

Self-Generation Incentive Program

HANDBOOK

Provides financial incentives for installing clean, efficient, on-site distributed generation

2026

Center for Sustainable Energy®

LA DWP Los Angeles Department of Water & Power

Southern California Edison®
Energy for What's Ahead®

PG&E Pacific Gas and Electric Company®

SDGE™

SoCalGas™



V3

What's New Self-Generation Incentive Program (SGIP)

The 2026 V3 Handbook has been updated to reflect the following changes:

- **Modified Sections**
  - § 4.5.2.1 RSSE TEPC
  - § 10 Performance Monitoring and Reporting Services for Solar Systems
- **Added**
  - § 8.3 (8) RSSE TEPC Attestation Form
  - Footnote 63
  - Footnote 96
  - Footnote 98

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Program Administrator Contact Information

Potential program participants can obtain information and apply for incentive funding through the following Program Administrators: [1]

Pacific Gas & Electric (PG&E)

Website:	www.pge.com/sgip
Email Address:	selfgen@pge.com
Telephone:	(415) 973-6436
Mailing Address:	PG&E Payment Research Attn: Self-Generation Incentive Program PO Box 997310 Sacramento, CA 95899

Center for Sustainable Energy® (CSE)

Website:	https://sgipsd.org/
Email Address:	sgip@energycenter.org
Telephone:	(858) 244-1177
Mailing Address:	Center for Sustainable Energy Attn: Self-Generation Incentive Program 3980 Sherman Street, Suite 170 San Diego, CA 92110

Southern California Edison (SCE)

Website:	www.sce.com/SGIP
Email Address:	SGIPgroup@sce.com
Telephone:	(626) 302-0610
Mailing Address:	Self-Generation Incentive Program Southern California Edison P.O. Box 800 Rosemead, CA 91770-0800

Southern California Gas Company (SoCalGas)

Website:	https://www.socalgas.com/for-your-business/power-generation/self-generation-incentive
Email Address:	selfgeneration@socalgas.com
Mailing Address:	Self-Generation Incentive Program Southern California Gas Company 555 West Fifth Street, GT19A9 Los Angeles, CA 90013-1011

Los Angeles Department of Water and Power (LADWP)

Website:	https://www.ladwp.com/residential-services/solar-programs/self-generation-incentive-program
Email Address:	sgip@ladwp.com
Telephone:	800-342-5397

[1] Potential eligible projects located in the service territory of Southern California Edison or Los Angeles Department of Water and Power as well as the Southern California Gas Company can apply for incentive funding to only one Program Administrator.

Program Overview

The Self-Generation Incentive Program (SGIP) provides financial incentives for the installation of new qualifying technologies that are installed to meet all, or a portion of the electric energy needs of a facility. The purpose of the SGIP is to contribute to Greenhouse Gas (GHG) emissions reductions, demand reductions and reduced customer electricity purchases, resulting in the electric system reliability through improved transmission and distribution system utilization; as well as market transformation for distributed energy resource (DER) technologies.

This handbook outlines the policies and procedures of the SGIP for potential program participants and other interested parties. The SGIP has been approved by the California Public Utilities Commission (CPUC) and is subject to change in whole or in part at any time without prior notice. Changes to the program shall be published in revisions to this Handbook. The Program Administrators (PAs) are Pacific Gas and Electric (PG&E), Southern California Edison (SCE), the Southern California Gas Company (SoCalGas) and Center for Sustainable Energy® (CSE)[2], and Los Angeles Department of Water and Power (LADWP).

[2] CSE is the Program Administrator for San Diego Gas & Electric (SDG&E) customers.

1 Budget

1.1 Statewide Program Budget and Administrator Allocations [3]

Ratepayer Allocations

Authorized incentive collections during program years 2020 through 2024 total $813,400,000. Authorized incentive collections for each Program Administrator are as follows:

Pacific Gas and Electric Company	$360,000,000
Southern California Edison Company	$280,000,000
Center for Sustainable Energy	$99,000,000
Southern California Gas Company	$74,400,000

The SGIP shall be administered on a continuous basis. Program Administrators will issue incentive reservations for any budget with available funds through December 31, 2025. [4] Therefore, the deadline to submit new applications is **December 30, 2025**. Additionally, all ratepayer funded SGIP waitlists will be closed on December 30, 2025. A budget overview, including funding availability and current incentive rates, can be found at www.selfgenca.com/home/program_metrics/.

Assembly Bill (AB) 209 Allocations

Decision (D.) 24-03-071 implementing AB 209 allocated $280 million from the Greenhouse Gas Reduction Fund (GGRF) to the SGIP Residential Solar and Storage Equity (RSSE) budget. Incentive allocation of AB 209 funding is as follows:

Pacific Gas and Electric Company	$99,000,000
Southern California Edison Company	$87,300,000
Los Angeles Department of Water and Power	$32,400,000
Center for Sustainable Energy	$19,800,000
SoCalGas	$13,500,000

AB 209 Sub-Budgets for Publicly Owned Electric Utility (POU) Customer Incentives

A sub-budget is adopted for POU customers that have been assigned to PG&E and SCE. The amounts identified as “POU share” in the table below are reserved for electric customers of POUs served by the respective assigned SGIP PA.

[3] CPUC Decision 25-12-003 established the requirements for closing out all SGIP activities related to 1) accrued IOU ratepayer collections since program inception, and 2) Greenhouse Gas Reduction Fund (GGRF) issued in AB 209 and modified by AB 102 and SB 123.

[4] Incentive funds include authorized ratepayer collections, returned funds from project attrition, application fee forfeitures, and accrued interest.

SGIP PA	Incentive Funds
PG&E	**$99,000,000**
All other share	$68,000,000
POU Share	$31,000,000
SCE	**$87,300,000**
All other share	$86,300,000
POU Share	$1,000,000

The deadline for new applications and waitlist applications to be submitted is June 30, 2028. After June 30, 2028 but before August 30, 2028, Southern California Gas Company, Pacific Gas and Electric Company, Southern California Edison Company, Los Angeles Department of Water and Power, and San Diego Gas & Electric Company via the Center for Sustainable Energy shall transfer unallocated incentives funds for the Greenhouse Gas Reduction Funded SGIP to Program Administrators with waitlists after the final applications Request for Reservation Forms are reviewed. The PAs must return to the Commission any unspent AB 209 funds by January 31, 2033, following the last SGIP Impact Evaluation Report in 2032.

1.2 Budget Allocation

Statewide budget allocations of the 2020 – 2024 ratepayer collections are as follows:

Table 1.2: Statewide budget allocations

Renewable Generation	12%
Energy Storage Technologies	88%
Large-Scale Storage	10%
Small Residential Storage	7%
Residential Solar and Storage Equity	3%
Non-Residential Equity	0%
Equity Resiliency	63%
Heat Pump Water Heaters	5% [5]
SJV Pilot Budget	0%

[5] D.22-04-036, Ordering Paragraph 8, authorized an additional collection of $40M from 2023 Cap-and-Trade Program allowance auction funds from SoCalGas, PG&E, and SDG&E for the HPWH subprogram.

2 Applications

2.1 Application Process

Applications are subject to the incentive rates of the Program Administrator to which they apply. Generally, applications will be assigned an incentive rate and reviewed in the order in which they are received. A lottery will be conducted in the event that application submissions for a given budget and step on a single day exceed the available funding in a given Program Administrator's territory. Additional details regarding the lottery process can be found in Section 2.1.1.1.4.

2.1.1 Application Process Flowchart

The application process is determined by the customer sector and system size. There are two application processes illustrated below:

1. Three-Step Application Process – Figure 2.1.1a
   - Non-residential projects 10 kW or greater
2. Two-Step Application Process – Figure 2.1.1b
   - All residential projects
   - Non-residential projects less than 10 kW

Figure 2.1.1a: Three-Step Application and Approval Process

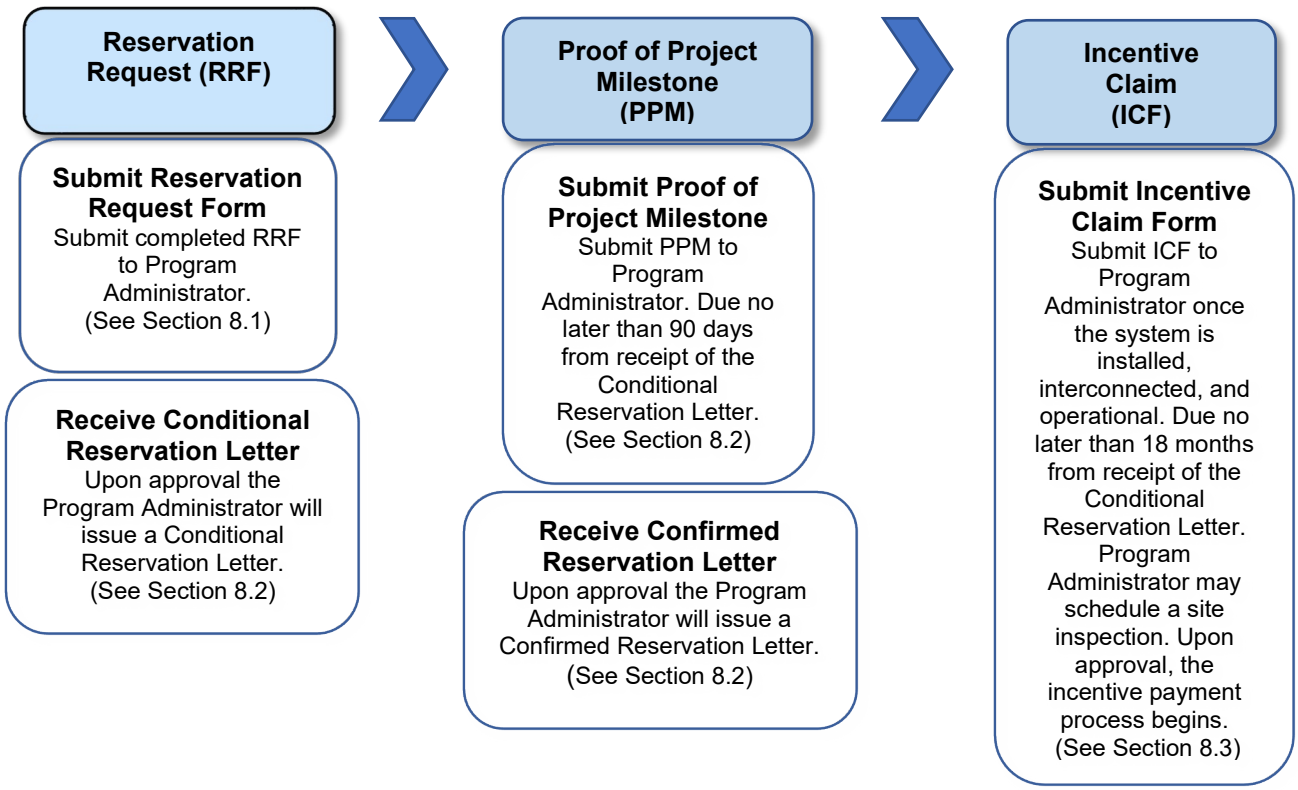
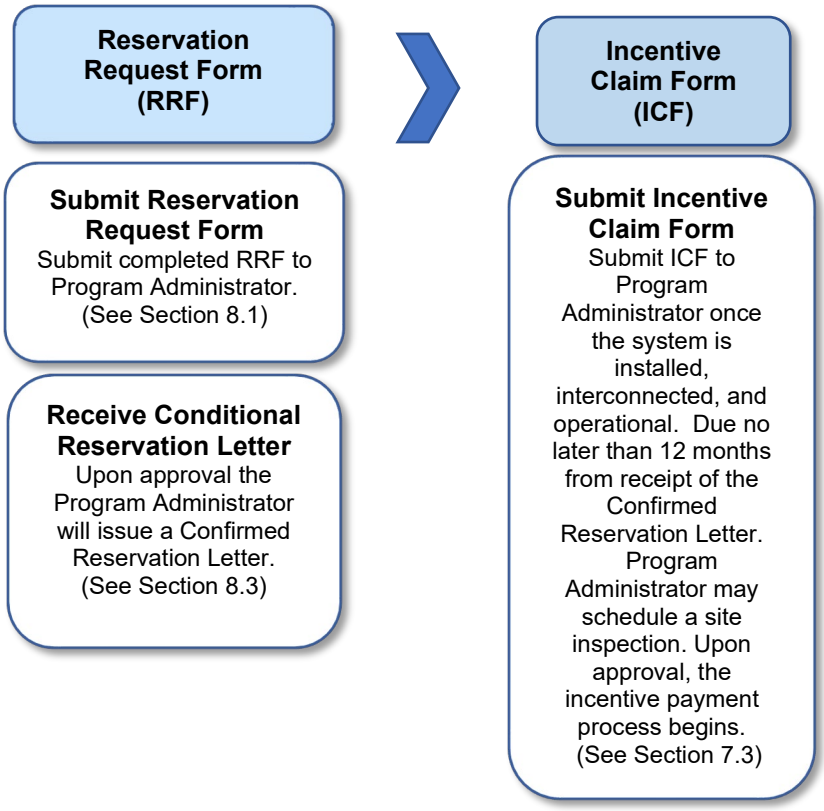


Figure 2.1.1b: Two-Step Application Process



2.1.1.1 Application Submissions

All SGIP applications and required documents [6] are submitted via the SGIP online application database at www.selfgenca.com. To submit an application and/or project documentation, companies or individuals must create an Applicant Account and register any anticipated users. All Applicants and Applicant Administrators must also agree to the SGIP online application database Terms of Use. Terms of Use can be found at www.selfgenca.com/terms_of_use/. **Mailed, emailed, faxed, or hand delivered applications will not be accepted.**

Only complete applications may be assigned incentive funds or be placed into a lottery. Only complete applications may receive an approved reservation. Duplicate applications or multiple submissions for the same project are not allowed and will be rejected. [7]

2.1.1.1.1 Residential Storage "Soft Target"

The Residential Storage Soft Target reserves 50% of the Step 6 and Step 7 general market small residential budget for:

[6] With the exception of the application fee check that is to be mailed directly to the Program Administrator. See Section 8.1 for more information.
[7] Duplicate applications are considered a program infraction. See Section 14 for information on program infractions. Definition of project can be found in Definitions and Glossary.

- Residential customers living in Tier 3 or Tier 2 High Fire Threat Districts (HFTDs); and/or
- Residential customers whose electricity has been turned off during two or more discrete Public Safety Power Shutoff (PSPS) events; and/or
- Residential customers who have experienced one PSPS event and one de-energization or power outage from an actual wildfire that occurred on or after January 1, 2017.
- Residential PG&E customers who have experienced five EPSS events on or after January 1, 2023.

Acceptance of Step 6 and Step 7 general market residential incentive budget applications that do not meet the criteria outlined above will be paused after such applications reach 50% of the total budget for each residential incentive step. Acceptance of applications will resume if applications that do not meet the above criteria drop below 50% of the funding in that budget step.

The PAs are authorized to change or remove the general market Small Residential storage budget "soft target" through a Tier 1 Advice Letter. This Advice Letter shall include justification for the change or removal to include low uptake, pending deadlines for returning the funds, or other reasons.

2.1.1.1.2 AB 209 Fund Tribal "Soft Target"

The Tribal "Soft Target" on AB 209 funding reserves 2% of each PA's incentive budget for low-income residential Tribal customers. The PAs may, through a Tier 2 Advice Letter, increase or decrease this initial percentage at any time. Any funds allocated to this "Soft Target" that remain unencumbered in the final twelve months of the program shall be released back into the RSSE budget and made available to any eligible customer.

2.1.1.1.3 Developer Caps

Any single Developer is limited to 20% of the SGIP incentive funding for a given general market budget category in each statewide incentive step. The Developer Cap will be calculated separately for the Generation Budget, Large Scale Energy Storage Budget, and Small Residential Energy Storage Budget. Applicants may not submit applications for Developers in excess of the statewide Developer Cap for the active step, and Program Administrators shall not issue reservations to projects by a Developer that has already applied for reservations in a given step that exceed 20%. The Developer Cap will be established by budget step and posted prior to program opening. The Developer Cap will remain fixed for each budget step once the step is opened even if the total available funds change. [8] Please see Section 3.6 for the definition of a Developer.

The Equity and Equity Resiliency Budgets are exempt from the Developer Cap.

[8] If an incentive step is open at least 12 months and at least two entities have reached their cap and there is otherwise low participation in the incentive step, the PAs will request modification or suspension to the Developer Cap via Advice Letter.

2.1.1.1.4 Lottery Process

A lottery will be triggered when applications submitted on a single day exceed funds available for a given budget and step that is not already on a waitlist.[9] Lotteries are to be conducted separately for each budget category within a PA's territory. Any application not selected in a lottery for a specific budget step will be rejected and must reapply in the next funding step to receive funding. If a lottery is triggered in the final step of a budget, projects not selected in the lottery will be placed onto the waitlist in the order in which they were submitted to the application portal.

Priority Projects for Lottery

The following energy storage projects shall have priority in the SGIP lottery process:

- Energy storage projects located within the service territory of Los Angeles Department of Water and Power (LADWP)[10]
- Energy storage projects located within the West Los Angeles Local Reliability Area of Southern California Edison's service territory
- Energy storage systems paired with an on-site renewable generator and claiming the Investment Tax Credit (ITC) or, if not claiming the ITC, charging a minimum of 75% from the on-site renewable generator

Energy storage projects that meet more than one criterion shall be given the highest priority.

Generation projects shall have priority in the SGIP lottery in the following order:

1) Renewable projects using wind, waste heat to power, pressure reduction turbines, or 100% on-site biogas will be given first priority.
2) 100% directed biogas will be given second priority.

2.1.1.1.5 Pause Periods

When a budget category changes to the next incentive step, the Program Administrator will initiate a pause period of no less than 20 days. During a pause period the following will occur:

- No new applications within the budget category are accepted.
- The Program Administrator may perform a pre-screen to reject applications with missing documentation or applications submitted above the Developer Cap, and verify projects identified with a locational priority.
- After 10 days, Program Administrators will determine if the incentive level reduction for energy storage technologies shall increase from $0.05/Wh to $0.10/Wh between incentive steps based on statewide oversubscription for a given step.

