inspector then performs the inspection, following the CSI SASH Field Inspection Protocol (provided in Appendix C). If inspection findings warrant an EPBB re-run, the third-party inspector produces a revised EPBB calculator model, along with a new (modified) DF. Per the third-party inspection flowchart, in the rare case that the modified DF drops below 0.95, system modifications can be made by GRID or the subcontractor to bring the DF within acceptable bounds.

When the system passes the inspection, the signed SASH Inspection Worksheet is passed to GRID, who records certain parameters (i.e., DF) in the SASH data system, and files the scanned inspection worksheet in the GRID file structure.

Inspection Protocol Adherence

Frequently, third-party inspectors did not follow the CSI SASH Field Inspection Protocol. Two sites having arrays with different orientations were grouped and modeled as a single array, which is contrary to the CSI Incentive Calculator User Guide and the SASH System Inspection Protocol (Appendix C), both of which require a separate EPBB calculator for each orientation. Several sites had tilt, azimuth, and shading discrepancies that were identified by Navigant field crews, but had passed third-party inspections.

Spot Measurement

As part of the field verification study, Navigant field crews performed an on-site spot measurement to verify proper system operation. The spot measurement proved to be a valuable tool, as it uncovered system issues that may have gone unnoticed for some time. Spot measurements uncovered two sites with wiring issues that decreased system production by ~ 50 percent, as well as one site that had been inadvertently shut off completely at a junction box switch. These sites are discussed in more detail below in the Field Verification Findings section.

These situations reveal an opportunity to provide an additional element of training to the system owners that would help them to know if/when their system may be having issues. Sites with microinverters can make feedback from the system particularly difficult. The in-home displays that are intended to show instantaneous system production (watts) and production-to-date (kWh) may not function properly. In some cases, the evaluation team found that the homeowners didn't know where the display was located, or the homeowner had moved the display to another location, which can disable the unit.

Field Verification Findings

Navigant's field verifications demonstrated that systems are generally operating as expected, with the exception of a small percentage of sites having wiring issues. Table A-1 shows a comparison of the number of inspection discrepancies discovered by third-party inspectors versus those discovered during the Navigant field verification study. The discussion below will note that the current third-party inspection protocol does not address wiring/connectivity issues.

Table A-1. Comparison of Inspection Discrepancies

Issue	Third-Party # of Discrepancies Found	Navigant # of Discrepancies Found
Array Grouping	0	2
Panel Miscounts	1	1
Tilt Angle	2	15
Azimuth	2	24
Shading Analysis	0	9
Wiring/Connectivity	N/A	3

Grouping

Out of the SASH sites visited, two of the sites had arrays which were incorrectly "grouped." According to the SASH System Inspection Protocol (Appendix C):

> *When an installation is split into sections having different tilt angles or different azimuth orientations, a separate Field Inspection Worksheet printout calculation must be submitted for each section of the array.*

While the majority of the sites with multiple arrays were treated correctly, the above mentioned two sites were incorrectly grouped, as they had different azimuths. In both cases, the third-party inspectors did not identify this error and passed the sites without requiring further EPBB calculations. The correction resulted in a reduction of the Design Factor by around 2-3 percent in both cases.

Panel Counts

At one site, the number of panels in each array was incorrectly reported. The total number of panels reported at the site level was correct, but GRID recorded five modules in one array and four in the other, and the third-party inspectors verified these numbers. However, the Navigant field crew counted and documented six panels in one array, and three in the other. While miscounts of this nature do not drastically affect the expected kW and kWh production for a site, they do have some effect, particularly if the azimuth or tilt values are very different for the two arrays. If the third-party inspector had followed the official SASH inspection protocol, this discrepancy would have been identified and corrected.

Tilt and Azimuth

The tilt angle and orientation angle (azimuth) have a large effect on system performance, since they determine the amount of exposure to sunlight the panels receive. For every SASH system, there is a theoretical optimum tilt and azimuth to maximize production. In the EPBB calculator, SASH systems are compared to this optimum configuration in order to determine the Design Factor for the installed system. While there is some measurement error inherent in taking tilt and azimuth readings, SASH inspection protocols clearly define the correct procedure. If the third-party inspectors find a tilt angle that differs by more than 3° or an azimuth bearing that differs by more than 5°, a new Design Factor must be calculated using the online EPBB calculator. Navigant field crews found 15 cases where the measured tilt differed from the reported values by 3°. Third-party inspections only found two cases. Navigant found 24 cases where measured azimuth differed from reported values by more than 5°, and the third-party inspectors again found only two. Many of the azimuth discrepancies were off by more than 10°, potentially signifying that magnetic bearings were not consistently being converted to true bearings. (Magnetic declination in California ranges from 12° to 16° depending on location.).

Shading Analysis

According to the SASH inspection protocols, a shading analysis must be done whenever the minimum shading requirement is not met. The minimum shading requirement is a simplified rule-of-thumb method for determining whether shading will be a significant factor affecting system performance. Shading factor is expressed as a percentage of total solar resource available on a monthly basis after accounting for shading. If the percentage varies by more than 5 percent for a single month, a new Design Factor must be calculated. Navigant field crews found nine sites where their shading analysis didn't agree with the reported values by more than 5 percent on a monthly basis. Third-party inspectors found no instances.

Wiring/Connectivity Issues

Navigant field crews found wiring/connectivity issues at three sites that significantly impacted overall system performance. At two sites, one of the two strings of panels was not properly connected at the junction box. While the system still produced output, it was only supplying 50 percent of the power it should have. This was difficult to identify, as the inverters still displayed instantaneous output numbers, though they were significantly lower than what would be expected from that system. At a third site, the Navigant field crews found an external junction box switch in the neutral position, and a power output reading of zero. The combination of junction box's close proximity to the ground and the external switch that could be inadvertently switched made it fairly easy for the system to be shut down.

Theft/Vandalism

A secondary research objective of the field verification study was to determine if there is are any SASH system impacts due to theft or vandalism in low income areas. Navigant field crews found no instances of theft, vandalism, or any other factors that could be hypothesized to be specific to low-income areas. The only factors Navigant found during the field study that degraded system performance beyond the system installation factors addressed by the CSI design factor were:

- Wiring/connectivity issues discussed above
- Soiling on panel surfaces

There is no reason to conclude that these factors are low income specific—we would expect to find these issues in any field study of solar system installations.

Design Factor Verification Rates

Design Factor is CSI's standard metric for determining whether sites are eligible for an incentive. For the low-income SASH and MASH programs, a *modified* Design Factor is used, so-called because it does not include corrections for the geographic location. It is essentially the ratio of estimated system summer kWh output (given installed system characteristics and shading) to an estimated "optimally configured" system for that location using the same equipment. In this document, "Design Factor" refers to the modified design factor used by CSI's low-income programs. SASH and MASH require a minimum 0.95 Design Factor to be eligible for funding.

During the field study, after discovering each inspection discrepancy or wiring/connectivity issue, Navigant re-ran the EPBB calculator to produce updated Design Factors for each site. While the updated values didn't tend to vary by more than about 1 percent, the array grouping, wiring issues, and panel miscounts generated a fairly significant effective change in the Design Factor. This was captured by the definition of a quantity called the Verification Rate, which is a ratio of the corrected Design Factor to the reported Design Factor. Thus, the "third-party" Verification Rate represents a correction to the reported values from GRID, as specified by the third-party inspections. The Navigant Verification Rate is an adjustment applied to the third-party values, informed by the Navigant field verification. The findings are summarized in Table 10 below. Note how the standard deviation in Navigant's Verification Rate was much greater than the third-party. This captures the sites for which the Verification Rate was very low (due to the wiring/connectivity issues) and high (due to panel miscount issues). Also, note that the "Navigant, no wiring" Verification Rate excludes sites with wiring issues, showing their high relative contribution to the overall verification rate. Keep in mind that wiring issues likely developed after the system installation and third-party inspections were complete.

Table 10. Design Factor Verification Rate Breakdown

Verification Rate	Mean	Standard Deviation
Third-party[1]	100.0%	0.2%
Navigant[2]	98.6%	13.7%
Navigant, no wiring[3]	100.0%	4.1%

[1]The third-party Verification Rate includes findings based solely on the third-party inspection protocol—not the more rigorous Navigant Field Verification Protocol.
[2]The Navigant Verification Rate includes findings based on a more advanced inspection protocol that allowed Navigant field crews to discover errors that the third-party inspection protocol would have missed. Navigant's Verification Rate of the third-party inspections following the SASH protocol would have been closer to 100%, with a smaller standard deviation.
[3]The 'Navigant, no wiring' verification rate excludes the 3 sites with wiring/connectivity issues to show the relative contribution of wiring issues.
**The uncertainty of all Verification Rate results presented in this table are better than 90/10 confidence/precision*

The takeaway message is that when the third-party protocols are followed, the inspections produce the desired result. However, deviations from protocol guidance results in inaccurate inspection feedback. The inspection protocols, including the process for updating the inspection forms and the EPBB calculator, should be strictly followed and monitored.

Data Management

Throughout the inspection process, data is transferred between parties and recorded by disparate individuals in remote locations. Data is reported at various levels using a number of data systems, including the SASH data system, third-party data systems, EPBB calculator, and GRID's internal file system. Files, in the form of .xls data extracts, .htm EPBB calculator runs, various phases of .pdf inspection worksheets, and other various data, some of which contain customer information, are emailed (unencrypted) between parties. There is not a centralized data repository that handles all of the aforementioned processes, reporting, and data. This significantly reduces program transparency and introduces several issues including:

» ***Version control***: As described in the SASH Program Process section above, several versions of single line diagrams, EPBB models, and inspection worksheets can be generated by the inspection process. There are versions stored in third-party inspector online data systems and versions stored in GRID's file structure, and there appears to be minimal tracking of the version of the documents. For example, the assumptions for a given site (e.g., shading factors, tilt, and azimuth) documented in the third-party inspection sheet provided to the evaluation team by GRID, frequently do not match those documented in the third-party inspection sheet provide by the third-party inspector. This increases the likelihood of clerical errors and reduces the transparency of the process.

