DOCKETED	
Docket Number:	07-SB-01
Project Title:	Eligibility Criteria and Conditions for Solar Energy System Incentives (SB1)
TN #:	224968
Document Title:	Draft Guidelines for California's Solar Electric Incentive Programs (Senate Bill 1), 7th Edition - Track Changes
Description:	*** THIS DOCUMENT SUPERSEDES TN # 224966 ***
Filer:	Erica Chac
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	10/12/2018 11:45:02 AM
Docketed Date:	10/12/2018

California Energy Commission

DRAFT GUIDELINES

Draft Guidelines for California's Solar Electric Incentive Programs (Senate Bill 1)

S~~ix~~eventh Edition

California Energy Commission

Edmund G. Brown Jr., Governor

October 2018~~November 2016~~ | CEC-300-~~2016~~2018-009~~008~~-D~~CMF~~

California Energy Commission

Robert B. Weisenmiller, Ph.D.
Chair

Commissioners
Karen Douglas, J.D.
J. Andrew McAllister, Ph.D.
David Hochschild
Janea A. Scott

~~James Folkman~~
~~Katharine Larson~~
Abtin Mehrshahi
Joseph Omoletski
~~Patrick Saxton~~
Primary Authors

Payam Narvand
Supervisor

~~Natalie Lee~~Armand Angulo
Office Manager
~~RENEWABLE ENERGY OFFICE~~INCENTIVES AND TECHNOLOGY OFFICE

~~Courtney Smith~~Natalie Lee
Deputy Director
RENEWABLE ENERGY DIVISION

~~Robert P. Oglesby~~Drew Bohan
Executive Director

DISCLAIMER

These guidelines were formally adopted by the California Energy Commission on December 19, 2007, pursuant to Public Resources Code Sections 25780 through 25784, and subsequently revised to this authority on December 3, 2008, June 23, 2010, July 13, 2011, January 9, 2013, ~~and~~ November 9, 2016, and XXX.

ABSTRACT

As required by Senate Bill 1 (SB 1, Murray, Chapter 132, Statutes of 2006, §4), this document presents guidelines for solar energy system incentive programs in California.

SB 1 requires the California Energy Commission to establish eligibility criteria, conditions for incentives, and rating standards to qualify for ratepayer-funded incentives provided by the Energy Commission, the California Public Utilities Commission, and local publicly owned electric utilities.

SB 1 requires three specific expectations to be met to qualify for ratepayer-funded incentives:

- High-quality solar energy systems with maximum system performance to promote the highest energy production per ratepayer dollar.
- Optimal system performance during periods of peak demand.
- Appropriate energy efficiency improvements in new and existing homes and commercial structures where solar energy systems are installed.

Keywords: Senate Bill 1, SB 1, California Solar Initiative, CSI, New Solar Homes Partnership, NSHP, California Energy Commission, Energy Commission, publicly owned utilities, investor-owned utilities, California Public Utilities Commission, CPUC, solar, solar energy systems, solar energy system incentive programs, electricity generation, photovoltaic, PV, PV Calculator, energy efficiency, guidelines, eligibility criteria, conditions for incentives, rating standards, benchmarking, retrocommissioning, HERS rating, field verification, energy audit, PMRS, smart inverter

Please use the following citation for this report:

~~Folkman, Jim, Katharine Larson,~~Mehrshahi, Abtin, Joseph Omoletski~~, Patrick Saxton~~. 2018~~6~~. *Draft Guidelines for California's Solar Electric Incentive Programs (Senate Bill 1), Seven~~ix~~th Edition.* California Energy Commission. CEC-300-2018~~2016~~-009~~006~~-D~~CMF~~.

Table of Contents

Page

LIST OF TABLES

LIST OF FIGURES

What's New in These Guidelines?

Several important changes were made in this edition of the *Guidelines for California's Solar Electric Incentive Programs (Senate Bill 1[1])* as compared with the November~~January~~ 201~~3~~6, sixth~~fifth~~ edition of the guidelines. These changes are expected to become effective on DATE~~November 9, 2016~~, and are summarized below.

Battery Storage System and Components (Chapter III, Section E; Appendix B, Section D)

This section and appendix change adds requirements for battery energy storage systems and batteries.

Photovoltaic Modules (Chapter III, Section A; Appendix B, Section A)

This section and appendix change modifies the requirements for incentive eligibility for PV module components by:

- Modifications to PV modules proof of certification in line with accepted national safety standards.
- Providing manufacturers, the option to submit additional optional performance data. Also details how the Energy Commission may replace the current required performance requirements in the future.
- Describing the acceptance of optional design qualification or performance information from manufacturers, and details the criteria for including new information.
- Removing some previously required or optional performance data.

Inverters (Chapter III, Section C; Appendix B, Section B)

This section and appendix change modifies the requirement for inverter components including providing the manufacturer the option of submitting additional information related to smart inverters.

Procedure for Removing Equipment From the Energy Commission's Eligible Equipment Lists (Appendix A, Section B)

This appendix change updates the methods through which the Energy Commission may notify a manufacturer that their equipment is being removed from the eligible equipment lists.

1 Changes were made to update references to pertinent statutes as a result of Assembly Bill 2227 (Bradford, Chapter 606, Statutes of 2012, Sec. 5)

~~Solar Energy System Design and Installation Standards and Incentives (Chapter IV, Section A)~~

~~This section adds an option for program administrators to design and offer a "flexible installation incentive" (FII), which would:~~

- ~~Pay upfront incentive based on the relative expected system performance.~~
- ~~Allow incentives to be determined based on the alternating current (AC) system size, location, and energy efficiency level.~~
- ~~Restrict eligibility to systems installed within an allowed azimuth range and tilt.~~
- ~~Account for shading if the "minimal shading" criteria are not met.~~

~~Field Verification (Chapter IV, Section F; Appendix C)~~

~~This section and appendix change third-party verifications adjustment to:~~

- ~~Increase maximum allowed sample group size for third party field verification *(1 in 15, vs. current 1 in 7)* for the FII structure.~~
- ~~Allow program administrators to design an alternative testing procedure to accommodate FII.~~

~~Energy Efficiency (Chapter V, Section B and Section C)~~

~~These sections add the "code-compliant" option and adjust Tier I and Tier II requirements for applications meeting the 2013 Title 24 Building Energy Efficiency Standards. Code-compliant projects do not require energy efficiency field verifications beyond those required for Title 24 Standards.~~

~~These sections also allow the program administrators to determine appropriate energy efficiency benchmarks for applications subject to future updates of the Title 24 Building Energy Efficiency Standards.~~

~~Appendix B: Criteria for Testing and Certification Before Adding Equipment to the Energy Commission's Eligible Equipment Lists~~

~~This appendix allows the accredited laboratory performing the photovoltaic module testing to determine similarity for grouping of modules for testing.~~

CHAPTER I: Introduction

Passed in 2006, Senate Bill 1 (SB 1)[2] directs the California Energy Commission (Energy Commission) to establish eligibility criteria, conditions for incentives, and rating standards for projects applying for ratepayer-funded incentives for solar energy systems.[3] According to SB 1, these guidelines establish minimum requirements to implement California's solar energy system incentive programs overseen by the Energy Commission, the California Public Utilities Commission (CPUC), and local publicly owned electric utilities (POUs). These guidelines are not intended to serve as the sole requirements for solar energy system incentive programs.[4] Other requirements specific to the Energy Commission, CPUC, and POU programs are expected to be addressed and delineated in the respective program guidebooks or handbooks.

The entities implementing these solar energy system incentive programs under SB 1 are referred to in this document as "program administrators."[5] The solar energy system incentive program administrators must incorporate the requirements in this document as part of their respective program guidebooks or handbooks.

This document covers:

- Program and legislative background, and basis for guidelines.
- Schedule for implementing these guidelines.
- Solar equipment component requirements.
- System design and installation requirements.
- Energy efficiency requirements.
- Reporting requirements for California POUs.

SB 1 directs the Energy Commission, in consultation with the CPUC, POUs, and the public, to establish eligibility criteria, conditions for incentives, and rating standards for solar energy system incentive programs. **Solar energy system incentive programs funded by California electricity**

2 SB 1 (Murray, Chapter 132, Statutes of 2006, § 4), as codified in Public Resources Code Sections 25780 – 25784. SB 1 covers many other matters besides the eligibility criteria, conditions for incentives, and rating standards addressed in these guidelines. These guidelines do not address those other matters.

3 Public Resources Code Section 25781(e) defines solar energy systems subject to these guidelines as follows: "Solar energy system" means a solar energy device that has the primary purpose of providing for the collection and distribution of solar energy for the generation of electricity, that produces at least 1 kilowatt (kW), and not more than 5 megawatts (MW), alternating current-rated peak electricity, and that meets or exceeds the eligibility criteria established under Section 25782.

4 These guidelines do not apply to incentives for solar thermal and solar water heating devices covered by Public Utilities Code Section 2851(b).

5 The term "program administrator" is used by many to refer to the entity (including a utility or third party) that is responsible for daily processing of applications, payment requests, and related tasks.

ratepayers must meet the requirements directed in these guidelines. These programs include solar energy system incentive programs established by the CPUC (California Solar Initiative) and the Energy Commission (New Solar Homes Partnership), and programs administered by California's POUs.

A. Background

SB 1 builds on the CPUC's California Solar Initiative (CSI) program,[6] the Energy Commission's New Solar Homes Partnership (NSHP), and POUs solar energy system incentive programs. SB 1 directs total expenditures of up to $3,350,800,000 by 2017[7] with goals to install solar energy systems with a generation capacity equivalent of 3,000 megawatts (MW), to establish a self-sufficient solar industry in 10 years so that solar energy systems are a viable mainstream option for homes and commercial buildings, and in 13 years to put solar energy systems on 50 percent of new homes. The overall goal is to help build a self-sustaining solar electricity market combined with improved energy efficiency in the state's residential and nonresidential buildings.

In 2015, Senate Bill 83 (SB 83, Committee on Budget and Fiscal Review, Chapter 24, Statutes of 2015) extended the life of the NSHP. SB 83 requires any funding made available pursuant to Public Utilities Code section 2851(e)(3) for the continuation of the NSHP to be encumbered no later than June 1, 2018, and disbursed no later than December 31, 2021. In June 2016, the CPUC approved Decision 16-06-006 pursuant to Public Utilities Code section 2851(e)(3), which approved the Energy Commission's request to direct the investor owned utilities to collect additional ratepayer funds necessary to continue the NSHP and achieve the $400 million in program funds originally authorized under SB 1 and designated the Energy Commission as the program administrator of the continued NSHP program.

Three specific expectations established by SB 1 must be met for the ratepayer-funded incentives:

- High-quality installation of the solar energy systems to maximize system performance for the highest energy production per ratepayer dollar.
- Optimal system performance during peak demand periods.
- Appropriate energy efficiency improvements in the new and existing home or commercial structure where the solar energy system is installed.

6 "California Solar Initiative" often refers to all of the various solar incentive programs in the state and addressed in SB 1, including programs administered by the CPUC, the Energy Commission, and the POUs. In this report, it is used to refer specifically to the CPUC's program that includes solar energy system incentives for new and existing commercial and existing residential customers served by San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company, collectively referred to as investor owned utilities.

7 Senate Bill 585 (Kehoe, Chapter 312, Statutes of 2011), which was enacted on September 22, 2011, amends Public Utilities Code Section 2851 and increases total expenditures of the California Solar Initiative from $3,350,800,000 to $3,550,800,000. The program funding for each entity under the California Solar Initiative shall not exceed the following: $2,366,800,000 (CSI program), $784,000,000 (POU program), and $400,000,000 (NSHP program).

To guide the state in developing a successful solar photovoltaic (PV) program, several principles were described in the *2005 Integrated Energy Policy Report* (IEPR). These principles include:

- Leveraging energy efficiency improvements as a primary consideration in deploying PV systems. To participate in the PV program, new buildings should be required to exceed the current building standards, while existing buildings should be required to improve efficiency. Combining energy efficiency measures with PV will ensure proper sizing of PV systems, contribute to the state's efficiency goals, and provide the maximum benefits to PV purchasers and electricity consumers.
- Rational targeting of PV deployment to achieve the greatest cost benefit as a central feature of a large-scale solar program. Solar installations should be targeted to climate zones with high peak demands for air conditioning and where solar systems can provide the most benefit.
- Transitioning away from capacity-based incentives to performance-based incentives and integrating energy efficiency and time-of-use energy considerations.

The *IEPR* also recognized the common policy vision of the loading order adopted by the state's principal energy agencies in the *Energy Action Plan* and the *2003 IEPR*. The loading order establishes the following priority for the development of energy resources: 1) energy efficiency and demand response, 2) renewable energy resources and distributed generation, and 3) clean, fossil fuel, central-station generation. The Governor highlighted the importance of the Million Solar Roofs Initiative and the aggressive pursuit of all cost-effective energy efficiency, consistent with the loading order in his energy policy to the Legislature.

There are also several other important energy policy directives as the Energy Commission responds to the SB 1 mandates:

- Senate Bill X1-2 (SBX1-2, Simitian, Chapter 1, Statutes of 2011, first extraordinary session) raised the state's Renewables Portfolio Standard (RPS) to 33 percent by 2020.
- Senate Bill 350 (De León, Chapter 488, Statutes of 2015) raised the state's RPS to 50 percent by 2030. Among other things, SB 350 also requires the State to double the energy efficiency of existing buildings by 2030.
- Clean Energy Jobs Plan – The Governor's *Clean Energy Jobs Plan* calls for adding 20,000 MW of new renewable capacity by 2020, including 8,000 MW of large-scale wind, solar, and geothermal, as well as 12,000 MW of localized electricity generation close to consumer loads. Included in the 12,000 MW goals are fuels and technologies accepted as renewable for the RPS, systems sized up to 20 MW, and systems located within the low-voltage distribution grid or supplying power directly to a consumer.
- Assembly Bill 32 (AB 32, Núñez, Chapter 488, Statutes of 2006) and the Climate Action Initiative – AB 32 reinforced Executive Order S-3-05, placing California in a global leadership position by establishing aggressive greenhouse gas emissions reduction targets. The *Climate Action Team's 2006 Report to the Legislature* highlighted the need to expand energy efficiency, coupled with increased installation of photovoltaic systems.

- Energy Efficiency Goals and Resource Procurement – Senate Bill 1037 (SB 1037, Kehoe, Chapter 366, Statutes of 2005) and Assembly Bill 2021 (AB 2021, Levine, Chapter 734, Statutes of 2006) directed electricity corporations subject to the CPUC's authority and local publicly owned electric utilities, respectively, to meet their resource needs first through all available energy efficiency and demand response resources that are cost-effective, reliable, and feasible.
- Green Building Initiative – The Green Building Initiative (GBI), Executive Order S-20-04, directed agencies to reduce state building electricity use by 20 percent by 2015, using all cost-effective measures described in the *Green Building Action Plan*, and strongly encouraged commercial building owners to reduce electricity use aggressively with the same measures. The GBI urged the CPUC to apply its energy efficiency authority to improve commercial building energy efficiency by the 20 percent goal.
- The CPUC's October 18, 2007, Decision 07-10-032 reaffirmed the *Energy Action Plan* commitment to the loading order and states California's highest priority is to increase energy efficiency measures. Through this decision, the CPUC adopted goals for new home construction to be zero net energy[8] by 2020 and new business construction to be zero net energy by 2030. The CPUC concluded that energy efficiency must become "business as usual" if the State is to meet growing energy demand and combat global warming.

To meet all the policy directives, the goal of the SB 1 incentive programs is to create a self-sustaining market for solar buildings using high levels of energy efficiency and high-performing solar energy systems. Combining high levels of energy efficiency and high solar energy system performance maximizes the major SB 1 investments, helps reduce greenhouse gas emissions, and maximizes the value of solar industry products and services to California ratepayers and consumers.

These guidelines establish eligibility criteria, conditions for incentives, and rating standards that align California's solar energy system incentive programs to meet the SB 1 goals.

B. Schedule

Under SB 1, the Energy Commission established eligibility criteria, conditions for incentives, and rating standards on December 19, 2007. SB 1 also directed the CPUC and the POUs to implement solar energy system incentive programs for ratepayers subject to their respective jurisdiction by January 1, 2008. The solar energy system incentive programs established by the CPUC and POUs must be consistent with the directives of SB 1 and meet these guidelines.

These guidelines create minimum program requirements, and all program administrators must conform their programs, as necessary, to these guidelines. These requirements shall apply only to

8 A zero-net-energy building produces as much energy as it consumes over one year. This goal can be achieved through a combination of implementing energy efficiency strategies and the use of on-site, clean, renewable energy technologies to generate energy.

new incentive applications that are received on or after a program administrator has implemented these requirements.

C. Audits

SB 1 requires the Energy Commission to conduct annual random audits of solar energy systems to evaluate operational performance of these systems.[9] To carry out this requirement, the Energy Commission will work closely with the program administrators.

9 Public Resources Code, Section 25783(d).

CHAPTER II:
Minimum Program Requirements

This chapter describes the minimum solar program requirements established in SB 1 and by the Energy Commission. Solar energy system incentive program administrators were required to meet these requirements by January 1, 2008.

Program administrators must have complied with the requirements covered in Chapters III through V regarding solar energy system component standards, system design and installation standards, and energy efficiency requirements by July 1, 2009. POUs with peak demand of 200 MW or less as reported for calendar year 2006 were required to comply with the requirements in Chapters IV and V by January 1, 2010.

A. Solar Energy System Definition

As specified by the statutory definition, "solar energy systems" eligible for financial incentives covered by these guidelines must have the primary purpose of collecting and distributing solar energy for electricity generation. Solar energy systems must produce at least 1 kilowatt (kW), and no more than 5 megawatts, alternating current- (AC) rated peak electricity, accounting for all system losses, and meet or exceed the eligibility criteria established in these guidelines.[10]

~~Eligible solar technologies must generate electricity.~~ For these guidelines, "PV" refers to flat-plate, nonconcentrating photovoltaic modules, and "other solar electric generating technologies" refers to all solar electric generating technologies except flat-plate, nonconcentrating photovoltaic modules.

These guidelines do not apply to solar thermal and solar water heating devices that do not primarily generate electricity, but that qualify for the CPUC's incentive program as specified in Public Utilities Code Section 2851(b).

B. Declining Incentives

Solar energy system incentives must decline at a rate of no less than an average of 7 percent per year and must be reduced to zero by the end of 2016, unless the program has been specifically extended beyond 2016.[11] The adoption in 2015 of SB 83 extended the life of the NSHP. SB 83 requires any funding made available pursuant to Public Utilities Code section 2851(e)(3) for incentives to be encumbered no later than June 1, 2018, and disbursed no later than December 31, 2021. Due to the extension of NSHP, the solar energy system incentive structure for NSHP was~~will be~~ revised in the tenth edition of the NSHP Guidebook.

10 Public Resources Code, Section 25781 (e).

11 Public Utilities Code, Section 387.5 (b), and Public Utilities Code Section 2851(a)(1). Section 387.5 was amended and renumbered as Public Utilities Code Section 2854 by Assembly Bill 2227 (Bradford, Chapter 606, Statutes of 2012, Sec. 5).

C. Incentive Level for Publicly Owned Utilities

Local publicly owned electric utilities were required to offer incentives for the installation of solar energy systems beginning at no less than $2.80 per installed watt (measured in alternating current, or AC), or the equivalent in terms of kilowatt-hours (kWh), on or before January 1, 2008.