[9] When additional funding is provided in a given budget category, applications on a waitlist will be awarded funding in the order they were received. No lottery is conducted for waitlist applications.
[10] All projects interconnecting into LADWP's electrical grid must abide by LADWP interconnection rules.

- Notification of lottery results will be sent to Applicants. Applications not selected during the lottery process will be instructed how to reapply for funding in the next step.
- Projects that are only able to be partially funded within a certain step must choose to reapply for funding in the next step or claim the remaining funds in the current step. [11]
- www.selfgenca.com is updated with information on the new incentive rate(s), available funds, and the date of the next application submission opportunity.

2.1.1.1.6 Waitlists

Once funds have been fully allocated in the final incentive step of a Program Administrator's given budget, applications will be placed on a waitlist in the order in which they were submitted to be funded as incentive funds become available. When there is enough attrition to fund waitlisted projects, those projects will be assigned an incentive rate in the last step and reviewed in the order in which they were submitted. In the event there are available funds and all waitlisted projects have been allocated funding, new applications will be accepted and subject to standard program procedures (see Section 2.1). Pursuant to D.25-12-003, all ratepayer projects with a "RRF Waitlist" status on December 31, 2025, will be canceled.

2.1.1.2 Incomplete Applications

If an application is found to be missing any required information or requires additional clarification, the Program Administrator or their representative will send an email to the Applicant requesting clarification and/or submission of missing information. Applicants have 15 calendar days to respond with the requested information for the Reservation Request Form and Proof of Project Milestone. Applicants have 30 calendar days to respond with the requested information for the Incentive Claim Form. If after that time the Applicant has not submitted the requested information or satisfied the eligibility requirement in question, the application may be cancelled. An application may not receive multiple [12] requests for the same missing or uncorrected item(s). Cancelled applications may reapply if funding is available and will be treated as a new application (i.e., all required documents must be resubmitted) and will be processed in sequence. Funds from cancelled projects will be reallocated to the currently active incentive step in the Program Administrator's SGIP incentive budget. If the Program Administrator is in a pause period when attrition occurs, the funds will be placed in the next incentive step.

2.1.1.3 Post-Installation Inspections

Upon receipt of a complete Incentive Claim Form package, the project may be selected for an on-site, post-installation inspection (or virtual inspection for select residential applications) [13] to verify that the incentivized system is installed as represented in the application, operational, interconnected, and conforms to the eligibility criteria of the SGIP.

[11] Projects are not allowed to be assigned a "split incentive" across two or more incentive steps.
[12] Number of request for clarification/missing information emails allowed is up to the discretion of the Program Administrator.
[13] Refer to Energy Storage Field Inspection and Discharge Testing Protocol and Field Inspection Sampling Protocol at www.selfgenca.com.

Prior to inspection, energy storage systems must be tested to validate the discharge energy capacity. HVAC-integrated S-TES systems must be tested to show their ability to provide enough thermal energy to turn off the compressor of the accompanying HVAC unit for the specified discharge duration period. Refrigeration TES systems must be tested to show their ability to provide enough thermal energy to turn off the compressor(s) and condenser(s) of the accompanying refrigeration system(s) for the specified discharge duration period. L-TES systems must be tested to show their ability to provide enough thermal energy to turn off the compressor of the accompanying chiller unit for the specified discharge duration period. This data is provided by the Developer at the Incentive Claim Form stage once the project has been selected for inspection.

On-site verification includes, but is not limited to:

- For all systems, the inspection will verify the system capacity rating to support the final incentive value.
- If the project is subject to PBI payments, the metering system will be inspected, and it will be verified that it follows the proposed monitoring plan and meets the metering requirements of the SGIP.
- If the project uses renewable fuel, the availability and flow rate of the renewable fuel will be demonstrated by the Host Customer and/or System Owner.
- If the project uses waste energy, the availability, temperature, and production rate of the waste energy will be demonstrated by Host Customer and/or System Owner.
- Energy storage projects will be inspected according to the Energy Storage Field Verification Protocol. Generation projects will be inspected according to the Generation System Inspection Protocol. The latest versions of the inspection protocols can be found on www.selfgenca.com/.

Solar Inspections

The inspectors will verify that the PV System is installed in accordance with information provided in the Incentive Claim documentation, and in compliance with SGIP Program rules. The following are some examples of what will be inspected and verified:

Modules and Inverter(s):

- Manufacturer
- Model number (if model nameplate is not visible, invoice is necessary for verification)
- Quantity

Installation Parameters:

- Tilt
- Azimuth
- Standoff height

- Shading of array(s) - The SGIP PA reserves the right to ask for a shading study from an Applicant. Shading studies will generally be requested for projects that do not meet the minimum shading requirements

Operation:

- System is operational, and output is reasonable for conditions at the time of the inspection based on an on-site inverter production reading

Acceptable Range of Parameters for Key Solar Project Components Reviewed During Inspection

The inspector will review, and record key project components found at the installation site. The SGIP PA will evaluate and compare the results of the inspection to the Incentive Claim documentation.

The inspection results must fall within the following tolerances to pass inspection:

- Tilt ± 3º
- Azimuth ± 5º
- Summer Shading (May-October) ± 5%

A new Expected Performance Based Buydown (EPBB) calculation will be generated and the project incentive modified accordingly if:

- The final inspection results are outside of the above tolerances,

  or

- The final inspection reveals other discrepancies between key project components and the project's Incentive Claim documentation.

An inspection suspension will be issued to the appropriate party if the incentive on the original Incentive Claim Form is 5%-10% greater or less than the incentive amount determined by the final inspection. Inspection failures will be issued if the incentive on the original Incentive Claim Form is more than 10% greater or less than the incentive amount determined by the final inspection. All project incentives are subject to the results of the final inspection.

Failed Post-Installation Inspection

If the results of the inspection indicate that the project cannot be approved, the Program Administrator will notify the Applicant, Host Customer, and System Owner of the reasons for failure. The Applicant, Host Customer, and System Owner will have up to 60 calendar days to bring the project into compliance and a subsequent inspection visit may be required to determine final approval. If the Applicant, Host Customer, and System Owner fail to bring the project to compliance within the requested time, the application may be cancelled.

If the site load, availability of renewable fuel, or waste energy forecast has not yet materialized, the Applicant will be given two options:

1. Receive payment based on the site load, renewable fuel, or waste energy availability (whichever is less) demonstrated at the time of initial inspection.
2. Wait for the site load, renewable fuel, or waste energy to materialize within 12 months from the date the Incentive Claim Form and documents were initially received. If the site load, renewable fuel, or waste energy has not materialized within the 12-month period, the project will be paid based on the site load or system operating capacity available at the end of the 12-month period, whichever is less.

2.1.2 Application/Project Modifications, Extensions and Cancellations

All projects are expected to be installed as described on the Conditional and Confirmed Reservation Letter. If changes are made during the development of the project and/or during the installation, it is the responsibility of the Host Customer and/or Applicant to notify the Program Administrator as soon as possible. Changes to the Host Customer or project site location are generally not permitted and must be approved on a case-by-case basis by the Program Administrator. Unapproved changes may result in project cancellation.

Modifications Pre-ICF

Changes pertaining to program participants (Applicant, System Owner, Developer, Payee, Installer), equipment type, fuel type, system capacity, or incentive step-down structure must be approved by the Program Administrator before the application can proceed. If the step to which a project is assigned has closed, modifications to the project will not result in additional incentive funding. At the Program Administrator's discretion, changes to an application resulting in additional incentive funding may be allowed only when a project is assigned to the active step and adequate funding is available.

Changes in equipment type, fuel type, system capacity, program participants (Applicant, System Owner, Developer, Payee, Installer), or other substantial changes may require the execution of a new RRF and/or PPM along with additional documentation. Once the request has been approved, a new reservation letter may be issued. Any such changes do not extend the reservation expiration date.

Modifications Post-ICF

In general, changes to completed projects are not allowed. If a system needs to be upgraded or changed due to poor performance, the Applicant must notify the Program Administrator of new equipment information and provide updated documentation to help support performance and measurement and evaluation activities. For system replacements, see Section 4.5.5.

If there is a change in ownership of the property which hosts the SGIP equipment, the new owner may continue to receive the remaining PBI if the new owner completes a new interconnection agreement. However, if the original Host Customer relocates the equipment, they may continue to receive the PBI incentive payments if the equipment is relocated within the same Program Administrator's service territory

within six months and the System Owner completes an interconnection agreement at the new address. In either case, the PBI payment sunset date will not be extended.

Extensions and Exceptions

Extension requests will be reviewed on a case-by-case basis and should be submitted in writing to the appropriate Program Administrator for review. Any extension granted to either the Proof of Project Milestone or Request for Proposal due date will not extend the reservation expiration date.

All projects will be limited to a maximum of three six-month extensions of the reservation expiration date, after which the reservation expires automatically.[14] Extensions will be for special circumstances only and will not be granted to projects that have not made progress toward project completion. Any request for an extension of the reservation expiration date requires Program Administrator approval, and the SGIP Program Administrator shall notify Applicants of the decision in writing within 30 days. When considering an extension request for a reservation expiration date, the SGIP Program Administrator will consider:

1. Whether the project's delay is outside the control of the Host Customer.
2. Whether the project has made significant progress toward completion, and a timeline is provided showing the expected date of commissioning of the project and that interconnection of the project will fall within the third six-month extension of the project's reservation expiration date.
3. Whether the extension of the project's reservation expiration date will affect the Program Administrator's ability to incentivize other projects.

Note: Pursuant to D.25-12-003, non-residential equity and non-residential equity resiliency projects are granted access to up to four additional 6-month extensions retroactively from February 1, 2025, if the applicant demonstrates ALL of the following:

1. The host customer has passed the Proof of Project Milestone submitted stage.
2. The project will be completed before all extensions expire.
3. The host customer agrees to participate in an SGIP qualifying Demand Response program for ten years from ICF submission.

Any PBI extension or pause requests received after December 4, 2025 will be denied, pursuant to D.25-12-003.

Wind Turbine Project Extensions:

The reservation expiration date for any project using wind turbines shall be automatically extended for the period of time the Applicant is awaiting a final non-appealable decision on a permit required for the installation and operation of such project or the utility's completion of any interconnection upgrades (i.e., interconnection facilities, distribution upgrades, and network upgrades). To administer this provision, upon the Program Administrator's request, the Applicant shall provide the Program Administrator with evidence

[14] D.15-06-002 granted a petition for modification to increase the number of six-month extensions from two to three.

satisfactory to the Program Administrator of (a) the date on which the Applicant filed its application for such permit, (b) the date on which the submitted interconnection application was submitted, (c) the date on which a final non-appealable decision on such permit has been issued, and (d) the date on which the utility has completed construction of any required upgrades. [15]

Developer Declares Bankruptcy or Otherwise Goes Out of Business

A reserved project that has been installed but unable to complete the required outstanding documentation (i.e., PTO, Final Monitoring Schematic) because the Developer has declared bankruptcy or otherwise gone out of business, a Host Customer or Applicant may request an additional 90-day extension. A request for a 90-day extension shall require unanimous SGIP Working Group approval. [16] Note: These projects will also require an exception to the service warranty and fleet GHG compliance enforcement actions which requires CPUC approval through the disposition of a Tier 2 Advice Letter submitted by the PAs.

3 Program Participant Eligibility

3.1 Host Customer

To receive an SGIP incentive funded by ratepayers, the Host Customer must be a retail electric or gas distribution class of customer (industrial, agricultural, commercial, or residential) of PG&E, SCE, SoCalGas, or SDG&E. [17] Additionally, to receive the SGIP incentive, the Host Customer is required to be the utility customer of record at the site where the SGIP system is to be located. If the Host Customer's name is not on the utility bill, a letter of explanation is required to address the relationship of the Host Customer to the utility customer of record. If the Host Customer is renting the property, a letter of explanation is required to address the relationship and approval from the homeowner to the tenant. Host Customers of AB 209 funded projects must be a California residential customer, which include customers receiving service from a local POU, rural electric cooperative, and other electric Load Serving Entities. PA assignments for AB 209 funded projects can be found on https://www.selfgenca.com/home/resources/. [18]

The Host Customer is the exclusive incentive reservation holder who is party to the SGIP Contract (accessible at https://www.selfgenca.com/home/resources/). The Host Customer has the authority to designate the Applicant, System Owner (if not Host Customer), and/ or Developer and change any of these parties at any time.

[15] No wind project will be suspended beyond June 30, 2027 unless the Legislature authorizes additional revenue collections for SGIP purposes such that the SGIP's sunset date is extended beyond the date of January 1, 2026 authorized in Senate Bill 700.
[16] For projects that are already beyond their 90-day extension in addition to the three six-month extensions, the additional 90-day extension commences with the disposition date of the PA-filed Tier 2 Advice Letter allowing for such an extension.
[17] "…retail electric or gas distribution class of customer…" means that the Host Customer pays for and receives distribution services, as defined by their respective utility rate schedule.
[18] Any customers or LSEs not listed in Appendix D – PA Assignments of the D.24-03-071, will be served by PG&E.

For multifamily buildings that are installing a system on behalf of tenants and are enrolled in a Virtual Net Energy Metering (VNEM) tariff, the Property Owner may be the Host Customer.

3.2 Host Customer Eligibility for the Equity, Equity Resiliency, and San Joaquin Valley Budgets

3.2.1 Residential Solar and Storage Equity Eligibility

For the Equity Budget, residential projects are classified as either multifamily low-income housing or single-family low-income housing. GHG emission standards, operating requirements, and incentive payment structure for multifamily projects will be determined by the project's "primary use" as defined in Section 3.3.

Multifamily

Multifamily residential customers applying for the Equity funding must comply with a specified pathway under both Criteria 1 and 2 **or** Criteria 3:

Table 3.2.1a: Pathways for Eligibility, Multifamily

Criteria	Pathways for Eligibility	Additional Guidance
1	Multifamily residential building of at least five rental housing units that is operated to provide deed-restricted low-income residential housing. [19]	
2	a) Located in a disadvantaged community [20] (including Indian Country [21]); or	CalEnviroScreen SB 535 Disadvantaged Communities Map (oehha.ca.gov/calenviroscreen/sb535) Non-Indian multifamily residences on privately owned fee land in Indian Country are not eligible under this expanded definition. If the in-holding has multiple owners, at least one owner must be a tribe or tribal member for the project to be eligible.
	b) Is a building where at least 80% of the households have incomes at or below 60% of the area median income. [22] Any customer account in such buildings will be eligible for the Equity Budget.	Housing and Urban Development's Income Guidelines for verifying area median income (huduser.gov/portal/datasets/il.html)
OR		

[19] As described in clause (i) of subparagraph (A) of paragraph (3) of subdivision (a) of § 2852 of the Public Utilities Code.
[20] Definition of "disadvantaged community" can be found in Definitions and Glossary section at end of Handbook.
[21] As defined in 18 USC §1151.
[22] As defined in subdivision (f) of § 50052.5 of the Health and Safety Code.

3	Have reserved funds in the MASH, or SOMAH programs; or are enrolled in MASH successor tariffs [23]	

[23] MASH successor tariffs must rely on the same income eligibility criteria as the MASH program or SGIP.

Single-Family

Single-family low-income residential customers applying for the Equity Budget funding must comply with Criteria 1 **or** Criteria 2. Single-family low-income residences in California Indian Country are eligible for the Equity Budget if they meet Criteria 1 **or** Criteria 2.

Table 3.2.1b: Pathways for Eligibility, Single Family

Criteria	Pathways for Eligibility	Additional Guidance
1	Income verification [24] (see Section 8.1 item #10 for more information); and	• Housing and Urban Development's Income Guidelines for verifying area median income (huduser.gov/portal/datasets/il.html) • Non-Indian residences on privately owned fee land in Indian Country are not eligible under this expanded definition. If the in-holding has multiple owners, at least one owner must be a tribe or tribal member for the project to be eligible.
OR		
2	Have completed income-verification as a result of participation in the SASH, DAC-SASH, CARE, FERA, or ESA [25] programs.	

[24] Documentation showing the Host Customer's household income is 80% of the area median income or less based upon a copy of the most recently available federal income tax documentation. Area Median Income is subject to annual changes based upon Housing and Urban Development's income guidelines (https://www.huduser.gov/portal/datasets/il.html).

[25] Customers that qualify for Self-Generation Incentive Program incentives through categorical eligibility that are later found ineligible or are disenrolled from the California Alternate Rates for Energy, Family Electric Rate Assistance, and Energy Savings Assistance programs, at any time prior to receiving the incentive payment, will have their application(s) cancelled.

3.2.2 Non-Residential Equity Eligibility

Non-residential customers applying for the Equity Budget funding must comply with a specified pathway under Criteria 1 **and** Criteria 2. Multi-tenant commercial building customers may only submit applications to the General Market Budgets. Such customers are not eligible for Equity or Equity Resiliency incentives.

Table 3.2.2: Pathways for Eligibility, Non-Residential

Criteria	Pathways for Eligibility	Additional Guidance
1	a) State or Local Governmental Agency	
	b) Tribal Government Agency	• Non-Indian businesses on privately owned fee land in Indian Country are not eligible under this expanded definition. If the in-holding has multiple owners, at least one owner must be a tribe or tribal member for the project to be eligible.
	c) Educational Institution	
	d) Non-Profit	
	e) Small Business	
2	a) Project site is located in a disadvantaged, tribal, or low-income community, or demonstrates that at least 50% of the census tracts it serves are disadvantaged, tribal, or low-income communities; or	• CalEnviroScreen SB 535 Disadvantaged Communities Map (oehha.ca.gov/calenviroscreen/sb535) • CPUC Non-Residential Eligibility Map for Disadvantaged, Tribal, and Low-Income Communities. (arcg.is/0vn19T)
	b) Any facility owned or operated by a public agency that provides services to DAC or low-income community members for which at least 50% of census tracts served are DACs or low-income communities.	