» ***Clerical errors***: Every parameter being claimed in the SASH database should be traceable to the underlying third-party verified documentation. However, a significant number of sites in the SASH data system have parameters that do not match third-party verified inspection worksheets; in fact, several of these sites in the SASH database have parameters that also do not match GRID-provided inspection worksheets or EPBB model runs.
» ***Lack of a clear "paper" trail***: The project development process should be clearly understandable to an auditor, evaluator, or regulator reviewing the project database and records. Changes made to the system between the original design, installed system, and results of the third-party inspection should all be included in the project "file" (whether this be a paper or electronic file) and easily traceable. In some cases, when a third-party inspection identified a "failed" element, the inspection forms were recreated and signed by the third-party inspector to reflect a "passed" inspection. Although in all of these cases, the final installed and inspected project was valid with a DF greater than .95, recreating the inspection form presents a distorted picture of the inspection findings and could mask significant issues that may arise in the future.

Impacts of Clerical Errors

As mentioned above, sometimes the Design Factor values reported in the SASH database did not match values verified by the third-party inspectors. While the majority of the differences were very slight (and some may be attributable to rounding), a handful of the clerical errors were greater than 1 percent. In no cases did the clerical error affect the passing or failing of a site because of a Design Factor below 95 percent. However, this reiterates the need for a centralized database for tracking and reporting the results of the installation and inspection process.

Reducing the Third-Party Inspection Rate

Decision 08-11-005 establishing SASH required that 100 percent of systems installed under the SASH program be inspected by a third-party. This SASH inspection standard is higher than that of the general market CSI program, which has a third-party inspection requirement of 1 in 7, or about 14 percent of projects. A CPUC ruling (in Rulemaking 10-05-004) issued on July 26, 2010, presented a proposal by CPUC staff to make certain modifications to the CSI program. Among these changes was a proposal to reduce the rate of SASH third-party inspection from 100 percent down to a level consistent with the general market CSI program. Making this change to the SASH third-party inspection requirement would necessitate certain changes to the current inspection request process in order to ensure that the sample of projects is selected randomly and no gaming occurs.

Currently, GRID is responsible for sending the inspection documents to the third-party inspector upon completion of each project. This works because *every* project is required to be inspected. However, if only a sample of projects is to be inspected, the responsibility for selecting these projects needs to be outside of GRID's control. There are a number of ways which this can be accomplished, from a convenience sample in which every seventh project is inspected, to a random sample drawn from completed projects on a weekly or monthly basis, to the development of a random number generator which indicates whether any particular project should be inspected. In any case, a set of protocols should be developed and agreed upon by all parties. The protocols should identify the sampling method used, include clear guidelines for selecting the sample, identify the parties responsible for each aspect of the inspection process, and establish a clear procedure for demonstrating that the sampling protocol is being followed.

Although a random sample establishes a good foundation for program quality assurance, layering additional elements to the inspection requirements may be prudent. For instance, to ensure that any issues are caught early, the inspection protocol may require that the first three to five projects from each SPP contractor receive a mandatory inspection. Lastly, any changes to the inspection rate should be made subject to change based on program conditions. The inspection results should be monitored over time and modifications made if pass rates fall or other issues arise.

Quality of Installation

Several factors influence the output of a particular PV array as compared to another installation comprised of the same physical equipment. Geographic variations in weather can cause two identical PV systems to perform differently in different regions, just as temporal variation in weather can cause the same array to produce different levels of energy year to year. Vertical tilt angle and horizontal orientation (azimuth angle) are two system characteristics that also affect the amount of sunlight that is captured by a specific array. Although there is theoretically an optimum tilt and azimuth for each array that maximizes annual energy output, in practice it is often difficult to build arrays at those specifications based on the orientation and slope of a home's roof. Generally, to maximize energy production, the optimum azimuth is somewhere around due south. Table 5 shows the relative percentage of Navigant-verified (visited) arrays facing east, south, and west. The percentages are based on quadrants of 90 degrees, centered on each cardinal direction. None of the verified SASH arrays were installed facing north.

Table 11. Quality of SASH Installations by IOU: Orientation

	% of Verified Arrays		
IOU	**East**	**South**	**West**
PG&E	1.9%	55.6%	42.6%
SCE	4.2%	54.2%	41.7%
SDG&E	5.0%	45.0%	50.0%

Another factor that can influence the output of a PV array is the amount of shading it receives throughout the year. Using a handheld shading calculator, Navigant crews verified the shading on each array. Annual averages were calculated based on each of the visited arrays, and then weighted by estimated annual kilowatt-hour (kWh) output and grouped by IOU. Table 6 shows the results.

Table 12. Weighted Average Shading De-rate Values for Verified Sites

IOU	Shading Derate
PG&E	97.8%
SCE	98.2%
SDG&E	97.8%

As evidenced by the two tables above, the quality of the PV installations is roughly the same across the different IOUs.

SASH Program Impacts

This section presents the results of the SASH program impact analysis. These results are based on simulated energy production as metered production data was not available.

Energy

The 330 SASH sites installed during 2009 and 2010 have generated approximately 626 MWh of electricity through the end of 2010. Energy impacts were calculated based on 8760 verified hourly modeled energy production, accounting for the installation dates of all 330 SASH systems installed in 2009 and 2010. Table 13 and Table 14 show the results of the energy impact calculations.

Table 13. Energy Impacts of the SASH Program by Year and Quarter, in MWh

Year	Q1 MWh	Q2 MWh	Q3 MWh	Q4 MWh	Total MWh
2009	0	1.155	7.707	14.321	23.183
2010	48.893	175.869	264.767	136.800	626.328

Table 14. Energy Impacts of SASH Program by Year and IOU, Including the Number of Sites Online by the End of the Year

Year	PG&E		SCE		SDG&E		Total	
	# of sites	MWh	# of sites	MWh	# of sites	MWh	# of sites	MWh
2009	36	12.987	17	2.055	18	8.141	71	23.183
2010	174	366.769	92	141.150	64	118.409	330	626.328

Capacity Factor

Capacity factor (CF) refers to the ratio of energy production of a power generation source to its energy production at full rated capacity. In the case of PV, capacity factor is kWh produced divided by the system's CEC-AC[22] rating. Because SASH systems are installed and come online at different times of the year, capacity factor is calculated on a daily basis and summed over the year or month.

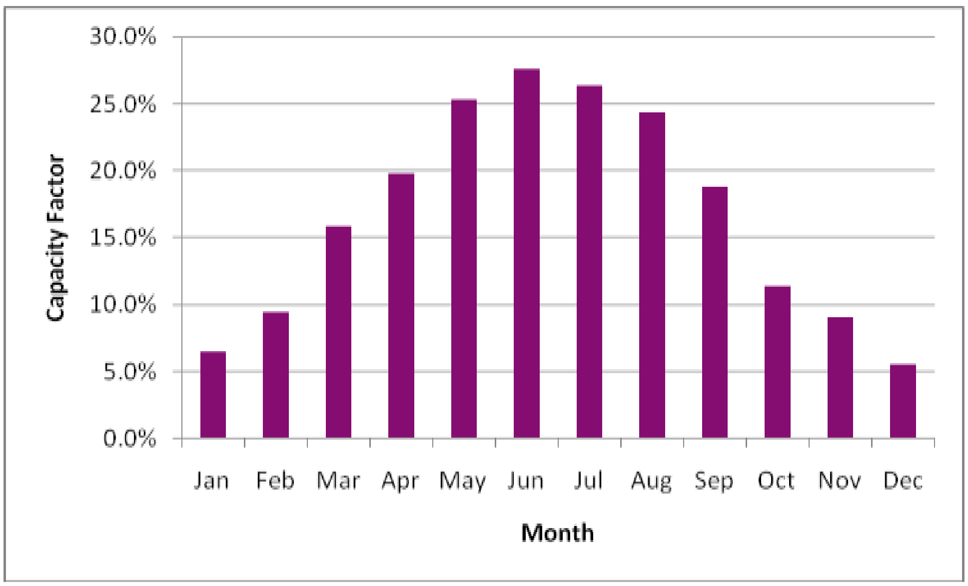
[22] The CEC-AC rating is the product of the number of PV panels, the PTC rating per panel, and the inverter efficiency.

Table 15 summarizes the program-wide annual CF by year, and Figure 7 shows how CF varies by month for year 2010. The weighted average annual capacity factor for SASH systems in 2010 was 16 percent. The relatively low CF for 2009 is due to the ramp-up of SASH installations occurring late in the year. The majority of 2009 system installations occurred in the Fall and Winter months when CF is significantly lower, as shown in Figure 7.

Table 15. SASH Program-Wide Capacity Factors for 2009 and 2010

Year	CF
2009	11.2%
2010	16.0%

Figure 7. Capacity Factor by Month for Year 2010



Differences in capacity factor year to year are primarily attributable to changes in weather, or more specifically, the amount of incident solar radiation on the PV system. Changes in capacity factor across a service territory can be caused both by differences in weather and the quality of the installation. (Systems facing due south typically perform better than systems facing east or west, for instance.) Although varying by IOU, capacity factor shows an increasing trend for all IOUs (Table 16).