D. System Location and Grid Interconnection

The solar energy system must be located on the same premises as the consumer's own electricity demand. The system must be connected to the electrical distribution grid of the utility serving the customer's electrical load.[12]

E. Solar Energy System Components

All components in the solar energy system must be new and unused and have not previously been placed in service in any other location or for any other application.[13] Additions to existing systems are allowed only for systems that met program requirements at the time of installation and were partially funded by program administrators in accordance with SB 1 and these SB 1 guidelines. For these existing systems, the program administrators have documentation identifying the equipment that was installed, the program warranty, and the system equipment standards and warranties that were met by the originally installed equipment. The newly added generating equipment shall be selected from the current lists of eligible equipment[14] and meet the current requirements, including the requirement for a 10-year warranty. All the current program eligibility criteria and documentation requirements apply to the added equipment.

All major solar energy system components eligible for ratepayer funding under SB 1[15] shall be included in the eligible equipment lists. ~~These components include PV modules, other solar electric generating technologies, inverters, and meters. As of July 1, 2009, PV modules were required to complete testing requirements outlined in Chapter III to be eligible for incentives. Requirements for other solar electric generating technologies are also in Chapter III.~~ Because unexpected changes may occur in the renewable energy industry and in renewable energy products, prospective applicants and participants of solar incentive programs should perform their own due diligence on the manufacturer of the product they plan to purchase, and the product, before applying for an incentive reservation or funding using that product. Information on solar energy system components can be found at http://www.GoSolarCalifornia.org.

12 Public Resources Code, Section 25782 (a)(5) and (6).

13 Public Resources Code, Section 25782 (a)(3).

14 The terms "equipment list," "eligible equipment lists," and other combinations of those terms in this guidebook refer ~~only~~ to a compilation of equipment that is in compliance with the requirements set by the Energy Commission in these guidelines~~eligible for an incentive under the appropriate program~~. ~~Equipment placed on a list of eligible equipment has met the criteria established by the Energy Commission for that equipment to be eligible for an incentive.~~

15 Public Resources Code, Section 25782 (c).

Equipment becomes eligible for incentives based on information provided to the Energy Commission by the manufacturer and verified by the Energy Commission to be true at the time the equipment is determined eligible for an incentive. The Energy Commission cannot and does not guarantee that this information will not change after a product has been determined to be eligible for an incentive and is not responsible for any damage that may result from such a change. If the Energy Commission becomes aware of such a change, it ~~may post a notation on its eligible equipment website at http://www.GoSolarCalifornia.ca.gov/equipment/index.php, advising consumers of the changes,~~ may take action to remove the equipment under Appendix A, Section B. Procedure for Removing Equipment From the Eligible Equipment Lists, and may take other appropriate actions. ~~Because unexpected changes may occur in the renewable energy industry and in renewable energy products, prospective applicants and participants of solar incentive programs should perform their own due diligence on the manufacturer of the product they plan to purchase, and the product, before applying for an incentive reservation or funding using that product.~~

F. Performance Meter

All solar energy systems shall be installed with a performance meter or an inverter with a built-in performance meter so that the customer can monitor and measure system performance and the quantity of electricity generated by the system.[16]

G. System Sized to Offset On-Site Electricity Load

The solar energy system must be intended primarily to offset part or all of the consumer's own electricity demand.[17,18] The minimum size of an eligible system is 1 kW_{AC}, accounting for all system losses.[19] Systems sized between 1 kW_{AC} and 5 kW_{AC}, inclusive, shall be assumed to primarily offset the customer's annual electricity demand.

H. System Warranty

All solar energy systems must have a minimum 10-year warranty to protect against defects and undue degradation of electrical generation output.[20] The 10-year warranty requirement is optional for standalone performance meters. Program administrators have discretion over how the 10-year warranty provisions are implemented under their respective solar programs.

When evaluating the potential installation of a photovoltaic system, it is important to consider the value of the warranty offered. A warranty offered by one manufacturer or installer may be more valuable than one offered by another manufacturer or installer. The Energy Commission is not a party to the warranty and is not responsible for the actions of the warrantor, nor will the Energy

16 Public Resources Code, Section 25782 (a)(7).

17 Public Resources Code, Section 25782 (a)(2).

18 Projects are allowed to use Virtual Net Metering under these guidelines.

19 Public Resources Code, Section 25781 (e).

20 Public Resources Code, Section 25782 (a)(4).

Commission engage in warranty disputes. If participants of solar incentive programs have concerns about their photovoltaic systems, they should contact the warrantor immediately for assistance.

I. Installation

The solar energy system must be installed in conformance with the manufacturer's specifications and in compliance with all applicable electrical and building code standards.[21] Chapter IV of these guidelines establishes installation standards that were to be complied with by July 1, 2009, except where noted.

All eligible systems shall be installed by individuals with a current A, B, C-10, or C-46 contractor license. Roofing contractors with a current C-39 license may place PV panels in accordance with the limitations of their license; however, electrical connections shall not be made by a roofing contractor. North American Board of Certified Energy Practitioners (NABCEP) certification of installers is encouraged, though not required. Systems may be self-installed by the purchaser (owner).

J. Energy Efficiency

Chapter V of these guidelines establishes energy efficiency requirements, which were to be complied with by July 1, 2009.

21 Public Resources Code, Section 25782 (a)(8).

CHAPTER III: Solar Energy System Component Standards

This chapter establishes rating standards for equipment, components, and systems to assure reasonable performance in accordance with SB 1.[22] Setting rating standards and guidelines to ensure the quality of systems and components is critical to a successful solar incentive program and to ensure incentives are given to high-performing systems. ~~The t~~Three main components of solar energy systems, for which these guidelines include ~~that are subject to~~ standards and ratings, ~~specific to PV installations~~ are ~~the~~PV modules, inverters, and meters. These guidelines also include standards related to equipment safety for battery storage systems and battery system components. Until the equipment is tested and placed on an eligible equipment list by the Energy Commission, applications specifying the equipment are not eligible for an incentive payment.

A description of the testing criteria and the criteria for reporting performance of eligible equipment is detailed in Appendix B—Criteria for Testing and Certification Before Adding Equipment to the Energy Commission's Eligible Equipment Lists.

The Energy Commission lists equipment that meet select safety and performance standards as applicable, but does not guarantee or warranty listed equipment safety, performance, or durability.

A. Photovoltaic Modules

Makers of eligible PV modules[23] shall be required to provide testing data from independent laboratories to ensure safety and high-quality data on module performance in the field. These data shall also be used to calculate the expected performance of the system. Eligibility of PV modules is determined by the Energy Commission.[24]

The PV module eligibility requirements are as follows:

- PV modules shall have a product certification indicating compliance with an American National Standard for safety~~UL 1703~~ from a Nationally Recognized Testing Laboratory.[25]

22 Public Resources Code, Section 25782(c).

23 For these guidelines, "PV modules" refers to flat-plate, nonconcentrating photovoltaic modules. A PV module is an environmentally sealed assembly of interconnected photovoltaic cells that convert sunlight to electricity.

24 Modules eligible under these requirements may be found on the following website http://www.gosolarcalifornia.org/equipment/pv_modules.php.

25 For PV module product certification, Nationally Recognized Testing Laboratories (NRTLs) shall be those laboratories that have been recognized by the U.S. Department of Labor, Occupational Safety & Health Administration (OSHA), in accordance with Title 29 of the Code of Federal Regulations, Section 1910.7, and are approved to test for the applicable standard~~UL 1703~~ under the scope of their OSHA recognition. All current NRTLs are identified on OSHA's Web page at http://www.osha.gov/dts/otpca/nrtl/index.html. Not all of the NRTLS recognized by OSHA are approved for each particular standard~~UL 1703~~ under the scope of their OSHA recognition.

(NRTL). Certification to UL 61730 (Parts 1 and 2) will be accepted as proof of compliance as of the effective date of these guidelines. Alternatively, certification to UL 1703 will be accepted until January 1, 2020.

- Additional testing for performance-related characteristics shall be conducted to specific subsections of International Electrotechnical Commission (IEC) Standard 61215:2005 or IEC 61646:2008 (depending on the type of PV module). Th~~e~~is~~ additional~~ testing shall be conducted by a laboratory with accreditation to ISO/IEC 17025 from an accreditation body that has signed the International Laboratory Accreditation Cooperation~~Corporation~~ (ILAC) Mutual Recognition Arrangement (MRA), and that has~~with~~ an accreditation scope that includes IEC 61215:2005 and/or IEC 61646:2008.[26] If comparable data becomes available, in accordance with different standards, that supports program administrators' minimum data requirements, the Energy Commission may replace this requirement with the optional requirement outlined in the bullet below.
- Starting on the effective date of these guidelines, the Energy Commission shall accept optional performance testing results acquired in accordance with the currently active version of IEC 61853. The testing shall be conducted by a laboratory with accreditation to ISO/IEC 17025 from an accreditation body that has signed the ILAC MRA, and that has an accreditation scope that includes the applicable version of IEC 61853. See Appendix B, Section A for further details.
- The nominal operating cell temperature (NOCT) for roof-integrated, building-integrated photovoltaic (BIPV) products shall be determined using the specification described in Appendix B – Criteria for Testing and Certification Before Adding Equipment to the Energy Commission's Eligible Equipment Lists.

~~The Photovoltaic Module Eligible Equipment List is updated monthly. Between January 1, 2008, and June 30, 2009, the Energy Commission accepted performance data based on test procedures specified in UL 1703, Section 18.1 (in-house laboratory and flash test data) to determine module eligibility.~~ Eligible equipment list for PV modules may include the additional test data and certification information based on Appendix B, Section A.1 and A.4 regarding the optional testing references.

B. Other Solar Electric Generating Technologies

Other solar electric generating technologies[27] shall be eligible for performance-based incentives (PBI) only.[28]

26 A laboratory within or outside the United States may be used to conduct this additional testing.

27 For these guidelines, "other solar electric generating technologies" refers to all solar electric generating technologies except flat-plate, nonconcentrating photovoltaic modules.

28 Future updates of these guidelines will consider inclusion of expected performance-based incentives (EPBI).

Other solar electric generating technology (OSEGT) products shall have a product safety certification from a~~n~~ NRTL.[29] An evaluation to determine whether any existing standards or portions of existing standards are applicable and/or whether development of new test protocols is necessary shall be performed by a~~n~~ NRTL. Any necessary development of new test protocols shall be performed by a~~n~~ NRTL. Manufacturers shall submit all new test protocols to the Energy Commission for review. The Energy Commission reserves the right to challenge the adequacy of test protocols for incentive eligibility purposes. If inadequacies are determined, the Energy Commission will consult the NRTL and manufacturer but may ultimately determine that the equipment is not eligible for an incentive if inadequacies are not resolved.

In addition, each manufacturer shall work with the appropriate program administrator to determine suitable estimates of capacity and energy production before reserving funds.

C. Inverters

The document "Performance Test Protocol for Evaluating Inverters Used in Grid-Connected Photovoltaic Systems"[30] should be used by a NRTL to determine ~~if~~the required inverter performance data. ~~are required i~~In addition, the manufacturer ~~to~~ must provide product certification indicating compliance with UL 1741 from a~~n~~ NRTL. The inverter test protocol requires the reporting of efficiency data at the full range of operating conditions (power and efficiency at the full range of possible voltages), along with the nighttime "tare loss"[31] for each inverter, to provide full performance information and enable hourly estimates~~ing~~ of the overall performance of the system.

Eligible inverters are identified on the Energy Commission's eligible equipment list for inverters.[32]

The following are inverter eligibility requirements:

- Inverters shall have a product certification indicating compliance with UL 1741 from a~~n~~ NRTL.[33]

29 For OSEGT~~,~~ product certification, NRTLs shall be approved for UL 61730, UL 1703 (as applicable, per Chapter III, Section A) or UL 1741 under the scope of their OSHA recognition. Not all of the NRTLs recognized by OSHA are approved to test for UL 61730, UL 1703 or UL 1741 under the scope of their OSHA recognition.

30 This document may be found at http://gosolarcalifornia.com/equipment/documents/2004-11-22_Test_Protocol.pdf.

31 The term "tare loss" as it applies to photovoltaics can be defined as "loss caused by the controller. One minus tare loss, expressed as a percentage is equal to the controller efficiency." http://www.teachmefinance.com/Scientific_Terms/Tare%20Loss%20.html.

32 Inverters currently eligible under these requirements may be found on the following website: http://www.gosolarcalifornia.org/equipment/inverters.php. An *inverter* is an electrical device that takes the direct current power produced by an array of PV modules and/or batteries and converts it into alternating current power for consumer use.

33 For inverter product certification, NRTLs shall be approved to test for UL 1741 under the scope of their OSHA recognition. Not all NRTLs recognized by OSHA are approved to test for UL 1741 under the scope of their OSHA recognition.

- Performance data (maximum continuous output power, conversion efficiency, and tare losses) tested in accordance with “Performance Test Protocol for Evaluating Inverters Used in Grid-Connected Photovoltaic Systems" by a~~n~~ NRTL shall be reported for each inverter.

Some inverters may include advanced functionality and communication abilities[34], and are commonly known as “smart inverters”. Smart inverters require additional testing and certification documentation to demonstrate the capability to perform the advanced functions. Inverters that have been properly documented as meeting each requirement, described herein following the Inverters Listing Request Procedures, shall be listed with additional information to reflect certain sets of functional capabilities on the eligible equipment list for inverters.

As of January 1, 2020, the Energy Commission will~~consider changes to~~ discontinue accepting requests to list inverters that do not incorporate smart inverter functionality.

Currently the certifications for advanced functionalities include:

- Product certification to UL 1741, inclusive of Supplement SA (“UL 1741 SA”), with optional sections, from a NRTL. The NRTL test report or summary of test results for Supplement SA testing must also be provided.
- Product certification from SunSpec Alliance to *Common Smart Inverter Profile* (CSIP) requirements, defined in IEEE 2030.5:2018, in accordance with the *SunSpec Common Smart Inverter Profile (CSIP) Conformance Test Procedures.*
- Product certification to IEEE 1547:2018 (or later version) and associated conformance test procedures from a NRTL.

Acceptance of any certification or testing, including possible alternatives to the above smart inverter requirements, is subject to Energy Commission review. The manufacturer or testing entity may be required to submit any new test protocol(s) or documentation of certification program(s) to the Energy Commission for review and acceptance. An application for listing will not be reviewed prior to approval of the test protocol or certification by the Energy Commission.

Any additional smart inverter functions, requisite testing, or certification shall be determined in accordance with applicable CPUC rulemaking decisions or resolutions in reference to CPUC Electric Rule 21 smart inverter functions. The added functions shall be as defined in CPUC Decisions 14-12-035, 16-06-052, and subsequent modifying decisions, resolutions, CPUC approved or accepted advice letters, or guidance issued by a CPUC-established working group. All the testing protocols and certifications must be capable of verifying the capability of each inverter to perform the functions specified therein.

D. Meters

Performance meters, whether stand-alone or integrated with the inverters, shall be required to meet the following eligibility criteria:

[34] The particular functionality required to be a “smart inverter” is defined by each application. For example, CPUC Electric Rule 21 includes specific required functionality for smart inverters interconnected to the investor-owned utilities.

- Meters with ± 2 percent accuracy are required for all performance-based incentive (PBI) applicants.
- All ± 2 percent accuracy meters shall be tested by a~~n~~ NRTL according to all applicable ANSI C-12 testing protocols.
- Meters with ± 5 percent accuracy (These are primarily inverter-integrated.) shall be allowed for expected performance-based incentive (EPBI) applicants.
- All meters shall measure and display both instantaneous power (kW or W) and cumulative energy produced (kWh or Wh).
- All meters shall retain production data during power outages.
- All meters shall be easy to read for the customer.
- All meters shall have a communication port capable of enabling connection to remote performance monitoring and reporting service (PMRS).

Eligible meters are identified on the Energy Commission's eligible equipment list for meters.[35]

E. Battery Storage

Battery storage systems are commonly installed as an integrated component of solar energy systems. Integrated battery storage contributes to the collection and distribution of solar energy. Manufacturers of battery energy storage systems[36] (BESS) or batteries may submit a request for listing on the Energy Commission's equipment lists. BESS and batteries must meet minimum safety requirements prior to being included on the applicable list.

- A battery energy storage system shall have a product certification indicating compliance with an American National Standard for safety from a NRTL. Certification to UL 9540 will be accepted as proof of compliance.
- A battery shall have a product certification indicating compliance with an American National Standard for safety from a NRTL. Certification to UL 1973 will be accepted as proof of compliance.

Proof of other safety testing and certifications exceeding the above minimum safety requirements may be accepted and reflected on the equipment lists.

35 Meters currently eligible may be found on the following website: http://www.gosolarcalifornia.org/equipment/system_perf.php.

36 A battery energy storage system is an electric power system that receives electrical energy and means to store that energy via electrochemical means as defined in UL 9540.

CHAPTER IV:
Solar Energy System Design and Installation Standards and Incentives

SB 1 requires high-quality design and installation of solar energy systems to promote the greatest energy production per ratepayer dollar and directs the Energy Commission to establish design and installation standards or incentives. This chapter establishes the guidelines for design and installation standards and incentives needed to achieve this mandate. Program administrators must have complied with these guidelines by July 1, 2009. POUs with peak demand of 200 MW or less as reported for calendar year 2006 must have complied with the requirements in this chapter no later than January 1, 2010.

To achieve high-performing solar energy systems, the incentive structures shall promote high-quality designs and installations. There are three approaches: flexible installation incentive (FII) approach, the performance-based incentive (PBI) approach, and the expected performance-based incentive (EPBI) approach. These are discussed further in this chapter.

A. Flexible Installation Incentives

The FII approach pays an upfront incentive calculated based on the relative expected performance of the system. This incentive structure takes into account the major aspects of the system to achieve high-performing system installations but does so while creating greater flexibility to builders.

SB 1 programs using this incentive structure shall take into account the following requirements and restrictions:

- Systems shall be installed with an azimuth within a designated range as determined by the program administrator.
- Systems may be required to be installed with a tilt within an allowed range as determined by the program administrator.

Program administrators shall calculate the incentive based on the incentive rate and must account for at minimum:

- Detailed performance characteristics data for modules (specified in Appendix B, Table B.1). These data shall be obtained from the library of eligible modules on the Energy Commission’s eligible equipment list for modules.
- Detailed performance data for inverters (performance curves over range of voltage and power conditions applicable). These data shall be obtained from the Energy Commission’s eligible equipment list for inverters.
- Adjustments to performance based on the geographic location of the system. The determination of appropriate adjusting or scaling factors will be at the discretion of the program administrator.

- Any shading beyond the minimal shading criteria outlined in Appendix C, Section B, Subsection 5(a).

Program administrators of SB 1 programs using this incentive structure shall detail the specific FII eligibility criteria and incentive calculation in the program handbooks.

B. Performance-Based Incentives

Providing a PBI[37] is the preferred way to promote high-performing systems since the solar energy systems receive incentives based on the actual production (kWh) over the period during which the incentives are being paid. The PBI incentive payment is calculated by multiplying the incentive rate ($/kWh) by the measured kWh output.

The PBI payments shall be made over a minimum five-year period following system installation, submission, and approval of incentive claim materials. Payments shall be based on a $/kWh incentive rate and the actual electricity (kWh) produced in periods established by the program administrator.