3.2.3 Residential Equity Resiliency Eligibility

Residential customers (single family or multifamily) applying for the Equity Resiliency Budget funding must comply with a specified pathway under both Criteria 1 **and** Criteria 2:

Table 3.2.3: Pathways for Eligibility, Residential Equity Resiliency

Criteria	Pathways for Eligibility	Additional Guidance
1	Project site is located in a Tier 3 or Tier 2 High Fire Threat District (HFTD); or	CPUC Fire Map available here: (https://capuc.maps.arcgis.com/apps/webappviewer/index.html?id=5bdb921d747a46929d9f00dbdb6d0fa2)
	Customers whose electricity was shut off during two or more discrete Public Safety Power Shutoff (PSPS) events prior to date of application for SGIP incentives; or	• List of circuits with two or more PSPS events posted on the SGIP portal. [26] • PG&E Resiliency Lookup Tool (https://vizmap.ss.pge.com/ • CSE PSPS Wildfire Event Lookup Tool (sgipsd.org/event-look-up) • SCE PSPS Lookup Tool (https://www.sce.com/residential/generating-your-own-power/incentive-program/psps-sgip)
	Customers whose electricity was shut off during one discrete PSPS event and one de-energization or power outage from an actual wildfire that occurred on or after January 1, 2017; or	• List of circuits with two or more PSPS events posted on the SGIP portal. • PG&E Resiliency Lookup Tool (https://vizmap.ss.pge.com/ • CSE PSPS Wildfire Event Lookup Tool (sgipsd.org/event-look-up) • SCE PSPS Lookup Tool (https://www.sce.com/residential/generating-your-own-power/incentive-program/psps-sgip)
	PG&E customers whose electricity was shut off during five or more Enhanced Powerline Safety Settings (EPSS) events on or after January 1, 2023.	• PG&E Resiliency Lookup Tool (https://vizmap.ss.pge.com/
2	Multifamily or single-family projects eligible for the RSSE Budget; or	• See Section 3.2.1
	A resident within the household project site must be eligible for the Medical Baseline program; or	

[26] To be updated 30 days after new PSPS event.

	The customer has notified their utility of a serious illness or condition that could become life-threatening if electricity is disconnected; or	
	a) Household relies on electric-pump wells for water supplies and also meets the following criteria: • The residential household meets the income eligibility requirements for the RSSE Budget; and • The project site is a primary residence occupied by either a homeowner or tenant; and • The residence is not provided water by a municipal or privately-owned utility. [27]	• Housing and Urban Development's Income Guidelines for verifying area median income. (https://www.huduser.gov/portal/datasets/il.html)

3.2.4 Non-Residential Equity Resiliency Eligibility

Non-residential customers applying for Equity Resiliency funding must comply with a specified pathway under Criteria 1, 2, **and** 3. Multi-tenant commercial building customers may only submit applications to the General Market Budgets. Such customers are not eligible for Equity or Equity Resiliency incentives.

Table 3.2.4: Pathways for Eligibility, Non-Residential Equity Resiliency

Criteria	Pathways for Eligibility	Additional Guidance
1	a) Project site is located in a Tier 3 or Tier 2 HFTD; or	• Maps available here: (https://capuc.maps.arcgis.com/apps/webappviewer/index.html?id=5bdb921d747a46929d9f00dbdb6d0fa2)

[27] The Electric Well Pump Attestation can be found at www.selfgenca.com/home/resources.

	b) Customers whose electricity was shut off during two or more discrete PSPS events prior to date of application for SGIP incentives. c) Customers whose electricity was shut off during one discrete PSPS event and one de-energization or power outage from an actual wildfire that occurred on or after January 1, 2017; or d) PG&E customers whose electricity was shut off during five or more Enhanced Powerline Safety Settings (EPSS) events on or after January 1, 2023.	• List of circuits with two or more PSPS events posted on SGIP portal. [28] • PG&E Resiliency Lookup Tool (https://vizmap.ss.pge.com/ • CSE PSPS Wildfire Event Lookup Tool (sgipsd.org/event-look-up) • SCE PSPS Lookup Tool (https://www.sce.com/residential/generating-your-own-power/incentive-program/psps-sgip)

[28] To be updated 30 days after new PSPS event.

2	a) Provides critical facilities or infrastructure to one or more communities in a Tier 3 or Tier 2 HFTD, a community with customers whose electricity was shut off during 2 or more discrete PSPS events prior to the date of application for SGIP incentives, or a community whose electricity was shut off during one discrete PSPS event and one de-energization or power outage from an actual wildfire that occurred on or after January 1, 2017; and b) At least one of those communities is eligible for the Equity Budget. Equity Budget eligible community refers to a disadvantaged or low-income community or California Indian Country. Emergency Feeding Organizations, homeless shelters, and independent living centers are exempt from the Equity requirement. [29]	• CalEnviroScreen SB 535 Disadvantaged Communities Map (oehha.ca.gov/calenviroscreen/sb535) • Priority Populations Map (https://webmaps.arb.ca.gov/PriorityPopulations/) • CPUC Non-Residential Eligibility Map (https://arcg.is/KHX9X)

[29] Non-residential customers with critical resiliency needs do not need to meet eligibility criteria for the SGIP Equity budget themselves. Non-residential customers with critical resiliency needs are not required to exclusively serve communities that are located in a Tier 3 or Tier 2 HFTD and are also eligible for the Equity budget.

3	Is one of the following critical facilities and infrastructures listed below: • Police stations • Fire stations • Emergency response providers with the addition of tribal government providers • Emergency operations centers • 911 call centers (also referred to as Public Safety Answering Points) • Medical facilities including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers, and hospice facilities • Public and private gas, electric, water, wastewater, or flood control facilities • Jails and prisons • Locations designated by the IOUs to provide assistance during PSPS events • Cooling centers designated by state, local or tribal governments • Homeless shelters supported by federal, state, or local, or tribal governments • Grocery stores, corner stores, markets, and supermarkets that have average annual gross receipts of $15 million or less as calculated at the single location applying for SGIP incentives • Independent living centers • Emergency Feeding Organizations

3.2.5 San Joaquin Valley Eligibility

Residential

Residential customers applying for San Joaquin Valley (SJV) funding must comply with both Criteria 1 **and** 2.

Table 3.2.5a: Pathways for Eligibility, Residential San Joaquin Valley

Criteria	Pathways for Eligibility
1	Customer is located in one of the following eligible SJV cities: Allensworth, Alpaugh, Cantua Creek, Ducor, Fairmead, Lanare, Le Grand, La Vina, Seville, West Goshen, and California City.
2	Eligibility for the approved residential SJV pilot is limited to households that participate in the pilot by replacing one or more propane, wood-burning, or inefficient or inoperable major electric appliances with the efficient electric appliances offered by the pilot.

CARE-eligible and Medical Baseline-eligible SJV pilot households that wish to access SGIP incentives must enroll in an SGIP-approved rate, if one is available, or in any CARE or Medical Baseline TOU rate if an SGIP-approved rate is not available, regardless of the date of submittal of the SGIP application.

Non-Residential

Non-residential customers applying for SJV funding must comply with a specified pathway under both Criteria 1 **and** 2.

Table 3.2.5b: Pathways for Eligibility, Non-Residential San Joaquin Valley

Criteria	Eligibility
1	Customer is located in one of the following eligible SJV cities: Allensworth, Alpaugh, Cantua Creek, Ducor, Fairmead, Lanare, Le Grand, La Vina, Seville, West Goshen, and California City.
2	Eligibility for the approved non-residential SJV pilot incentives is one of the following critical facilities and infrastructure as listed in Criteria 3 under Section 3.2.4.

Both Residential and Non-Residential SJV Pilot customers must adhere to the GHG reduction requirements.

3.3 Host Customer Eligibility for the Small-Residential and Large-Scale Budgets

Residential energy storage projects not eligible for the Equity, Equity Resiliency or San Joaquin Valley budget categories are eligible for the Small Residential Storage budget. Single-family residential projects are capped at 30 kWh and are not eligible for the Large-Scale Storage budget. All non-residential and multifamily projects not eligible for the Equity, Equity Resiliency or San Joaquin Valley budget categories are eligible for the Large-Scale Storage budget.

3.4 Classification of Multifamily Properties

For the purposes of GHG emission standards, operational requirements and incentive payment structure, the classification of energy storage systems installed at multifamily properties will be determined by the energy storage system's primary use.

Virtual Net Energy Metering (VNEM) Projects

If the energy storage system is paired with a solar photovoltaic system and interconnects through virtual net energy metering (VNEM), the primary use will be determined by the VNEM Generation Credit Allocation Request Form.

If 51% or greater of VNEM credits are allocated to tenant accounts, the energy storage system will be considered residential, and residential GHG emission standards, operational requirements, and incentive payment structure will apply. If 50% or greater of VNEM credits are allocated to a common area account(s), the system's primary use will be considered "common load", and the applicable GHG emission standards, operational requirements and incentive calculation will be determined by the common meter account's rate schedule. If the common meter is on a residential rate, the project will be considered residential and residential GHG emission standards, operational requirements, and incentive payment structure will apply. If the common meter account is on a non-residential rate, non-residential GHG emission standards, operational requirements and incentive payment structure will apply.

Non-Virtual Net Energy Metering (VNEM) Projects

If the energy storage system is located behind the Host Customer's electric utility meter, and serves either tenant utility accounts, common area accounts, or a combination of the two, the Applicant will be required to define the system's primary use and provide supporting documentation to substantiate this primary use.

If 51% or greater of the kWh discharged by the system benefit tenant utility accounts, the system's primary use will be considered residential, and residential GHG emission standards, operational requirements and incentive calculations will apply. If 50% or greater of the kWh discharged by the system benefit common area utility accounts, the system's primary use will be considered "common area" and the applicable GHG emission standards, operational requirements, and incentive payment structure will be determined by the common area meter's rate schedule. If the common area meter is on a non-residential rate, non-residential GHG emission standards, operational requirements, and incentive payment structure will apply. If the common area meter is on a residential rate, residential GHG emission standards, operational requirements, and incentive payment structure will apply.

If the primary use case of a multifamily project is determined to be residential, all benefiting tenant accounts will be required to be enrolled in an SGIP-approved residential TOU rate.

3.5 System Owner

The System Owner is the owner of the SGIP incentivized equipment. In the case when a vendor sells a system to a Host Customer, the Host Customer is the System Owner. In the case of a leased system, the lessor is the System Owner. The System Owner shall be designated on the Reservation Request Form.

If the System Owner is not the Host Customer and withdraws from the project, the Host Customer will retain sole rights to the incentive reservation and corresponding incentive reservation number. To preserve such incentive reservation and corresponding reservation number, the Host Customer must submit revised application documentation [30] to the Program Administrator.

3.6 Applicant

An Applicant is the person or entity that is responsible for completing and submitting the SGIP application and serves as the main point of contact for the Program Administrator throughout the application process. Host Customers may act as the Applicant, or they may designate a third party to act as the Applicant on their behalf. Host Customers may elect to change the Applicant at any time with prior written notice to the Program Administrator.

3.7 Developer

A Developer, if not an individual homeowner applying for SGIP incentives for a system located on their own property, is the corporate entity registered and in good standing with the Secretary of State of California that handles a substantial amount of the project's development activities. [31]

For the purposes of the SGIP, completing a substantial amount of the following project activities qualifies an entity to assume the role of project Developer:

1. Approaching or communicating with the Host Customer about the project and learning about its needs and energy profile
2. Developing the specifications for a system based on the customer's needs and interests
3. Soliciting bids from multiple manufacturers for the specified system
4. Gaining the customer's commitment to purchase or lease the specified system, usually but not necessarily by signing a purchase order with a customer or other form of agreement
5. Purchasing the specified system from the manufacturer to fulfill the obligation to provide a system to the customer
6. Securing permits for the system on behalf of the customer
7. Securing interconnection permission for the system on behalf of the customer
8. Submitting SGIP applications on behalf of the customer
9. Liaising with the Program Administrators on incentive reservations

[30] Application documentation may include: the latest SGIP application form that was submitted (Reservation Request Form, Proof of Project Milestone Form, Incentive Claim Form) and all preceding supporting documentation submitted.
[31] If the Homeowner is handling a substantial amount of the project's development activities, they may apply to be the Developer and would not require standing with the Secretary of State.

10. Liaising with the Program Administrators on data reporting requirements
11. Supplying project data to SGIP evaluators
12. Physically constructing the system at the customer's premises
13. Installing the system at the customer's premises

The Program Administrators, with approval from the Statewide Working Group, have discretion to determine whether a participant handles such activities, and whether a participant handles a substantial amount of these activities for a given project. If a reassignment of Developer status for a given project occurs after an SGIP application is submitted but before a confirmed reservation is issued and leads to a participant retroactively exceeding its Developer Cap for a given incentive step, the project will be cancelled or a sufficient number of alternate reservation requests for that Developer will need to be cancelled to bring the Developer under its Developer Cap.

Developer Application Process

SGIP projects must select an approved Developer before the application may be submitted. A list of approved Developers is available at https://www.selfgenca.com/home/resources. Entities interested in becoming an approved SGIP Developer can submit a Developer Eligibility Application (www.selfgenca.com/home/dev_register/) [32] to the Program Administrators, containing the following information: [33]

- If a parent company for the participant exists, the ultimate owner of the parent company, if the parent company is nested within other parent-child corporate relationships, revelation of the ultimate owner is required.
- Any ownership interest, including a minority interest, in the Developer held by another Developer or ultimate owner of another Developer is required.
- The identity of the entity, if reasonably foreseeable, that will execute any of the development activities not performed by the Developer named in the Developer Eligibility Application
- If the Developer plans to divide project development activities with another entity in different ways for different projects, the Developer must note that on the application form and submit supplemental information with the Developer Eligibility Application describing those other ways for other projects.
- To the extent not described in the section asking for information on execution of project development activities, a description of relationships with other SGIP participants (including commercial or financial relationships between Developers that do not share the same majority ownership) in developing and/or owning any existing projects funded in whole or in part by the

[32] Downloadable from the www.selfgenca.com website under Forms and Documents.
[33] Approval by the Program Administrators of a Developer Eligibility Application does not guarantee that a participant qualifies as a Developer for any given project.

SGIP or reasonably foreseeable future projects that may be funded in whole or in part by the SGIP is required.

Additionally, if requested by the Program Administrator, Developers may be required to provide the following documentation:

1. Articles of Incorporation
2. Certificate of Incorporation
3. Operating agreements or similar applicable organizational document of Developer and most current financial statements

Only one entity per project can be determined by the Program Administrators, with approval from the Statewide Working Group, to handle a substantial portion of the project's development activities.

The customer contract will be verified at Proof of Project Milestone to confirm the Developer's representations. When applicable, the Developer Cap will apply to any combination of affiliated Developers under the same majority ownership. Majority ownership may be evidenced by the ownership interest in different Developers by a single parent corporation, the distinct subsidiaries of a single parent corporation, a private equity firm, an investment bank, a group of individual shareholders, or any other entity that the Program Administrators or Energy Division in their discretion determine to constitute the same majority ownership of different Developers.

To ensure that majority ownership can be accurately assessed by the Program Administrators, all Developers will be required, upon request, to disclose the identity of all their equity holders, including the ultimate ownership interests in those equity holders.

Failure to disclose relationships with other participants in a Developer Eligibility Application shall be considered an infraction (see Section 13.2).

Advanced Payment Program

Developers wishing to participate in the Advanced Payment Program will need to establish eligibility and complete an agreement form. See the latest information in the document named "SGIP Advanced Payment Program Guidelines" found in the *Forms and Documents* tab on selfgencan.com for complete instructions and necessary forms for developers interested in participating.

3.8 Installer

The entity installing the SGIP system at the project site must have an active license issued by the Contractors State License Board (CSLB) that complies with all current CSLB licensing requirements for the SGIP-eligible technology that is being installed. A list of CSLB licenses currently accepted in the program can be found at www.selfgenca.com/home/resources.

3.9 Performance Data Provider

SGIP projects subject to Performance-Based Incentive payments must select an approved Performance Data Provider (PDP) for a minimum of five years. A PDP is a company that contracts with the SGIP Participant to record performance data from the installed metering and monitoring equipment and submit it to the Program Administrators on a monthly basis. See Chapter 10 for more detailed PDP requirements.

3.10 Payee

A Payee is the person or entity to whom the SGIP incentive check is made payable. The Payee, if not the Host Customer, must be a person or entity designated by the Host Customer on the Incentive Claim Form.

3.11 Entity

Applications submitted to the Non-Residential Equity Budget are subjected to a $5 million cap per individual Applicant Entity.[34] For the purposes of SGIP, an individual Applicant Entity is defined as follows:

- The various divisions and/or departments of a city shall together constitute an individual Applicant Entity (such as City Police Department and City Department of Public Health).
- The various divisions and/or departments of a county shall together constitute an individual Applicant Entity (such as County Office of Emergency Services and County Sheriff).
- Each unique state agency, municipal utility (such as a municipal water district), or joint powers authority shall constitute an individual Applicant Entity.
- Each unique university, college, or community college shall constitute an individual Applicant Entity (i.e., as opposed to California's community college, state college, and university systems as a whole).
- Each school district shall constitute an individual Applicant Entity and shall be considered separately from any county or city entity.
- All affiliates of a parent company and the parent company shall together constitute one individual Applicant Entity.

3.12 Manufacturer

The manufacturer is the entity responsible for the assembly and production of a substantial portion of the SGIP system. The manufacturer is required to submit operational and performance data when requested by the SGIP evaluator to ensure comprehensive data submission. Infractions may be issued for manufacturers that do not provide the information requested by the PAs or the SGIP evaluator in the

[34] The individual Applicant Entity Cap is applied to any projects subjected to the lottery as directed in D.20-10-015 and any additional waitlisted projects.

timeframe requested. Any manufacturer with two infractions for this reason may be suspended from verified equipment lists for six months. See section 14.2 Infractions for more details.

4 Incentives

4.1 Incentive Rates

The following sections outline the incentive rates and adders for the various SGIP budget categories.