Table 16. SASH Annual Capacity Factors for 2009 and 2010 by Utility

IOU	YEAR	CF
PG&E	2009	10.5%
	2010	15.9%
SCE	2009	10.1%

	2010	14.9%
SDG&E	2009	13.1%
	2010	17.8%

Demand

Demand impacts are based on California Independent System Operator (CAISO) definitions for 2009 and 2010. The dates are as follows, in Table 17:

Table 17. 2009-2010 CAISO Peak Hour Definition

Year	CAISO Peak
2009	September 3, 3:00 to 4:00 p.m. (PDT) [1]
2010	August 25, 4:00 to 5:00 p.m. (PDT) [2]

[1] *Source: Itron Report*

[2] *Source: CAISO website* (http://www.caiso.com/)

Demand reductions during the system peaks were calculated from hourly modeled results using actual 2009 and 2010 weather data from CIMIS weather stations. Only systems that were interconnected before the date of the system peak were included in the results.

At the time of CAISO peak, Navigant models estimated a peak demand reduction of about 26 kW in 2009, with a capacity factor of 56 percent at the time of peak. In 2010, the 214 systems installed at the time of CAISO peak were responsible for an approximate 208 kW peak reduction, with a peak capacity factor of approximately 39 percent. Table 18 and Table 19 show these results.

Table 18. CAISO Peak Demand Reductions Attributable to Interconnected SASH Systems

Year	# of PV Systems Online	Installed Capacity (kW)	Demand Reduction (kW)	Peak Capacity Factor
2009	14	26.47	14.8	56.0%
2010	214	539.53	207.8	38.5%

Table 19. CAISO Peak Demand Reductions Attributable to Interconnected SASH Systems by IOU

Year	IOU	# of PV Systems	Installed Capacity (kW)	Impact (kW)	Peak Capacity Factor
2009	PG&E	9	16.8	10.4	61.9%
2009	SCE	1	1.9	0.6	28.9%
2009	SDG&E	4	7.8	3.9	50.0%
2010	PG&E	113	312.2	123.1	39.4%
2010	SCE	53	132.5	47.7	36.0%
2010	SDG&E	48	94.9	37.0	39.0%

Greenhouse Gas

The SASH program solar systems were responsible for 300.6 tons of CO_2 emissions reductions during 2009 and 2010. Table 20 summarizes the CO_2 emission impacts by IOU and year, as well as the overall program impact and is based on an hourly greenhouse gas production curve from the E3 CSI/SGIP Avoided Cost Calculator[23].

Table 20. Avoided CO_2 Emissions Due to SASH PV Output by Year and IOU

Year	IOU	Avoided CO_2 Emissions (Tons)	Energy Impact (MWh)
2009	PG&E	6.1	12.987
	SCE	1	2.055
	SDG&E	3.8	8.141
2010	PG&E	170.2	366.769
	SCE	64.9	141.150
	SDG&E	54.6	118.409
	Total	300.6	649.511

LIEE

All SASH participants, if eligible, are required to apply for participation in the LIEE program. Since income qualifications are different between the SASH and LIEE programs, not all SASH customers qualify to participate in the LIEE program. Only basic energy efficiency measures are included in the LIEE program, and they are installed free of charge. Each IOU provided LIEE participation summaries by SASH customer, including measures installed and deemed kWh savings. Based on the IOU-provided LIEE data the LIEE participation in the PG&E territory appears to be significantly higher than participation in other IOU territories. PG&E accounts for 53 percent of SASH participants, and 52 percent

[23] E3 CSI/SGIP Avoided Cost Calculator, dated April 30, 2010.

of PG&E's SASH participants also participate in the LIEE program. SCE and SDG&E LIEE participation is significantly lower. Table 21 summarizes the savings attributed to LIEE for the SASH customers who received LIEE installations.

Table 21. LIEE Participation Summary

IOU	# SASH Participants	# LIEE Participants	LIEE Participation Rate	Total Annual Energy Savings (kWh/yr)
PG&E	174	91	52%	29,520
SCE	92	27	29%	5,566
SDG&E	64	18	28%	5,528

Customer Bill Impacts

Navigant estimated SASH participant annual bill impacts in 2009 and 2010, attributable to participation in the SASH program only ("PV-only"), as well as participation in SASH and the LIEE program ("PV + LIEE"). As opposed to the CSI general market program, where customers often switch from their standard tiered rate structure to a time-of-use (TOU) schedule to take advantage of the net metering benefits of higher peak rates, SASH customers are not being switched to TOU rates as a matter of course. Therefore, the scope of this bill impacts analysis is restricted to investigating customer rate impacts with respect to a tiered rate structure.

In 2010, SASH participants saw a typical annual bill reduction of approximately $336; participants that also participated in the LIEE program saw only modest bill reductions from LIEE as compared to the SASH program. The final bill savings summarized in Table 22 represents a weighted average of CARE and non-CARE customer status, reported by year, for the PV and PV+LIEE cases assuming all participants were under the tiered rate schedule before and after participating in SASH.

Table 22. Typical Annual Customer Bill Savings Breakdown

	Number of Sites	PV+LIEE Bill Reduction ($/Site/Yr)	PV-Only Bill Reduction ($/Site/Yr)
2009	71	$ 284.20	$ 273.56
2010	259	$ 347.01	$ 336.61

The bill impacts of the SASH program average around $300 per site per year in savings. In other words, the average SASH participant can expect to save about $300 per year. The bill savings are relatively low due to the reduced rate schedules associated with CARE customer participation.[24] Although CARE customers enjoy reduced energy costs, they also experience a reduction in generation revenue as defined by the concept of net metering, where energy generated is valued at the rate the utility charges for energy consumed. Likewise, the vast majority of SASH participants have CARE rate schedules (87 percent before the upgrades and 96 percent after the upgrades).

It is important to note the limited relative billing impacts of LIEE participation. SASH solar systems are sized to reduce a site's annual energy consumption to net zero, which requires high financial investment. The limited LIEE energy efficiency measures, conversely, require much smaller investments, but are very limited in their potential energy savings. Furthermore, the LIEE participation data provided by the IOUs required significant cleaning and showed very low participation in measures like HVAC and refrigeration. Therefore, it is possible that more robust LIEE datasets could yield higher relative savings for LIEE.

The increase in savings from 2009 to 2010 is most likely the result of a higher percentage of larger-loadresidences starting participation in 2010 than in 2009 (see Table 23). Additionally, significantly more systems were connected for the summer months in 2010, when CF is highest, compared to 2009.

Table 23. Bill Savings Impact of Residence Size

	Number of Sites	Installed PV Size Range	PV+LIEE Bill Reduction ($/Site/Yr)	PV-Only Bill Reduction ($/Site/Yr)
Small	169	1.1 – 2.2 kW	$ 218.82	$ 209.30
Medium	103	2.2 – 3.5 kW	$ 348.75	$ 340.29
Large	58	3.5 – 12.9 kW	$ 640.56	$ 623.83

Navigant divided home size into three groups (small, medium, and large), each with an approximately equal total installed PV capacity. This method of grouping gives larger facilities better representation due to the skew of the data set and the long upper tail.

SASH Cost-Benefit Analysis

This section presents the results of the cost-benefit analysis conducted for the SASH program. These results were calculated based on simulated energy production values rather than metered production data. In addition, these results do not include the costs incurred by SCE to provide SASH administrative services.

[24] In PG&E, the new CARE Tier 3 rate structure will likely increase the "bill savings" of SASH clients since their PV-systems will reduce the customers' net consumption and their Tier.

Levelized Bill Reductions

Navigant used the growth rate described above to project the bill reductions, and then levelized these values with the utility and participant discount rates. Levelized bill reductions are shown in Table 24. The reductions of approximately 10 to 11 cents per kWh reflect the relatively low CARE rates on which most of the participants are.

Table 24 Levelized Bill Reductions

Discount Rate	2009 Participation	2010 Participation
Utility	$0.10/kWh	$0.10/kWh
Participant	$0.10/kWh	$0.11/kWh

Avoided Costs

The levelized avoided costs for each climate zone, participant year, and discount rate combined with the typical annual savings to create avoided costs by participant year, as shown in Table 25.

Table 25 Levelized Avoided Costs

Discount Rate	2009 Participation	2010 Participation
Utility	$0.18/kWh	$0.19/kWh
Societal	$0.19/kWh	$0.20/kWh

Benefit-Cost Tests

The E3 calculator performed the five benefit-cost tests as specified by the California Standard Practice Manual.[25] In addition, we calculated customer payback as the difference between system cost and incentives divided by the first year bill reduction.

The SASH program is cost effective from the participant perspective, but not from the societal, program administrator, ratepayer or total resource perspectives, as shown in Table 26. The participant benefit-cost ratio of 2.02 to 2.05 reflects significant value to the participant. The payback period of about five years reflects a relatively modest attractiveness, less so than the participant test because the effect of increase in home value is not a factor in the payback calculation. The benefit-cost ratios of 0.15 to 0.48 for the other four tests indicate the program is not close to passing the tests.

The ratios are highest from the participant perspective because the participants are paying only a fraction of the system costs. The participants get the benefit of the bill reductions. However, relative to other participants in the CSI program, the bill reductions are modest because most SASH participants are on

[25] California Governor's Office of Planning and Research. 2002.

reduced rates, primarily CARE[26]. Without consideration of the increase in home value, the benefit-cost ratio would only marginally be greater than 1.0[27].