C. Expected Performance-Based Incentives

The expected performance-based incentive (EPBI) approach pays an upfront incentive based on calculated expected performance, taking into account all major factors that affect performance of the particular installation in a given location. This incentive method may be more appropriate than a PBI approach for systems installed on newly constructed buildings or for smaller systems. ~~The EPBI approach shall be used for systems that do not use the PBI approach.~~

To meet the expectations of SB 1 for optimal system performance during periods of peak demand and IEPR policy to target PV deployment to achieve the greatest cost benefit, EPBI shall be based on time-dependent value (TDV) weighted hourly generation.[38]

The EPBI calculation shall be based on hourly modeling of the interactive performance of solar energy systems using the third-party tested performance characteristics of the specific modules and the inverter over the range of conditions that affect component performance. This calculation addresses all installation characteristics expected to affect significantly the performance of the components and the solar radiation, ambient temperature, and wind conditions expected at the site.

The hourly performance of the system shall be based on the interaction of the components due to the expected conditions during each hour. The hourly production shall be weighted in each hour to account for the time-dependent value to the utility of that hour's production to obtain

37 As an example, the CPUC's California Solar Initiative program requires larger solar energy systems (for example, those 100 kWAC or larger capacity beginning in 2007) to use PBI. The CSI program also requires PBI for systems 50 kWAC and larger as of January 1, 2008, and for systems 30 kWAC and larger as of January 1, 2010. Projects below these size thresholds may voluntarily use the PBI approach.

38 Information on TDV can be referenced at http://www.energy.ca.gov/title24/2008standards/prerulemaking/documents/E3/index.html.

the annual time-dependent weighted energy results for the system (kWh_{TDV}). The total incentive for the solar energy system is based upon the annual kWh_{TDV} performance.

1. Hourly Photovoltaic Production Calculation

The PV production shall be calculated using a model that complies with the following minimum requirements:

- The calculation model shall cover fixed flat-plate collector technologies at a minimum and include single- and dual-axis tracking if the program administrators allow these technologies to have incentives under the EPBI approach.[39]
- The model shall use hourly weather data for 1 of the 16 climate zones in California, with the use of solar radiation (global horizontal, direct normal, and diffuse), dry bulb temperature[40], and wind speed as minimum parameters in calculation to describe the conditions for the hour.
- The model shall determine the incident solar radiation on the modules based on the azimuth and tilt angle of the installation, using the weather data and location longitude and latitude information.
- The model shall use the detailed performance characteristics data for modules (specified in Appendix B, Table B.1) in determining the hourly production at given conditions for the hour (both weather and electrical). These data shall be obtained from the library of eligible modules on the Energy Commission's eligible equipment list for modules.
- The model shall have the ability to determine the operating voltage of a system at a given hour by discerning the circuit design of the system in terms of the number of modules in each string and the number of strings.
- The model shall account for the mounting offset of the array from a surface below to assess the change in operating temperature (normal operating cell temperature impact). This is especially important to determine the performance of building-integrated photovoltaics (BIPV), as compared to rack-mounted modules.
- The model shall account for the height above the ground that the array is mounted to capture the effect of wind speed on the module operating temperature.
- The model shall use detailed performance data for inverters (performance curves over a range of voltage and power conditions applicable) in determining the hourly production at given conditions for the hour (weather and electrical). These data shall be obtained from the Energy Commission's eligible equipment list for inverters.[41]

39 Systems employing tracking may be offered incentives using the PBI approach as an alternative to developing a calculation of expected performance for these systems.

40 The temperature of air measured by a thermometer freely exposed to the air but shielded from radiation and moisture.

41 The list of eligible inverters referred to here is the list maintained by the Energy Commission at http://www.gosolarcalifornia.org/equipment/inverters.php.

- The model shall limit the production of the system based on the size and voltage of the array, inverter voltage, and power capacity.
- The model shall generate hourly estimates of PV production for the entire year, which can then be weighted by time-dependent value (TDV) multipliers.
- The model shall determine the solar position for each hour of the year in terms of altitude and azimuth (used to determine the effect of shading from an obstruction).
- The model shall determine the hourly effect of shading from obstructions using a shading protocol as described in Shading Verification, Appendix C.
- The model shall report the effective hourly production values for the entire year after factoring the effect of shading and applying the appropriate TDV multipliers for the climate zone and building type (residential or nonresidential).
- The model shall generate a performance verification table for each specific system that reports the expected production for the specific system and installation as a function of incident solar radiation and ambient temperature. This performance verification table shall enable field verification of actual vs. expected instantaneous production. This occurs by comparing the output reported by the performance meter to the value in the performance verification table at the specific incident radiation and ambient temperature, measured at the site at the time of the verification.
- Generate an output report as a printable report[42]. The output report shall include, at a minimum, the entire system description, including installation specifics for the system, location, shading details, and confirm all the inputs for the calculation, and the performance verification table.

2. Reference System and Location

The incentive calculation shall use a reference system and location established by the program administrator to convert an incentive level established in terms of \$/W to the $\$/kWh_{TDV}$ equivalent through the following calculation:

$$\$/\text{kWh}_{\text{TDV}} = \frac{\text{Reference System Watts}_{\text{CEC-AC}} \times \$/\text{Watt (incentive level)}}{\text{Reference System Annual kWh}_{\text{TDV}}}$$

The specification of the reference system shall include:[43]

- Location of the system to determine the weather data and corresponding applicable TDV factors to be used.

42 A program administrator may choose not to require the submission of this compliance certificate along with the incentive application.

43 For an example of a reference system specification, see the Energy Commission's New Solar Homes Partnership Guidebook at http://www.gosolarcalifornia.org/documents/nshp.php.

- Size of a system that represents the median in the applicable utility program.
- Selection of a reference module from the Energy Commission's eligible equipment list, along with all related performance characteristics, that is considered as a median for the applicable utility program.
- Selection of an inverter from the Energy Commission's eligible equipment list that is considered a median for the applicable utility program.
- The installation characteristics that comprehensively describe the system, including, but not limited to:
    - Azimuth.
    - Tilt.
    - Mounting offset (BIPV or rack with specific height above substrate).
    - Height above ground (one story or higher).
    - Electrical circuit design (modules per string and number of strings).
    - Shading conditions (minimal shading).
    - Other system losses (such as dirt, dust, and wiring losses).

The $/kWh$_{TDV}$ (or the $/W before the above conversion) shall be chosen to ensure that the full range of improvement in performance (in kWh$_{TDV}$) is provided with increasing incentives.

3. Incentive Calculation

The total incentive for the applicant system shall be determined by multiplying the TDV weighted annual kWh production with the $/kWh$_{TDV}$ determined in the previous step (using the reference system).[44]

$$\text{Total Incentive \$} = \text{Applicant System Annual kWh}_{\text{TDV}} \times \text{\$/kWh}_{\text{TDV}}$$

The basic structure of the Energy Commission's PV calculator[45] can be used to meet these requirements. The calculator can be modified or another calculator used, as long as it meets Requirements 1 through 15 of the Hourly Photovoltaic Production Calculation. The reference system, location, and incentive level are specified by the program administrator. POU program administrators may use time-of-use multipliers that are applicable to the administrators' service territories instead of TDV.

EXCEPTION: The CPUC and POU program administrators were not required to comply with the above hourly photovoltaic production calculation requirements as of July 1, 2009. The CPUC

44 The program administrator may adopt a tolerance of ± 5 percent for approving total incentive payments. The program administrator may allow variations in incentive amounts among the incentive application, field-verified performance, and payment claim requests up to this tolerance.

45 The current implementation of the Energy Commission PV calculator is a spreadsheet-based tool and runs the five-parameter PV model to determine the hourly production. The calculator will be made available upon request to any program administrator.

should determine whether it believes that changes should be made to the CPUC's CSI calculation methods and under what time frame it would make changes. POU program administrators may choose to use a calculation method that complies with the hourly photovoltaic production calculation requirements or the expected performance-based incentive calculation method used by the CPUC. The Energy Commission strongly encourages the CPUC's CSI program to upgrade the current methods for estimating the expected performance of solar electric generating systems to better promote high-quality solar energy systems with maximum system performance to promote the highest energy production per ratepayer dollar and to achieve optimal system performance during periods of peak electricity demand. The Energy Commission recommends that, as the CPUC upgrades its calculation methods, it endeavors to meet the hourly photovoltaic production calculation provisions of these guidelines. POU program administrators who choose to use the CPUC's expected performance-based incentives calculation method are expected to use improved versions that are updated to better meet the hourly photovoltaic production calculation provisions. The CPUC shall comply with the shading, performance verification, and field verification requirements of these guidelines.

D. Shading

The method that shall be used as the minimum criteria for addressing shading is detailed in Appendix C Field Verification and Diagnostic Testing of Photovoltaic Systems.

E. Peak Load

For systems receiving incentives under the expected performance calculation approach, the incentive shall be based on weighting the hourly production with TDV factors to promote systems with higher performance at peak load conditions. TDV factors have been developed for the 16 Building Energy Efficiency Standards climate zones in California using investor-owned utilities' (IOU) generation, transmission, and distribution cost data.[46]

POU program administrators should use either the TDV factors determined for the 16 climate zones or hourly time-of-use weighting factors that are applicable for the respective service territories.

F. Field Verification

To be eligible for incentive payment, FII[47] applicants, EPBI applicants and PBI applicants whose systems are smaller than 50 kW shall be required to successfully complete third-party field verification on a sampling basis. Field verification is encouraged for other PBI applicants. The field verification, at a minimum, shall include visual inspection of components, installation characteristics, and shading conditions to verify that the project is installed as represented in the incentive application, is operational, is interconnected, and conforms to the SB 1 eligibility

46 More information on TDV can be referenced at http://www.energy.ca.gov/title24/2008standards/prerulemaking/documents/E3/index.html.

47 If the FII option is implemented in a SB 1 incentive program, the program handbook shall detail the adopted FII eligibility criteria.

criteria. For FII and EPBI systems, performance shall be verified using the protocol described in Appendix C Field Verification and Diagnostic Testing of Photovoltaic Systems.

When third-party field verification is completed by a qualified Home Energy Rating System (HERS) rater, verification shall be completed in one of two ways:

1. Field verifications completed on a minimum sample size of 1 in 7 projects.
2. Field verifications completed on a minimum sample size of 1 in 15 projects. This option is available only for programs using the FII structure.

When the program administrator or the program administrator's designated qualified contractor completes the third-party field verification, verification shall be completed in one of two ways:

1. Field verifications completed on a sample size of 1 in 7 projects.

2. Field verifications completed on a sample size of 1 in 12 projects **and** complied with the following:

- The program administrator or the program administrator's qualified contractor is required to complete two successful field verifications on projects completed by a new qualified contractor before implementing the 1-in-12 field verification sampling on projects completed by that contractor.
- The program administrator or the program administrator's qualified contractor shall complete field verification on each self-installed project. Field verifications conducted on self-installed projects do not count toward the 1-in-12 field verification sampling.

The program administrator may require the inspection of additional projects from any qualified contractor and may determine whether to conduct an onsite field inspection randomly based on the contractor's participation in the solar incentive program.

If multiple utilities/program administrators participate in a single solar incentive program, all utilities shall follow the same field verification requirements to ensure that these requirements are applied consistently across all utilities in the program. Program administrators shall provide details on the chosen method of field verification in the respective solar incentive program guidelines.[48]

G. Installation

The installers shall certify all aspects of the installation using the protocol for field verification (Appendix C). This includes the actual components used, the installation characteristics, shading conditions, and the specified onsite instantaneous performance verification. The same protocol will be used by both the installer and the verifier, with the difference of the installer having better access to the installation in some cases. It will be the responsibility of the

48 Program administrators shall update their program requirements to reflect such changes.

installer to document all proof for items that may be more easily observed and measured by the installer than by the verifier.

EXCEPTIONS: The program administrator may waive the installer requirement to follow the field verification protocol under any one of the following conditions:

1. The program requires field verification on 100 percent of the systems (without using sampling approach).
2. The installer follows the alternate protocol described in Installer System Inspection, Appendix C and signs a certificate of having completed the same.
3. The installer follows an alternate testing protocol designed by the program administrator for FII projects.

H. Performance Monitoring and Maintenance

All systems using the PBI approach shall have a five-year service contract[49] with a performance monitoring and reporting service (PMRS).

For systems using the EPBI approach, PMRS requirements shall be determined by the program administrator. If multiple utilities participate in a single solar incentive program, all utilities shall follow the same PMRS and cost cap requirements to ensure that these requirements are applied consistently across all utilities in the program. Program administrators shall provide specific details on PMRS and cost cap requirements in their respective solar incentive program guidelines.[50]

For all systems, it is recommended that program administrators ensure that information regarding system maintenance is provided to the owner or facility manager of the property who has oversight of the system. The information should address, at a minimum, the following considerations:

- Cleaning schedule for the array to remove dirt and dust buildup.
- Periodic checking of electrical connections (for corrosion, and so forth).
- Checking the inverter for instantaneous power and long-term energy output, and diagnosing and taking corrective action if production is significantly lower than expected.
- Checking for tree/plant growth or other obstructions that cause shading on the array and advising how to minimize or eliminate that shading.

49 The applicant has the option of switching PMRS providers during this period, if necessary, but must demonstrate that the minimum five-year term of PBI payments is covered through a PMRS provider.

50 Program administrators shall update their program requirements to reflect such changes.

CHAPTER V: Energy Efficiency

This chapter specifies energy efficiency requirements that shall be met as conditions for ratepayer-funded incentives for newly constructed and existing residential and commercial buildings. The chapter identifies separate energy efficiency requirements for each type of building. As an alternative to meeting these requirements for specific buildings, program administrators may choose to use the Alternative Portfolio Energy Savings Approach described in Section G of this chapter. The energy efficiency requirements specified in this chapter are minimum requirements. Program administrators are encouraged to promote greater levels of energy efficiency as they find feasible.

A. Newly Constructed Buildings

Minimum energy efficiency criteria based upon California's *Building Energy Efficiency Standards* (Title 24, Part 6; herein Title 24 Standards) shall be conditions for the solar energy system incentive programs overseen by the CPUC, the Energy Commission, and POUs for all newly constructed buildings statewide.[51]

B. Residential Buildings

Newly constructed residential buildings may achieve higher energy efficiency levels than the requirements of the Title 24 Standards in effect at the time the application for a building permit is submitted.

For building permits submitted before January 1, 2010, the applicant is required to meet either of the following two tiers of energy efficiency:

- Tier I – 15 percent reduction in the combined space heating, space cooling, and water heating energy of the residential building compared to the 2005 Title 24 Standards.[52]
- Tier II – 35 percent reduction in the combined space heating, space cooling, and water heating energy of the residential building and 40 percent reduction in the space cooling energy of the residential building compared to the 2005 Title 24 Standards.[53]

51 Newly constructed buildings are ones for which the building permit for the solar energy system is approved prior to the original occupancy of the structure.

52 Tier I was developed to match the energy efficiency requirements of the New Construction Programs for investor-owned utilities such as those implemented by PG&E, SCE, and SDG&E.

53 Tier II was developed to encourage builders to go beyond the minimum requirements of Tier I. Tier II efficiency level was developed to match the Building America program requirements.

For building permits submitted on or after January, 1, 2010, and before July 1, 2014, the applicant is required to meet either of the following two tiers of energy efficiency:

- Tier I – 15 percent reduction in the combined space heating, space cooling, and water heating energy of the residential building compared to the 2008 Title 24 Standards.[54]
- Tier II – 30 percent reduction in the combined space heating, space cooling, and water heating energy of the residential building and 30 percent reduction in the space cooling energy of the residential building compared to the 2008 Title 24 Standards.[55]

For building permits submitted on or after July 1, 2014, and before January 1, 2017, the applicant is required to meet one of the following three tiers of energy efficiency:

- Code-compliant – at a minimum must meet the 2013 Title 24 Standards.[56]
- Tier I – achievement of appropriate energy efficiency improvements compared to the 2013 Title 24 Standards, as determined by the program administrator.
- Tier II – achievement of additional energy efficiency improvements compared to Tier I for the 2013 Title 24 Standards, as determined by the program administrator.

For building permits submitted after January 1, 2017, the program administrator may determine the appropriate energy efficiency tiers.

For either Tier I or II, each appliance provided by the builder shall be ENERGY STAR®[57] labeled if this designation is applicable for that appliance.

Solar water heating may be used to help meet the energy efficiency requirements of any energy efficiency tier.[58]

Field verification of energy efficiency measures shall be required and be consistent with Title 24 Standards field verification procedures and protocols in effect at the time the application for a building permit is submitted. The CF-1R[59] form used to demonstrate Title 24 compliance with the current *Building Energy Efficiency Standards* shall be provided with the solar incentive

54 Tier I was developed to match the energy efficiency requirements of the California Green Building Standards (Title 24, Part 11).

55 Tier II was developed to encourage builders to go beyond the minimum requirements of Tier I. Tier II efficiency level was developed to achieve energy efficiency best practices to align with the *Integrated Energy Policy Report (IEPR)* and the California Public Utilities Commission (CPUC) Strategic Plan initiatives.

56 Program administrators may impose additional criteria for code-compliant projects. For example, the NSHP Guidebook, 9th Edition, requires code-compliant to meet the building energy code requirements prior to claiming efficiency credit for the solar energy system.

57 ENERGY STAR® is a joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy. An ENERGY STAR designation is available for appliances that exceed minimum federal energy efficiency standards. For more information on the ENERGY STAR designation, go to http://www.energystar.gov.

58 For more information on using solar water heating to meet the energy efficiency requirements, please refer to the Go Solar California website http://www.gosolarcalifornia.org/solarwater/nshp/index.php.

59 This output report summarizes the minimum energy performance specifications needed for compliance, including the results of the heating and cooling load calculations.

application to the program administrator as proof of attainment of the Tier I or Tier II level. For these projects, compliance documents shall be completed by persons who are Certified Energy Plans Examiners (CEPE) or Certified Energy Analysts (CEA) by the California Association of Building Energy Consultants (CABEC). CABEC requires CEPEs and CEAs to have a certification for the residential standards, as well as separate certifications for each of the different editions of Title 24. At the time the compliance documentation is signed, the CEPE or the CEA must have a valid CABEC certification for residential buildings and for the edition of Title 24 in effect on the date on which the building permit application is submitted to the building department.

Code-compliant applications must meet current Title 24 Standards at a minimum and do not require energy efficiency field verification beyond those required for Title 24 compliance.

~~Investor-owned utilities (IOUs) fund energy efficiency programs through a public goods charge (PGC) with program oversight by the CPUC. POUs conduct and oversee their own energy efficiency programs. IOUs and POUs are strongly encouraged to provide energy efficiency incentives for each tier described in these guidelines.~~

C. Nonresidential Buildings

Newly constructed commercial buildings[60] may achieve higher energy efficiency levels than the requirements of the *Building Energy Efficiency Standards* (Title 24, Part 6) in effect when the application for a building permit is submitted.

For building permits submitted before January 1, 2010, the applicant is required to meet either of the following two tiers of energy efficiency:

- Tier I – 15 percent reduction in the combined space heating, space cooling, lighting, and water heating energy of the commercial building compared to the 2005 Title 24 Standards.[61]
- Tier II – 30 percent reduction in the combined space heating, space cooling, lighting, and water heating energy of the commercial building compared to the 2005 Title 24 Standards.[62]

For building permits submitted on or after January 1, 2010 and before July 1, 2014, the applicant is required to meet either of the following two tiers of energy efficiency:

- Tier I – 15 percent reduction in the combined space heating, space cooling, lighting, and water heating energy of the commercial building compared to the 2008 Title 24 Standards.[63]

60 For these guidelines, "commercial buildings" include all nonresidential buildings and structures.

61 Tier I was developed as the minimum level of participation to match the Leadership in Energy and Environmental Design (LEED) New Construction Energy and Atmosphere prerequisite.