4.1.1 General Market Energy Storage Budgets

The incentive rates for the General Market Budget categories of the SGIP are provided below. The General Market Energy Storage Budgets, Large-Scale Storage and Small Residential Storage, decline by $0.05/Wh between incentive steps. However, if the previous incentive step becomes fully subscribed within 10 calendar days across all Program Administrator territories, the incentive decline will be $0.10/Wh rather than $0.05/Wh.

A Resiliency Adder of $0.15/Wh is available to Non-Residential Large-Scale Storage Projects that meet all the requirements outlined in Section 3.2.4 Non-Residential Equity Resiliency Eligibility with the exception of Criteria 2b Equity Budget eligibility. The Resiliency Adder is added to the base incentive rate of the project.

The incentive for Large-Scale Storage projects claiming ITC will maintain a 72% differential from the incentive rate for non-ITC Large-Scale Storage projects in all steps for equipment purchased before December 31, 2021.

Please visit www.selfgenca.com for a list of current incentive rates.

Table 4.1.1 Incentive Rates for the General Market Budget Categories of the SGIP

Budget Category	Step 1	Step 2	Step 3	Step 4	Step 5	Step 6	Step 7
Small Residential Storage ($/Wh)	$0.50	$0.40	$0.35	$0.30	$0.25	$0.20	$0.15
Large-Scale Storage ($/Wh)	$0.50	$0.40	$0.35	$0.30	$0.25	N/A	N/A
Large-Scale Storage Resiliency Adder ($/Wh)	$0.15	$0.15	$0.15	$0.15	$0.15	N/A	N/A
Large-Scale Storage (w/ ITC) ($/Wh)	$0.36	$0.29	$0.25	$0.22	$0.18	N/A	N/A

4.1.2 Equity and Pilot Budgets

The table below outlines the incentive rates for the Equity, Equity Resiliency, and San Joaquin Valley Budget categories. These rates are a flat rate and not subject to an incentive step-down structure.

See Section 3.2 for the eligibility requirements needed for each budget category.

Table 4.1.2: Incentive Rates for Equity, Equity Resiliency, and San Joaquin Valley

Budget Category	Incentive Rate
Residential Solar and Storage Equity	Solar: $3.10/W
	Storage: $1.10/Wh
Non-Residential Storage Equity	Storage $0.85/Wh
Equity Resiliency	Storage: $1.00/Wh
San Joaquin Valley Residential	Storage: $1.10/Wh
San Joaquin Valley Non-Residential	Storage: $1.00/Wh

4.1.3 Renewable Generation Budget

The table below outlines the incentive rates for the generation budget. These rates are a flat rate and not subject to a step-down structure.

Table 4.1.3: Incentive Rates for the Generation Budget

Budget Category	Incentive Rate ($/W)
Generation Base Incentive	$2.00
Generation Resiliency Adder (added to base incentive)	$2.50

4.1.3.1 Renewable Generation Resiliency Adder

A Resiliency Adder of $2.50/W is available to generation customers that meet all of the requirements outlined in Section 3.2.2 Non-Residential Equity Resiliency Eligibility with the exception of Criteria 2b. The Resiliency Adder is added onto the base incentive rate of the project and is available to non-residential customers only.

4.2 Incentive Calculation

4.2.1 Energy Storage Technologies

Incentives for a proposed energy storage system are calculated by multiplying the energy capacity (Wh) of the system by the incentive rate for the appropriate step.

***Incentive ($)** = Energy capacity (Wh) * incentive rate ($/Wh)*

Single-family energy storage incentives are capped at 30 kWh.

4.2.1.1 Incentive Declines Based on Storage Duration

Incentive Step-Down for Projects with Backup Capability

Energy storage incentives are reduced as the duration of energy storage (Wh) increases in relation to the rated capacity (W) according to the following schedule. The duration step-down incentive structure is as follows. [35]

Table 4.2.1.1a: Energy Storage Incentive Duration Decrease (Projects with Backup Capability)

Discharge Duration (hours)	Percent of Base Incentive
0 to 2 hours	100%
Greater than 2 hours up to 4 hours	100%
Greater than 4 hours up to 6 hours	50%
Greater than 6 hours	0%

Incentive Step-Down for Projects without Backup Capability

For projects that have indicated that they will not be installing a backup capable storage system on the RRF, the incentives are reduced as the duration of energy storage (Wh) increases in relation to the rated capacity (W) according to the following schedule:

Table: 4.2.1.1b: Energy Storage Incentive Duration Decrease (Projects without Backup Capability)

Discharge Duration (hours)	Percent of Base Incentive
0 to 2 hours	100%
Greater than 2 hours up to 4 hours	50%
Greater than 4 hours up to 6 hours	25%
Greater than 6 hours	0%

4.2.1.2 Incentive Declines and Caps Based on Energy Capacity (Wh)

Non-residential energy storage incentives are paid up to 6 MWh of capacity with tiered incentive rates. For non-residential energy storage projects that are greater than 2 MWh, incentives decline according to the following schedule:

Table 4.2.1.2: Tiered Incentive Rates

Energy Capacity (MWh)	Percent of Base Incentive
0 to 2 MWh	100%
> 2 MWh – 4 MWh	50%
> 4 MWh - 6 MWh	25%

[35] Energy Storage duration decrease examples for projects with and without backup capability can be found in Appendix H.

> 6 MWh	0%

4.2.2 Renewable Generation Technologies

Incentives for a proposed generation system are calculated by multiplying the rated capacity (W) of the system [36] by the incentive rate.

Incentive = *rated capacity (kW) * incentive rate*

For proposed generation systems that qualify for the resiliency incentive (as outlined in Section 4.1.3.1):

Incentive = *rated capacity * (incentive rate + Resiliency Adder incentive rate)*

4.2.3 Incentive Declines Based on Generation Rated Capacity

SGIP incentives are paid for up to 3 MW of rated capacity with tiered incentive rates. For projects that are greater than 1 MW, the incentives identified in Table 4.1.3 decline according to the following schedule:

Table 4.2.3: Tiered Incentive Rate

Rated Capacity (MW)	Percent of Base Incentive
0 – 1 MW	100%
> 1 MW – 2 MW	75%
> 2 MW – 3 MW	50%
> 3 MW	0%

4.2.4 Photovoltaic Systems

SGIP provides fixed, up-front, capacity-based incentives for qualifying solar energy systems, using the EPBB methodology originally developed for the California Solar Initiative program. SGIP provides incentives for new solar energy systems and does not provide incentives for the expansion of existing solar. [37] The EPBB methodology calculates the incentive based on verified solar energy system characteristics such as location, system size, shading, orientation, and the maximum continuous power output rating of the solar system's inverter. For multifamily projects, at least 51% of the system's electric output must directly offset tenant load and be provided to tenants in the form of virtual net energy metering (VNEM) bill credits. The amount of the incentive for SGIP depends on the capacity of the installed system, the energy percentage split between tenant and common area serving-load, and the other eligible funding resources that the project

[36] For more information on rating criteria for system output, see Section 7.3.
[37] Per Finding #10 in CPUC Resolution E-5362: "It is reasonable to limit the RSSE to supporting only new solar systems and not the expansion of existing solar." PV Systems must conform to the requirements as set forth in Section 7.4.5.

may leverage, such as the Federal Investment Tax Credit (ITC) and Low-income Housing Tax Credit (LIHTC).

SGIP incentives may cover the full cost of the portion of the photovoltaic (PV) system that offsets tenant load; however, the total SGIP incentive payment cannot exceed the full cost of the system, taking into account other eligible non-tax-credit-based incentives the project receives. See Section *4.5.6 Incentives from Other Sources* for additional information. The criteria for determining solar suitability include roof condition, shading, and condition of electrical system. SGIP typically does not allow installation on properties with less than 10 years of roof-life remaining before a roof replacement is needed, to ensure maximum benefit to Applicants for the lifetime of the system. EPBB Methodology SGIP will pay incentives for projects through an up-front incentive referred to as an Expected Performance Based Buydown (EPBB). These incentives are based on the system's capacity and design, which provide an estimate of the system's future performance. The SGIP PA will use the California Energy Commission's CEC-AC method to determine the system rating. The following formula determines the EPBB calculation:

EPBB Incentive Payment = Reserved Incentive Rate x (Lesser of System Rating x Design Factor or the Maximum Continuous Power Output Rating of the Solar Inverter)

The maximum continuous power output rating of the solar inverter is listed on the inverter specification sheet and also on the California Energy Commission’s list of Grid Support Solar/Battery inverters and is the maximum AC power output (in kW) allowed by the solar inverter under normal operating conditions.

The Design Factor is a ratio comparing a proposed system to a reference system. Very simply, it reflects:
Design Factor = Proposed System / Reference System

More specifically, the Design Factor is calculated as follows:

DF = Dcorr * Gcorr * Icorr

Dcorr (Design Correction) = Ss,p,p / Ss,p,o

- Ss,p,p = The system's estimated summer kWh output at the proposed location, with proposed tilt and azimuth
- Ss,p,o = The system's estimated summer kWh output at the proposed location, with summer optimized tilt and azimuth allowing for equal treatment of proposed systems oriented from South to West (i.e., the optimized system's orientation shall be the same as the proposed system for orientations due south to due west)

Gcorr (Geographic Correction) = As,p,o / As,r,o

- As,p,o = The system's estimated annual kWh output at the proposed location, with summer optimized tilt and south azimuth
- As,r,o = The system's estimated annual kWh output at the reference location, with summer optimized tilt and south azimuth

Icorr (Installation Correction) = PTCadj / PTC

- PTCadj = The adjusted PTC DC rating accounting for mounting method, NOCT and power temperature coefficient for that specific module
- PTC = The DC rating of the panels at PVUSA Test Conditions

In sum, the Design Factor for EPBB will:

- Treat all systems oriented between 180º and 270º equally
- Assign optimal orientation tilt for each compass direction in range of 180º and 270º, optimized for summer production
- Include location-specific criteria to account for weather variation and shading
- Be based on an optimal reference system and location
- Determine optimal reference latitude tilt that relates to local latitude

SGIP requires a minimum Design Factor of 75% to ensure that the incentivized solar system provides significant benefit to the host customer and system owner.

4.3 Performance-Based Incentive (PBI) Payment

4.3.1 Energy Storage Technologies

All new non-residential energy storage projects will be paid 50% of the incentive upon project completion and verification. The remaining 50% will be paid on a Performance-Based Incentive (PBI). Annual kilowatt hour-based payments will be structured so that under the expected annual operational requirements [38] a project would receive the entire stream of performance payments by the end of the performance period.

To calculate the basis ($/kWh) of the annual PBI payments the following calculation is made:

$/kWh = *remaining 50% of incentive / total anticipated kWh discharge/offset*

Total anticipated kWh discharge/offset = *energy capacity (kWh) * 104 full discharges * 5 years*

[38] See Section 6.1.1 Operational Requirements.

Pursuant to D.25-12-003, any non-residential project entering the PBI status after December 30, 2025, will have a reduced PBI period of two years:

To calculate the basis ($/kWh) of the annual PBI payments the following calculation is made: [39]

***$/kWh** = remaining 50% of incentive / total anticipated kWh discharge/offset*

***Total anticipated kWh discharge/offset** = energy capacity (kWh) * 104 full discharges * 2 years*

PBI payments will be paid annually based on recorded kWh of electricity discharged or offset over the previous 12 months.

***PBI Payment** = $/kWh * actual annual kWh discharged/offset*

For new non-residential projects defined as submitted on or after April 1, 2020, annual PBI payments are subject to PBI payment reductions based on GHG emissions. See Section 4.3.1.1 for more details.

Large thermal energy storage (L-TES) systems are subject to a provisional one-year 30/70 PBI structure for L-TES, which would allow 30% of the total incentive to be paid up front based on the Applicant's requested incentive amount that is estimated by using the Applicant's proprietary modeling. The remaining 70% will be paid out, based on actual performance, over five years. [40]

4.3.1.1 Performance-Based Incentive (PBI) GHG Performance Penalty

Non-residential energy storage systems must reduce GHG emissions by 5 kg CO_2 per rebated energy capacity (kWh) on an annual basis. Projects that do not reduce GHG by 5 kg CO_2/kWh will have their PBI payment reduced by $1/kg CO_2 emitted above this level. The reduction is capped at 100% of the annual PBI payment. PBI payment deductions are permanently forfeited and returned to the SGIP incentive budget. The SGIP PAs have the discretion to decrease the amount of any given PBI payment deduction in exceptional circumstances and with the written approval of CPUC Energy Division. Exceptional circumstances include, but are not limited to, causes not reasonably under the Developer or customer's control, and causes that were not reasonably foreseeable.

4.3.2 Renewable Generation Technologies

On-site biogas, directed biogas, wind, waste heat to power, and pressure reduction turbine projects 30 kW and larger will be paid 50% of the full incentive amount upon project completion and Post-Installation Inspection. The remaining 50% of the incentive will be paid annually over five years. Annual payments will

[39] Energy Storage Performance-Based Incentive (PBI) Payment Calculation Examples can be found in Appendix H.
[40] After one year of the provisional Large Thermal Energy Storage (L-TES) 30/70 Performance-Based Incentive (PBI) period, should five L-TES incentive reservations be submitted, within 60 days, the Self-Generation Incentive Program (SGIP) Program Administrators (PAs) shall file their recommendation for or against restoring the 50/50 PBI structure for L-TES to the Energy Division via a joint Tier 2 advice letter.

be structured so that based upon the expected capacity factor a project would receive the entire stream of performance payments in five years.

***$/kWh** = remaining 50% of incentive / total anticipated kWh production*

***Total anticipated kWh production** = rated capacity * anticipated capacity factor * hours per year * 5 years*

For a five-year period, the PBI payment will be paid annually based on recorded kWh of electricity produced or offset over the previous 12 months.

***PBI Payment** = $/kWh * actual annual kWh*

Pursuant to D.25-12-003, any project entering the PBI status after December 30, 2025, will have a reduced PBI period of two years:

To calculate the basis ($/kWh) of the annual PBI payments the following calculation is made:

***$/kWh** = remaining 50% of incentive / total anticipated kWh production*
***Total anticipated kWh production** = rated capacity * anticipated capacity factor * hours per year * **2** years*

4.3.2.1 PBI Payment Exceedance Cap for Generation Projects

Generation projects have an annual PBI payment exceedance cap of no greater than 25% of what was expected to be received. This cap allows annual payments to slightly exceed the expected amount, however, the total PBI for any project will never exceed the amount reserved.

4.3.2.2 PBI Payments for Export to the Grid Projects

SGIP projects that qualify for the feed-in tariff are allowed to export a percentage of their output to the grid. Once on-site electric load has been met, excess generation of electricity may be exported to the grid. The amount exported to the grid is not to exceed 25% of on-site consumption on an annual basis.

In cases where a customer is exporting electricity to the grid, the PBI payment will be calculated based on generated electricity consumed on-site as opposed to the generating system's output.

Based on this description and the $/kWh calculated during the incentive claim step of the project, the calculation of a PBI payment is as follows:

***PBI** = $/kWh * generated electricity consumed on-site*

Program Administrators must be informed of arrangements made with the utility for sale of excess generation. For verification purposes, proof of export documentation may be required prior to payment.

4.4 California Manufacturer Adder

An additional incentive of 20% will be added to the technology incentive for projects in which the equipment used is manufactured in California.[41] For a project to be eligible for the 20% adder, it must demonstrate that at least 50% of its capital equipment value is manufactured by an approved California Manufacturer.

4.4.1 Eligibility Criteria and Verification

All California Manufacturers will be required to submit an application for California Manufacturer status and proof to support each criterion below.[42]

California Manufacturers must meet the following requirements:

- Operate a manufacturing facility in California
- Licensed to conduct business in California
- Registered with a primary or secondary manufacturing NAICS code

In addition, lithium battery manufacturers must show they are responsible for a substantial portion of the manufacturing and assembly of the fully operational energy storage unit. Lithium battery manufacturing processes include:[43]

- Cell testing including voltage, atmospheric, extended cycling, and fire propagation
- Chemical adhesion bonding;
- Installation of circuit boards and sensing equipment;
- Laser welding of cells into battery modules
- Battery Management System (BMS), firmware, and thermal systems design and production
- Module testing including mechanical shock temperature ingress and extended cycling (includes UL certification testing)

4.4.2 Project Equipment Verification

Equipment is deemed to be manufactured in California if at least 50% of the value of the capital equipment has been made in a dedicated production line by an approved California Manufacturer. For the purposes of determining eligibility, the SGIP recognizes the following equipment types:

Table 4.4.2: Equipment Types

Generation	Energy Storage
Generator/Prime Mover	Storage medium (e.g., battery)
Ancillary equipment	Inverter

[41] The incentive for each project including the California Manufacturer adder shall be capped based upon the Incentive Limitations outlined in Section 4.5.
[42] Approved California Manufacturers, Request for California Manufacturer Status Application can be found at www.selfgenca.com/home/resources.
[43] This manufacturing processes list is not exhaustive, and PAs have authority to propose additional processes.

	Balance of System

4.4.3 How to Determine Value

The total value of the capital equipment for a project will be the sum of all equipment types as listed above. The combined total amount of equipment shown to be supplied by California Manufacturer(s) in a California manufacturing process will be considered in calculating the appropriate percentage in the total value of capital equipment.[44] Examples for how to determine the total value of capital equipment can be found in Appendix H.

4.5 Incentive Limitations

Incentive amounts for both generation and storage projects can be limited by several factors, including maximum incentive amount, total eligible project costs (TEPC), sizing limitations per site, and incentives from other sources. See Section 4.2.1 (Energy Storage) and Sections 4.2.2 (Generation) for additional technology specific incentive calculations.

4.5.1 Maximum Incentive Amount

The maximum incentive amount per project site shall not exceed $5 million.

4.5.2 Total Eligible Project Costs

No project can receive total incentives (to include any combination of the technology incentive and/or California Manufacturer) that exceed the TEPC. Submittal of project cost details is required to report TEPC and to ensure incentive limits are not exceeded. Equipment and other costs outside of the project envelope are considered ineligible project costs but must also be reported.