Table 26 Benefit-Cost Ratios

Test	2009 Participation	2010 Participation
TRC	0.23	0.45
Societal	0.27	0.44
Program Administrator	0.16	0.25
RIM	0.15	0.22
Participant Tests	1.99	1.96
Customer Payback (years)	4.61	5.11

Achieving benefit-cost ratios of greater than 1.0 could be achieved with the following changes for each perspective. It should be noted that these changes would have to be substantial.

- **TRC, Societal, Program Administrator, and RIM**
    - Increased marginal costs of energy, which could result from higher natural gas costs and/or greenhouse gas costs.
    - Increased costs of capacity, which could result from higher commodity costs resulting from world-wide demand.
- **TRC and Societal**
    - Lower cost of PV systems[28].
- **Program Administrator and RIM**
    - Lower rebate levels.

[26] It should be noted that customers must re-enroll into the CARE program every 2 years. It is possible that over the 30-year life of the PV system, a customer will move from the CARE rate to the general rate structure, thus increasing the household savings derived from the PV system.
[27] The LBNL study was not published at the time of the CSI cost-effectiveness evaluation, published August 4, 2010 by E3. The increase in house value results in the TRC ratio being lower than the program administrator ratio.
[28] It should be noted that the TRC Test allows for benefits derived from federal tax incentives. The SASH Program does not take advantage of federal incentive tax credit.

MASH Findings

MASH Program Status

The MASH program has taken more time to produce installed systems due to project size and complexity. Because few projects were forecast to be installed at the end of 2010, MASH was not included in the scope of this impact study. The following tables summarize program participation through 2010, detailing the number of interconnected and in-process projects, along with their respective capacities.

MASH Program Summary

Table 27 and Table 28 show the CEC-AC rated capacity of interconnected and in-process MASH projects. Of note is the fact that MASH projects have already surpassed SASH projects in terms of the installed capacity and the capacity in process.

Table 27. Summary of Projects Interconnected and in Process as of January 1, 2011

	Interconnected		In Process	
IOU	**# of Projects**	**Capacity (kW)**	**# of Projects**	**Capacity (kW)**
CCSE	6	151.7	24	1,872.2
PG&E	20	994.5	143	8,292.2
SCE	8	699.8	124	8,281.9
Total	34	1,846.1	291	18,446.3

The installations have not been nearly as steady in the MASH program as compared to SASH. A number of very large systems were installed during the third quarter in 2010, accounting for a disproportionate amount of the overall capacity.

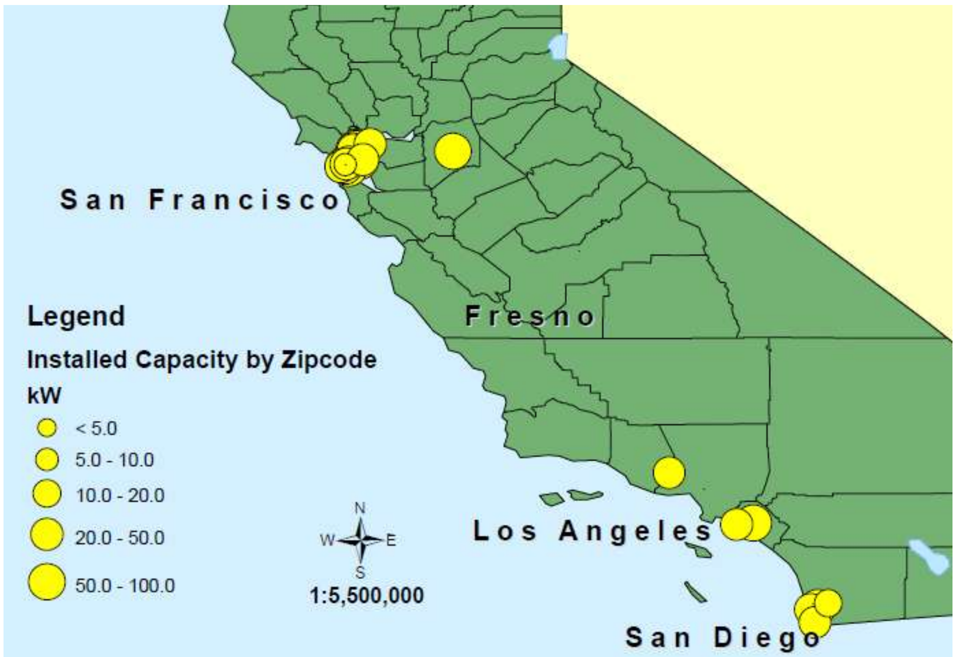
Table 28. Interconnected Systems by Quarter

Year	Quarter	# of Projects	Capacity (kW)
2010	1	4	255.9
	2	5	216.6
	3	15	1,078.9
	4	10	294.6
	Total	34	1,846.1

[1]CCSE and CSE data are summarized from a Power Clerk export on January 7, 2011. PG&E data are based on Power Clerk data provided by PG&E and dated January 14, 2011.

Figure 8 shows the relative distribution of MASH projects throughout the state. The systems are grouped by zip code. A larger circle means a greater capacity of systems were installed in a particular zip code.

Figure 8. Distribution of MASH System Capacity Statewide



MASH Inspections

All MASH sites are required to be inspected by a third-party inspector before interconnection to the grid. In order to verify the effectiveness of these inspections, Navigant obtained the third-party inspection reports from all third-party inspectors, manually standardized the data, and made high-level observations on the quality of the inspections. Although Navigant did not perform any onsite verifications of MASH sites, Navigant reviewed inspection reports for 26 of the 34 MASH sites interconnected in 2010, from all three third-party inspectors. Table 29 below shows a summary of the third-party inspections Navigant summarized.

Table 29. MASH Third-Party Inspection Summary

Inspector	# Sites Inspected	# PV Arrays	3rd-Party DF Verification Rate[1]	Total Installed kW
AESC	9	92	100.0%	834
CCSE	6	7	100.0%	152
KW	11	109	100.0%	576
Total	26	208	100.0%	1,562

[1]The 3rd-Party DF Verification rate is based solely on the inspection results of third-party inspections

Although weighted-average third-party DF verification rates are 100% at the PA level and program level, DF verification rates at the array level varied from 88% to 111%, showing that inspectors are finding discrepancies in the field.

Quality of Third-Party Inspections

Generally, the third-party inspectors appear to be following MASH inspection protocols, and collecting all required data. However, the quality of data varied from inspector to inspector. Since Navigant did not perform any on-site verification of MASH projects, the only insight to the quality of third-party inspections is through a thorough desk review of all inspection reports.

Organization of inspection documents

Generally, manual intervention was required to match all project documents, photos, .pdfs, to single projects: files were not keyed to make this matching easy or automatic. However, KW's organizational method was fairly good, as all files were separated by file type, by project.

Reported Discrepancies

Discrepancy reporting varied widely from inspector to inspector. This could be a function of a few variables: varied quality of installations, varied quality of inspections, or errors in reporting. AESC discovered a significant number of errors, and organized errors into standardized reports, which was very helpful. On the other hand, CCSE found no errors, which could be related to the very few number of arrays inspected.

Data Management

As in the SASH program, throughout the inspection process, data is frequently transferred between parties and recorded by disparate individuals in remote locations. Data is reported at various levels using a number of data systems, including the MASH data system, third-party data systems, and the EPBB calculator. Files, in the form of .htm EPBB calculator runs, various phases of .pdf inspection worksheets, photos, and other various data, some of which contain customer information, are emailed (unencrypted) between parties. There is not a centralized data repository that handles all of the aforementioned processes, reporting, and data. This introduces several issues including:

- *Clerical errors*: Every parameter being claimed in the MASH database should be traceable to the underlying third-party verified documentation. However, a significant number of sites in the MASH data system have parameters that do not match third-party verified inspection worksheets.
- *Lack of project primary keys*: A primary key, in relational database terms, is a unique identifier that persistently identifies a record through time. Each MASH project should contain a primary key that lives with that project forever. Additionally, each array within a given project should also have a primary key. Power Clerk contains primary keys; however, third-party inspections do not refer to the primary key listed in Power Clerk, making manual intervention necessary to match Power Clerk listings with third-party inspections. All changes made to a project (original design, installed system, results of the third-party inspection, EPBB runs, etc.) should all be keyed on this primary key and be made easily traceable.

Impacts of Clerical Errors

As mentioned above, sometimes the CEC-AC rating values reported in Power Clerk did not match values verified by the third-party inspectors. While the majority of the differences were very slight (and may be attributable to rounding), a significant number clerical errors were greater than 1%. This reiterates the need for a centralized database for tracking and reporting the results of the installation and inspection process.

Recommendations

This section summarizes the key recommendations that are found throughout the report. These recommendations are closely related to the key findings in Section 3, SASH Findings and Section 4, MASH Findings. These recommendations focus on opportunities to improve the implementation of MASH and SASH by the program implementers and to facilitate more robust and transparent oversight of the programs in the future.

Data Management

SASH

To maximize transparency and minimize the introduction of clerical errors, the centralized SASH data system can be used more effectively as a data management tool:

- Document version control should be maintained by the system, and the update of parameters such as CEC rating and design factor should be automatic, requiring no manual intervention;
- Primary keys should be used to relate all site documents (EPBB runs, third-party inspections, single-line diagrams) to a site key in the SASH database. If a site has multiple arrays, the arrays should also be appropriately keyed to allow easy matching with the SASH database.
- Real-time data validation should be implemented, ensuring clean data as the data comes into the system.
- User accounts, with specific data roles, should be established for third-party inspectors, evaluators, GRID, and CPUC.
- Instead of scanning and emailing .pdf inspection files, the third-party inspector should go directly to the SASH database to enter their findings, which should be automatically tied to a site, and the CPUC and GRID should be able to view these findings in real time.