62 Tier II was developed to encourage developers to go beyond the minimum requirements of Tier I. Tier II is in line with the 2030 Challenge http://www.architecture2030.org.

63 Tier I was developed as the minimum level of participation to match the energy efficiency requirements of the California Green Building Standards (Title 24, Part 11).

- Tier II – 30 percent reduction in the combined space heating, space cooling, lighting, and water heating energy of the commercial building compared to the 2008 Title 24 Standards.[64]

For building permits submitted on or after July 1, 2014, and before January 1, 2017, the applicant is required to meet one of the following three tiers of energy efficiency:

- Code-compliant – Must meet the current 2013 Title 24 Standards.
- Tier I – achievement of additional energy efficiency improvements compared to the 2013 Title 24 Standards, as determined by the program administrator.
- Tier II – achievement of additional energy efficiency improvements compared to Tier I for the 2013 Title 24 Standards, as determined by the program administrator.

For building permits submitted after January 1, 2017, the program administrator may determine the appropriate energy efficiency tiers.

For either Tier I or II, any equipment or appliance provided by the builder shall be ENERGY STAR-labeled if this designation is applicable to that equipment or appliance.

Solar water heating may be used to help meet the energy efficiency requirements of any energy efficiency tier.[65]

Compliance documents used to demonstrate Title 24 compliance, including the PERF-1 form[66] and accompanying supporting forms, shall be provided as proof of attainment of the Tier I or Tier II levels. Compliance documents shall be completed by persons who are CEPE- or CEA-certified by the CABEC.

Code-compliant applications must meet current Title 24 Standards and do not require energy efficiency field verification beyond Title 24 compliance.

For commercial buildings that are constructed in phases with the shell built first and further energy systems installed in later phases as tenant improvements, an agreement shall be made between the building owner[67] and the tenant. This agreement shall obligate future tenant improvements to install lighting, HVAC, and water-heating equipment necessary to meet the overall building tier level that was committed to by the building owner. A copy of the agreement shall be included with the solar energy system incentive application.

~~Investor-owned and publicly owned electric utilities are strongly encouraged to provide energy efficiency incentives for each tier described in these guidelines.~~

64 Tier II was developed to encourage developers to go beyond the minimum requirements of Tier I. Tier II energy efficiency level was developed to achieve energy efficiency best practices to align with IEPR and CPUC Strategic Plan initiatives.

65 For more information on using solar water heating to meet the energy efficiency requirements, please refer to the Go Solar California website http://www.gosolarcalifornia.org/solarwater/nshp/index.php.

66 The PERF-1 form is the Performance Certificate of Compliance that is produced by compliance software used to show compliance with Title 24.

67 An agreement may be made with a developer/property manager and the tenant.

D. Existing Buildings

1. Energy Audit, Information, and Disclosure

Specific information about energy efficiency measures shall be provided to the building owner. The intent of the information is for the person responsible for paying the utility bill and the person responsible for building operations to receive information on 1) the energy use of their building, 2) energy efficiency investigation options for their buildings, and 3) possible energy efficiency improvements. These persons may not be the same entity for all applications. For these guidelines, these persons are referred to as the building owner/manager/ratepayer.

The program administrator or the utilities covered by the program administrators shall provide information to the building owner/manager/ratepayer before the design and installation of any proposed photovoltaic system to enable the building owner/manager/ratepayer to make informed decisions on energy efficiency investments. The building owner/manager/ratepayer shall sign and provide to the program administrator a copy of the signed disclosure that certifies that this information was provided to him or her and identifies which, if any, energy efficiency measures will be taken. If measures are to be installed after the installation of the solar energy system, then the building owner/manager/ratepayer shall declare on the disclosure when the measures are expected to be installed.[68]

For existing commercial buildings with conditioned floor area of less than 100,000 square feet and for existing homes, an energy efficiency audit shall be conducted. The program administrator may allow online or telephone audits or may require onsite energy audits, as they specify for particular categories of customers. Building owners, managers, and/or ratepayers shall be responsible for submitting a copy of the audit results with their solar incentive applications. The information and disclosure shall be provided to the building owner/manager/ratepayer via a Web-based information portal or paper format. The building owner/manager/ratepayer shall complete and sign the disclosure form and submit a copy to the program administrator.

2. Information to Be Provided to the Building Owner/Manager/Ratepayer:

- Most recent 12 months of the energy consumption of the building—this information may be provided directly by the utility; if so, the program administrator is obligated to assure only that it was provided.
- List of building energy use assessment services and tools available for use by the building owner for further investigation—for commercial buildings, this list shall include information on available retrocommissioning services.
- List of possible cost-effective energy efficiency measures applicable to the building.
- List of current utility energy efficiency rebates and incentives that are available.

68 The data gathered through the information and disclosure process will be used to develop future energy efficiency requirements for solar energy system incentive programs.

3. Disclosures to Be Signed by the Building Owner/Manager/Ratepayer and Submitted With the Solar Incentive Application:

- Certification that the building owner/manager/ratepayer has received the above information.
- The energy use assessment services or tools the building owner/manager/ratepayer used to identify cost-effective energy efficiency measures that could be installed in the building.
- The energy efficiency measures that have been installed or will be installed before or in conjunction with the installation of the solar energy system.
- If energy efficiency measures are planned to be installed later, the date by which these measures are planned to be installed.
- A copy of the energy audit report for existing homes and businesses with less than 100,000 square feet.

E. Existing Commercial Buildings – Benchmarking, Retrocommissioning, and Efficiency Improvements

1. Benchmarking

For solar energy systems to be eligible for incentives when installed to serve an existing commercial building, the energy use intensity (EUI)[69] shall be benchmarked[70] using Portfolio Manager or the equivalent energy performance rating for building types that cannot receive a rating by Portfolio Manager. Portfolio Manager can be accessed on the Internet at https://www.energystar.gov/istar/pmpam/.

Building types that are not able to receive an energy performance rating using Portfolio Manager shall be benchmarked using the Energy Commission's equivalent energy performance rating system.[71]

2. Retrocommissioning

Retrocommissioning[72] shall be required for all existing commercial buildings that are 100,000 square feet or larger and have a benchmark rating of less than 75, or an equivalent energy performance rating as determined by the Energy Commission. Retrocommissioning is required to

69 EUI is a unit of measurement that represents the energy use of a building relative to size.

70 *Benchmarking* is a process that compares the energy use of the building to the energy use of a population of similar buildings.

71 The Energy Commission is working with the U.S. EPA on an equivalent rating system that can be used to benchmark commercial buildings not able to be rated using Portfolio Manager.

72 *Retrocommissioning* identifies how major energy-using equipment is being operated and maintained and to identify specific improvements to the performance of those energy-using systems. The process uses a whole-building-systems approach to identify problems and needed repairs or adjustments to achieve energy savings, occupant comfort, and improved systems performance. A commissioning agent identifies and makes the necessary equipment adjustments and identifies energy efficiency projects that will improve overall building performance. For further information regarding the benefits of retrocommissioning, see the *California Commissioning Guide: Existing Buildings*, California Commissioning Collaborative, 2006, at http://www.cacx.org/resources/documents/CA_Commissioning_Guide_Existing.pdf.

begin no later than one year after the completion of the installation of the PV system. Systems to be retrocommissioned include, but are not limited to:

- Heating, ventilation, and air-conditioning systems and controls.
- Lighting systems and controls.
- Daylighting systems and controls.
- Domestic hot water systems and controls.
- Renewable energy systems and associated equipment and controls.
- Process equipment and appliances specific to hospitals, restaurants, and hotels/motels.
- Refrigeration in supermarket and refrigerated warehouses.

Equipment repairs and adjustments and cost-effective energy efficiency measures identified in the building retrocommissioning assessment shall be implemented to improve the energy performance rating of a building. If a building is improved to exceed a rating of 75, further energy efficiency measures are not required. A building does not need to be rebenchmarked to receive an incentive. If equipment/appliance replacement is recommended during the retrocommissioning, the replacement shall be made with ENERGY STAR equipment or appliances, or equipment or appliances that qualify for utility energy efficiency incentives, whichever is more efficient. IOUs and POUs are strongly encouraged to provide energy efficiency incentives for retrocommissioning and for the installation of cost-effective energy efficiency measures, appliances, and equipment.

3. Commitment Agreement

For buildings equal to or larger than 100,000 square feet and with a benchmark or equivalent energy performance rating of less than 75, retrocommissioning, equipment repairs and adjustments, and energy efficiency improvements identified through a retrocommissioning assessment shall be completed either before or in conjunction with the installation of the solar energy system. Alternatively, retrocommissioning shall be committed to be completed later by the building owner/manager/ratepayer through a commitment agreement. The commitment agreement shall indicate when the retrocommissioning will begin and commit the owner/manager/ratepayer to complete equipment adjustments, or cost-effective efficiency improvements identified in the retrocommissioning assessment. The retrocommissioning shall begin no later than one year after the installation of the PV system.

4. Energy Efficiency Exceptions for Existing Commercial Buildings

The specific energy efficiency requirements in these guidelines for existing businesses are not required for the following:

- Agricultural and industrial buildings not covered by Portfolio Manager or the Energy Commission's equivalent benchmark rating are not required to be benchmarked.
- Energy efficiency is not required to be addressed when solar energy systems are not serving electricity to a building.

- The energy audit, benchmarking, and retrocommissioning are not required for buildings that have complied with Title 24 requirements for newly constructed buildings during the last 12 months before application for the solar energy incentive; proof of Title 24 compliance shall be included with the solar energy system incentive application.
- Retrocommissioning is not required for existing commercial buildings that have a current ENERGY STAR label.
- Retrocommissioning is encouraged but not required for PBI applicants.

F. Existing Residential Buildings

For solar energy systems serving an existing residential building, the energy audit, information, and disclosure requirements shall be met as discussed above.

1. Energy Audit Exception for Existing Residential Buildings

The energy audit is not required for buildings that have complied with Title 24 requirements for newly constructed buildings in the past three years before application for a solar energy incentive; proof of Title 24 compliance shall be included with the solar energy system incentive application. There is no exception for the other information and disclosure requirements.

G. Alternative Portfolio Energy Savings

As an alternative to the requirements discussed above, program administrators may instead design and conduct a program that achieves a total 20 percent energy efficiency savings over the group of EPBI participants in their SB 1 participation portfolio. This alternative enables program administrators to pursue different levels of energy efficiency with different program participants over time. Program administrators shall provide the Energy Commission with a three-year plan that describes the initiatives they will take to achieve this level of energy efficiency savings. Program administrators shall report annually to the Energy Commission on their progress in achieving a total 20 percent energy efficiency savings over the group of EPBI participants in their SB 1 portfolio. Energy Commission staff shall review the plans to determine that participants will successfully achieve the 20 percent savings.

The Energy Commission may return the plan to the program administrator for further development, if it deems necessary. Plans shall be considered for possible approval at a regularly scheduled Energy Commission business meeting and, once approved and implemented, shall be used as an alternative to the specific energy efficiency requirements otherwise required in these guidelines. Alternative portfolio energy-saving plans shall be approved by the Energy Commission at its discretion and may be rejected if the Energy Commission determines the plan will not result in the requisite 20 percent energy efficiency savings. If a plan is approved, the program administrators shall be required to report annually on their progress of achieving the 20 percent savings. The Energy Commission may discontinue its approval of a plan or direct an expansion or modification of the plan if the Energy Commission determines that progress under the plan to achieve the 20 percent energy savings is not being achieved.

Program administrators may conform the plan to the requirements in the previous sections of this chapter for any particular EPBI participating buildings in their SB 1 portfolio and establish an alternative portfolio energy savings plan covering just the remaining EPBI participating buildings. For example, a program administrator may conform the plan to the requirements in the previous sections for newly constructed buildings, both residential and commercial, and establish an alternative portfolio energy-savings plan just for existing EPBI participating buildings, both residential and commercial.

CHAPTER VI: Reporting Requirements

Under SB 1, local publicly owned electric utilities are required to make available key solar program information. This information shall be made available to its utility customers, the California State Legislature, and the Energy Commission.[73] This information shall be made available no later than July 1 of **each** subsequent year for the duration of the program.

These reporting requirements will provide state officials the information needed to monitor how these programs are progressing, ensure consistent program design and implementation, and determine what changes may be needed to effectively meet goals and targets established under SB 1. The annual reporting data is posted on the Energy Commission's website at http://www.energy.ca.gov/sb1/pou_reports/index.html.

A. Reporting Requirements

The reporting period shall be from January 1 to December 31 of the prior year. Each POU shall report the following information.

1. Solar program overview and contribution toward goals, including:
    a. Outreach and marketing, overview of program administration, and activity during reporting period.
    b. Problems identified and resolutions or recommended mitigation.
    c. Opportunities for the year ahead.
2. Number of submitted applications, including:
    a. Number of applications received.
    b. Number of EPBI, FII, and PBI applications approved and rejected/cancelled.
    c. Primary reasons for application rejections/cancellations.
3. Total incentives awarded, including:
    a. Total solar funds collected for the life of the program.
    b. Total solar incentive expenditures by category (reserved/awarded, paid, administration, marketing).
4. The total number of systems installed, including:

73 Initially required by Public Utilities Code Section 387.5 (e). Now required by Public Utilities Code Section 9507 (c) and Section 9508 (d), effective January 1, 2013.

a. Breakdown for installations serving newly constructed buildings (Tier I vs. II, if available) and existing buildings.

b. Breakdown by category type, including:

    1. Residential

        a) Market-rate housing

        b) Affordable housing/low-income

    2. Commercial

    3. Nonprofit

    4. Government

    5. Industrial

    6. Agricultural

    7. Mixed-use

5. Amount of added solar capacity installed and expected generation:

    a. For PV systems, the solar electric capacity added in kilowatts (kW_{AC}) and the estimated annual electrical generation in kilowatt hours (kWh).

    b. For other solar electric generating systems, the solar electric capacity added in kilowatts (kW_{AC}), the estimated annual electrical generation in kilowatt hours (kWh), and a description of the specific technology deployed.

6. Program support activities and goals, including:

    a. Any training or builder/installer assistance, if available.

    b. Auditing of installed systems, if available.

    c. Goals in kilowatts (kW_{AC}) for program duration, if available.

Each local publicly owned electric utility shall submit an electronic version to the Energy Commission no later than June 1 of each program year. Electronic copies can be sent to renewable@energy.ca.gov or the SB 1 program lead. For more details go to the Energy Commission's website at http://www.energy.ca.gov/sb1/index.html.

LIST OF ACRONYMS

AC: Alternating current

BESS: Battery energy storage system

BIPV: Building-integrated photovoltaics

CABEC: California Association of Building Energy Consultants

CEA: Certified Energy Analyst

CEPE: Certified Energy Plans Examiner

CPUC: California Public Utilities Commission

CSI: California Solar Initiative

CSIP: Common Smart Inverter Profile

DC: Direct current

EPBI: Expected performance-based incentive

EUI: Energy use intensity

FII: Flexible Installation Incentive

HERS: Home Energy Rating System

HVAC: Heating, ventilation, and air conditioning

IEPR: *Integrated Energy Policy Report*

IEC: International Electrotechnical Commission

IEEE: Institute of Electrical and Electronics Engineers

IOU: Investor-owned utility

ILAC: International Laboratory Accreditation Cooperation~~Corporation~~

kW: Kilowatt

kWh: Kilowatt hour

MRA: Mutual Recognition Arrangement

MW: Megawatt

NOCT: Nominal operating cell temperature

NRTL: Nationally Recognized Testing Laboratory

NSHP: New Solar Homes Partnership

OSEGT: Other solar electric generating technology

PBI: Performance-based incentive

PMRS: Performance monitoring and reporting service

POU: Publicly owned utility

PV: Photovoltaic

OSHA: Occupational Safety & Health Administration

SB 1: Senate Bill 1

SB 83: Senate Bill 83

TDV: Time-dependent value

UL 1741 SA: UL 1741 safety standard, inclusive of Supplement SA testing

APPENDIX A: Criteria for Adding Equipment to or Removing Equipment From the Energy Commission's Eligible Equipment Lists

This appendix summarizes the criteria and procedures for adding to or removing equipment from the Energy Commission's eligible equipment lists. Equipment that is included on the Energy Commission's eligible equipment lists may be used in a renewable energy system that is eligible for a solar electric incentive under SB 1.

A. Procedure for Adding Equipment to the Energy Commission's Eligible Equipment Lists

To be included on the eligible equipment lists, equipment must meet nationally or internationally recognized electrical standards or other appropriate criteria, information submittal requirements, and other requirements specified by the Energy Commission. Until the equipment is determined eligible for incentives by the Energy Commission and included in the Energy Commission eligible equipment lists (lists of eligible equipment), no funding may be reserved or paid for a system using such equipment. Equipment that has not met the aforementioned requirements will not be included in the lists of eligible equipment.

To have equipment reviewed for incentive eligibility by the Energy Commission, the equipment manufacturer must provide the Energy Commission with:

- The name, address, and contact information for the equipment manufacturer.
- A description of the equipment, including the equipment type, model number, system specifications, such as type of solar module and mounting type, and any other additional information requested on the equipment application form.
- Certification ~~D~~documentation ~~demonstrating that the equipment has a product certification~~ from a~~n~~ NRTL indicating compliance with applicable standard(s) and that the equipment meets all other testing and performance requirements.
- A copy of applicable ~~certification and~~ test reports.
- Any additional product information necessary to determine the efficiency and performance of the equipment.
- ~~A declaration confirming the equipment is new, unused, and not rebuilt or refurbished equipment.~~

PV modules, inverters, battery storage, and meters are periodically added to and removed from the lists of eligible equipment.

B. Procedure for Removing Equipment From the Energy Commission's Eligible Equipment Lists

The Energy Commission may remove equipment from the lists of eligible ~~PV modules, inverters, or meters~~equipment ~~by~~ after providing the manufacturer ~~of such equipment~~ with notice of the removal ~~of the equipment~~. If the manufacturer has provided a valid email address to the Energy Commission, then notice by email shall be provided to the manufacturer. If the manufacturer has not provided a valid email, then notice shall be sent to the manufacturer's physical mailing address if one has been provided by the manufacturer. If the manufacturer has not provided the Energy Commission with a valid email address or physical mailing address, then notice of removal shall be posted on the Energy Commission's website on the following publicly accessible page: (LINK TO BE ADDED). ~~The~~All notices shall identify the reason(s) for the removal of the equipment and ~~shall~~ provide the manufacturer at least 10 business days ~~from receipt of the notice~~ from transmittal or posting to respond to the Energy Commission and address the stated reason(s) for removing the equipment[74].

Pending the manufacturer's response to a notice of removal, the Energy Commission and/or program administrators may suspend processing of any reservation applications or applications for funding that propose a renewable energy system using the equipment subject to removal. ~~In addition, the Energy Commission shall alert consumers and program participants of the equipment subject to removal by posting information on the Energy Commission's website.~~

If a component is removed from an eligible equipment list before an incentive reservation or application for funding is granted, applicants may be required to modify their systems by replacing the removed component with an eligible component before a payment is approved.