The following costs may be included in the TEPC:

- Engineering feasibility study costs
- Engineering and design costs
- Environmental and building permitting costs
- Equipment capital costs
- Primary heat recovery equipment (i.e., heat recovery equipment directly connected to the generation system whose sole purpose is to collect the waste heat produced by the power plant). For example, a heat exchanger or heat recovery boiler (a.k.a., heat recovery steam generator or HRSG) used to capture heat from a gas turbine is an eligible cost.
- Heat recovery piping and controls necessary to interconnect the generating equipment to either the Primary Heat Recovery Equipment or the heat recovery piping and controls within the space primarily occupied by the generator partitioned by a fence or wall, whichever cost is less. If there

[44] SGIP PAs reserve the right to request for a third-party auditing firm to verify the eligibility of relevant projects costs, at cost to the manufacturer adder applicant.

is no identifiable Primary Heat Recovery Equipment and no identifiable space primarily occupied by the generator, eligible heat recovery piping and control costs shall be limited to the generator skid.

- Construction and installation costs. For projects in which the equipment is part of a larger project, only the construction and installation costs directly associated with the installation of the energy equipment are eligible.
- Interconnection costs, including:
    - Electric grid interconnection application fees
    - Natural gas grid interconnection costs
    - Metering costs associated with interconnection
- Warranty and/or maintenance contract costs associated with eligible project cost equipment. The cost of this component is capped at 10% of the total claimed project costs.
- System metering, monitoring and data acquisition equipment as well as additional on-board monitoring equipment and costs associated with the PDP contract.
- Air emission control equipment capital cost
- Gas line installation costs, limited to the following:
    - Costs associated with installing a natural gas line on the customer's site that connects the serving gas meter or customer's natural gas infrastructure to the distributed generation unit(s)
    - Customer's cost for an additional (second) gas service to serve the distributed generation unit if this represents a lower cost than tying to the existing meter or gas service
    - Customer's cost for any evaluation, planning, design, and engineering costs related to enhancing/replacing the existing gas service specifically required serving the distributed generation unit
- For renewable fuel projects (except wind turbines), the cost of equipment to remove moisture and other undesirable constituents from renewable fuels that would damage the generation equipment. Such equipment includes but is not limited to "gas skids," dryers/moisture removal, and siloxane removal towers.
- Electricity storage devices
- Electrical and critical loads panel and wiring upgrades are allowable costs for Equity Resiliency and Equity Budget projects with a maximum reimbursement of $3,500 per project.
- Renewable fuel projects (except wind turbines) may claim the cost associated with securing a bond to certify use of renewable fuel, described in the SGIP Contract, as eligible costs.
- Sales tax and use tax
- Cost of capital included in the system price by the vendor, contractor, or subcontractor (the entity that sells the system) is eligible if paid by the System Owner.

- For steam turbine CHP projects where new or existing boiler capacity is being increased to generate power with a steam turbine, only the incremental costs directly associated with the increased capacity is considered an eligible project cost. If the boiler or any ancillary equipment directly associated with the increased capacity received an incentive or rebate from another source, the incentive or rebate amount is an ineligible project cost and must be deducted from the eligible cost of the project.
- Solar equipment capital costs, including tracking systems and other ancillary equipment associated with the solar energy system.
- Meter collars and meter socket adapters are considered eligible project costs.
- Solar inverters are an eligible solar cost component. Solar inverter upgrades or replacements are eligible costs if one of the following conditions are met: (i) a new inverter is required to add storage; and (ii) a new inverter is to replace the existing inverter if the existing one is over 10 years old or out of warranty.
- Performance Monitoring and Reporting Service (PMRS) equipment and/or services.
- Customers may claim certain mounting surface costs as eligible project costs. Costs may include mounting surfaces for the PV modules and/or the materials that provide the primary support for the PV modules. Only the percentage of mounting surface directly under the PV modules is eligible.
- Construction management and project development costs incurred by the Host Customer if separate from the solar vendor, contractor, subcontractor, or seller (the entity that sells the system), and clearly documented via contracts, invoices, or equivalent.

4.5.2.1 RSSE TEPC Verification

All RSSE projects, regardless of application submission date, reporting a TEPC above 90 percent of the maximum SGIP incentive[45] for the system's size, must provide further TEPC verification requirement at the Incentive Claim Form stage for PA review before the project is paid an SGIP incentive. Applicants must acknowledge that additional TEPC verification will be required before receiving a Confirmed Reservation Letter and any associated advanced payment. The table below outlines how TEPC verification impacts RSSE projects:

[45] Maximum SGIP Incentive is calculated based on the capacity of the energy storage system in kWh and the CEC-AC rating of the solar system. Example: 13.2 kWh x $1.10/Wh = $14,520 allowable storage cost, 5 kW x $3.10/W = $15,500 allowable solar cost, $30,020 = maximum SGIP Incentive. The actual SGIP incentive may be lower for the project depending on factors such as CSI rating

Table 4.5.2.1: TEPC Verification at ICF for RSSE Application

TEPC	TEPC Verification Required at Incentive Claim Form
At or below 90% of maximum SGIP incentive	Processed following existing SGIP procedures
Above 90% and at or below 100% of maximum SGIP incentive	Submit receipts for the system equipment and labor contracts covering the construction and installation (i.e. labor) costs [46]
Above 100% of maximum SGIP incentive	• Submit receipts for the system equipment and labor contracts covering the construction and installation (i.e. labor) costs. • Any other invoices or documentation needed to validate each cost category reported at ICF to justify the full TEPC. • RSSE Cost Verification Form

If an applicant chooses to reduce the reported TEPC, or if the PA must reduce the TEPC for a project because costs cannot be verified, the applicant must submit an amended contract signed by the host customer showing the lower TEPC.

A developer can choose to establish a baseline TEPC for all RSSE projects. Through this pathway, the developer must provide receipts or documentation to support the average project cost for each cost category reported at ICF. Documentation may include total financing costs for cost of capital, a bulk invoice for system equipment that can be averaged on a per module basis, and estimated hours worked and salary for the typical project.

Baselines shall be established on a per PA territory basis and only upon request by the Developer. To establish a baseline TEPC, the Developer must submit a representative portfolio of projects within the applicable PA territory. The required portfolio submission shall include a minimum of ten (10) projects for Developers with fewer than 200 projects in the PA territory or a minimum of twenty (20) projects for Developers with 200 or more projects in the PA territory. The baseline TEPC shall be calculated as the average cost for each eligible cost category across the submitted project portfolio.
PAs will review submitted portfolio documentation to determine the baseline for all submitted project cost categories. The PA may approve, reject, or request additional documentation.

For projects with a TEPC below the approved baseline, the developer must report actual project costs at ICF. For projects with a TEPC above the approved baseline, the developer must submit project-specific documentation to justify the higher TEPC. For example, a project that includes a panel upgrade (up to the

[46] As a substitute to a labor contract, a document describing the salary range of the employee and the hours worked on the project would be sufficient.

$3,500 cap allowed in SGIP) or that had higher installation and construction costs due to building complexity must provide supplementary documentation.

If a PA identifies, through cost verification, that an applicant has consistently overstated the TEPC for their projects, the PAs have existing authority to cancel all the applicant's projects on the waitlist and disqualify the developer from submitting new applications.

4.5.2.1.1 RSSE TEPC Review Priority

The SGIP PAs will prioritize review of submitted RSSE ICFs in the following order:

1. **Group A:** Projects with a TEPC less than 100 percent of the maximum allowed SGIP incentive for that size of project and projects with a TEPC above 100 percent of the maximum SGIP incentive that applied for interconnection before February 20, 2026. *These projects may be flagged for auditing by the PAs or the Commission for projects with the highest TEPCs or out-of-pocket costs.*
2. **Group B:** Projects with a TEPC above 100 percent of the maximum allowed SGIP incentive for that size of project that have customer out-of-pocket costs less than $3,000 or are multifamily projects not in Group A. *PAs or the Commission may flag projects in this group with the highest TEPCs or out-of-pocket costs for auditing.*
3. **Group C:** Projects with a TEPC above 100 percent of the maximum allowed SGIP incentive for that size of project that do not meet any of the criteria in Group B. *These projects will be randomly sampled for auditing in addition to the cost verification conducted by PAs.*

When projects are flagged for auditing after the review of the complete cost verification documentation, PAs may withhold 30 percent or more of the SGIP incentive until the audit can be completed.

4.5.3 Incentive Calculation for Site with Multiple Systems

Program participants can apply for incentives for multiple types of systems installed at one site. The total SGIP incentive is the sum of the incentive for each type of technology. When calculating the total eligible incentive for generation technologies, the incentives are to be calculated sequentially until the 3 MW limit is reached. When calculating the total eligible incentive for energy storage technologies, the incentives are to be calculated sequentially until the 6 MWh limit is reached.

4.5.4 Calculating Incentives with Existing Systems

A system may be installed in addition to existing systems if all program eligibility requirements are met by the project. Backup generators are not considered "existing on-site generation."

Sites with existing systems that have met their permanency requirements: The existing SGIP system capacity is not accounted for when determining the current incentive. However, if the existing system is still in operation the existing capacity must be accounted for to best determine new system size according to Section 6.3.

Sites with existing SGIP systems that have not met their permanency requirements: The existing SGIP system capacity is accounted first at the highest incentive rate and then the proposed system capacity incentive is added on top of the existing capacity to determine in which incentive capacity tier the proposed system falls. Energy storage system capacity is non additive with generation capacity for purposes of calculating the tiered incentive. The incentive calculation and capacity limits are treated separately for energy storage and generation technologies.

4.5.5 Calculating Incentives for System Replacements

Installation of a new system intended to replace an existing system is allowed if all program eligibility requirements have been met and the replaced system has either never received incentives from the SGIP or the Energy Commission's Emerging Renewables Program (ERP) or has received incentives from the SGIP or ERP programs but has been in service for at least the applicable program's permanency requirement. Systems that did receive incentives but have not met the appropriate program's permanency requirements may only receive incentives on the incremental increase above the existing system's rated capacity (kW for generation or kWh for energy storage). [47]

The replaced system must also be fully decommissioned and removed from the site. The Program Administrator will confirm this has been completed as part of the Post-Installation Inspection.

4.5.6 Incentives from Other Sources

Host Customers, Applicants, and System Owners are required to disclose information about all other incentives they have received, plan to receive, or have applied for.

SGIP assumes a 30% federal tax credit will always be utilized and the remaining 70% of the TEPC may be covered by the SGIP incentive, unless a customer provides documentation at Request for Reservation Form stage validating:

a. Why the project is ineligible for the federal tax credit; and
    i. This criterion is removed for single-family customer owned projects with permission to operate date after December 31, 2025 and all single-family projects funded by ratepayer funds.
b. Why the project could not be third-party owned (TPO).
    i. This criterion is removed for TPO projects.

TPO and non-residential systems may alter the percentage of IRA tax credit reported at the incentive claim stage based on the bonus credits, which may reduce the SGIP share of the project below 70%. If TPO and non-residential projects decrease their expected IRA tax credit value at the incentive claim stage, the project may obtain more SGIP funds (if available). The TPO or non-residential entity must

[47] All applicable Incentive Limitations apply. See Section 4.5.

submit documentation explaining why the IRA tax credit percentage decreased to claim the additional funds. If a project received material assistance from a prohibited foreign entity, the project is not exempt from the assumed 30 percent reduction to the TEPC.

A disclaimer will appear on the SGIP forms indicating if the SGIP incentive is ratepayer funded, or state funded.

For all projects, the sum of the SGIP incentive and any other incentive or tax credit received for the project may not exceed the TEPC for the SGIP-eligible system. If the total exceeds the eligible costs, the SGIP incentive will be reduced until the sum of the SGIP, and other incentive equal the total eligible costs.

For example, a customer is claiming a tax credit towards the purchase of the SGIP system, the ITC would be applied to the SGIP incentive as follows:

> **TEPC:** $30,000.00
>
> **Tax credit as a % of TEPC:** 30% ($9,000.00)
>
> **Calculated SGIP Incentive Amount:** $27,000.00
>
> **Final SGIP Incentive Amount:** $21,000.00 [48]
>
> Tax credit Amount of $9,000.00 + Final SGIP Incentive Amount of $21,000.00 allows the customer to cover the full eligible project costs of $30,000.00

For projects receiving incentives under other programs, the SGIP incentive may be reduced depending on the source of the other incentive(s):

- For other incentives funded 100% by Investor-Owned Utility (IOU) ratepayers, the total SGIP incentive will be reduced by the full amount of the other incentive(s).
- For other incentives funded by Non-IOU Ratepayers, the total SGIP incentive will be reduced by 50% of the amount of the other incentive(s).

The time it takes for a customer to monetize the IRA tax credit against their tax liability is an acceptable reason to claim ineligibility for the IRA tax credit. [49] Example: TEPC is $32,000.00, eligible IRA tax credit is $9,600.00, tax liability of $1,920.00 or more per year over 5 years. A host customer's tax liability less than $1,920.00 would be considered ineligible for the IRA tax credit in SGIP as stated in the example.

A specific developer not having a TPO option available is not sufficient to demonstrate that the credit could not otherwise be utilized or transferred by a third-party entity. To protect against entities creating governance structures or affiliations that would allow them to achieve more funding than the capped

[48] The SGIP incentive amount is reduced from $27,000.00 to $21,000.00 as the sum of the SGIP incentive amount and any incentive or tax credits received cannot exceed the TEPC.

[49] Per Resolution E-5373, 5 years is a reasonable timeline.

amount, it is required that Host Customers, Applicants, and System Owners disclose information about all other incentives and eligible tax credits applicable to the project or any of their affiliates applicable to the project. **Failure to disclose such information will be considered an infraction and is subject to the penalties indicated in Section 13.**

4.5.6.1 RSSE Budget IRA Tax Credit Pathways

There are three pathways for residential customers.

1. Host customer can own the system and claim the IRA tax credit for 30% of the TEPC and receive an SGIP incentive for up to 70% of the TEPC if the system is placed in service (PTO issued) by December 31, 2025.
2. For Storage Systems: Host customer can contract with a TPO developer and the TPO will monetize the tax credit at 30 to 70 percent of the TEPC and receive an SGIP incentive for up to the remainder of the TEPC.

   For Solar Systems: Host customer can contract with a TPO developer and the TPO will monetize the tax credit at 30 to 70 percent of the TEPC and receive an SGIP incentive for up to the remainder of the TEPC. To receive the tax credit, the solar system must be placed in service (PTO issued) by the taxpayer by December 31, 2027. If a project is past the PTO date for the solar and the TPO entity attests they will not be able to claim the solar tax credit, the SGIP incentive may be increased if there are still funds available.
3. Host customer can submit documentation demonstrating why their project is ineligible to receive the IRA tax credit (for projects with a PTO before December 31, 2025) and why the project could not be TPO to receive the full SGIP incentive.

5 Program Equipment Requirements

The SGIP intends to provide incentives for reliable, permanent, and safe systems that are professionally installed and that comply with all applicable federal, state, and local regulations. Host Customers and System Owners are strongly encouraged to become familiar with applicable equipment certifications, design, and installation standards for the systems they are contemplating.

The following table lists specific equipment eligibility criteria required to participate in the SGIP.

Table 5: Equipment Eligibility Criteria Required to Participate

Eligible Equipment	• Mechanical, electrochemical, and thermal energy storage systems
	• Generation Technologies:
	  ○ Pressure Reduction Turbines
	  ○ Photovoltaics
	  ○ Wind Turbines
	  ○ Gas Turbines
	  ○ Waste Heat to Power Systems
	  ○ Microturbines
	  ○ Steam Turbine CHP Systems
	  ○ Internal Combustion Engines
	  ○ Linear Generators
	  ○ Fuels Cell CHP Systems
	  ○ Fuel Cell Electric Systems

Ineligible Equipment	• Backup systems intended solely for emergency purposes • Rebuilt, refurbished, or relocated equipment (e.g., second life batteries) • Field demonstrations for proof-of-concept operation of experimental or non-conventional systems partially or completely paid by research and development funds • Any generation equipment that is capable of operating on, or switching to, diesel fuel or diesel cycle for start-up or continuous operation

Interconnection	• Any system that discharges electricity must be connected to the local electric utility's distribution system and must be installed on the Host Customer's side of the electric utility meter. [50]
	  ○ SGIP eligibility includes systems that interconnect to the local electric utility's distribution system under the requirements of a virtual net metering tariff.
	• Energy storage systems must also be configured to operate in parallel with the grid.
	• Written certification of interconnection and parallel operation is required prior to the Reservation Expiration date.
	• Systems are eligible to receive a reservation up to 12 months after receiving a permission to operate (PTO) in parallel with the grid from the electric utility.
	  ○ If PTO has occurred at or before the time of the Reservation Request stage, the Applicant is required to provide the PTO date. Equipment that has been interconnected for more than 12 months is ineligible and any Reservation Request for a system with a PTO date greater than 12 months from the RRF submittal date will be rejected.

Commercial Availability	Only commercially available, [51] factory-new equipment is eligible for incentives.

[50]The interconnection, operation, and metering requirements for the systems shall be in accordance with the local electric utility rules for customer generating facility interconnections.
[51] Major system components are acquired through conventional procurement channels.

Certifications	All eligible technologies must be certified for safety by a nationally recognized testing laboratory (NRTL).
	• Applications may be submitted prior to receiving the NRTL certification so long as the certification process is underway.
	• Proof of certification must be submitted no later than the Incentive Claim stage. Failure to submit proof of certification with the Incentive Claim documents will result in cancellation of the project.
	• If NRTL certification is not applicable for the technology type, it must be supported by the following which is consistent with Rule 21 interconnection standards:
	  ○ A 10-year service warranty. For energy storage systems, a 10-year performance warranty can be used in lieu of a service warranty (See details in Section 8.1 #5).
	  ○ A 10-year manufacturer's warranty, if required.