Each project file and database records should provide a clear "paper" trail documenting the evolution of the project over the course of the program process:

- The project development process should be clearly understandable to an auditor, evaluator, or regulator reviewing the project database and records. Changes made to the system between the original system design, installed system, and results of the third-party inspection should all be included in the project "file" (whether this be a paper or electronic file) and easily traceable. Each iteration of the EPBB calculator, inspection forms, single-line drawings, and other documents, as appropriate, should be included in the project files and properly labeled using standard naming conventions.
- A clear process for updating the project documents resulting from "failed" third-party inspection findings should be developed and followed. Metrics reporting the inspection findings, including discrepancies at the individual line item level, should be easily identified and reported through program records.

MASH

To maximize transparency and minimize the introduction of clerical errors, the centralized MASH data system be used more effectively as a data management tool:

- Primary keys should be used to relate all site documents (EPBB runs, third-party inspections, single-line diagrams, photos, etc) to a site key in the MASH database. If a site has multiple arrays, the arrays should also be appropriately keyed to allow easy matching with the SASH database;
- Instead of scanning and emailing .pdf inspection files and photos, the third-party inspector should go directly to the MASH database to enter their findings, which should be automatically tied to a site, and the CPUC and PAs should be able to view these findings in real time.

Wiring/Connectivity Issues

To identify wiring and connectivity issues that develop after the system installation and third-party inspection, Navigant recommends that each SASH system owner be provided with a customized production target number, which indicates how much power the system should be producing on any given sunny day. A reasonable algorithm for this number will be recommended in the final report, but the number would alert the system owner of potential issues with the system. The owner should always be given the appropriate training on how to read instantaneous output, how to compare this to their production target number, and who to call if their number does not pass the test. Training on the proper placement of in-home displays is important for microinverter systems.

Calculation of Site Design Factor

Currently, the SASH Design Factor is calculated for each array at a site and then averaged to get a Design Factor for each site. However, this method does not accurately capture the case when arrays are of different sizes. A more appropriate method for calculating a site-wide Design Factor for the SASH program would be to sum the kWh production values for each array and then divide by the optimal summer kWh production values, accounting for the Installation Correction factor for each array. The following equation summarizes this recommended method for calculating a site-level Design Correction factor:

$$DF_{site} = \frac{\sum_i kWh_i \times I_{corr,i}}{\sum_i kWh_{opt,i}}$$

Where:

- DF_{site} is the overall site design factor
- kWh_i is the predicted summer kWh production of array i, or (e) from EPBB calculator output
- $I_{corr,i}$ is the installation correction factor for array i
- $kWh_{opt,i}$ is the summer kWh production at optimal tilt for array i, or (f) from EPBB calculator output

SASH Third-Party Inspections

Navigant does not think that is it necessary to subject SASH to a higher inspection rate than the general market CSI program, provided that certain modifications are made:

» The sample of inspections must be selected independently and outside of GRID control. Currently, because every system must be inspected, GRID is responsible for passing the inspection documents to the third-party inspector. If the inspection rate is reduced from 100 percent, protocols should be developed in order to ensure that the sample of projects is selected randomly and no gaming occurs.

» The results produced by the third-party inspection should not be processed or cleaned by GRID, and the final EPBB model should only be run by the third-party inspector. The final third-party inspection worksheet, photos, and related data, along with the EPBB model for inspected sites should be input directly to the SASH data system by the third-party inspector.

» Finally, the third-party inspection findings and failure rate should be monitored on an ongoing basis. A high number of failed inspections or projects with other issues may indicate the need to provide further independent oversight through an increase in the inspection rate.

To ensure that the third-party inspection protocols are followed consistently in the future, Navigant recommends additional training for third-party inspectors on inspection protocols.

Appendix A: Site Visit Protocol

Scheduling an Inspection

Recruiting and scheduling will be carried out by Navigant. The Navigant scheduler will use the online database system (FACT) and a pre-approved script to recruit customers from the sample.
Each site will have a designated "host" who has agreed to be at the house during the time of the site visit. This may or may not be the same person who applied for the SASH incentive. It is highly recommended, but not required, that the applicant attend the inspection.

Preferential Scheduling

Because of the nature of the measurements being taken by field crews, the sun must be at a high angle to the PV array (i.e. nearly directly overhead, not a glancing angle) at the time of the site visit. In order to facilitate this condition, the scheduling database will include a preferential scheduling time of day (morning, midday, afternoon). If someone from the household is not available during a preferential time, the scheduler can go ahead and schedule the visit outside the preferential time, making a note in the online system to that effect.

On-Site Procedure

Step 1: Introduction

Upon arriving at the site, the field crew should introduce themselves to the customer, and request a few minutes to ask him/her general questions about the site and the location of the PV system components. Begin by briefly reiterating the purpose of the study, and have a copy of the CPUC introduction on hand letter in case the owner has lost theirs. **If the electric utility is something other than PG&E, SCE, or SDG&E, thank the participant and terminate the site visit.**

Step 2: Data Collection and Verification

Once oriented on site, the field crew should work through the field forms, collecting data in the most efficient way possible. The following sections map directly to the sections of the field form and are laid out in the manner in which they appear on the form.

Residence Characteristics

C1. Estimate the total square footage of the house, or find out if the host knows the square footage. This includes connected garages, unfinished basements, etc.
C2. Determine the conditioned square footage of the home.
C3. Note the number of stories the home has.
C4. Note the year or decade the home was built.

C5. Note the orientation of the longest axis of the house. This may or may not be the same orientation as the PV array. See the diagram below for an example:

Figure 9. Residence Orientation, NW/SE Oriented Home

D. Draw a quick sketch of the plan view layout of the site and location of the PV system. Include numerals corresponding to where on the site each photograph was taken.

D1. Photograph Check List

1. To differentiate one site from the next and to prevent confusion, take a photograph of the mailbox/house number. If either of these is not available/accessible, take a photo of the cover sheet for that site with the site address readable.
2. Take a photo of the inverter/fuse boxes, preferably with any access panels open.
3. Take a contextual photo of the site with the array in plain view.
4. If multiple arrays, take other contextual photos as necessary to show relative locations of each array on site.

If the field crew identifies other interesting items that would benefit from a photograph (damaged/vandalized equipment, unconventional installation, etc.) please take extra photographs. These can be uploaded to the online FACT system as well.

D2. Prepaid Gift Card – Record the last 4 numbers of the gift card given to owner, and check the box once the card has been given to the owner.

Photovoltaic Modules

E1/E2. Manufacturer/Model Verification. Verify manufacturer and model numbers from the PV module nameplates. This will often require the use of a “mirror on a stick” and a flashlight to see the nameplate on the back of panels. If the nameplates are inaccessible see if the homeowner has invoices from the installer. If the panels are only a few inches off the roof, a 3’x4’ sheet of closed-cell foam may make it more comfortable to lie on the roof to get this information, as it will likely be hot to the touch on a sunny day. Also, in some instances, a camera can be used to take a picture if the nameplate is hard-to-reach.
E3/E4/E5. Count the number of modules installed for each Array ID. If possible, determine and record the # of modules per string, and # of strings in parallel for each array. This can usually be determined by inspecting the grouping of wires as they come into the fuse box or the inverter. See the photo below for an example showing three parallel strings coming into a DC fuse box. If there were 24 panels on the roof, this configuration would suggest there are three strings of eight panels each.

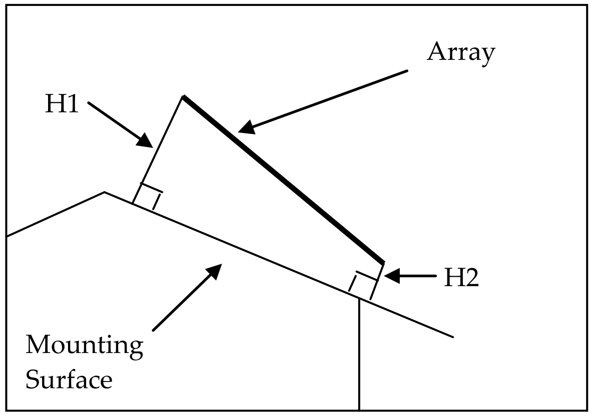
Figure C.2. Typical DC Fuse Box

If there is no DC fuse box or you cannot access it, you can make an educated guess as to the number of panels in a string using the Optimal Voltage method. From the nameplate on the back of the PV panel, make a note of the panel's typical operating voltage (not the open circuit voltage). This is the expected output voltage from the panel if the radiation it is receiving is 1000 W/m^2. The following equation should give a rough estimate of the number of panels in series:

- # Panels in Series ≅ Array DC Voltage / Panel Operating Voltage * Solar Radiation / 1000.
- Array DC Voltage can typically be read off the inverter display panel.
- Operating Voltage (sometimes called Optimal Voltage) can be read off the nameplate.
- Solar Radiation is the instantaneous insolation (in W/m^2) the array is receiving (see F3).

E6. Array Adjustment. Verify that the array is fixed, not a tracking system. All SASH sites should be fixed array types, but be sure to make a note if you find otherwise.
E7. Standoff Height. Using a tape measure or ruler, measure the standoff height from the mounting surface as the distance from the back of the PV module to the mounting surface.
For modules that are not parallel to the plane of the roof, use the average of the two following measurements: the maximum (H1) and minimum (H2) standoff distance of the array, as in figure 1.1

Figure C-3. Measurement of PV Standoff



The selections for Standoff Height are as follows:

- *0″ average standoff (flush mount or BIPV)* – The PV modules are in direct contact with the mounting surface.
- *>0″ to 1″ average standoff* – Average standoff is less than or equal to 1″.
- *>1″ to 3″ average standoff* – Average standoff is less than or equal to 3″ and greater than 1″.
- *>3″ to 6″ average standoff* – Average standoff is less than or equal to 6″ and greater than 3″.
- *>6″ average standoff* – Average standoff is greater than 6″.