The Energy Commission reserves the right to remove any equipment from its eligible equipment lists for any reason that adversely affects the goals or successful implementation of the program, including, but not limited to, an invalid or expired safety certification, poor equipment performance, concerns about equipment design or safety, concerns about the quality of the data presented for equipment eligibility, or lack of manufacturer support for equipment maintenance and warranties. ~~The equipment in question may be removed from the list of eligible equipment at any time and may be subject to further review.~~

74 This process does not preclude the Energy Commission from initiating a formal review of the equipment in question following the complaint and investigatory process set forth in the California Code of Regulations, Title 20, Section 1230, et seq.

APPENDIX B: Criteria for Testing and Certification Before Adding Equipment to the Energy Commission's Eligible Equipment Lists

This appendix summarizes the criteria used for testing and certification of components to meet the requirements for inclusion on an eligible equipment list. Eligible equipment ~~(PV modules, inverters, and performance meters)~~ is periodically added to and removed from the equipment lists~~ of eligible equipment~~.

The Energy Commission does not certify or test equipment. ~~Where a certification is required to be submitted to the Energy Commission for a system component to become eligible for incentives,~~ The Energy Commission relies on certifications and test data produced by third parties.

The Energy Commission lists equipment that meet select safety and performance standards as applicable, but does not guarantee or warranty listed equipment safety, performance, or durability.

A. Photovoltaic Modules

All flat-plate PV modules shall have certification conducted by a~~n~~ NRTL[75] to an American National Standard for safety. UL 61730 certification from a NRTL shall be accepted as proof of compliance to applicable requirements as of the effective date of these guidelines. UL 1703 certification from a NRTL may be used for equipment listing requests submitted through December 31, 2019. For incentive eligibility, a unique model number shall be required for each PV module that has a different power rating. Manufacturers may distinguish multiple PV modules at a given power rating by using additional unique model numbers. For incentive eligibility, each unique model number shall be explicitly identified on the ~~UL 1703~~ certification documentation.

Additional testing shall be conducted to specific subsections of IEC Standard 61215, *Crystalline ~~S~~silicon ~~T~~terrestrial ~~P~~photovoltaic (PV) ~~M~~modules - Design ~~Q~~qualification and ~~T~~type ~~A~~approval~~,~~* (second ~~E~~edition~~ 2.0~~, April 2005~~2005-04~~), or IEC Standard 61646, *Thin~~-F~~film ~~T~~terrestrial ~~P~~photovoltaic (PV) ~~M~~modules – Design ~~Q~~qualification and ~~T~~type ~~A~~approval~~,~~* (second ~~E~~edition~~ 2.0~~, May 2008~~-05~~), except as specified in Note 3 of Table B.1 below. The additional testing shall be conducted by a laboratory with accreditation to ISO/IEC 17025 from an accreditation body that

75 Nationally Recognized Testing Laboratories must be approved to conduct test UL 61730 or UL 1703 (as applicable) under the scope of their OSHA recognition. Not all Nationally Recognized Testing Laboratories recognized by OSHA are approved to test for UL 61730 or UL 1703.

has signed the ILAC MRA and with an accreditation scope that includes IEC 61215:2005 and/or IEC 61646:2008.

IEC Standard 61215:2005 Sections

- 10.2 Maximum Power Determination
- 10.4 Measurement of Temperature Coefficients[76]
- 10.5 Measurement of Nominal Operating Cell Temperature (NOCT)
- 10.6 Performance at Standard Test Conditions (STC) and NOCT
- 10.7 Performance at Low Irradiance

IEC Standard 61646:2008 Sections

- 10.2 Maximum Power Determination
- 10.4 Measurement of Temperature Coefficients[77]
- 10.5 Measurement of NOCT
- 10.6 Performance at STC and NOCT
- 10.7 Performance at Low Irradiance
- 10.19 Light-Soaking

Manufacturers providing certification to UL 61730 as proof of safety certification shall comply with the provisions of UL 61730-2, Annex DVA, by sampling production modules as defined.

For manufacturers electing to use UL 1703 (as allowed in Chapter III, Section A), ~~T~~the factory-measured maximum power of each production module, as specified in UL 1703, Section 44.1, and the lower bound of the manufacturer's stated tolerance range, under UL 1703, Section 48.2, shall be no less than 95 percent of the maximum power reported to the Energy Commission.

The performance data and information in Table B.1 shall be submitted to the Energy Commission in a test report issued by the laboratory that completed the testing. This data may be made available to the public. For multiple model numbers, data may be grouped together as described in Section A.2 below.

76 The Energy Commission requires the reporting of the three~~five~~ temperature coefficients~~, whereas~~ tested in IEC 61215 ~~requires the reporting of only three temperature coefficients~~.

77 The Energy Commission requires the reporting of the three~~five~~ temperature coefficients~~, whereas~~ tested in IEC 61646 ~~requires the reporting of only three temperature coefficients~~.

Table B.1: Module Performance Parameter Testing

Parameter	Symbol	Units	Notes
Maximum Power	P_{max}	Watts	1, 5
Voltage at Maximum Power	V_{pmax}	Volts	1, 5
Current at Maximum Power	I_{pmax}	Amps	1, 5
Open Circuit Voltage	V_{oc}	Volts	1, 5
Short Circuit Current	I_{sc}	Amps	1, 5
Nominal Operating Cell Temperature	NOCT	˚C	3
Temperature Coefficients	β_{Voc} (at V_{oc}) ~~β_{Vpmax} (at V_{pmax})~~ α_{Isc} (at I_{sc}) ~~α_{Ipmax} (at I_{pmax})~~ γ_{Pmax} (at P_{max})	%/˚C	2
Voltage at Maximum Power and Low Irradiance	$V_{pmax,low}$	Volts	4
Current at Maximum Power and Low Irradiance	$I_{pmax,low}$	Amps	4
~~Open Circuit Voltage at Low Irradiance~~	~~$V_{oc,low}$~~	~~Volts~~	~~4, 6~~
~~Short Circuit Current at Low Irradiance~~	~~$I_{sc,low}$~~	~~Amps~~	~~4, 6~~
Voltage at Maximum Power and NOCT	$V_{pmax,NOCT}$	Volts	5
Current at Maximum Power and NOCT	$I_{pmax,NOCT}$	Amps	5
~~Open Circuit Voltage at NOCT~~	~~$V_{oc,NOCT}$~~	~~Volts~~	~~5, 6~~
~~Short Circuit Current at NOCT~~	~~$I_{sc,NOCT}$~~	~~Amps~~	~~5, 6~~

Notes:

1) Values shall be measured at standard test conditions after preconditioning according to IEC Standard 61215:2005, Section 5, or after light-soaking according to IEC Standard 61646:2008, Section 10.19. Modules may be light-soaked by the manufacturer prior to submitting the modules to a testing laboratory. The testing laboratory shall verify the module stabilization in accordance with IEC Standard 61646:2008, Section 10.19.
2) Values shall be measured and calculated according to IEC ~~Standards~~ 61215:2005 and IEC 61646:2008, Section 10.4.
3) Values shall be measured in accordance with IEC ~~Standards~~ 61215:2005 and IEC 61646:2008, Section 10.5. For BIPV modules, the measurements shall be made using the mounting specified below.
4) Values shall be measured at low irradiance according to IEC ~~Standards~~ 61215:2005 and IEC 61646:2008, Section 10.7.
5) Values shall be measured at STC and NOCT according to IEC ~~Standards~~ 61215:2005 and IEC 61646:2008, Section 10.6.

~~6) The submission of these data is optional.~~

Source: California Energy Commission

If the optional performance testing for PV modules described in Appendix B, Section A, Subsection 1 below becomes available, then these optional performance testing specifications can be used in place of the currently identified testing requirements for list eligibility.

1. Optional Performance Testing for PV Modules

Starting on the effective date of these guidelines, the Energy Commission will accept additional performance testing results acquired in accordance with the currently active version of IEC 61853, *Photovoltaic (PV) module performance testing and energy rating*. The testing shall be conducted by a laboratory with accreditation to ISO/IEC 17025 from an accreditation body that has signed the ILAC MRA, and that has an accreditation scope that includes the applicable version of IEC 61853.

Manufacturers that elect to provide this data shall submit the test report produced by the testing laboratory. This data will be inclusive of the maximum power, open circuit voltage, short circuit current, and voltage at maximum power at the different testing conditions specified in the standard. The data provided may be used to evaluate the PV module performance and the effects if temperature and radiation variances.

~~1.~~2. Mounting Specifications for NOCT Testing for Building Integrated Photovoltaic (BIPV) Modules Intended for Roof-Integrated Installations

Tilt Angle: The test modules shall be positioned so that they are tilted at 23° ± 5° (5:12 roof pitch) to the horizontal.

Configuration: The test modules shall be in the middle of an array that is at least four feet high and four feet wide. The array shall be surrounded on all sides with a minimum of three feet of the building system for which the BIPV system is designed to be compatible, and the entire assembly shall be installed and sealed as specified by the manufacturer for a normal installation.

Substrate and Underlayment: The test modules shall be installed on a substrate of oriented strand board with a minimum thickness of 15/32-inch that is covered by #30 roofing felt with a minimum R-10 continuous insulation under and in contact with the oriented strand board and include any other manufacturer-recommended underlayments.

~~2.~~3. Grouping of Modules for Testing

For testing and reporting of performance values, families of similar modules may be grouped together to reduce the required number of tests.

Module similarity for grouping of modules for testing shall be determined by the ISO/IEC 17025 accredited laboratory performing the additional testing as required on pages B-1 and B-2. ~~The August 14, 2015, draft version of~~ IEC~~/~~ TS 62915~~, Edition 1.0~~ *Photovoltaic (PV) Modules –* ~~Retesting for t~~*Type approval, design and safety qualification - Retesting* shall~~may~~ be used for guidance.

For each group, the following tests shall be performed on a model number that has an STC power rating that is within 95 percent (rounded to the nearest watt) of the highest STC power rating in the group:

1. Nominal operating cell temperature (NOCT) determination
2. Temperature coefficient of short-circuit current
3. Temperature coefficient of open-circuit voltage

~~4. Temperature coefficient of maximum power current~~

~~5. Temperature coefficient of maximum power voltage~~

~~6.~~4. Temperature coefficient of maximum power

Each group can be further categorized into subgroups where one model number will have further testing performed. All model numbers included in the subgroup shall have the same number of cells. The subgroup may contain model numbers such that the highest STC power rating in the subgroup is 110 percent (rounded to the nearest watt) of the tested model number STC rating of the subgroup and the lowest STC power rating in the subgroup are 90 percent (rounded to the nearest watt) of the tested model number STC rating of the subgroup. The tested model number in each subgroup shall be tested for:

Performance at STC:

1. Short-circuit current
2. Open-circuit voltage
3. Current at maximum power
4. Voltage at maximum power
5. Maximum power

Performance at NOCT:

~~1. Short-circuit current (optional)~~

~~2. Open-circuit voltage (optional)~~

~~3.~~1. Current at maximum power

~~4.~~2. Voltage at maximum power

Performance at low irradiance:

~~1. Short-circuit current (optional)~~

~~2. Open-circuit voltage (optional)~~

~~3.~~1. Current at maximum power

~~4.~~2. Voltage at maximum power

Example: If a manufacturer has a family of identical modules with STC power ratings of 160 W, 165 W, 170 W, 175 W, 180 W, 185 W, 190 W, 195 W, and 200 W, the following testing is required. For the 190 W module, NOCT determination and temperature coefficient testing shall be performed. The results from these tests are applicable to the entire group of modules. Subgroups can then be created as follows:

175 W, 180 W, 185 W, 190 W, 195 W, and 200 W

160 W, 165 W, and 170 W

For the 190 W and 165 W modules, the specified performance testing at the following conditions shall be performed: STC, NOCT, and low irradiance. The results from these tests apply to the modules in the respective subgroup.

4. Additional Optional Testing for PV Modules

The Energy Commission will identify photovoltaic modules that have voluntarily completed additional testing, in accordance with the currently active version of IEC 61215, *Terrestrial photovoltaic (PV) modules - Design qualification and type approval* (all parts, beyond the required minimum testing for eligibility. The testing shall be conducted by a laboratory with accreditation to ISO/IEC 17025 from an accreditation body that has signed the ILAC MRA, and that has an accreditation scope that includes the applicable version of IEC 61215. Module similarity for grouping of modules for testing shall be determined by the ISO/IEC 17025-accredited laboratory performing the optional testing. IEC TS 62915 shall be used for guidance.

Listings may also reflect additional optional data for PV modules. These optional data may be voluntarily submitted to support additional identification of design and performance characteristics on the eligible equipment list for PV modules. Any optional information or data provided will not be part of the eligibility requirements to be added to the list.

B. Inverters

All inverters shall have certification conducted by a~~n~~ NRTL[78] to UL 1741. Smart inverters, as defined in Chapter III, Section C, shall additionally provide applicable documentation as follows:

- Certification for UL 1741 SA from a NRTL, and associated test report or test summary.
- Certification for CSIP from SunSpec Alliance.
- Certification for IEEE 1547:2018 (or later) and associated conformance test procedures from a NRTL.

78 Nationally Recognized Testing Laboratories must be approved to test for UL 1741 under the scope of their OSHA recognition. Not all the Nationally Recognized Testing Laboratories recognized by OSHA are approved to test for UL 1741.

Alternative test procedures or certifications may be used, in accordance with the conditions stated in Chapter III, Section C.

Each model of inverter shall also be tested by a NRTL for performance ratings according to sections of the test protocol titled *Performance Test Protocol for Evaluating Inverters Used in Grid-Connected Photovoltaic Systems*, prepared by Sandia National Laboratories, Endecon Engineering, BEW Engineering, and Institute for Sustainable Technology, October 14, 2004, version[79] ~~and the *Guidelines for the Use of the Performance Test Protocol for Evaluating Inverters Used in Grid-Connected Photovoltaic Systems*~~. This version of the test protocol ~~and guidelines are~~is available on the Energy Commission website at: http://www.gosolarcalifornia.org/equipment/documents/2004-11-22_Test_Protocol.pdf ~~and http://www.gosolarcalifornia.org/equipment/documents/Sandia_Guideline_2005.pdf~~. The tests shall be performed in accordance with Sections 3, 4, 5.1, and 5.2 of the test protocol, as further clarified in the guidelines. The following tests are required:

- **Maximum Continuous Output Power.** Section 5.4 shall be performed in entirety for test condition A of Table 5-2 with the following exceptions: 1) the test shall be performed at an ambient temperature of 40˚C, rather than 45˚C, and 2) the dc V_{nom} may be selected by the manufacturer at any point between V_{min} +0.25* (V_{max}-V_{min}) and V_{min}+0.75* (V_{max}–V_{min}). It is not necessary to perform Section 5.4 for test conditions B through E of Table 5-2.
- **Conversion Efficiency.** Section 5.5 shall be performed for test conditions A, B, and C of Table 5.3, subject to the following: 1) the tests shall be performed with dc V_{nom} equaling the same voltage as selected above for the Maximum Continuous Power Output test, 2) steps 1 through 8 of the test procedure (Section 5.5.1) shall be performed at 25˚C, and not at 45˚C, 3) the DC input power shall be adjusted such that the unit produces AC power equal to or less than the power produced from the Maximum Continuous Output Power test, and ~~3~~4) to reduce time for each test condition, begin at the highest power level and go to the lower power levels. If done in this order, it will be necessary only to wait for temperature stabilization at the 100 percent power level. In addition, the unit only needs to be operated at full output power for one hour, rather than 2.5 hours, and no preheating is necessary if the Conversion Efficiency test is performed within 1 hour of full operation under test ,5.4 provided the unit has not been exposed to ambient temperature of less than 22˚C.
- **Tare Losses.** Section 5.7.1 shall be performed in entirety. It is not necessary to perform the tests under Section 5.7.2 or Section 5.7.3.

All of the above data will be used as inputs for calculating the expected performance of the system.

79 This version of the test protocol is identified by the file name “InvertrTestProto_041014.doc” as shown in the left-hand side of the footer on each page of the protocol.

The tests for Power Foldback (Section 5.8) and Inverter Performance Factor/Inverter Yield (Section 5.9) are NOT required.

The data and reports resulting from the tests for Maximum Continuous Output Power (Section 5.4), Conversion Efficiency (Section 5.5) and Tare Losses (Section 5.7.1) shall be submitted to the Energy Commission and will be made public. The inverter tested shall use the same hardware and software configuration evaluated during the certification to UL 1741.

C. Meters

All eligible meters shall comply with the requirements stated below, to be identified as eligible on the Energy Commission's ~~Meter E~~eligible ~~E~~equipment ~~L~~list for meters. Meter Measurement: Meters shall measure net generated energy output as well as instantaneous power.

- Meter Testing Standards: ± 2 percent meters shall be tested by a~~n~~ NRTL, according to all applicable ANSI C-12 testing protocols.
- Meter Certification: Meter accuracy ratings shall be certified by a~~n~~ NRTL. All test results or NRTL documentation supporting the certification shall be maintained on file for inspection by the Energy Commission.
- Meter Data Access: All meters shall provide the PMRS provider with the ability to access and retrieve the minimum required solar performance/output data from the meter using the Meter Communication/Data Transfer Protocols. In the event that the system is not required to have a PMRS provider, the system owner shall have a means to retrieve the minimum required solar performance/output data from the meter.
- Meter Display: All meters shall provide a display showing measured net generated energy output and measured instantaneous power. This display shall be easy to view and understand. This display shall be located either on the meter, inverter, or on a remote device.
- Meter Memory and Storage: All meters shall have the ability to retain collected data in the event of a power outage. Meters that are reporting data remotely shall have sufficient memory to retain 60 days of data if the standard reporting schedule is monthly and 7 days of data if the standard reporting schedule is daily. Meters that do not remotely report the data shall retain 60 days of data. In all cases, meters shall be able to retain lifetime production.

D. Battery Storage

All battery energy storage systems and batteries shall have certification conducted by a NRTL to UL 9540 and UL 1973, respectively. Each equipment must have a unique model number; the model number shall be included in the certification. NRTL certification testing shall include all of the technology-appropriate appendices and annexes from UL 9540 or UL 1973.

Proof of other safety testing and certifications exceeding the above minimum safety requirements may be reflected on the equipment lists.

APPENDIX C: Field Verification and Diagnostic Testing of Photovoltaic Systems

A. Background

This appendix covers the minimum requirements of the field verification protocol to be followed for applicant systems using the EPBI and FII approaches. At this time, it addresses systems that use fixed, flat-plate collector technology.[80] For the EBPI approach, third-party field verification shall be conducted on a minimum sample of 1 in 7 projects, or 1 in 12 projects, if the additional requirements in Chapter IV are met. For the FII approach, third-party field verification shall be conducted on a minimum sample of 1 in 15 projects. Testing will ensure that the components of the solar system, installation, performance, and shading estimation are consistent with the characteristics used to determine the estimated performance.

B. EPBI Testing Protocol

The EPBI incentive amount is based on the expected performance of the solar system, which accounts for the tested and certified performance of the specific modules and inverter, the mounting type, cell temperature, the orientation and tilt of the modules, and the extent to which the system is shaded. A calculator tool will account for these parameters that are under the control of the owner and installer, as well as the solar and climatic conditions for the building location, to determine hourly estimated production, which is weighted to account for the time-dependent valuation of the electricity that is produced. Third-party field verification shall be conducted to ensure that the components of the solar system and installation are consistent with the characteristics used to determine the estimated performance. Field verification can be carried out by a HERS rater or the program administrator (or the program administrator's designated qualified contractor).