Permanent Installation	The intent of the SGIP is to provide incentives for equipment installed and functioning for the duration of its useful life. Only systems permanently installed, both physically and contractually, are eligible for incentives.
	<u>Physical permanence</u>
	• Demonstrated by electrical, thermal, and/or fuel connections in accordance with industry practice for permanently installed equipment
	• Secured to a permanent surface (e.g., foundation)
	• Any indication of portability, including, but not limited to, temporary structures, quick disconnects, unsecured equipment, wheels, carrying handles, dolly, trailer, or platform, will deem the system *ineligible.*
	• Under rare and extenuating circumstances, solar equipment relocation may be warranted. Allowance of the relocation is at the sole discretion of the SGIP PA
	<u>Contractual permanence</u>
	• Minimum length of the applicable warranty period (10 years)
	• All agreements involving the system receiving an incentive are to be provided to the Program Administrator during the application process. [52]
	  ○ System Owner must notify the Program Administrator in writing a minimum of 60 days prior to any change in either the site location or change in ownership of the system if the change(s) takes place within the applicable warranty period.
	  ○ If the solar energy system is voluntarily removed by the System Owner prior to end of the 10-year warranty period, either:
	  ▪ The solar energy system may be installed at another site within the utility service territory within six months in accordance with the requirements of this section and with the approval of the SGIP PA. The relocated system installed

[52]These agreements include, but are not limited to, system purchase and installation agreements, warranties, leases, energy or services agreements, energy savings guarantees, and system performance guarantees, and are required at the Reservation Request stage for 2-step applications and Proof of Project Milestone for 3-step applications.

	at the alternate site would not be eligible for an additional SGIP incentive; or ▪ The incentive shall be returned to the Program Administrator (prior to June 30, 2028), or the California Public Utilities Commission (after June 30, 2028); and ▪ The System Owner would be unable to participate in the SGIP Program for any additional installations under the SGIP Program, including any active reservations that have not yet been paid. ▪ A mandatory final inspection is required for all relocated equipment. See Section 2.1.1.3, Post Installation Inspections, for more information.
Contractor's License	The Installer of the proposed SGIP system must have an active license issued by the Contractors State License Board (CSLB) that complies with all current CSLB licensing requirements for the SGIP-eligible technology that is being installed. [53] Although not required, solar installation contractors are encouraged to become certified by the North American Board of Certified Energy Practitioners (NABCEP). For additional information on NABCEP, go to **nabcep.org**. In all cases, systems must be installed in conformance with the manufacturers' specifications and with all applicable electrical and building codes and standards.
Eligibility for New Technologies	• Systems consisting of new technologies not already eligible for the SGIP may become eligible if its first commercial installation occurred less than 10 years prior to SGIP funding. • New technologies must meet all applicable eligibility and program requirements. • Developers of such technologies seeking eligibility must follow the Program Modification Guidelines as outlined in Section 15.

[53] List of currently accepted CSLB license types is posted in the Resources page of www.selfgenca.com.

6 Energy Storage Technologies

The following sections outline the eligibility requirements, rating criteria, incentive calculation guidelines, application documentation requirements, and metering requirements specific to SGIP energy storage projects. Additionally, all projects are subject to the general program requirements as outlined in Sections 2, 3, and 4.

6.1 Eligibility Requirements

All SGIP projects are required to meet the SGIP GHG emissions reduction, cycling, and other system and operational requirements as these ensure that storage systems receiving incentives will not be used only or primarily to provide backup power.

6.1.1 Operational Requirements

Energy storage projects may be stand-alone or paired with generating systems and must be capable of discharging fully at least once per day. Energy storage systems paired with wind generation must have the ability to handle hundreds of partial discharge cycles each day. Residential energy storage projects, whether stand-alone or paired, must comply with additional requirements specified in the Residential Energy Storage Eligibility Affidavit [54] designed to ensure that all residential energy storage systems participating in the SGIP will be used for more than just back-up emergency purposes. New non-residential systems are required to discharge a minimum of 104 full discharges per year. Residential systems are required to discharge a minimum of 52 full discharges per year. A “full discharge” is the

[54] Included as part of the Reservation Request Form.

equivalent of discharging the SGIP-incentivized energy capacity, whether it is during a single or multiple discharges. [55]

Legacy non-residential projects required to discharge a minimum of 260 full discharges a year may opt to discharge a minimum of 130 full discharges a year by notifying their respective SGIP PA.

6.1.2 Paired with On-site Renewables

To be considered paired with and charging from on-site renewables, energy storage systems must either be claiming the Investment Tax Credit (ITC) or charge a minimum of 75% from the on-site renewable generator.

6.1.3 Demand Response Dual Participation

Energy storage projects funded through the SGIP are eligible to provide demand response services or participate in demand response programs.

6.2 Greenhouse Gas (GHG) Requirements

6.2.1 Greenhouse Gas Signal

A GHG signal provides energy storage Developers with information they need to charge the storage system during low-GHG emission periods and to discharge during high-GHG emission periods to reduce GHGs and remain in compliance with the statute: [56]

- The signal is a digitally accessible (in API format), real-time, marginal GHG emissions factor for the appropriate California Independent System Operator (CAISO) sub-regions, at five-minute intervals, in units of kg CO_2/kWh.
- The signal is calculated using the same heat rate-based methodology as in the most recent Avoided Cost Calculator (ACC), but with updated parameters and data sources more suitable for real-time use.
- This signal provides the marginal emissions per kWh calculated based on a natural gas-fired power plant producing energy at a price equaling the real-time (five-minute) CAISO Locational Marginal Price with costs equal to the most recent publicly available data on gas prices, CO_2 prices, and variable operating costs constrained by reasonable maximum and minimum efficiencies. When the calculated heat rate is zero or below, instead it is assumed that the marginal generator is renewable and the marginal emissions rate is zero.
- The marginal GHG emission signal includes non-CAISO territories where SGIP incentives are available, using the same methodology for non-CAISO regions as for CAISO areas, using the closest representative input data.

[55] Each discharge does not have to be a 100% depth of discharge, but the aggregate amount of discharges over the year must equate to 104 full discharges for new non-residential customers or 52 full discharges for residential customers.
[56] Public Utilities Code Section 379.6(b)(3).

A five-minute real time GHG signal is used as the basis of determining compliance with the GHG requirements adopted in the decision; as such, this signal is referred to as the "GHG compliance signal." The GHG compliance signal is used for verification of both project and fleet GHG emission compliance. The following forecasting tools are also available:

- Fifteen-minute forecast, with five-minute granularity and updated every 15 minutes
- One hour-ahead forecast, with five-minute granularity and updated every 15 minutes
- Day-ahead forecast, with five-minute granularity and updated every 15 minutes
- Longer term forecasts: 72-hour ahead, month-ahead, and year-ahead

The GHG signal and forecasting tools are available online at www.selfgenca.com.

6.2.2 New Non-Residential Projects

All new non-residential systems, regardless of system size, must be enrolled in an SGIP-approved Demand Response program by incentive claim submission. All existing Net Energy Metering (NEM) 1.0 and 2.0 solar customers are required to transition to the Net Billing Tariff (NBT). A list of Demand Response Programs can be found on www.selfgenca.com.

During the PBI term, all new non-residential energy storage projects are required to reduce GHGs by a minimum of five kilograms of CO_2 per rated energy capacity (kg/kWh) annually to recoup full incentive payment.

To calculate the GHG emissions, all new non-residential energy storage projects are to submit PBI data, including cycling data and data on net energy charged and discharged (kWh) and net real power charged and discharged (kW), in 15-minute intervals on a monthly basis using the SGIP online application database PDP Portal. The SGIP PAs shall verify each new non-residential project's GHG reductions annually using PBI data in combination with the five-minute real time GHG signal and will provide each project with monthly feedback on GHG performance.

After the last year that a PBI payment is issued, new non-residential energy storage projects should continue to annually reduce GHG emissions by 5 kg/kWh through the 10th year of their permanency period verified on a fleet basis. New non-residential energy storage projects must submit cycling data on a quarterly basis to the SGIP online application data PDP Upload Portal. The PAs will use this data in combination with the GHG signal to provide quarterly feedback to Developers on their GHG emissions. The annual SGIP storage impact evaluation will report the fleet GHG emissions performance of new non-residential energy storage projects in years six through ten of their permanency periods, by Developer. Large non-residential energy storage projects that are not otherwise part of a Developer fleet are also subject to these requirements.

6.2.3 Legacy Non-Residential Projects

All non-residential energy storage systems with applications that were in a RRF Submitted status prior to April 1, 2020, will have three options to comply with the SGIP GHG emission standards:

1. Option 1: RTE Pathway – Operational Requirements
    - The project will continue to comply with the operational requirements and the SGIP Handbook procedures in place at the time of project approval, including the annual RTE requirement of 66.5%, with the exception that projects with a 260 per year cycling requirement may reduce this to 130 cycles per year.
2. Option 2: Storage Rate/DR Pathway – Operational Requirements
    - These are identical to those of Option 1 with the exception that the project may substitute the RTE requirement in place when the project was approved with one of the following:
        - Enrollment in an economic DR program that is integrated into the CAISO or the DRAM mechanism
        - Enrollment in an approved storage rate including:
            - PG&E: Option S or A-1-STORE
            - SCE: Option E or TOU-GS-1
            - A rate available to non-residential customers with storage systems that reduces, eliminates, or otherwise does not include non-coincident demand charges and that is approved for use through a Tier-2 advice letter process.[57]
3. Option 3: GHG Pathway – Operational Requirements
    - Projects that select Option 3 that are within their 10-year permanency requirement are required to emit 0 kg/kWh GHGs or less at the Developer fleet level on an annual basis.
    - Must cycle a minimum of 130 times per year.
    - The annual RTE requirement is eliminated.

Regardless of what option a non-residential energy storage project selects, all verification and enforcement standards will fall under the SGIP Handbook version that was approved by the CPUC at the time of application submittal. If a project wishes to change which pathway they are on, they must notify the appropriate PA by December 15th of any calendar year. Any changes made will go into effect in the forthcoming calendar year.

[57] The SGIP PAs will update the Handbook with approved storage rates that reduce or eliminate non-coincident demand charges periodically. For the latest information regarding available rates, please reach out to the appropriate IOU for where the project is based.

6.2.4 New Residential Projects

All new residential systems, regardless of system size, must have a single cycle round trip efficiency (SCRTE) of 85% or greater, and require the host customer to be on an SGIP-approved rate [58] and enrolled in an SGIP-approved Demand Response program by incentive claim submission. All residential low-income customers that have applied or will apply to the RSSE budget (including applications from the Residential Storage Equity budget) are exempted from the requirement to participate in a qualifying demand response program. All existing Net Energy Metering (NEM) 1.0 and 2.0 solar customers not qualifying for the program under RSSE, low-income qualified Equity Resiliency, or San Joaquin Valley Residential are required to transition to the Net Billing Tariff (NBT). Customers who apply for standalone storage and do not have solar can choose either the SGIP-approved TOU rates which have at least a 1.69:1 peak to off-peak ratio, or may enroll in TOU rates required for all NBT customers; however, a customer must be on the NBT in order to use these TOU rates to qualify for SGIP if these rates do not otherwise meet the differential requirement. A list of SGIP-approved residential rates and Demand Response Programs can be found on www.selfgenca.com.

However, for California Alternate Rates for Energy (CARE) and Medical Baseline eligible customers, if a CARE or Medical Baseline TOU rate meeting the above criteria is not available at the time of SGIP reservation request submittal, the customer may enroll in any CARE or Medical Baseline TOU rate. CARE and Medical Baseline TOU customers may not utilize TOU bill protection measures.

Customers that do not have access to an approved TOU rate may be eligible if they can demonstrate that the energy storage system charges only from an on-site solar photovoltaic system (defined as a battery that begins charging at dawn and continues charging from the solar unit until fully charged, and that never charges from the grid) or has set relevant storage parameters to the appropriate manufacturer-certified functionalities at the time of installation to enable solar-self-consumption mode (defined as systems using a battery to store solar generation and discharging the stored power only to meet on-site load). If a non-IOU electric customer does not have access to an SGIP- approved TOU rate or one with an equivalent differential, they will be required to enroll in another TOU rate offered by their load serving entity if one is available. PAs, in consultation with the SGIP working group, may exempt an applicant from the Demand Response participation requirement if Non-IOU customers do not have access to qualified Demand Response programs or if the customer would have to forfeit a low-income rate to join a Demand Response program.

6.2.5 Legacy Residential Projects

Residential energy storage systems that were in a RRF Submitted status prior to March 2, 2020 are no longer subject to the round-trip efficiency requirements in place at the time the reservation was issued. The annual cycling requirement of 52 cycles per year must still be maintained for all legacy residential

[58] Requirements for “SGIP-approved rate” and “SGIP-approved qualified DR programs” can be found in Definitions and Glossary at end of Handbook.

projects completed. These projects are encouraged to enroll at an SGIP-approved rate as described in the glossary definition of SGIP-Approved Rate.

6.3 System Size Parameters

Non-residential system size requirements are applicable for energy storage systems that are rated above 10 kW. Non-residential systems that are rated at 10 kW or less are exempt from the sizing requirements.

Single-family system size requirements are applicable for applications seeking an incentive for an energy capacity greater than 15 kWh. Single-family applications for systems with an energy capacity of 15 kWh or less are exempt from load justification requirements. Multifamily residential storage system size requirements are applicable for applications seeking an incentive for an energy capacity greater than 12.5 kWh per tenant. Applications for an energy capacity of 12.5 kWh or less per tenant are exempt from sizing requirements. Additionally, multifamily systems that are serving common area load are considered non-residential and will be sized according to non-residential sizing requirements.

For single-family projects seeking an incentive for an energy capacity greater than 15 kWh and multifamily residential systems seeking an incentive for an energy capacity greater than 12.5 kWh per tenant, the following storage system sizing methodology will be used for load justification:

- Storage paired with solar: the storage system must be sized to the average daily excess solar generation during a summer calendar month;[59] or.
- Standalone Storage: the storage system must be sized to the average daily energy consumption during the 4-9pm window during a summer calendar month.

If a residential project's load justification legitimizes an energy capacity in kWh between 15 kWh and the project's proposed energy capacity, the incentive will be the justified kWh times the incentive rate.

Projects applying to the Equity Resiliency budget or to the RSSE budget[60] for the purpose of resiliency may opt for modular sizing if the load justification proves a need of more than 50% for the additional module.

For incentivized solar systems in the Residential Solar Storage Equity budget, solar systems at 5 kW or less (and 5 kW or less per tenant load for Multifamily Projects[61]), and are not being oversized above 100% of the customer's annual on-site load for future load growth are exempt from the load documentation requirement. The applicant, if applying to an SGIP PA that is also the utility electric provider to the host customer, may request from the SGIP PA an estimation of the maximum kWh offset available for existing annual common area electricity consumption and aggregated tenant electricity

[59] A summer calendar month is defined as a month between June and October.

[60] RSSE customers must live in a HFTD, have experienced 2 or more PSPS events, experienced 1 PSPS event and 1 power outage from an actual wildfire, or experienced 5 or more EPSS events.

[61] 5kW threshold will be based on an aggregated average tenant load.

consumption. The SGIP PA will provide the IOU Data during the Reservation Request Milestone. SDG&E must provide this information without delay to CSE when requested.

Non-residential energy storage projects that are not receiving Equity Resiliency Budget incentives or projects that are not receiving the Resiliency Adder, whether paired or stand-alone, may be sized up to the Host Customer's previous 12-month annual peak demand (kW).

Non-residential energy storage systems that are receiving Equity Resiliency Budget incentives or that are receiving the Resiliency Adder may be sized greater than the Host Customer's previous 12-month peak demand if this is necessary due to modular component sizes (kW) of the proposed system to accommodate the customer's peak load. For these projects, systems may be sized up to one modular component larger than the customer's peak load and will be required to supply an ad-hoc letter explaining the need for the larger system to cover the customer's previous 12-month annual peak demand before the incentives are paid.

For new construction or projects with future load growth, projects can be sized up to future peak demand, but the load must be substantiated before the incentive can be paid. SGIP does not prohibit customers from installing additional energy storage equipment at a property that would cause the total installed rated capacity at the site to be greater than the system sized according to SGIP requirements. This additional equipment is, however, ineligible for SGIP incentives.

Projects that will receive PBI payments are required to separately meter SGIP-incentivized and non-incentivized equipment, to ensure that the payments are accurate to the recorded kWh of electricity actually discharged or offset by the incentivized portion. Other projects which may have both incentivized and non-incentivized equipment are not required to be separately metered.

Multifamily projects sizing to tenant loads may aggregate each tenant unit at an assumed 12.5 kWh load per tenant. For example, a building with 10 residential units may assume a load of 125 kWh for sizing purposes. If the system is sized greater than the assumed aggregated load, the project is subject to normal sizing requirements and must justify the actual load the system will be serving.

HVAC-integrated S-TES systems must be sized no larger than the tonnage of their accompanying HVAC unit and cannot be integrated with HVAC units greater than 20 tons. Refrigeration TES systems must be sized no larger than the tonnage of their accompanying refrigeration system(s).

Large TES systems must be sized no larger than the tonnage of their accompanying chiller system(s). Large TES systems consist of TES systems paired with chiller units greater than 20 tons and must be sized no larger than the tonnage of their accompanying chiller system(s).

Oversizing for Single Family or Multifamily Residential Energy Storage System Based on Future Load Growth:

If the proposed energy storage system is being paired with a new photovoltaic system, the application must include an engineering estimate with appropriate substantiation of the site's annual energy

consumption forecast. This can be provided by using the Energy Storage Sizing Tool available on the selfgenca.com website[62]. Backup documentation such as green button data, monthly bills, PV generation data (such as output from NREL's PVWatts[63]) must also be provided in addition to a copy of a filled out (populated) version of this tool. As noted above, the size of the energy storage system will be based on the highest average daily excess photovoltaic generation during a summer calendar month.
Similarly, if the proposed energy storage system is being paired with an existing solar system the application must include an engineering estimate with appropriate substantiation of the site's annual energy consumption forecast, and as above, the energy storage sizing tool can be used for this purpose. However, the program only allows the expansion of existing PV systems to accommodate future load growth if they are not incentivized[64]. If the solar system is not being expanded and since the sizing of the energy storage system is based on the highest average daily excess photovoltaic generation during a summer calendar month, the added load may result in a lower than expected (or even negative) sizing of the energy storage system when using the tool. In these cases, it is possible to apply for the 15 kWh energy storage system size and not request an increased system size based on future load growth.