E8. Tilt from Horizontal. Using an inclinometer or digital level, measure the tilt of the PV modules parallel to the sloped edge of the panel. This will be pre-populated and our goal is to verify or dispute the number recorded. It is recommended that the reading be taken no less than 3 separate times, in order to be certain of the verification/dispute of the tilt.

- For modules that are tilted along two axes, the measuring tool should be placed on a module and slowly rotated in the plane parallel to the module. The steepest angle seen during the rotation of the measuring tool is the tilt angle of the module.
- If the array is inaccessible, estimate the rise and run of the array on site and confirm with documentation from the installer, if available.
- Use the tilt of the array, not the roof shingles.
- Some smart phones have applications that can display the tilt of the surface. If you use one of these devices, be sure to calibrate it to a known level surface (you can use a carpenter's spirit level to verify the calibration surface is level).

E9. True Azimuth. The azimuth of an array is the horizontal direction that a module face is pointing. For arrays that are tilted along two axes, the azimuth is the horizontal direction of the steepest tilt. Again, this is a verification exercise. No less than 3 separate measurements should be taken until you are confident that the number is either verified or there is a discrepancy with the pre-populated values.

- The azimuth of an array pointing due south is 180°.

- » Take magnetic azimuth readings using a handheld compass 10-15 feet away from metal and unknown objects. Sometimes PV Panels can cause error in a very sensitive compass (some digital compasses, for instance). It is good to verify the azimuth on the ground as well as on the roof.
- » If using a regular needle compass, correct the magnetic azimuth reading to the true azimuth by adding the magnetic declination to the compass reading. The magnetic declination in California is typically 13° to 16° east of true north depending on the location of the site. Magnetic declinations can be obtained from http://www.ngdc.noaa.gov/geomagmodels/Declination.jsp.
- » Azimuth is irrelevant when the tilt angle is 0°.
- » A simple way to verify azimuth angle is to spray water on the top of a panel until it "runs". As long as the wind is not blowing heavily, the direction of the drip is the direction of the azimuth.

E10. Identify the module STC (Standard Test Conditions) output (this is the "DC rating") of the module, i.e. 120W
E11. Calculate the total array DC rating in Watts as E5*E10.
E12. Permanently Anchored. Verify that the array is permanently anchored.

Inverters

E13/E14. Manufacturer/Model Verification. Verify manufacturer and model from nameplate. You may need to use a screwdriver to carefully open the front panel of the inverter. If the nameplate is inaccessible, use invoices from the installer. If the inverter make and model does not match the prepopulated values on the data sheet, make a note.
E15. # Inverters. Verify the number of inverters. For "microinverter" systems (each panel has its own inverter), verify that the number of inverters is equal to the number of modules.
E16. Inverter Efficiency. The nameplate may or may not have the inverter's efficiency listed. If it does, verify it with the pre-populated value from the data sheet.
E17. Verify the rated output for the inverter (usually included on the nameplate).
E18. Note the total AC production to date using the menus on the inverter display, if available. For multiple inverters, simply sum their total production values. Note that some inverters can be networked to indicate the combined system output on all displays.
E20. For each array, the data from the SunEye™ is needed for more in-depth analysis, and needs to be uploaded via the FACT system. The reports, data files, and shading snapshot images will be compressed as a zip file. The reports in this file are generated using averages of all "skylines" for each session stored in the SunEye™'s internal memory. To this end, any erroneous skylines should be deleted, and only one skyline should remain for each vertex of an array. Once the file has been uploaded to the FACT system, please check this box to confirm. The file should be named using the following convention: "<SiteID>_<ArrayID>_ShadingData.zip"

Shading

1. Use a Solmetric SunEye™ to perform the shading analysis. A separate shading analysis should be done for each unique array determined in section 1.2.1. The monthly shading derate factors should be entered into the field form. The SunEye™ will generate the needed averages, which can be recorded on the field sheet either in the field or once back at the office.

2. There are a number of ways to perform a shading analysis. The following are suggestions:
    a. The most common method is to take shading measurements at the major corners of an array and average the values for each month. "L" shaped arrays may require measurements at six points (one at each vertex).
    b. In cases where corner shade measurements do not adequately represent the shading of an array, it is critical that the positions of the shade measurements are documented and communicated so the analysis may be duplicated.

Spot Measurement

F1. Record the sky conditions (clear, partly cloudy, overcast).
F2. Record the time the measurement was taken.
F3. For each array, record the instantaneous solar radiation using the handheld solar radiation measuring tool. Make sure the units being displayed are W/m^2, not Btu/ft^2 (this can be done by pressing the SET button on the DBTU1300. The white spot on the top of the device is the solar radiation sensor. This should be aligned parallel to the array, such that the spot is receiving exactly the same sun and incidence angle as the array. This must be done simultaneously with F7, thus a team of two people is needed: one at the array, and one at the inverter.
F4. Record the temperature at the back of one of the panels in °C using the leaf-type thermocouple attached to the digital thermometer.
F5. Note whether the array is receiving shading from trees, chimneys, etc. at the time of the spot measurement. If so, this may mean the spot measurement will not be as indicative of the array's true performance with respect to the worst case expected output.
F6. If you answered yes in F5, estimate the percentage of the array that is currently shaded.
F7. For each array, record the instantaneous power production in W by reading it off of the inverter display. Inverters should have a display which shows the instantaneous AC production of the connected array. *Simultaneous measurements should be coordinated among the field crew so as to occur at the same time. This will reduce variation in the solar radiation (due to clouds moving in front of the sun).*
F8. The power temperature coefficient for this array should be pre-populated (based on the PV manufacturer and model number listed in E1-E2). If not, or if there was a discrepancy with the observed equipment and the pre-populated equipment, use -0.004 as the Power Temperature Coefficient.
F9. Using a calculator, determine the temperature-based derate factor using the equation listed on the field form.
F10. Using a calculator, determine the expected array output from the equation given on the field form.
F11. Compare the expected (theoretical) output from F10 with the instantaneous (observed) output. Circle Y if the Actual output is less than the expected output, otherwise circle N.
If you marked Y for F11, and the array is not receiving shading, there may be some problems with wiring, or damage to the system causing one or more of the panels (or strings) to perform poorly. In order to determine whether there is any mismatch in production between strings, the troubleshooting section (F12) should be completed, and try to figure out what could be causing the mismatch.
F12. Note whether there are 2 arrays with differing tilt or azimuth values
F13. If you marked Y for F12, try to determine whether both arrays are connected to one inverter. If this is the case, the spot measurements will be less relevant and a failed spot test should not be cause for

concern in this instance. If there is not more than one unique array, the following troubleshooting procedure should be followed:

Troubleshooting a failed spot measurement

1. Check for excessive soiling, and make a note if it appears to be a factor in the low output yield of the system.
2. Conduct a spot measurement of power factor at the main breaker panel
3. If possible, get current measurements on each string of panels. They should be equal.

Soiling/System Condition

Soiling, in the form of accumulated dust or debris on the PV panels, can degrade the PV system's performance. Flat and near-flat (<20°) panels are more susceptible to soiling.
G1. For each array, do a "swipe test" for a module with a clean rag, damp with window cleaning solution, to help quantify the degree of soiling.
G2. Take a photograph of the swipe test area at a 45 degree angle from about 3 feet away, so that both the soiled and cleaned portions of the module are in the viewfinder. Try to avoid direct glare from the sun off the module. See the photograph below as an example:

Figure C-4. Typical Soiling Photograph

G3. Uploaded the file to the online database.
G4. For each array, rate the degree of soiling from 0 (clean) to 5 (very dirty).
G5. Note any damage to the system components including weather damage, and any evidence of tampering/vandalism or theft.
G6. Make note of any obvious safety hazards such as frayed wires, loose mounting brackets, etc.
G7. Note any other possible contributing factors to loss (or gain) of production

Sites Requiring Multiple Forms

Page 2 of the field forms is required for every unique Array ID. An Array ID is required per array if any of the following is encountered on site.

- PV modules with different STC rated outputs are installed at one location. A separate Array ID must be created and a field form must be filled in for each type of module so that the different arrays can be modeled individually.
- An installation is split into sections having different tilt angles or different azimuth orientations. A unique Array ID must be used for each section of the array.
- Inverter models with different peak efficiencies are installed at one location. Unique Array IDs must be used for each type of inverter (making sure the PV panels associated with each are included in the sheet).
- If there is more than one array for a site, each array must have a separate Array ID. (1, 2, 3, etc.)

Upon Returning from the Field

Download data from the Solmetric Suneye™

1. For each array, save the generated zip file from each session with the following filename format: <SiteID>_<arrayID>_ShadingData.zip For example, for a site with an ID of 0621, and an array with ID of 2, the filename should be "0621_2_ShadingData.zip"
2. Make sure the shading file is close at hand, as it will need to be uploaded to the FACT online web tool.

Enter data from field forms into the online FACT system

Data should be entered at the end of each day while the site visits are still fresh in your mind, rather than waiting until the end of the week.