The field verification and diagnostic testing procedures described in this section are intended to ensure that the:

- PV array and inverters used in the expected performance calculations are actually installed at the applicable site.
- PV array is minimally shaded, or if shaded, that the actual shading does not exceed the shading characteristics that were included in the expected performance calculations.
- Measured AC power output from the system matches the expected AC power output table at the prevailing conditions at the time of field verification and diagnostic testing.

80 Tracking and concentrating solar technologies may be addressed in an update of these guidelines. Program administrators may specify a field verification protocol for such technologies.

1. Responsibilities

Field verification and diagnostic testing are the responsibility of both the PV system installer and the verifier who completes the third-party field verification. The PV installer shall perform the field verification and diagnostic testing procedures in this document for every system that is installed. The verifier then performs independent third-party field verification and diagnostic testing of the systems. The third-party field verification shall be conducted on a minimum sample of 1 in 7 projects, or 1 in 12 projects if the additional requirements in Chapter IV are met.

The field verification and diagnostic testing protocol is the same for both the PV installer and the verifier. The protocol anticipates that the PV installer will have complete access to the system that the verifier may not have. For rooftop systems, the measurements required by this protocol are not required to be completed on the roof, but more accurate measurements are possible with roof access. The measurements required by the protocol may be performed in multiple ways as described in the subsections below.

EXCEPTIONS: The program administrator may waive the installer requirement to follow the field verification protocol under one of the following conditions:

1. The program requires field verification on 100 percent of the systems (without using sampling approach).
2. The installer follows the alternate protocol described in the Installer System Inspection section later in this appendix and signs a certificate of having completed the same.

2. Field Verification and Diagnostic Testing Process

The field verification and diagnostic testing of solar systems follow the process described below. A solar system is one or more strings of PV modules connected to one inverter[81]. Documentation of the process uses three forms that are counterparts to the compliance forms used for the *Building Energy Efficiency Standards*.

1. The applicant enters the necessary input data into a calculator, which produces an output report[82] that documents the specific modules, inverters, and meters that are used in each solar system that is installed on the building, the anticipated shading of each system (either the intent for the system to meet the minimal shading requirements or the actual shading that is anticipated), and a table of predicted AC power output for each system over a range of solar irradiance and ambient air temperature. The output report shall be provided to the program administrators at application time.

81 This definition of a solar system is applicable for field verification as outlined in this appendix only and not for program administration related to system size or program participation criteria. Multiple systems, such as microinverter-based systems, may be grouped for field verification using the sampling approach.

82 For NSHP, the output report is the CF-1R-PV Certificate of Compliance Form.

2. Once each solar system is installed, the PV installer completes either the field verification and diagnostic testing protocol or the alternate protocol for each solar system on the building and documents the results on the installer field verification certification[83], verifying that the installation is consistent with the calculator output report. The PV installer documents and certifies that the PV system meets the requirement of this appendix and provides a copy of the installation certificate to the owner/builder and to the verifier[84].

3. The verifier completes independent third-party field verification and diagnostic testing of each solar system and documents the results on the photovoltaic system inspection form[85], independently verifying that the installation is consistent with the calculator output report. The verifier provides a copy of the certificate of field verification and diagnostic testing to the owner/builder (and the HERS provider in the case where HERS raters are used for field verification).

4. The payment claim shall be based on system characteristics that produce expected performance calculations that are no better than calculations based on the characteristics reported in the certificate of field verification and diagnostic testing.

   In conjunction with the installation certificate, the applicant shall provide to the installer and verifier a site plan that for each lot:

   a) Identifies the height category (small, medium, or large) of all pre-existing, planted, and planned trees and the location and height of any structures that will be built on the lot and neighboring lots of the building with the solar system.

   b) Shows the bearing of the property lines and the azimuth and tilt or roof pitch of each PV array.

   EXCEPTIONS: A program administrator may exempt the following requirements for all retrofit projects (residential and nonresidential):

   1. Site plan showing property lines.

   2. Identification of unknown future trees.

   3. Identification of neighboring structures that are not already constructed or that are unknown to be planned for construction in the future.

83 For NSHP, the installer field verification certification is the CF-6R-PV Installation Certificate.

84 The installer certificate shall be submitted to the program administrator if the field verification is the responsibility of the program administrator and assigned to a field verifier thereafter.

85 For NSHP, the photovoltaic system inspection form is the CF-4R-PV Certificate of Field Verification & Diagnostic Testing.

5. The applicant shall also provide the verifier a product specification (cut sheet) for the modules, inverter, and meter for the specific system, along with an invoice or purchase document that specifies the make and model of PV modules installed in the project.

3. Relationship to Other Codes, Standards, and Verification

The local jurisdiction must issue a building permit for the qualifying PV system, either as a separate permit or as part of the new construction building permit or retrofit application. The PV system must meet all applicable electrical code, structural code, and building code requirements. In addition, the local electric utility will have standards regarding interconnection to the electric grid and other matters that shall be complied with.

The field verification and diagnostic testing procedures described in this document do not substitute for normal electrical, structural, or building plan check or field inspection. Nor do they substitute for field verification by the local utility regarding interconnection to the electric grid.

4. Field Verification Visual Inspection

The visual inspection described in this protocol verifies that the modules, inverter, and meter specified in the calculator output report are properly installed in the field. The verifier shall use binoculars or another means to view the installation if access to the system is restricted due to insurance and liability reasons (sloping or unprotected rooftop access, for example) and shall verify the models and numbers of modules against the cut sheet/invoices. The verifier may rely on photographic evidence provided by the installer on the models and numbers of modules, standoff distance, and shading. In the absence of such evidence, the verifier shall rely on a conservative determination based solely on one's own observation.

a. Photovoltaic Modules

The PV installer and the verifier shall confirm that the same number of each make and model number of PV modules used in the expected performance calculations are installed in the field. The PV installer and verifier shall also confirm the module mounting type (flush-mounted BIPV or rack-mounted) and, in the case of rack-mounted modules, the standoff distance of the modules above the mounting surface. The PV installer and the verifier shall also observe and confirm the mounting height of the modules (one story, two stories, or measured minimum distance above the ground).

b. Inverters

The PV installer and the verifier shall confirm that the make and model of inverters used in the expected performance calculations are installed in the field.

c. System Performance Meters

The PV installer and the verifier shall verify that either a separate system performance meter or an inverter with an integral system performance meter is installed that is the same make and model specified on the reservation application form and meets all eligibility requirements for system performance meters.

d. Tilt and Azimuth

The PV installer and the verifier shall confirm that the tilt and azimuth (orientation) of the PV modules installed in the field match the values that were used to determine the expected performance of each solar system, ***within ± 5 degrees***[86]. In some systems, PV modules may be installed in multiple arrays with different tilts and azimuths; in these cases, the tilt and azimuth of each array shall be confirmed.

i. Determining Tilt

The tilt angle of the PV modules is measured in degrees from the horizontal. (Horizontal PV modules will have a tilt of zero, and vertically mounted PV modules will have a tilt of 90 degrees.) The tilt of the PV modules may be determined in the following ways:

Using the Building Plans: The as-built or construction drawings for the building will state the slope of the roof, usually as the ratio of rise to run. If the PV modules are mounted in the plane of the roof, then the slope of the PV modules is the same as the slope of the roof. Table C.1 may be used to convert rise-to-run ratios to degrees of tilt.

Table C.1: Conversion of Roof Pitch to Tilt

Roof Pitch (Rise:Run)	Tilt (degrees)
2:12	9.5
3:12	14.0
4:12	18.4
5:12	22.6
6:12	26.6
7:12	30.3
8:12	33.7
9:12	36.9
10:12	39.8
11:12	42.5
12:12	45.0

Source: California Energy Commission

Using a Digital Protractor: A digital protractor may be used to measure either horizontal or vertical angles (Figure C.1). These devices, when sighted up the slope of the PV modules from the ground, will display the slope relative to the horizontal.

Figure C.1: Digital Protractor

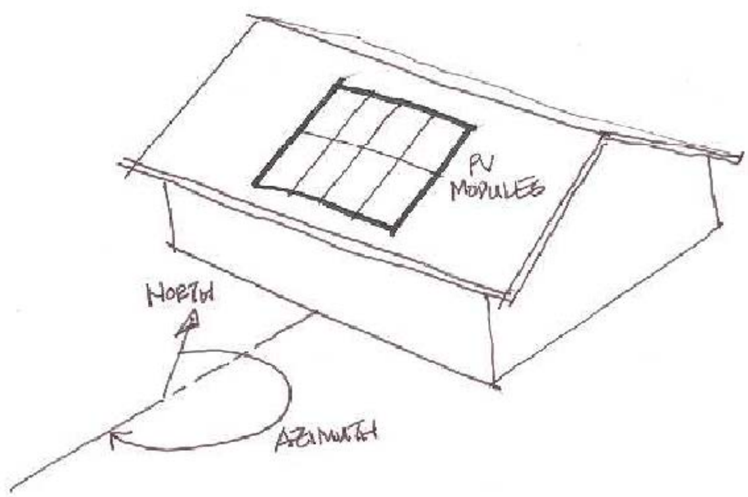
86 Program administrators may choose a tighter tolerance for their program.

Source: California Energy Commission

ii. Determining Orientation (Azimuth)

The PV installer and the verifier shall determine the orientation by measuring the azimuth of the PV modules and confirm that the azimuth is the same as that used to determine the expected performance of each solar system. The convention that is used for measuring azimuth is to determine the degrees of angle clockwise from north; north azimuth is zero degrees, east is 90 degrees, south is 180 degrees, and west is 270 degrees. (See Figure C.2.)

Figure C.2: Azimuth of the PV Array



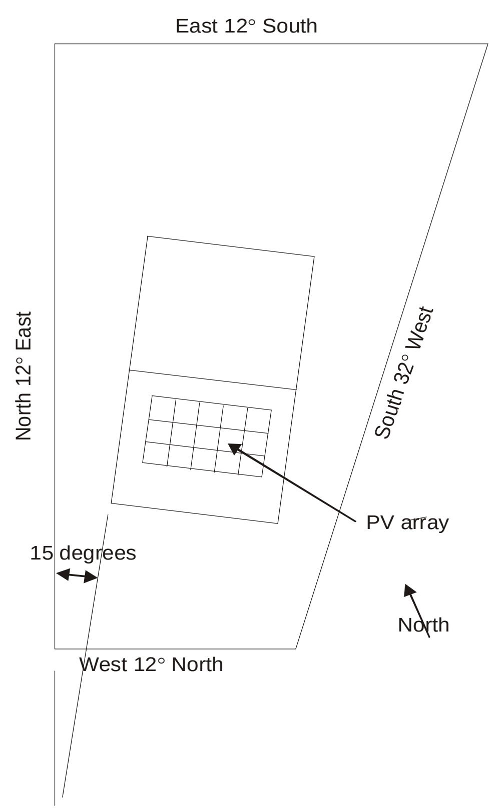
Source: California Energy Commission

The following methods may be used to determine the azimuth.

Using the Plot Plans: In new subdivisions, the house plans will often not show the property lines since the plans are used on multiple lots. However, the subdivision plot plan will show the property lines of the lots. The plot plan will show the bearing of the property lines, and from this information, the azimuth of the roof surfaces where the PV modules are mounted may be determined from the position of the house on the lot relative to the bearings of the property lines.

Figure C.3 shows an example plot plan with a house located on it. In this case, the house does not align with any of the property lines but is rotated 15 degrees from the westerly property line as shown. Property lines on plot plans are typically labeled in terms of their bearing, which is the direction of the line. The westerly property line is labeled "North 12˚ East." If the house was aligned with this property line, the southerly exposure of the house would have an azimuth of 192˚ (180˚ plus the 12˚ bearing of the property line). Since the house is rotated an additional 15˚, the azimuth of the southerly face of the house and the azimuth of the PV array is 207˚ (192˚ plus 15˚). Usually, the house will be aligned with one of the property lines, and the calculation described above will be simplified.

Figure C.3: Example Plot Plan



Source: California Energy Commission

Using a Compass With a Sighting Feature and an Adjustment for Magnetic Declination: The installer and verifier shall ensure that the compass has a sighting feature. The compass may have an adjustment built in for magnetic declination so that the reading on the compass is true north, or the installer and the verifier shall determine the magnetic declination using the tool available at https://www.ngdc.noaa.gov/geomag/declination.shtml and adjust the compass reading to account for the magnetic declination. Position the compass and determine the array azimuth angle between compass north and the direction that the PV modules face. It's usually convenient and most accurate to align the compass along the edge of the array using the sighting feature. (See Figure C.4.)

Figure C.4: Compass With a Sighting Feature

Source: California Energy Commission

5. Shading Verification

Shading of photovoltaic systems, even partial shading of arrays, can be the greatest cause of failure to achieve high system performance. Significant shading should be avoided whenever possible. Shading can be avoided by careful location of the array at installation or, in some cases, particularly during building construction by moving obstructions to locations where they do not shade the array. Partial shading from obstructions that are relatively close to the array, particularly obstructions that are on the roof even if they are relatively small, can be particularly problematic because they cause partial shading of the array for longer periods of the year. Shading caused in the future by maturing trees that are immature at PV system installation can also be a major cause of failure to achieve high performance over the life of the PV system.

The PV installer and the verifier shall confirm that the shading conditions on the system in the field are consistent with those used in the expected performance calculations. The estimated performance calculations will be done either assuming that the "minimal shading" criterion is met or based on the specific shading characteristics of the system.

a. Minimal Shading Criterion

The "minimal shading" criterion is that no obstruction is closer than a distance ("D") of twice the height ("H") it extends above the PV array. (See Figure C.5 for an artistic depiction of "H" and "D.") As the figure illustrates, the distance "D" shall be at least two times greater than the distance “H.” Any obstruction that projects above the point on the PV array that is closest to the obstruction shall meet this criterion for the PV array to be considered minimally shaded. Obstructions that are subject to this criterion include:

i. Any vent, chimney, architectural feature, mechanical equipment, or other obstruction that is on the roof or any other part of the building.

ii. Any part of the neighboring terrain.

iii. Any tree that is mature at the time of installation of the solar system.

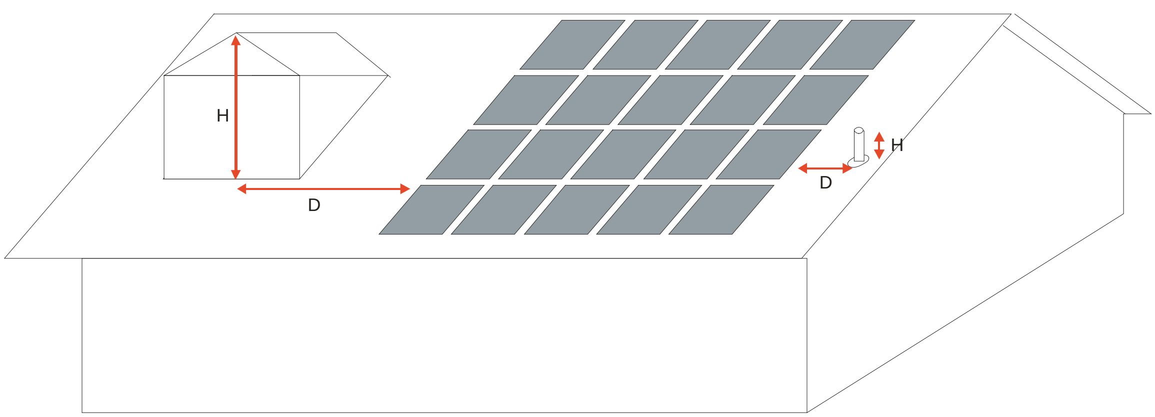
iv. Any tree that is planted on the building lot or neighboring lots or planned to be planted as part of the landscaping for the building. (The expected shading shall be based on the mature height of the tree.)

v. Any existing neighboring building or structure.

vi. Any planned neighboring building or structure that is known to the builder or building owner.

vii. Any telephone or other utility pole that is closer than 30 feet from the nearest point of the array.

Figure C.5: The Minimal Shading Criterion – Artistic Depiction of “H” and “D”



Source: California Energy Commission

To determine whether the minimal shading criterion is met, the PV installer and the verifier shall determine for each shading obstruction the smallest ratio of the horizontal distance from the obstruction to the array divided by the vertical height of the obstruction above that point on the array. (This is the “closest point on the array.”) Often the point on the obstruction that results in the smallest ratio is the topmost point of the obstruction, but in cases where the shape of the obstruction is complex, points on the obstruction that are not the topmost but are closer to the array may actually produce the lowest ratio. “H” is the vertical height of the shading obstruction point above the horizontal projection to the closest point on the array. “D” is the horizontal distance from the closest point on the array to the vertical projection from the point on the obstruction that results in the lowest ratio of “D” divided by “H.” *Any obstruction located north of all points on the array need not be considered as shading obstructions*. When an obstruction is north of some parts of an array but east, south, or west of other parts of the array, the minimal shading criterion shall be determined to the closest point on the array that is west, north, or east of the obstruction.

The PV installer and the verifier may confirm through visual inspection that all obstructions meet the 2:1 criterion. (An altitude angle of 26.5 degrees is equivalent to the 2:1 criterion.) For obstructions that visual inspection indicates potentially do not meet the criterion, the PV installer and verifier shall measure the height and distance of the obstruction(s) relative to the PV array as described above to verify that the 2:1 shading criterion (or a lower than 26.5 altitude angle through the same points on the obstruction and array) is met. A tolerance of ± 5 percent will be permissible when determining the ratio (or the altitude angle).

b. Accounting for Actual Shading

When a PV installation does not meet the minimal shading criterion, it can still qualify for an incentive and participate in the program, but the shading conditions for each PV system at the site shall be accounted for in the expected performance calculation as described in this section. The basic method is used when the shading condition is measured using a tape measure or a digital protractor. A different method is used when measurements are made with a solar assessment tool.

When a tape measure or digital protractor is used to measure shading obstructions that are accounted for in the expected performance calculation, the calculator will produce on the output report a table similar to Table C.2 that shows the distance-to-height ratio and altitude angle for the closest point on the array for each obstruction, including mature trees that shade the PV array. This table divides the compass into 11 (about 22.5 degree) sectors, progressing clockwise around the compass from north. The table provides the distance-to-height ratio and altitude angle for each sector of the compass. When there is more than one obstruction in a sector, the information is reported for the obstruction with the lowest distance-to-height ratio (highest altitude angle). The distance-to-height ratio will be a number less than or equal to two because if it is greater than two, the minimal shading criterion is satisfied in that direction, and shading is not considered in the expected performance calculation for that sector. The table also shows the minimum distance to small, medium, and large trees to meet the minimal shading criterion for trees that are not at mature heights. The data in Table 2 are specific to a particular PV system installation. In this example, the minimal shading condition is not met for five sectors of the compass – ESE, SSE, S, SW, and WNW.

The PV installer and the verifier shall confirm that the shading conditions that exist (or are expected to exist in the case of the mature heights of trees that are planted on the building lot or neighboring lots or planned to be planted as part of the landscaping for the building or planned buildings or structures on the building lot or neighboring lots that are known to the builder or building owner). These conditions, at the site, are to be identified not to cause greater shading of the modules than the shading characteristics that were used in the expected performance calculations.