In the event the load is shrinking which will result in an increase in excess solar generation from the existing photovoltaic system, this needs to be documented by entering the forecasted reduced load into the Energy Storage Sizing Tool along with the PV generation data in order to determine the eligible energy storage system size. Please note that this reduced load will have to be substantiated at ICF by resubmitting the energy storage sizing tool with actual data. If the eligible energy storage system size determined by the tool at ICF is less than that approved at RRF the incentive may be reduced.
If the energy storage system is standalone and not paired with a photovoltaic system the Energy Storage Sizing Tool can be used along with Green Button Data or monthly bills plus an estimate of the future load growth to determine the eligible energy capacity of the system.

System Sizing for Projects without Peak Demand Information

Sites with 12 months of previous energy usage data (kWh) but without peak demand (kW) information available (e.g., customers on rate schedules without a demand component) will have an equivalent peak demand calculated using the highest amount of energy consumed (kWh) in a given interval in the previous 12 months of consumption at the project site divided by the duration of that interval, in hours. The largest interval that may be used is 1 hour, however, the smallest granular interval should be used.

[62] https://www.selfgenca.com/documents/application_forms/storage_sizing

[63] *When using PV Watts to develop PV generation data for use with the Energy Storage Sizing Tool please use the PTC rating of the panels as the input to PV Watts rather than the STC rating. This allows PV Watts to model the PV generation with a more real-world expectation of the solar performance at the site. This is also in line with the use of the PTC rating in the EPBB calculator for the calculation of the solar incentive.*

[64] The Residential Solar and Storage Budget does not allow for the incentivization of solar expansions.

For example, if a residential customer's meter collected hourly interval data for a 12-month period, and this data revealed that the greatest hourly consumption data was 5.5 kWh during the previous 12 months, then the estimated peak demand would be 5.5 kW. If the data revealed that the greatest consumption within a 15-minute interval was 5.5 kWh during the previous 12 months, then the estimated peak demand would be 22 kW.

For customers with less than 12 months of history with the utility or customers that have meters incapable of recording interval usage data, methodology from Section 220 of the National Electric Code (NEC) may be used to determine instantaneous peak demand. For residential customers, the Program Administrators may use the project site's square footage and available energy consumption data to support the project site's annual peak demand and substantiate the NEC 220 calculations.

The SGIP PAs are authorized to revise sizing requirements as necessary for storage systems via a Tier 2 Advice Letter.[65]

6.4 Rating Criteria

6.4.1 Rated Capacity (kW)

The rated capacity (kW) for energy storage technologies is calculated as follows:

- DC/AC systems: The nominal voltage multiplied by the amp-hour capacity multiplied by the applicable efficiency divided by the duration of discharge ((V_{DC} x Amp-Hours x (1 kW/1000W) x Applicable Efficiency) / Duration of Discharge)
    - The following specifications must be provided to calculate rated capacity:
        - Duration of discharge (hours)
        - DC dischargeable amp-hour capacity, associated with the duration of discharge specified, including all losses and ancillary loads (such as power conditioning and thermal management)
        - Nominal voltage (VDC)
        - Applicable efficiency (if necessary), which accounts for conversion, transformation, or other efficiency losses (e.g., Inverter CEC weighted efficiency, DC-DC converter efficiency)
        - The continuous maximum power output capability of the system.[66] For DC systems, this is rated in DC, and for AC systems, this is rated in AC.
- HVAC-integrated S-TES: Calculated using the Conversion Tables for HVAC-integrated S-TES found in Appendix C, based on the Seasonal Energy Efficiency Ratio (SEER) rating and tonnage

[65] D.24-03-071 Ordering Paragraph 31 grants PAs authority via a Tier 2 Advice Letter for CPUC approval to adopt any modifications into SGIP storage sizing requirements.

[53] Maximum continuous output may be determined by the maximum continuous discharge power/current of the system or by the continuous rated output of the inverter depending on which is less.

of the HVAC unit with which the S-TES system will be integrated and the climate zone in which the project is located. [67]

- Refrigeration TES: Calculated using the Refrigeration TES kW Worksheet, and is based on the following parameters of the refrigeration system(s) with which the Refrigeration TES system will be integrated:
    - Energy Efficiency Ratio (EER) of the compressor group, nameplate BTUh capacity of the compressor group, and maximum recorded output of the compressor group (as a percentage of nameplate compressor group horsepower)
    - The number of condenser fans, nameplate condenser fan power, and maximum recorded output of the condenser fan group (as a percentage of nameplate condenser fan group output)
- Large TES: Calculate 1-in-10 Peak kW using the UC Davis methodology. The UC Davis methodology is provided in Appendix F of the Handbook.

6.4.2 Energy Capacity (kWh)

The energy capacity (kWh) for energy storage technologies is calculated as follows:

- DC/AC systems: The nominal voltage multiplied by the amp-hour capacity multiplied by the applicable efficiency (V_{DC} x Amp-Hours x (1 kW/1000W) x Applicable Efficiency)
    - The following specifications must be provided to calculate energy capacity:
        - Duration of discharge (hours)
        - DC dischargeable amp-hour capacity, associated with the duration of discharge specified, including all losses and ancillary loads (such as power conditioning and AESC if you would please thermal management)
        - Nominal voltage (V_{DC})
        - Applicable efficiency (if necessary), which accounts for conversion, transformation, or other efficiency losses (e.g., Inverter CEC weighted efficiency, DC-DC converter efficiency)
- HVAC-integrated S-TES: The rated capacity (W) multiplied by the avoided compressor(s) run-hours that the system can provide in a single discharge. For systems that fully avoid compressor(s) run-time during discharge, the entire duration is considered the discharge duration. For systems with compressor(s) running a percentage of time during discharge, the avoided compressor run-time (hours) is considered the discharge duration. See Appendix H for examples of energy capacity calculations. [68]

[54] If compressor(s) is running for a percentage of time during system's discharge duration, rated capacity may be determined by calculating the percentage of peak kW reduction by the system for the Application Interval and Meter Interval Reports. (kW Offset (from the Conversion Tables in Appendix C) x (Avoided Compressor Run-Time) / (Duration of Discharge)). See Appendix H.
[55] Systems that can vary the compressor's runtime in interval periods should use the maximum HVAC compressor runtime in an interval period to calculate the avoided compressor(s) run-hours. See Appendix H for example calculations.

- Refrigeration TES: The rated capacity (W) multiplied by the avoided compressor(s) and condenser(s) run-hours that the system can provide in a single discharge
- Large TES: The energy capacity (Wh) for a single discharge can be estimated using building simulation model output (using industry accepted building simulation models). L-TES Applicants who submit their initial system performance estimates using proprietary simulation models must use building energy simulation software that complies with ANSI/ASHRAE Standard 140-2017 and ASHRAE Standard 90.1 2016/2019 Appendix F. The energy capacity must be updated at ICF by calibrating the building simulation model using monitored data as described in Section 9.1.4 and Appendix G. The methodology used to determine the rated capacity is described in the steps below:
    1. Model building using building simulation software
    2. Analyze model data as follows:
        a. Existing system
            i. Divided into 1°F bins based upon ambient DB temperature
            ii. Further divided into separate occupied and unoccupied bins
        b. Proposed system
            i. Model KW of proposed system Configurations
                1. TES System off (8760)
                2. TES System recharging (8760)
                3. TES System Discharging (8760)
            ii. Divide each Configuration into 1°F bins for each occupancy type
                1. Occupied
                2. Unoccupied
                3. Each bin to represent 1 hour of time
            iii. Interpolation
                1. Extend bins
                    a. from highest modeled temperature (TMY3 worst hour)
                    b. to 1-in-10 worst hour
                2. Number of bins
                    a. One bin for 1-in-10 worst hour
                    b. Two bins for next lower temperature
                    c. Continue this extension, with number of bins never less than two nor higher than the number of hours at highest DB in TMY3 file
                3. Straight line estimate
                    a. Delta KW between

i. 1-in-10 high KW (as determined by UC Davis methodology (provided in Appendix F)
ii. Highest hour

b. Divided by number of °F between 1-in-10 and TMY3
c. Applied equally to each bin between high and low

7 Renewable Generation Technologies

The following sections outline operational eligibility, system size, incentive calculation, application documentation requirements, and metering requirements specific to SGIP renewable generation projects. Additionally, all projects are subject to the general program requirements as outlined in Section 5.

7.1 Operational Eligibility Requirements

Generation technologies must meet or exceed a minimum operating efficiency requirement by meeting either (1) waste heat utilization requirements or (2) minimum electric efficiency requirements as outlined below.

Table 7.1a: Operational Eligibility Requirements for All Generation Technologies

All Generation Technologies [69]	
(1) Waste Heat Utilization	**(2) Minimum Electric Efficiency**
P.U. Code 216.6 (a) => $T / (T + E_{ELEC}) \geq 5\%$	Electrical Efficiency = $E / F_{HHV} \geq 40\%$
P.U. Code 216.6 (b) => $(E_{ELEC} + 0.5 \times T) / F_{LHV} \geq 42.5\%$	

In addition, IC Engines, microturbines, and gas turbines must (1) meet the 60% minimum system efficiency requirement [70] **and** (2) not exceed a NOx emissions standard of 0.07 lbs/MW-hr. [71]

Table 7.1b: Operational Eligibility Requirements for IC Engines, Microturbines and Gas Turbines

IC Engines, Microturbines and Gas Turbines	
(1) Minimum System Efficiency Standard	**(2) NOx Emissions Standard**
CHP System Efficiency = $(E + T_{WHR}) / F_{HHV} \geq 60\%$	<= 0.07 lbs/MWhr
Electric Only System Efficiency = $E / F_{HHV} \geq 40\%$	

[69] "Cogeneration" means the sequential use of energy for the production of electrical and useful thermal energy. The sequence can be thermal use followed by power production or the reverse, subject to the following standards: (a) At least 5% of the facility's total annual energy output shall be in the form of useful thermal energy; (b) Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output equals not less than 42.5% of any natural gas and oil energy input.
[70] The minimum system efficiency shall be measured as useful energy output divided by fuel input in higher heating value. The calculated minimum system efficiency shall be based on 100% load.
[58] An emission credit for waste heat utilization may be used to adjust the final emissions determination of eligibility.

Table 7.1c: Operational Eligibility Requirements, Legend

Symbol	Description
T	The annual useful thermal output used for industrial or commercial process (net of any heat contained in condensate return and/or makeup water), heating applications (e.g., space heating, domestic hot water heating), used in a space cooling application (i.e., thermal energy used by an absorption chiller)
E_{ELEC}	The annual electric energy made available for use, produced by the generator, exclusive of any such energy used in the power production process
F_{LHV}	The generating system's annual Lower Heating Value (LHV) non-renewable fuel consumption
E	The generating system's rated electric capacity as defined in Section 7.3, converted into equivalent Btu/hr using the factor 3,414 Btu/kWh
F_{HHV}	The generating system's Higher Heating Value (HHV) fuel consumption rate (Btu/hr) at rated capacity
T_{WHR}	The generating system's useful waste heat recovery rate (Btu/hr) at rated capacity

7.1.1 Locational Requirements – IC Engines

Internal combustion engine projects may not be located in a county listed as a severe or extreme federal nonattainment area for particulate matter (PM10 or PM2.5) or 8-hour ozone (O3) in the U.S. Environmental Protection Agency Green Book for any of the three years prior to the SGIP application date.

7.2 Capacity Factors

Generation systems are expected to operate at the following assumed capacity factors.

Table 7.2: Assumed Capacity Factors

Technology Type	Capacity Factor
Wind Turbine	25%
Other Generation Technologies – Dispatchable Resource	15%
All Other Generation Technologies – Baseload Resource	80%

Wind turbines are expected to operate at a 25% capacity factor. All other types of generation are expected to operate at a capacity factor that aligns with its intended operation. Systems intended to operate to offset a customer's ongoing baseload generation needs are expected to operate at an 80% capacity factor. Systems intended to operate as a dispatchable generation resource to firm on-site intermittent renewables, provide peak load shaving, and/or support flexible load are expected to operate at a 15% capacity factor.

7.3 Sizing Requirements

The following table provides the sizing requirements for the applicable generation systems rated above 5 kW.

Table 7.3a: Sizing Requirements for the Applicable Generation Systems

Generation Technology	Incentivized Capacity	Sizing
Wind Turbines	Based on the highest electrical output from the manufacturer's power output curve for wind speeds up to 30 mph including inverter losses. Systems less than 30 kW in capacity require a minimum hub height of 25 feet. Systems 30 kW and greater do not have a height limitation.	< 333 kW Up to 200% of previous 12-month Annual Peak Demand (1)
		≥ 333 kW Up to 300% of previous 12-month Annual Peak Demand (1)
Photovoltaics	The minimum system size eligible for an incentive is 1 kW CSI rating. The SGIP PA will use the lesser of the CSI rating, which includes the design factor, or the maximum continuous power output rating of the solar inverter to determine CSI rating which will be used to determine system size eligibility. Specific rules for interconnection may vary by utility. For all SGIP systems, the system size must be calculated using the CEC-AC rating standards, including inverter DC-to-AC losses.	Up to 100% of Host Customer's previous 12-month annual energy usage with the ability to oversize with an additional 50% (See Section 8.1.6). For oversizing, the customer must attest to expecting to increase their usage to correspond with the system size within 12 months of interconnection.
Pressure Reduction Turbine (PRT)	Based on the average pressure drop across and flow through the turbine, when flow exists, as determined by historical flow and pressure data from the previous year, if available, or from an engineering estimate if new construction or expanded load. Eligible technology system rated capacity must be substantiated with documentation from the manufacturer.	Up to the Host Customer's Previous 12-Month Annual Peak Demand (2)
Waste Heat to Power	Based on the average waste heat production rate and temperature, when waste heat is available, as determined by historical waste heat and temperature data from the previous year, if available, or from an engineering estimate if new construction or expanded load.	
Microturbines – CHP		

Gas Turbines – CHP	Using Directed Biogas: Based on full load net continuous rated capacity of the packaged prime mover/generator at ISO conditions. Using On-site Biogas or Hydrogen: Based on the average annual available fuel flow rate at ISO conditions.	
Internal Combustion Engines – CHP		
Linear Generators		
Fuel Cells	Using Directed Biogas: Based on full load net continuous rated capacity of the packaged prime mover/generator at ISO conditions. Using On-site Biogas or Hydrogen: Based on the average annual available fuel flow rate at ISO conditions.	
Steam Turbines – CHP	Based on the rated capacity, which is the net continuous power output of the packaged prime mover/generator at the average pressure and temperature of the steam produced by a boiler.	

Notes:

(1) Sites hosting existing generation, must also meet these sizing limits including both the capacity of the proposed wind turbine and the capacity of any existing generators (excluding any backup generators)

(2) If the site hosts existing generation, the combined capacity of the proposed and existing generators (excluding any backup generators) must be no more than the Host Customer's maximum site electric load.

The following table provides the system sizing requirements for generation systems participating in Export to Grid, Fuel Cell Net Energy Metering (FCNEM) Tariff, or the Renewable Energy Self-Generation Bill Credit Transfer (RESBCT) Program.

Table 7.3b: Sizing Requirements for the Applicable Generation Systems

Application	**Incentivized Capacity**	**Sizing**
Export to Grid [72]	Based on 100% Annual Energy Consumption	Based on 125% Annual Energy Consumption
Fuel Cells Participating in FCNEM [73]		Based on 100% Annual Energy Consumption

[72] The incentivized capacity will be determined by dividing the annual electrical consumption at the site (in kWh) by 8760 hours and the expected capacity factor of the technology as stated in Table 7.2.1.

[73] Fuel cell customers who have been determined by the CPUC to achieve reductions in emissions of greenhouse gases pursuant to subdivision (b) of Public Utilities Code § 2827.10 and meets the emissions requirements for eligibility for funding set forth in subdivision (c) of Public Utilities Code Section 379.6 and has commenced operation on or before January 1, 2015.

Customers Participating in RESBCT Tariff [74]		

7.3.1 System Sizing Limitations - Ineligible Host Customer Loads

The following loads cannot be considered when sizing a system:

- Any generation system where a customer has entered into contracts for distributed generation services (e.g., distributed generation installed as a distribution upgrade or replacement deferral) and who are receiving payment for those services. This does not include Power Purchase Agreements, which are allowed.
- Any portion of a Host Customer's load that is committed to electric utility interruptible, curtailable rate schedules, programs, or any other state agency-sponsored interruptible, curtailable, or demand-response programs. For electric utility customers who are on an interruptible rate, only the portion of their electric load designated as firm service is eligible for the SGIP. Customers must agree to maintain the firm service level at or above capacity of the proposed generating system for the duration of the applicable warranty period. Customers may submit a letter requesting an exemption to the firm service rule if they plan to terminate or reduce a portion of their interruptible load. **Wind turbines need not abide by this portion**.
- Publicly-owned or investor-owned gas or electricity distribution utilities, or any electrical corporation (ref. Public Utilities Code Section 218) that generates or purchases electricity or natural gas for wholesale or retail sales.

7.4 Renewable Fuel Eligibility Requirements

Eligible fuels are those that produce useful energy when undergoing combustion or a chemical reaction and are classified as renewable. [75]

Customers are required to use 100% renewable fuel for the lifetime of the project.

7.4.1 Directed Biogas Projects

Directed biogas projects must meet the following eligibility requirements and conditions:

- Directed renewable fuel must be produced within California and injected into a common carrier pipeline.
- Any request to change the fuel provider during the 10-year fuel contract must be submitted to the SGIP Program Administrator for approval. [76]

[74] Local government sites participating in the RES-BCT tariff must comply with the 5 MW cap per site.
[75] For the purposes of the SGIP, renewable resources such as wind, pressure, waste heat, and water are not categorized as a fuel.
[76] PAs shall respond to requests to change fuel supplier within 30 days.

7.4.1.1 Directed Biogas Project Renewable Fuel and Fuel Source Audits

Program Administrators or a third-party designee will conduct an annual audit of the renewable fuel invoices for 10 years after the renewable fuel contract commences to verify renewable fuel consumption.