Log in to the FACT system with your username and password, and use the filtering system to locate the sites visited for the day. For each site, fill in all the appropriate information from the field forms and make sure they have been submitted properly. Note that some fields are required, and there is some format checking on the fields to ensure realistic ranges and values.

Upload pictures and files and to the online FACT system

Make sure to upload pictures and shading files using the proper name formats. These are outlined in the manual in the next several sections.

Scan and upload the field forms

Field forms should be scanned and uploaded as well. This will allow the analysis team to do quality control if anything is unclear or typos are suspected.

Appendix B: On-Site Data Collection Forms

California Solar Initiative Low Income Programs
2010 Impact and Cost Benefit Evaluation

A. Customer Information *(pre-populated from online scheduling database)*

Site ID:		Customer Name:			
Customer Address:					
City:		Zip:		Phone Number:	
Alt. Phone:		Utility:		Inspection Date:	

B. Site Visit Scheduling *(pre-populated from online scheduling database)*

B1. Assigned Field Worker:						
B2. Scheduler:						
B3. Scheduled Date & Time:						
B4. Site Considerations:	#Stories:		Roof pitch:		Roof material:	
Comment 1:						
Comment 2:						
Actual Arrival Date & Time:		*Note: Site visit must be made between 1000 and 1600 hours*				
Total Time Spent On Site:						

C. Site Characteristics

Check Box When Complete ☐

C1. Total Square Footage:		C2. Total Conditioned Floorspace:				
C3. Number of Stories:		C4. Year Built:				
C5. Orientation: *(Select the orientation of the main axis of the home)*	North/South	East/West	NE/SW	NW/SE		
C6. Dominant Cooling Type: *(Circle one)*	A/C (split)	AC (packaged)	A/C (window)	Evap	None	Other:___________
C7. Dominant Heating Type: *(Circle one)*	Furnace	Electric Resistance	Electric Heat Pump	None	Other:___________	
C8. Dwelling type *(Circle one)*	Mobile Home	Single Family	Attached <4 Units	Attached >4 Units		
C9. Gas Meter Number (if available):						
C10. Additional Notes about Residence:						

D. Site Sketch/Photos/Gift Card

Draw a sketch of the site including building location and orientation, the array(s), and numerals indicating where each photo was taken.

D1. Photo List

1. House/Mailbox Number	☐
2. Inverter / fuse boxes	☐
3. Overall site/array context 1	☐
4. Overall site/array context 2	☐

D2. Prepaid Gift Card

1. Gave Prepaid Gift Card	☐
2. Gift Card #	

E. Photovoltaic System Verification

Array ID ______ of ______

Original Inspected Values		Verification Visit		Corrections/Comments (REQUIRED if Discrepancy is circled)
Photovoltaic Modules				
E1. Manufacturer:	prepopulated	Ok Discrepancy		
E2. Model #:	prepopulated	Ok Discrepancy		
E3. # of Modules per String:				
E4. # of Strings in Parallel:				
E5. # of Modules: *(QC check: E5=E3*E4)*				
E6. Array Adjustment:	fixed	Ok Discrepancy		
E7. Standoff Height:	prepopulated	Ok Discrepancy		
E8. Tilt from Horizontal:	prepopulated		°	
E9. True Azimuth (180 = South):	prepopulated		°	
E10. Module Output: *(rated at Standard Testing Cond.)*			W	
E11. Total Array DC Rating: *(E5*E10)*			W	
E12. Permanently Anchored:	Yes	Ok Discrepancy		
Inverter				
E13. Manufacturer:	prepopulated	Ok Discrepancy		
E14. Model #:	prepopulated	Ok Discrepancy		
E15. # of Inverters:	prepopulated	Ok Discrepancy		
E16. Inverter Efficiency:	prepopulated	Ok Discrepancy		
E17. Rated Output:	prepopulated	Ok Discrepancy		
E18. Production to Date (if available):			kWh	
Shading: Monthly Shading Derate Factors (% - average of values at array vertices)				
Jan	prepopulated		%	
Feb	prepopulated		%	
Mar	prepopulated		%	
Apr	prepopulated		%	
May	prepopulated		%	
Jun	prepopulated		%	
July	prepopulated		%	
Aug	prepopulated		%	
Sep	prepopulated		%	
Oct	prepopulated		%	
Nov	prepopulated		%	
Dec	prepopulated		%	
E20. Solar Eye Measurements: *Uploaded zip file of autogenerated report to FACT.*				File Uploaded ☐

F. Spot Measurement

Check Box When Complete ☐

F1. Sky Cover:	Clear Partly Cloudy Overcast	F2. Time:		F3. Solar Radiation: *W/m2*	
F4. Temperature of Module: *°C*		F5. Is the Array currently receiving shading?			Y N
F6. Estimated % of Array Shaded? *%*		F7. Instantaneous Array AC Output: *W*			

Onsite Calculations

				F8. Power Temp Coeff't: -0.004 default value	
F9. Temperature Derate: = *1 + F8 * (F4 - 25)*		F10: Expected Output: = *E11 * F3/1000 * F9 * E16 * 0.898 (Watts)*			
F11. Is the Actual Output less than the Expected Output? *F7 < F10*			Y N	If F11 = N, move on to G1 below.	
If F11 = y, and F5 = N, Fill out the following troubleshooting section and then call either Vergil's cell (828-423-0765) or Eric's cell (617-821-5413)					
F12. Are there multiple arrays with differing tilt or azimuth?		Y N			
If F12 = Y, Are the arrays connected to the same inverter?		Y N	Notes:		

G. System Condition

Check Box When Complete ☐

G1. Performed Swipe Test?	Y N	G2. Took Photo:	Y N	G3. Uploaded Photo:	Y N
G4. Levels of Soil on Surface: *(0 is Perfectly Clean & 5 is Very Dirty)*			0 1 2 3 4 5		
G5. Damage Found:	None, Normal Wear, Weather, Other: ______				
G6. Safety Issues Found:	/A Other: ______				

NOTES:	

Appendix C: CSI SASH Third-Party Field Inspection Protocol

Scheduling an Inspection

The Field Inspector will coordinate with GRID Alternatives to schedule inspection.
If the applicant is not present for the inspection, the inspector will not conduct the inspection unless permission was previously obtained in writing or via e-mail allowing the inspector to conduct the inspection without the applicant present.

Access to all of the equipment must be provided or the inspector will not conduct the inspection.

Field Inspection Worksheet

The “Field Inspection Worksheet” will be provided to the Field Inspector by GRID Alternatives. The Field Inspection Worksheet will contain “Reference Design Considerations” which should be verified by the Field Inspector. If any of the “Reference Design Considerations” differ from what the Field Inspector observes at the installation Site, then the Inspector must rerun the EPBB Calculator to confirm the Modified Design Factor meets the 95% Design Factor required for SASH. If the re-calculated Modified Design Factor (MDF) is below 95%, then the system will fail the inspection. If the differences do not result in a MDF below 95%, the system will pass inspection and GRID Alternatives will ensure that its records are updated with the correct information.

Photovoltaic Modules

a. Manufacturer/Model Verification
   Verify manufacturer and model numbers from the PV module nameplates. If the nameplates are inaccessible, use invoices from the installer.
b. Count the number of modules installed for each Array ID.
c. Array Azimuth
   - The azimuth of an array is the horizontal direction that a module face is pointing. For arrays that are tilted along two axes, the azimuth is the horizontal direction of the steepest tilt (see d.ii below).
   - The measured azimuth must be within 5° of the reference Design Consideration, otherwise the EPBB Calculator must be rerun.
   - The azimuth of an array pointing due south is 180°.
   - Take magnetic azimuth readings using a handheld compass.
     10-15 feet away from metal and unknown objects.
   - Correct the magnetic azimuth reading to the true azimuth by adding the magnetic declination to the compass reading. The magnetic declination in California is typically 13° to 16° east of true north depending on the location of the site. Magnetic declinations can be obtained from http://www.ngdc.noaa.gov/seg/geomag/jsp/Declination.jsp .
   - Azimuth is irrelevant when the tilt angle is 0°.
   - Note if the array azimuth is fixed or adjustable (Fixed/Seasonal/Automatic).
d. Array Tilt
   - Using an inclinometer or digital level, the tilt of the PV modules should be measured parallel to the sloped edge of the panel.

- For modules that are tilted along two axes, the measuring tool should be placed on a module and slowly rotated in the plane parallel to the module. The steepest angle seen during the rotation of the measuring tool is the tilt angle of the module.
- The measured tilt must be within 3° of the reference Design Consideration, otherwise the EPBB Calculator must be rerun.
- If the array is inaccessible, estimate the rise and run of the array on site and confirm with documentation from the installer.
- Use the tilt of the array, not the roof shingles.

e. Mounting method
  - Using a tape measure or ruler, the standoff height from the mounting surface should be measured as the distance from the back of the PV module and the mounting surface.
  - For modules that are not parallel to the plane of the roof, use the average between the maximum and minimum standoff distance of the array.
  - The selections for Mounting Method are as follows:
    - 0" average standoff (flush mount or BIPV) - the PV modules are in direct contact with the mounting surface.
    - >0" to 1" average standoff- Average standoff is less than or equal to 1".
    - >1" to 3" average standoff- Average standoff is less than or equal to 3" and greater than 1".
    - > 3" to 6" average standoff- Average standoff is less than or equal to 6" and greater than 3".
    - >6" average standoff- Average standoff is greater than 6".