EXCEPTION: Program administrators may waive the requirement to account for future shade in the expected performance calculations for all solar projects on residential and nonresidential existing buildings on the condition that a copy of a disclosure statement is provided to the building owner and program administrator identifying existing trees on the building site and adjoining sites that are smaller than 50 feet, which may cast potential future shade that would reduce future system performance.

Table C.2: Example Output Report Format for PV Shading

Orientation	Obstruction Type	Altitude Angle to Shading Obstruction	Distance-to-Height Ratio	Minimum Distance to Small Tree	Minimum Distance to Medium Tree	Minimum Distance to Large Tree
ENE (55 – 79)	NA	Minimal Shading	2.00	16	46	76
E (79 -101)	NA	Minimal Shading	2.00	16	46	76
ESE (101 – 124)	Neighboring structure	45 degrees	1.00			
SE (124 – 146)		Minimal Shading	2.00	16	46	76
SSE (146 – 169)	On roof obstruction	50 degrees	0.84			
S (169 – 191)	Tree (existing-mature)	70 degrees	0.36			
SSW (191 – 214)		Minimal Shading	2.00	16	46	76
SW (214 – 236)	Tree (existing-not mature)	30 degrees	1.5			
WSW (236 – 259)		Minimal Shading	2.00	16	46	76
W (259 – 281)		Minimal Shading	2.00	16	46	76
WNW (281 – 305)	Tree (planned)	65 degrees	0.49			

Source: California Energy Commission

c. Measuring Heights and Distances or Altitude Angles

One of the following procedures may be used to measure heights and distances or altitude angles to obstructions. Program administrators may determine the allowable tolerance related to field verification of these measurements for their specific programs. One reason for this tolerance is to account for the potential for user error when measurement tools are used.

i. Using a Tape Measure

A tape measure or other measuring device may be used to measure the distance (“D”) from the point on the PV array corresponding to the lowest ratio of distance to height (“H”) for each shading obstruction for each 22.5 degree compass sector. The distance to a tree that has not reached mature height is measured to the nearest edge of the trunk of the tree. Once the height difference (“H”) and distance (“D”) are determined in each compass sector, the ratio is calculated and shall be greater than the value used in the expected performance calculation as reported on the output report. (See the fourth column in Table C.2 labeled Distance-to-Height Ratio.) This method can be employed from the ground without access to the roof, when factoring in the rooftop dimensions.

The height measurement for trees that are immature shall be based on the Mature Tree Height section below. Determining the distances and heights of obstructions for buildings and structures that are planned but have not yet been constructed shall be based on plans for those structures.

ii. *Using a Digital Protractor*

A digital protractor (Figure 1) may be used to measure the highest altitude angle from the obstruction to the closest point on the array (using the same points on the array and on the obstruction that produce the lowest ratio of “D” to “H” if those dimensions were measured instead of the altitude angle). The measured altitude angle for each obstruction in each compass sector shall be smaller than or equal to that used in the expected performance calculation as reported on the output report. (See the third column in Table C.2.) To use the digital protractor measurement directly, the measurement shall be made from the roof. Alternatively, the digital protractor measurement may be made from the ground, and trigonometric adjustments will be required to correct for the height difference between the ground, where the measurements are made, and the point of maximum shading of the PV array in that compass sector.

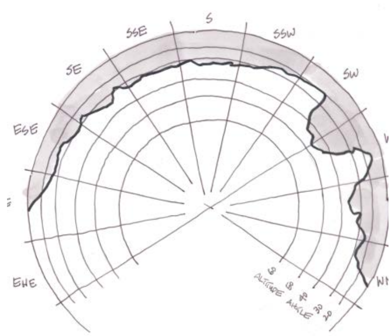
This method does not address expected shading resulting from the mature heights of planted immature trees or planned trees. To determine distances for planted immature trees, a tape measure should be used. The height measurement for trees that are immature shall be based on the Mature Tree Height section below. Determining the distances and heights of obstructions for buildings and structures that are planned but have not yet been constructed shall be based on plans for those structures.

iii. *Using a Solar Assessment Tool*

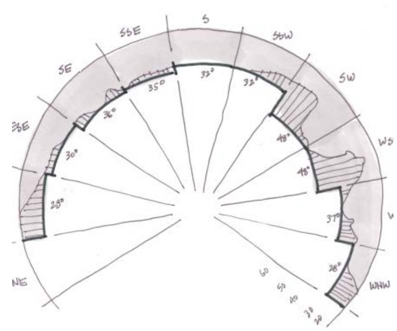
For shading from existing obstructions shading conditions may be verified using a solar assessment tool. This procedure will typically be used by the PV installer, but the verifier may not have direct access to the array and, if not, would rely on the adequacy of documentation by the installer to confirm the shading conditions.

At each measurement point, the tool is placed on the PV array, leveled, and oriented consistent with the manufacturer’s instructions. Once the tool is properly positioned, it will determine the obstructions that cast shade and the month and time of day when shading will occur. The tool will enable these determinations either with a digital photograph or a manual tracing on an angle estimator grid overlay. These results for a single point of reference on the array are converted into a format that can be used by the calculator, either through software provided by the tool manufacturer or manually, as shown in Figure C.6 (b), to determine the altitude angle of an obstruction in each compass sector.

Figure C.6: Conversion of Results From Solar Assessment Tool for a Single Point of Reference on the Array



(a) This diagram shows the 22.5 º compass sectors used by the PV Calculator and the altitude angles determined by a solar assessment tool for a single point of reference on the array.



(b) Within each compass sector, the highest altitude angle is selected and used for that entire sector. This datum is shown for a single point of reference on the array.

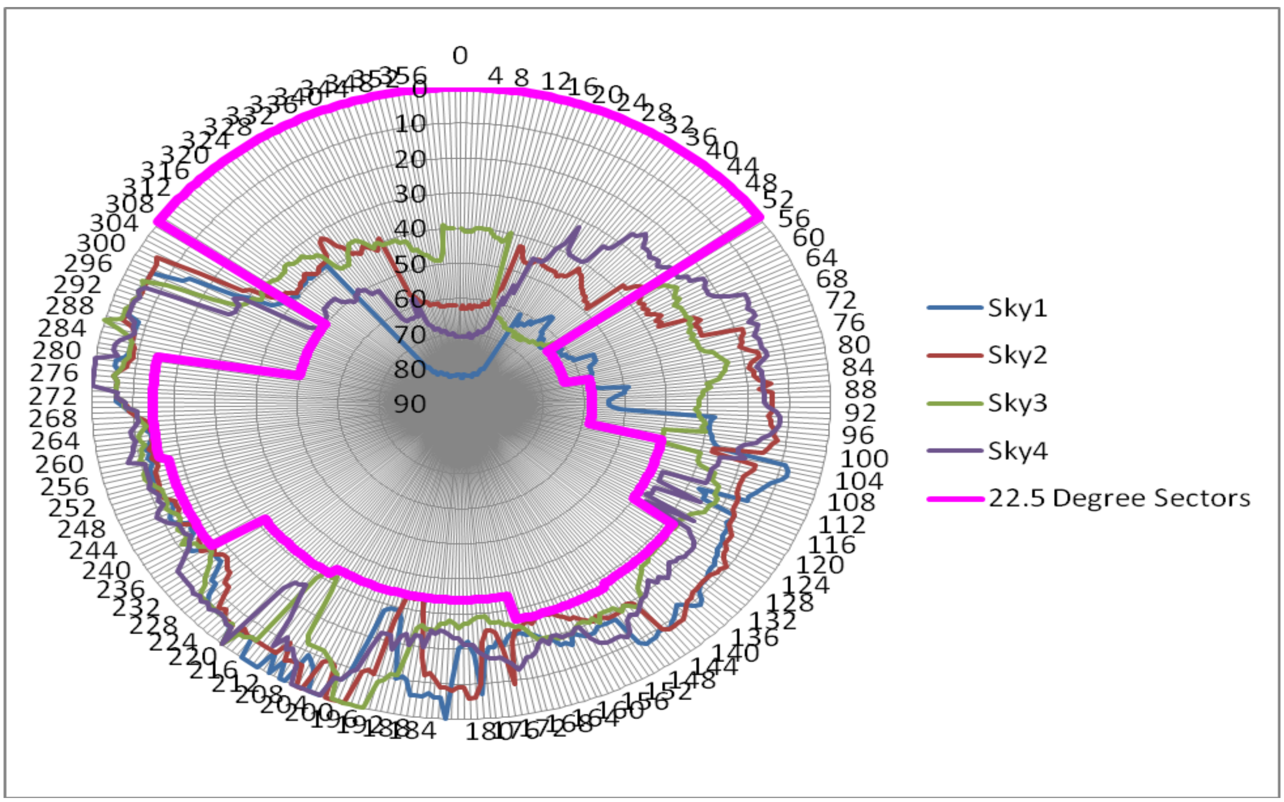
Source: California Energy Commission

Measurements shall be made at all the major corners of the array with no adjacent measurement being more than 40 feet apart. (See example in Figure C.9.) The points of measurement shall be distributed evenly between two major corners if they are more than 40 feet apart such that the linear distance between any sequential points is no more than 40 feet. However, if any linear edge of the array has no obstructions that are closer than two times the height they project above the closest point on the array, then the intermediate measurements along that edge do not need to be made.

1. The altitude angles measured at each major corner shall be overlapped onto a single diagram or processed with the tool manufacturer's software. The maximum altitude angles measured at any of the major corners of the array within a given sector shall be applied to the entire sector. This creates a set of 11 values that are used in the PV calculation. (See Figure C.7.)

Figure C.7: Example of Combining the Maximum Altitude Angle in the 11 Compass Sectors for Four Points on the Array

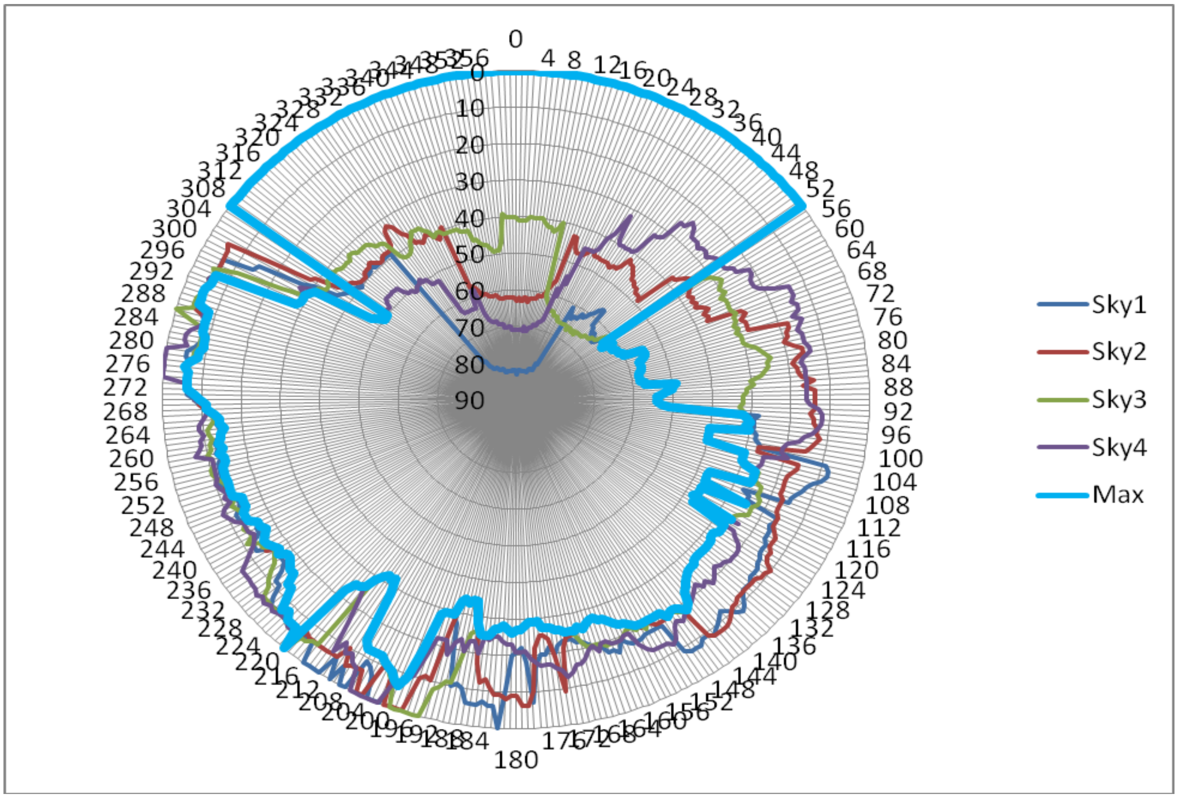
Azimuth	Altitude angle
ENE (55 – 79)	64
E (79 -101)	58
ESE (101 – 124)	40
SE (124 – 146)	27
SSE (146 – 169)	28
S (169 – 191)	34
SSW (191 – 214)	32
SW (214 – 236)	30
WSW (236 – 259)	17
W (259 – 281)	15
WNW (281 – 305)	50



Source: California Energy Commission

2. Alternatively, the maximum altitude angle measured at each of the major corners of the array may be reported for each 1 degree increment of the azimuth. This would create a set of 360 values, one for each degree of the compass orientation. These values may be electronically transferred to the calculator, depending on the implementation by the program administrator.

Figure C.8: Example of Combining the Altitude Angles Measured at Four Points on the Array on a Per-Degree Azimuth Increment



Source: California Energy Commission

The installer shall attach the diagram shown in Figure C.8 to the installation certificate, along with photographic evidence of the shading shown on the tool, the location of the tool on the array, and the shading obstructions that are indicated on the tool, for the verifier to verify the results shown on the diagram.

This method does not address expected shading resulting from the mature heights of planted immature trees or planned trees or expected construction of buildings or other structures on neighboring lots. To determine distances for planted immature trees, a tape measure should be used. The height measurement for trees that are immature shall be based on the Mature Tree Height section below. Determining the distances and heights of obstructions for buildings and structures that are planned but have not yet been constructed shall be based on plans for those structures. Such shading shall be addressed separately.

The results determined by the tool in combination with the expected future shading described above are compared to the data used in the expected performance calculations to ensure that there is not greater shading at the site than was used in the expected performance calculations.

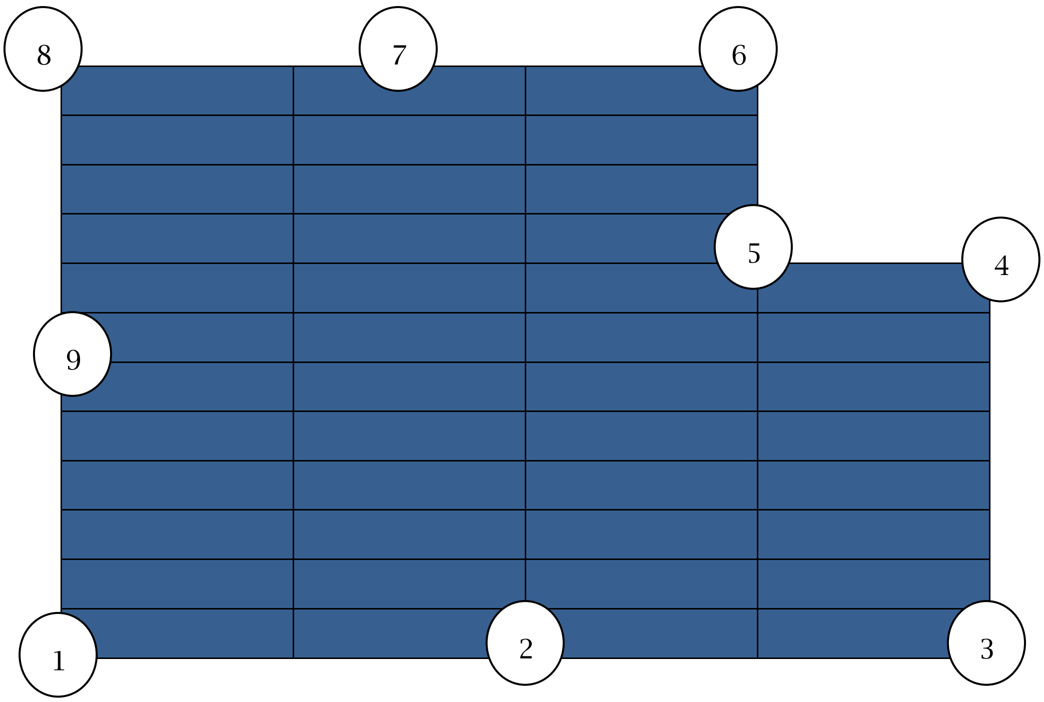
d. Measuring Solar Availability

As an alternative to measuring heights and distances or altitude angles, program administrators may allow the use of solar availability as a method to estimate the shading effect on hourly production. The following method shall be followed when the solar availability is used in a calculator. Program administrators may determine the appropriate tolerance related to this method for field verification. One reason for this tolerance is to account for the potential for user error when measurement tools are used.

i. Using a Solar Assessment Tool

The measurements shall be made at all the major corners of the array with no adjacent measurement being more than 40 feet apart. (See example in Figure C.10.) The points of measurement shall be distributed evenly between two major corners if they are more than 40 feet apart such that the linear distance between any sequential points is no more than 40 feet. However, if any linear edge of the array has no obstructions that are closer than two times the height they project above the closest point on the array, then the intermediate measurements along that edge do not need to be made.

Figure C.9: Example of Points Where Measurement Shall Be Made Using a Solar Assessment Tool (Overall Array Dimensions 76 feet by 50 feet)



Source: California Energy Commission

ii. Monthly Solar Availability Option

The monthly solar availability shall be reported by the tool as monthly values averaged over all the points of measurement and averaged as monthly solar availability numbers (7 a.m. to 7 p.m. local standard time), except for June through September, where three periods in every day of the month shall be reported. Program administrators may weigh the monthly solar availability during peak periods (noon to 3 p.m. and 3 p.m. to 7 p.m.) during summer using TDV-based weighting factors determined by the Energy Commission. Each value shall be reported as a percentage of the unshaded insolation available on the array during the period given the location, azimuth, and tilt. The monthly solar availability shall be reported in the format shown in Table C.3.

When using monthly solar availability values in the PV production calculations for incentive, the values shall be applied to the estimate of unshaded production for the applicable month using the following equation. If the kWh_{shaded} value determined using this equation is negative, the production for the month is set to zero.

$$kWh_{shaded} = kWh_{unshaded} \text{ x } (1- (1- \text{Availability}/100) \text{ x Shade Impact Factor})$$

Where:

kWh_{shaded} = kWh produced in the month including the effect of shading

$kWh_{unshaded}$ = kWh produced in the month if the array was completely unshaded

Availability = Solar availability for the month

Shade Impact Factor = Factor that accounts for production loss due to shading

The default shade impact factor shall be 2.0. The doubling of shade loss accounts for the disproportionate effect on production due to partial shading on modules and strings. Technologies that can demonstrate effective tolerance to partial shading losses in a system shall be considered by the Energy Commission for a lower shade impact factor.

Table C.3: Example of Monthly Solar Availability Table

Month			
	7 am to 7 pm		
1	74%		
2	83%		
3	91%		
4	94%		
5	95%		
	7 am to 12 noon	**12 noon to 3 pm**	**3pm to 7 pm**
6	89%	100%	100%
7	89%	100%	100%
8	88%	100%	98%
9	89%	100%	88%
	7 am to 7 pm		
10	88%		
11	76%		
12	67%		

Source: California Energy Commission

iii. Hourly Solar Availability Option

As an alternative to the monthly solar availability, the hourly solar availability option may be used. The solar availability shall be reported by the tool as hourly values averaged over all the points of measurement. Each value shall be reported as a percentage of the unshaded insolation available on the array during the hour given its location, azimuth, and tilt. The hourly solar availability values shall be provided by the solar assessment tools as an electronic file with the 8,760 values representing each hour of the year. The file format and security of data transfer shall be determined based on the implementation of the PV production calculator.

When using hourly solar availability values in the PV production calculations for incentive, the values shall be applied to the estimate of unshaded hourly production for the applicable hour using the following equation. If the kWh_{shaded} value determined using this equation is negative, the production for the hour is set to zero.

$$kWh_{shaded} = kWh_{unshaded} \text{ x } (1- (1- \text{availability}/100) \text{ x shade impact factor})$$

Where:

kWh_{shaded} = kWh produced in the hour including the effect of shading

$kWh_{unshaded}$ = kWh produced in the hour if the array was completely unshaded

Availability = Solar availability for the period including the hour

Shade impact factor = Factor that accounts for production loss due to shading

The default shade impact factor shall be 2.0. The doubling of shade loss accounts for the disproportionate impact on production due to partial shading on modules and strings. Technologies that can demonstrate effective tolerance to partial shading losses in a system shall be considered by the Energy Commission for a lower shade impact factor.

e. Mature Tree Height

The expected performance calculations require the mature height to be used when accounting for the shading effect of planted immature trees and planned trees. This section provides guidelines for determining the mature height of such trees. Applicants shall identify the height category (small, medium, or large) of all planted and planned trees at the site. That information shall be documented in conjunction with the installation certificate and provided to the verifier for confirmation. Any existing tree with a height greater than 50 feet at the time observations are made shall be recorded with the actual height instead of the height category of the tree species.

All trees are classified as small, medium, or large by species. Trees with a mature height of 20 feet or smaller are small trees. Trees with a mature height greater than 20 feet but less than 50 feet are medium trees. Trees with a mature height greater to or equal to 50 feet are large trees. If the type of tree is unknown, it shall be assumed to be large. The mature heights of small, medium, and large trees that shall be used in the expected performance calculations are 20 feet, 35 feet, and 50 feet, respectively.

The Center for Urban Forestry Research of the U.S. Department of Agriculture's Forest Service has published tree guides for tree zones that are applicable to California. Table C.4 shows the appropriate tree guide to use for each of California's climate zones for the expected performance calculations.

The guides provide tree selection lists for each tree zone. The lists provide either the mature height or the size category in that tree zone for each species. These tree guides are posted at http://www.nrcs.usda.gov/wps/portal/nrcs/detail/plantmaterials/technical/publications/?cid=nrcs143_026853.

For trees not listed in the tree selection tables of the tree guides, the *Sunset Western Garden Book* should be consulted. This document provides the mature height range or maximum height for each species. If a range is given, the average of the maximum height range should be used to determine if the tree is small, medium, or large.

Table C.4: Appropriate Tree Guide to Use for Each California Climate Zone

CEC Climate Zones	Tree Regions	Tree Guide to Use	
1, 2, 3, 4, 5	Northern California Coast	Under Development (Use Sunset Western Garden Book)	
6, 7, 8	Southern California Coast	McPherson, E.G., et al. 2000. Tree guidelines for coastal Southern California communities. Sacramento, CA: Local Government Commission	Chapter 5, pages 57-65
9, 10	Inland Empire	McPherson, E.G., et al. 2001. Tree guidelines for Inland Empire communities. Sacramento, CA: Local Government Commission	Chapter 6, pages 65-82
11, 12, 13	Inland Valleys	McPherson, E.G., et al. 1999. Tree guidelines for San Joaquin Valley communities. Sacramento, CA: Local Government Commission	Chapter 5, pages 50-55
14, 15	Southwest Desert	McPherson, E.G., et al. 2004. Desert southwest community tree guide: benefits, costs and strategic planting. Phoenix, AZ: Arizona Community Tree Council, Inc.	Chapter 7, pages 51-53
16	Northern Mountain and Prairie	McPherson, E.G, et al. 2003. Northern mountain and prairie community tree guide: benefits, costs and strategic planting. Center for Urban Forest Research, USDA Forest Service, Pacific Southwest Research Station.	Chapter 5, pages 47-55

Source: California Energy Commission

Table C.5 shows the horizontal distance that trees of each mature height category would need to be located from nearest point of the PV array to meet the condition of minimal shading.

Table C.5: Horizontal Distance Trees Would Need to Be Located From the Closest Point of a PV Array to Qualify for Minimal Shading

Mounting Location	Small Tree (20 ft)	Medium Tree (35 ft)	Large Tree (50 ft)
1 Story (Lowest Point of Array at 12 ft)	16	46	76
2 Story (Lowest Point of Array at 22 ft)	Any Distance	26	56
3 Story (Lowest Point of Array at 32 ft)	Any Distance	6	36

Source: Energy Commission

6. Verification of System Performance

For EPBI systems, the PV installer and verifier shall confirm that the AC power output from the PV system is consistent with that predicted by the expected performance calculations. A calculator will determine an estimate of system AC power output for a range of solar irradiance and outdoor air temperature conditions and print a table on the output report. The values in the table will be 90 percent of the output estimated by a calculator for each set of conditions in the table. (The calculations also include the default adjustment of 0.88 for losses such as dirt, dust, and mismatched wiring.) The values in the table are for an unshaded array. An example of the data that will be produced is shown in Table C.6. The data in the table are specific to each PV system.

Verification of system performance shall be performed after the PV system is installed and connected to the electricity grid. Measurements shall be made with a minimum irradiance of 300 W/m² in a plane parallel to the array. The PV installer and/or the verifier shall:

- Measure the solar irradiance in a plane parallel to the array.
- measure the ambient air temperature:
- Determine the expected AC power output for the measured field conditions from the table on the output report.

The PV installer or the verifier shall then observe the AC power output displayed on the inverter and confirm that the AC power output is at least the amount shown in the table for the field-measured conditions. To qualify for EPBI system incentives under these guidelines, PV systems shall have a performance meter or an inverter that has a built-in meter that measures AC power output.

The PV installer and verifier shall observe the AC power output on the inverter after waiting for a period of stable conditions during which the measured solar irradiance has stayed constant within ± 5 percent.

Table C.6: Example Table of Expected AC Power Output From Calculator (Watts)

(W/m^2)	T=15	T=20	T=25	T=30	T=35	T=40	T=45	T=50	T=55	T=60	T=65	T=70	T=75	T=80	T=85	T=90	T=95	T=100	T=105	T=110	T=115	T=120
300	614	606	599	591	584	576	568	560	553	544	536	528	520	512	504	496	487	479	471	463	454	446
325	665	657	648	640	632	623	615	607	598	590	581	572	564	555	546	537	528	519	510	501	492	483
350	716	707	698	689	680	671	662	653	643	634	625	616	606	597	588	578	569	559	550	540	530	520
375	766	757	747	738	728	718	708	699	689	679	669	659	649	639	629	619	609	598	588	578	568	557
400	817	807	797	786	776	765	755	745	734	723	713	702	691	681	670	659	648	637	626	615	604	593
425	868	857	846	835	824	813	802	790	779	768	757	745	734	722	711	699	688	676	664	653	641	629
450	918	907	895	883	872	860	848	836	824	812	800	788	776	764	752	739	727	715	702	690	677	665
475	967	955	943	931	919	907	894	882	869	856	843	831	818	805	792	779	766	753	740	727	714	700
500	1016	1004	991	978	966	953	940	927	913	900	887	873	860	846	832	819	805	791	777	763	750	736
525	1065	1052	1038	1025	1012	998	984	971	957	943	929	915	901	887	872	858	843	829	814	800	785	770
550	1113	1099	1085	1071	1057	1043	1029	1014	1000	986	971	956	942	927	912	897	882	866	851	836	820	805
575	1161	1147	1132	1117	1102	1088	1073	1058	1043	1027	1012	997	982	966	951	935	919	903	887	871	855	839
600	1209	1194	1178	1163	1147	1132	1116	1100	1085	1069	1053	1037	1021	1005	989	972	956	940	923	906	890	873
625	1256	1240	1224	1208	1192	1176	1159	1143	1126	1110	1093	1077	1060	1043	1026	1009	992	975	958	941	924	906
650	1302	1286	1269	1252	1236	1219	1202	1185	1168	1150	1133	1116	1098	1081	1063	1046	1028	1010	992	974	957	939
675	1348	1331	1314	1296	1279	1261	1244	1226	1208	1190	1172	1154	1136	1118	1100	1081	1063	1045	1026	1007	989	970
700	1394	1376	1358	1340	1322	1304	1285	1267	1248	1230	1211	1192	1174	1155	1136	1117	1098	1078	1059	1040	1021	1001
725	1439	1420	1401	1383	1364	1345	1326	1307	1288	1269	1249	1230	1210	1191	1171	1151	1132	1112	1092	1072	1052	1032
750	1483	1464	1444	1425	1405	1386	1366	1346	1327	1307	1287	1267	1246	1226	1206	1185	1165	1144	1124	1103	1082	1061
775	1526	1506	1487	1466	1446	1426	1406	1385	1365	1344	1323	1303	1282	1261	1240	1219	1198	1176	1155	1134	1112	1090
800	1569	1549	1528	1507	1486	1466	1445	1423	1402	1381	1360	1338	1317	1295	1273	1252	1230	1208	1186	1164	1141	1119
825	1611	1590	1569	1547	1526	1504	1483	1461	1439	1417	1395	1373	1351	1328	1306	1284	1261	1238	1216	1193	1170	1147
850	1653	1631	1609	1587	1565	1542	1520	1498	1475	1452	1430	1407	1384	1361	1338	1315	1292	1268	1245	1221	1198	1174
875	1693	1671	1648	1626	1603	1580	1557	1534	1510	1487	1464	1440	1417	1393	1369	1345	1322	1298	1273	1249	1225	1200
900	1733	1710	1687	1663	1640	1616	1593	1569	1545	1521	1497	1473	1449	1424	1400	1375	1351	1326	1301	1276	1251	1226
925	1772	1748	1725	1701	1676	1652	1628	1603	1579	1554	1529	1505	1480	1455	1430	1404	1379	1354	1328	1302	1277	1251
950	1811	1786	1762	1737	1712	1687	1662	1637	1612	1586	1561	1536	1510	1484	1459	1433	1407	1381	1354	1328	1302	1275
975	1980	1823	1798	1772	1747	1721	1696	1670	1644	1618	1592	1566	1540	1513	1487	1460	1434	1407	1380	1353	1326	1299
1000	1980	1980	1980	1807	1781	1755	1729	1702	1676	1649	1622	1595	1569	1542	1514	1487	1460	1432	1405	1377	1349	1322
1025	1980	1980	1980	1980	1815	1788	1761	1734	1706	1679	1652	1624	1597	1569	1541	1513	1486	1457	1429	1401	1372	1344
1050	1980	1980	1980	1980	1980	1820	1792	1765	1737	1709	1681	1653	1624	1596	1568	1539	1511	1482	1453	1424	1395	1365
1075	1980	1980	1980	1980	1980	1980	1823	1795	1767	1738	1709	1680	1652	1623	1593	1564	1535	1506	1476	1446	1417	1387
1100	1980	1980	1980	1980	1980	1980	1980	1825	1796	1766	1737	1708	1678	1648	1619	1589	1559	1529	1499	1468	1438	1407
1125	1980	1980	1980	1980	1980	1980	1980	1980	1824	1794	1764	1734	1704	1674	1643	1613	1582	1551	1520	1490	1458	1427
1150	1980	1980	1980	1980	1980	1980	1980	1980	1980	1822	1791	1760	1729	1698	1667	1636	1605	1573	1542	1510	1479	1447
1175	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1817	1786	1754	1722	1691	1659	1627	1595	1563	1530	1498	1466
1200	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1810	1778	1746	1714	1681	1649	1616	1583	1550	1517	1484

Source: California Energy Commission

a. Measuring Solar Irradiance

Solar irradiance shall be measured using an irradiance meter. When making this measurement, the PV installer or verifier shall place the irradiance meter in a plane parallel to the PV modules. The PV installer should position the irradiance meter on top of the PV modules or on the roof next to the PV modules. If the verifier is not able to get on the roof, he or she shall position the irradiance meter such that it is in full sun and is in plane that is parallel to the PV modules. Digital protractors or other instruments may be used to properly position the irradiance meter.

b. Measuring Ambient Air Temperature

Ambient air temperature shall be measured with a digital thermometer in the shade. The instrument shall have an accuracy of ± 2° C.

c. Observing AC Power Output at the Inverter

The PV installer and the verifier shall observe and record the reading as soon as possible after making the measurements of solar irradiance and ambient temperature. The inverter may cycle between multiple readings (total kWh of production, AC power output, and so forth), so the PV installer or verifier will need to wait until the power is displayed and record this reading. Several readings should be made to make sure that they are consistent and stable.

d. Multiple Orientation Arrays

Multiple orientation arrays are those with parallel strings, each with an equal number of modules, in different orientations (azimuth and tilt) connected to the same inverter.[87] When parallel strings in different orientations are connected to the same inverter, separate calculator output reports shall be prepared for each orientation, and solar irradiance shall be measured separately in a plane parallel to each orientation. The expected AC power output is determined separately for each orientation, and the sum is used for verification.

For example, a qualifying 3 kW PV system has 20 modules grouped evenly into two parallel strings of 10 modules each, one facing south with an azimuth of 170 degrees and one facing west with an azimuth of 260 degrees. The verifier evaluates system performance at 11:30 a.m. in March with an ambient temperature of 62°F. The verifier measures 950 W/m² of solar irradiance in the plane parallel to the south array and 500 W/m² in a plane parallel to the west-facing array.[88]

87 Substantial reductions in performance will result if there are different numbers of modules in each string or if the strings with different orientations are connected in series.

88 When testing systems with multiple orientation arrays, the solar irradiance levels on all arrays must remain constant within ± 5 percent as discussed in Verification of System Performance above.

The total expected AC power output table on the output report indicates that the system should be producing 1,200 W at 950 W/m² and 700 W at 500 W/m² of solar irradiance. The expected AC power output is calculated as 1,900 W by summation of the expected AC power output (1,200 W + 700 W = 1,900 W) of each orientation. This calculated value must be compared to the inverter display.

7. Installer System Inspection

These steps[89] shall be followed by the PV installer if the program administrator allows for the exemption from performing the field verification protocol. The PV installer shall complete the following steps under relatively stable solar irradiance conditions and submit a copy of a signed certificate of completing the same on every system.

These steps are applicable only for systems that have two or more source circuits (strings) connected in parallel to the same inverter and where the source circuits being evaluated receive consistent solar irradiance by having the same azimuth and tilt and being subject to consistent shading impacts. For all other systems, the PV installer shall follow the same protocol as the field verifier.

1. Complete a visual check of the system to ensure the modules and all other system components are bolted securely, and all wiring connections have been made properly according to the system schematic, manufacturer's instructions, and applicable electrical code requirements.
2. Check the polarity of all source circuits to be correct.
3. The open circuit voltages of source circuits shall be tested and measured to be within 2 percent of each other.
4. The operating current of each source circuit shall be tested and measured with a clamp-on meter to be within 5 percent of each other.[90]

C. Flexible Installation Incentive (FII) Testing Protocol

If adopted by the program administrator, the FII amount is calculated using the major factors affecting the expected performance of the solar system, including the tested and reported performance of the specific modules and inverters, as well as a scaling factor to account for the geographic location of the system. Third-party verification will be conducted to verify the components of the system to ensure the proper calculation of the

89 The steps are based on the North American Board of Certified Energy (NABCEP) *Study Guide for Photovoltaic System Installers* recommendations for Performing a System Checkout and Inspection. This document provides important information regarding proper procedures and safety precautions.

90 Measurement of operating current has been substituted for the measurement of short circuit current specified in the NABCEP document.

expected performance. Testing will also ensure that the system meets the requirements for FII, as outlined in Chapter IV. Field verification will be carried out by a certified HERS Rater.

1. Responsibilities

Field verification and diagnostic testing are the responsibility of both the PV system installer and the HERS Rater who completes the third-party field verification. The PV installer shall perform field verification and diagnostic testing for every system that is installed. The HERS Rater then performs independent third-party field verification and diagnostic testing of the systems. The third-party field verification shall be conducted on a minimum sample of 1 in 15 projects.

2. Field Verification and Diagnostic Testing Process

The field verification and diagnostic testing of solar systems following the FII process shall follow the verification process described in the sections below. Please refer to Appendix C, Section B for additional information on testing methodologies. An alternative process deemed equivalent by the program administrator may be substituted.

3. Relationship to Other Codes, Standards, and Verification

The local jurisdiction must issue a building permit for the qualifying PV system, either as a separate permit or as part of the new construction building permit or retrofit application, and the PV system must meet all applicable electrical code, structural code, and building code requirements. In addition, the local electric utility will have standards regarding interconnection to the electric grid and other matters that shall be complied with.

The field verification and diagnostic testing procedures described in these guidelines do not substitute for normal electrical, structural, or building plan check or field inspection. Nor do they substitute for field verification by the local electric utility regarding interconnection to the electric grid.

4. Field Verification Visual Inspection

The visual inspection described in this protocol verifies that the modules, inverter, and meter specified in the calculator output report are properly installed in the field. The HERS Rater shall use binoculars or another means to view the installation if access to the system is restricted due to insurance and liability reasons (sloping or unprotected roof top access for example) and shall verify the models and numbers of modules against the cut sheet/invoices. The HERS Rater may rely on photographic evidence provided by the installer on the models and numbers of modules and shading, but in the absence of such evidence, shall rely on a conservative determination based solely on the HERS Rater’s own observation.

a. Photovoltaic Modules

The PV installer and the HERS Rater shall confirm that the same number of each make and model number of PV modules used in the expected performance calculations are installed in the field.

b. Inverters

The PV installer and the HERS Rater shall confirm that the make and model of inverters used in the expected performance calculations are installed in the field.

c. System Performance Meters

The PV installer and the HERS Rater shall verify that either a separate system performance meter or an inverter with an integral system performance meter is installed that is the same make and model specified on the reservation application form and meets all eligibility requirements for system performance meters.

d. Tilt and Azimuth

The PV installer and the HERS Rater shall confirm that the tilt and azimuth (orientation) of the PV modules installed in the field are within the eligible ranges of azimuth and tilt.[91] In some systems, PV modules may be installed in multiple arrays with different tilts and azimuths; in these cases, the tilt and azimuth of each array shall be confirmed to be within the allowed range. Any array outside the eligible range will not disqualify parts of the system meeting the minimum requirements. In these circumstances, the program administrator's handbook shall specify how the reduced incentive amount shall be calculated.

For more information on measuring the tilt and azimuth, please refer to Appendix C, Section B, Subsection 4(d).

5. Shading Verification

The PV installer and the HERS Rater shall confirm that the shading conditions on the system in the field either meets the "minimal shading" requirements or matches the solar access identified in the calculator output report.

For more information on the "minimal shading" criterion and measuring the annual solar access of a system, please refer to Appendix C, Section B, Subsection 5(a).

6. Verification of System Performance

The HERS Rater shall confirm that the AC power output from the PV system is consistent with that predicted by the expected performance calculations as outlined in Appendix C,

91 As determined by the program administrator and specified in the program handbook.

Section B, Subsection 4. An alternative method deemed equivalent by the program administrator may be substituted.