Inverters

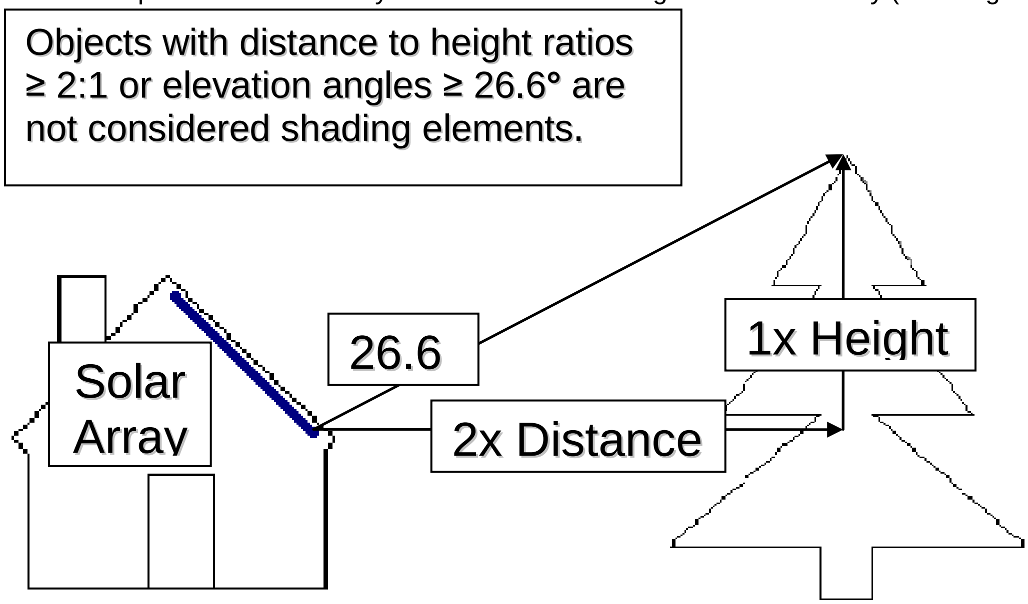
Manufacturer/Model Verification

- Verify manufacturer and model from nameplate. If the nameplate is inaccessible, use invoices from the installer.
- Verify the number of inverters installed.

Shading Documentation

- Use a Solmetric SunEye, Solar Pathfinder, or equivalent tool to perform a shading analysis. The Solar Pathfinder must be used in conjunction with the Solar Pathfinder Assistant Software for systems with an azimuth other than 180º.
- The reported monthly solar availability must be within +/- 5 percentage point tolerance to measured values.
- There are a number of ways to perform a shading analysis. The following are suggestions:
  - The most common method is to take shading measurements at the major corners of an array and average the values for each month. "L" shaped arrays may require measurements at six points (one at each vertex).
  - In cases where corner shade measurements do not adequately represent the shading of an array, it is critical that the positions of the shade measurements are documented and communicated so the analysis may be duplicated.
- Depending on site location, objects in the northerly direction, roughly between 305° to 55° relative to the most northerly points on the PV array, may not be considered shading elements for minimal shading.

- An object is not considered a shading element for minimal shading if its distance from the closest point on the PV array is at least twice its height above the array (see diagram



below).

If all shading objects have altitude angles less than 26.6°, the array is minimally shaded.

An altitude angle is the inverse tangent of the shading element's height above the array divided by the shading element's distance from the array.

Array ID

- When an installation is split into sections having different tilt angles or different azimuth orientations, a separate Field Inspection Worksheet printout calculation must be submitted for each section of the array.
- When inverter models with different peak efficiencies are installed at one location, a separate Field Inspection Worksheet printout must be submitted for each type of inverter.

Modified EPBB Design Factor Calculation/ Installation Standard

To qualify for SASH Program incentives, an installation must meet a minimum performance requirement, which is 95% of the Design Factor (DF) based on a modified Estimated Performance Based Buydown (EPBB) calculation. If the modified Design Factor is less than 95%, the system does not qualify for the SASH Program incentive.

The modified EPBB Design Factor calculation for the SASH Program must be calculated without the geographic correction (i.e. the geographic correction will always be 100%). Since the current online EPBB calculator auto-fills the geographic correction based on the Site's address and may be less than 100%, the SASH Program Design Factor may need to be re-calculated manually by multiplying:

i. the actual Design Correction [Dcorr]percentage (as calculated by the EPBB calculator)
ii. a Geographic Correction [Gcorr] of 100% (may be different from EPBB calculator value)
iii. the actual Installation Correction [Icorr] percentage (as calculated by the EPBB calculator)

Manual calculations of the Design Factor may require and can be calculated as follow.

<u>Example:</u> The following example illustrates how to manually calculate the SASH Program Design Factor using data from the EPBB Calculator's results page (see Image 1on the next page). Also, note that the incentive rate calculated by the EPBB Calculator does not apply to the SASH Program (see Section 3 for SASH Program incentives).

Manual Calculation for SASH-approved Design Factor (see Image 1 on next page):
0.97046 (actual Dcorr) x 1.00 (modified Gcorr) x 0.98840 (actual Icorr) = <u>95.92%.</u>
Since the Design Factor is over 95%, this system would be eligible for the SASH Program incentive.

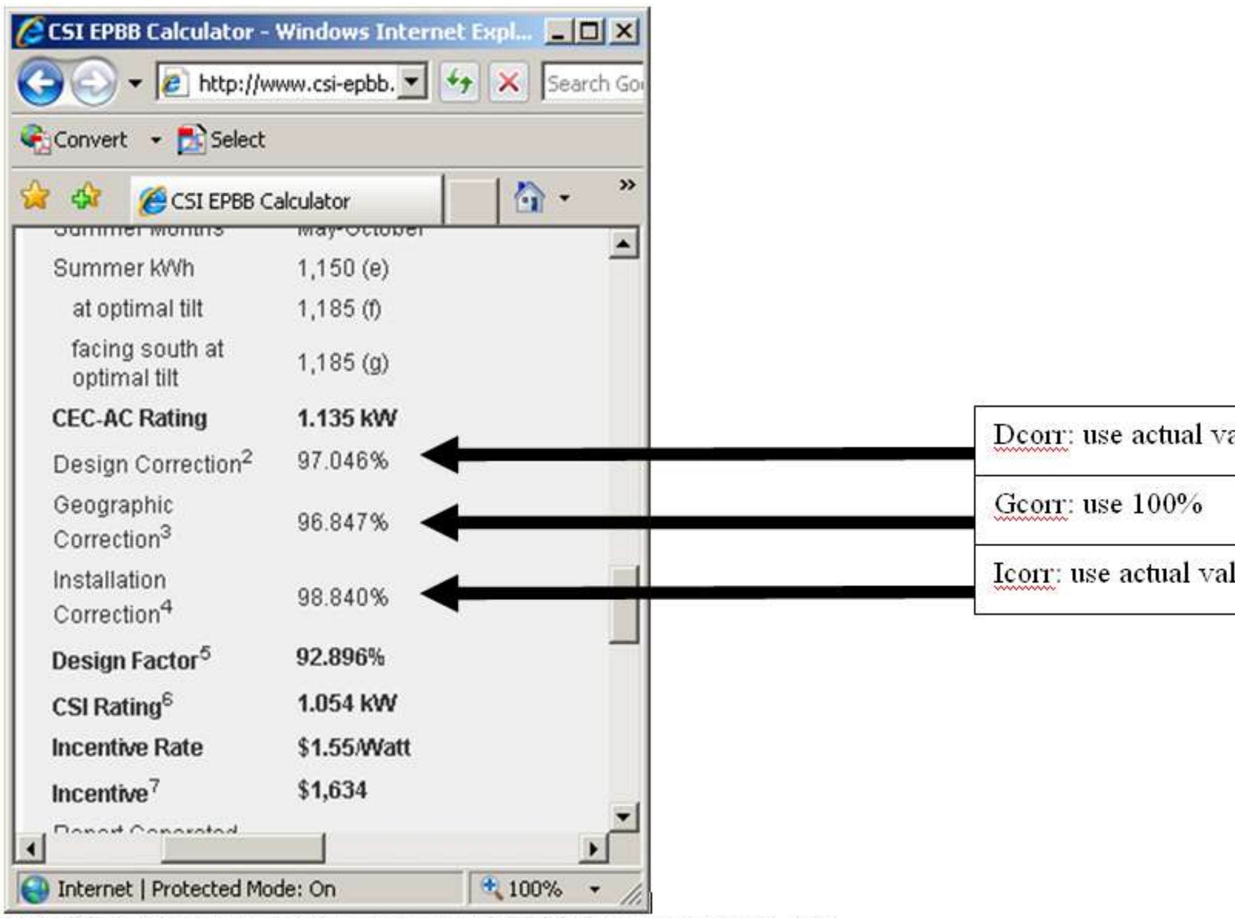


IMAGE 1: this is a partial screenshot of an EPBB Calculator results page.

Installation Issues and Photos

- Confirm physical permanence as demonstrated in accordance with industry standards.
- Confirm that the PV system serves the host customer site. If not, describe in notes section.
- Photograph all major system components and nameplates.
- Note whether the system is permanently anchored.

Safety Protocol

- The safety of the inspector, applicant, and host is the first priority.
- The inspector will not mount any roof, house, building, or structure under the following conditions:
  - The inspector does not deem it to be safe. This could be if the roof is too steep, too slippery, too fragile, too wet, too hot, etc.
  - The inspector judges that part of the roof could easily be damaged during the inspection.
  - The inspector does not have a safe way to get up (i.e. ladder is damaged).
  - The weather makes the conditions unsafe, such as lightning, strong wind, rain, etc.
- If the inspector is unable to complete the inspection safely, s/he will work with the applicant and/or host to determine as best possible the most appropriate values for the inspection report.