The audit and verification will use metered fuel consumption data for SGIP directed biogas projects, invoices for directed renewable fuel purchases, documentation/verification of deliveries of directed renewable fuel along the path from the original directed renewable fuel supply source to the SGIP participant, and documentation to verify the amount and energy content of directed renewable fuel injected into the path. The Program Administrator or a third-party designee will request all pertinent information from the System Owner and/or renewable fuel provider at the completion of each year after renewable fuel contract start date.

If invoices show that nominated renewable fuel deliveries fell below the generator's fuel demand during any one-year period, the SGIP Program Administrators may request that the System Owner refunds the appropriate SGIP incentive amount and reserve the right to request a refund of additional costs (i.e., any administrative or legal fees incurred).

SGIP Program Administrators will also conduct random no-warning spot checks of directed biofuel sources. These spot checks will include verification of the biogas source, biogas flowrate, biogas cleanup equipment necessary to make it ready for injection into the natural gas grid, and the biogas interconnection equipment with the natural gas grid.

7.4.2 On-site Biogas Project Gas Quality Standard for IC Engines

On-site renewable biogas used in internal combustion engine projects must meet a 96% methane gas quality standard. These projects will be required to self-certify that the equipment necessary to achieve this requirement will be installed. Verification of installation will be completed during the on-site inspection as well as during subsequent measurement and verification assessments.

7.4.3 Hydrogen Projects

Technologies operating on hydrogen are eligible if the hydrogen is produced at the project site or is delivered to the project site by vehicle or dedicated pipeline.

Eligible hydrogen sources include:

- Non-combustion thermal conversion of biomass through gasification or pyrolysis. This does ***not*** include the use of purpose grown crops as a source of biomass. Forest debris is an appropriate (though not exclusive) fuel for this purpose.
- Electrolysis using 100% renewable electricity, as defined by the Renewables Portfolio Standard
- Hydropower, if the project is located on-site or if the electricity is directly connected to the project via a dedicated line

If the renewable electricity is not generated on-site, the purchase program or load serving entity must provide bundled Renewable Energy Credits to the electricity purchaser.

Hydrogen produced via steam methane reforming using either fossil or renewable fuel feedstocks are ineligible for use in SGIP incentivized projects.

7.4.4 Pressure Reduction Turbines

Any steam turbine replacing a pressure reduction valve will be considered eligible under the pressure reduction turbine category.[77] However, if the steam turbine is a straight power generator using incremental fuel to create steam, the technology will be considered as a steam turbine, and any incremental fuel used must be 100% renewable fuel.

7.4.5 Photovoltaic Systems

PV systems (i.e., systems that cause direct conversion of sunlight to electricity) are the only solar electric generating technology that are eligible to receive incentives from SGIP. Non-PV technologies, including solar hot water systems, are not eligible for the SGIP program incentive.

All major system components (panels and inverters) must not have been previously placed in service in any other location or for any other use case. Rebuilt, refurbished or relocated equipment is not eligible to receive SGIP incentives. Components that are critical to the PV systems must be certified by a Nationally Recognized Testing Laboratory (NRTL). System component ratings must also be certified by the California Energy Commission (CEC) and placed on the CEC's Eligible Equipment List. Components must also meet all requirements for interconnection with the electric utility, including Rule 21 requirements. The CEC provides a list of currently certified eligible equipment on the Go Solar California site at **https://www.energy.ca.gov/programs-and-topics/programs/solar-equipment-lists**. Equipment is periodically added and removed from the CEC lists of eligible equipment, so Applicants should confirm that the components purchased for a system are eligible prior to installation. All meters used in SGIP for the Performance Measurement and Reporting Service (PMRS) requirements must be accurate to within ± 5%. A list of eligible PMRS providers may be found on the Go Solar CA website: **https://www.energy.ca.gov/media/3770**

New panels added to existing inverter(s) that are already in service are not eligible to receive a SGIP incentive.

7.5 Fuel Documentation Requirements for PBI

The following table outlines the data and verification requirements for directed and on-site renewable generation PBI annual payments of systems 30 kW and larger.

[77] Steam turbines replacing a pressure reduction valve consider the “waste steam” as an eligible fuel source and do not consider the fuel used in the associated boiler.

Table 7.5: Fuel Documentation Requirements for PBI

Renewable Fuel Type	Measurement and Documentation Requirements
Directed Biogas	Amount of directed renewable fuel consumed – reported monthly [78]

	Transportation Path and Energy Accounting – reported monthly
	• Documentation from source showing the amount of directed biogas being moved into the pipeline
	• Any non-renewable gas added at the source must be identified
	• Documentation from gas transmission system showing:
	  ○ Receipt of directed biogas [79]
	  ○ Pipeline losses or fees paid in gas (not carried over)
	  ○ Positive or negative imbalances (carried over)
	  ○ Delivery of directed biogas to either another pipeline, storage facility, or California receipt point

	Gas Fuel Consumption – Reported quarterly • Documentation from the gas utility matching the directed renewable fuel receipts reporting the metered total energy input to the generator
On-Site Biogas	Amount of renewable fuel consumed (installation of a revenue grade meter required) [80] – reported monthly

It is the responsibility of the System Owner to contract with a performance data provider (PDP) for a minimum of five years and ensure that renewable fuel data is provided to the Program Administrator or their designee monthly for five years. The PDP is responsible to supply the renewable fuel use documentation and to ensure that the renewable fuel is reported to the Program Administrator or their designee on a monthly and quarterly basis for five years.

All gas generation technologies must use 100% renewable fuel to be eligible for incentives. Annual PBI payments will be adjusted according to the verified consumption of renewable fuel. [81]

7.6 Certification Requirements for Wind Turbines

Wind turbines must be certified by an accredited certification body to AWEA 9.1-2009, ACP-101-1-2021, or IEC 6400-1 or -2 (design) plus IEC 61400-12 (performance) and IEC 61400-11 (acoustics).

[78] Must be provided through the SGIP database. Applicant or PDP is required to provide the source, path, and destination of the renewable fuel. Reporting commences one month after the initial payment.
[79] From source, storage, or other pipelines.
[80] System Owner must provide make, model, specifications, and serial number of installed revenue grade gas meters.
[81] Generation projects are also subject to applicable incentive limitations in Section 4.5.

8 Documentation Requirements

Scanned copies of original signature forms or electronically signed forms [82] are required for all SGIP generated forms. This includes, but is not limited to, Reservation Request Forms, Proof of Project Milestone Forms, Incentive Claim Forms, and all affidavits/attestations. The signature on any signed document submitted to the Program Administrator shall create a valid and binding obligation of the party executing (or on whose behalf such signature is executed) with the same force and effect as if such signature page were an original thereof.

8.1 Reservation Requests

To request an incentive, an online RRF must be submitted with all required documents. Projects that include multiple SGIP eligible technologies must submit separate applications for each technology.

Completed RRF and all required documents are submitted to the Program Administrator. Once a project is assigned funding in a given step (on either a first-come or lottery basis), the Program Administrator reviews the Reservation Request and supporting documents. Once the documentation has been approved and eligibility requirements have been met, a Conditional Reservation Letter is issued for 3-step applications and Confirmed Reservation Letter is issued for 2-step applications.

3-Step Applications

Upon approval of the Reservation Request Package, a Conditional Reservation Letter will be issued to show that a specific incentive amount is conditionally reserved for the project. The letter will list the Proof of Project Milestone (PPM) due date, Request for Proposal (RFP) due date (public entity projects), and the Reservation Expiration date (18 months after the date of the Conditional Reservation Letter). All reservations are conditional until the Program Administrator reviews and approves the PPM documentation (to be received on or before the PPM due date).

2-Step Applications

Upon approval of the Reservation Request package, a Confirmed Reservation Letter will be issued. The Confirmed Reservation Letter will list the reserved incentive amount and the Reservation Expiration date (12 months after the date of the Confirmed Reservation Letter). Upon project completion and prior to the Reservation Expiration date, the completed ICF must be submitted along with all the required documentation to request an incentive payment.

Required Documentation for the Reservation Request

SGIP applications must provide a copy of the following:

[82] All electronic signatures of SGIP generated forms must be accompanied by a signature audit page. SoCalGas only accepts OneSpan Sign, Adobe Sign, DocuSign, and DropBox Sign electronic signatures for their SGIP generated forms.

Table 8.1: Reservation Request Requirements

Required Materials
1. Online Reservation Request Form *(all projects)*
2. Application Fee (*non-residential projects)*
3. Equipment Specifications *(all projects except any energy storage system listed on the SGIP Public Equipment List)*
4. Proof of Utility Service (*all projects)*
5. Copy of Executed Contract or Agreement for Installation *(all projects)*
6. Load Documentation (single-family storage projects >15 kWh, multifamily residential projects >12.5 kwh per tenant; *non-residential projects >10kW, single-family solar projects >5 kW, multifamily solar projects >5 kW per tenant)*
7. Preliminary Monitoring Plan (*energy storage projects paired with on-site renewable generators, projects subjected to PBI, and generation projects >=30 kW)*
8. Minimum Operating Efficiency Worksheet w/Backup Documentation (*generation projects)*
9. Proof of Adequate Fuel or Waste Energy Resource *(generation projects)*
10. Proof of Equity Eligibility *(energy storage projects applying for an Equity or Equity Resiliency Budget)*
11. Proof of Resiliency Eligibility (*Equity Resiliency projects, Resiliency Adder projects, and projects opting into resiliency)*
12. Proof of Coordination with Local Government and California Office of Emergency Services (*non-residential Resiliency Adder and Equity Resiliency projects)*
13. Ineligibility for IRA Tax Credit (*projects claiming ineligibility for IRA tax credit)*

1. ***Online Reservation Request Form*** *(all projects)*

All Applicants are required to complete the online RRF. The RRF is used to provide project details, contact information, and signed declarations. Residential energy storage projects must also fill out the Residential Energy Storage Eligibility Affidavit portion of the RRF.

As part of the RRF, the project Host Customer must attest that an Energy Efficiency Audit (EEA)[83] has been performed for the project site and they received and reviewed the findings of the audit.

For storage systems not pursuing resiliency, the Host Customer must also attest on the RRF that their Developer has notified them that the system is not intended for backup capability.

[83] An Energy Efficiency Audit (EEA) report issued within the past five years. A Title 24 energy efficiency compliance report issued within the past three years may also be used in lieu of an Energy Efficiency Audit.

The RRF must be signed by the Applicant, Developer, Host Customer, and System Owner (if not Host Customer). A copy of the signed document must be uploaded to the online application database and the information contained on the signed copy of the RRF must match the information provided on the online RRF.

2. ***Application Fee*** *(non-residential projects)*

The application fee for non-residential project applications is equal to 5% of the requested incentive amount, payable by check, cashier check, or money order, and should reference the project by site address.[84] The application fee is the only required document that must be mailed directly to the Program Administrator.[85] After a project is assigned to an incentive step, if the application fee is not already received, the Program Administrator will send out an Application Fee Invoice Notice with specific instructions on how and where to mail the application fee. The application fee check must be mailed within seven calendar days of the Application Fee Invoice Notice. If the check is not mailed within seven calendar days, the project may be cancelled. Application fee checks returned by the financial institution without payment may result in cancellation of the application.

The application fee will be refunded upon completion and verification of the installed SGIP project. Prior to project completion, application fees are non-refundable once Confirmed Reservation has been issued.[86] All forfeited application fees will be allocated to the Program Administrator's current incentive step.

Wind Projects Only

Prior to project completion, application fees are non-refundable once a Confirmed Reservation has been issued, unless the Host Customer subsequently cancels the project, requests a refund, and certifies to the Program Administrator Working Group that it was unable to obtain a permit required for the installation and operation of the project or that the utility required installation of distribution upgrades that rendered the project financially unfeasible. In this case, the Program Administrator Working Group shall approve such requests unless it determines that the original Confirmed Reservation was obtained in bad faith or without the Host Customer having a reasonable expectation of obtaining the required permit or a financially feasible interconnection of the project.

3. ***Equipment Specifications*** *(all projects except any energy storage system listed on the SGIP Public Verified Equipment List)*

Electrochemical Energy Storage Projects

Equipment and/or component pairings that have been evaluated and deemed eligible for participation in the program can be found on the SGIP Public Verified Equipment List at www.selfgenca.com. For

[84] Application fees are specific to an application, not a site. If the same site reapplies to the program, they will need to submit a new application fee.
[85] A single application fee check for each non-residential project is required.
[86] Application fees will not be altered due to project changes that may result in a different incentive.

projects using equipment and/or component pairings not yet evaluated by the Technical Working Group, manufacturer equipment specifications for all major components of the system, such as the storage component, as well as the inverter, DC-DC converter, controller, and/or additional system components when applicable, are required. Rated capacity (kW), energy capacity (kWh), and round-trip efficiency [87] for the storage system must be provided. Equipment specifications may be submitted to any PA via email to the contact information listed on www.selfgenca.com.

DC/AC systems must provide all specifications necessary to calculate the rated capacity and energy capacity, such as:

- Duration of discharge (hours)
- DC dischargeable amp-hour capacity, associated with the duration of discharge specified, including all losses and ancillary loads (such as power conditioning and thermal management)
- Nominal voltage (V_{DC})
- Inverter CEC-AC efficiency
- DC-DC converter efficiency
- Inverter continuous power output rating (kW)
- The continuous maximum power output capability of the system. [88] For DC systems, this is rated in DC, and for AC systems, this is rated in AC.

HVAC-integrated S-TES Projects

Must provide the TES system equipment specifications, HVAC system equipment specifications identifying the SEER and tonnage of the HVAC unit and the climate zone in which the project is located. Must provide the TES system's maximum HVAC compressor runtime and its interval period during system's discharge duration.

Refrigeration TES Projects

Must provide TES system equipment specifications, refrigeration system equipment specifications, the Refrigeration TES kW Worksheet and backup documentation of any site-specific conditions, if relevant.

L-TES Projects

Must provide TES system equipment specifications, chiller system equipment specifications, cooling tower equipment specifications (if applicable), the L-TES kW/kWh-AC Offset Worksheet that has been populated by the calibrated building simulation model output, a copy of the building simulation model inputs and output, and backup documentation of any site-specific conditions, if relevant. If the simulation model used is proprietary, substantiation must be provided to show that the model is

[87] AC-AC for AC systems and DC-DC for DC systems
[88] Maximum continuous output may be determined by the calculated maximum continuous discharge power of the energy storage system or by the continuous rated power output of the inverter depending on which is less.

compliant with ANSI/ASHRAE Standard 140-2017 and ASHRAE Standard 90.1 2016/2019 Appendix F.

Generation Projects

Manufacturer equipment specifications for all major components of the system are required, in addition to the nameplate capacity, rated capacity (kW) efficiency, and, if necessary, fuel consumption and waste heat recovery rate of the system.

Proof of power factor eligibility is also required for microturbines, internal combustion engines, gas turbines, and stream turbine CHP applications (where applicable) and must include self-generating facility design specifications and/or manufacturer's specifications which show that the system will be capable of operating between 0.95 PF lagging and 0.90 PF leading.

Solar PV projects must provide the following for modules and inverters:

- Manufacturer
- Model number
- Quantity

4. *Proof of Utility Service* *(all projects)*

Participation in the SGIP is restricted to IOU customers who are located in PG&E, SCE, SoCalGas, or SDG&E service territories and physically connected to the electric utility transmission and distribution system. All applications in SCE, SoCalGas, and SDG&E service territories must include a complete copy of a recent electric utility bill (all pages), indicating the account number, meter number, site address, and Host Customer name.[89] For new construction, the Host Customer must submit confirmation from the serving utility that their site is within the Program Administrator's service territory. Customers applying in PG&E[90] and SoCalGas territory must also submit a copy of a recent gas utility bill. CSE may require the Authorization to Receive Customer Information form for any project at any time during the application process if additional utility information must be verified in order to approve the application.

Multifamily Projects

Proof of number of and types of accounts benefiting from the incentivized system must be provided.

Projects interconnecting under a VNEM tariff must submit a VNEM Generation Credit Allocation Request Form to determine the project's primary use case (residential or non-residential). See Section 3.3 for more information on how multifamily projects are classified. If the primary use case is

[89]A utility bill may be required at PG&E's discretion.
[90] PG&E customers are only required to submit a copy of a recent gas utility bill if not receiving electricity from PG&E.

determined to be residential, all benefiting tenant accounts will be required to be enrolled in an SGIP-eligible TOU rate.[91]

Projects interconnecting under a VNEM tariff applying for Equity Resiliency incentives, the Resiliency Adder, or the increased discharge duration for Resiliency systems must also demonstrate 1) the applicable utility's VNEM tariff allows installed storage to serve on-site load; and (2) the Applicant intends to use a switching and isolation technology arrangement allowed under Rule 21 at the time the of application to provide for discharging the battery to serve on-site load and to island.

5. ***Executed Contract and/or Agreement for System Installation*** *(all projects)*

A copy of the executed contract for purchase and installation of the system, and/or alternative System Ownership Agreement (such as a Power Purchase Agreement or Third-Party Ownership Agreement) is required. The contract/agreement must be legally binding and clearly spell out the terms and scope of work. Purchase and/or installation agreements must also include system equipment and eligible system costs. All contracts/agreements must be signed by appropriate representatives (Host Customer, [92] Installer, and/or System Owner) who are a party to the agreements of the SGIP reservation.

Agreements for the purchase of a system or system equipment must be in writing and must include, at a minimum, the following information:

- The quantity, make and model number (as shown on the SGIP Equipment List and/or California Energy Commission lists of eligible equipment) for the incentivized equipment
- The total purchase price of the system before applying the incentive
- SGIP incentivized storage equipment, either coupled with solar incentivized equipment or non-incentivized equipment, must have costs broken-down by the following categories:
    - Equipment costs
        - Storage: Battery and inverter(s) costs
        - Solar: Solar PV panels and inverter(s)
    - Installation costs listed separately for storage and solar
    - Design, permitting, and interconnection costs.
    - Electrical and critical loads panel and wiring upgrades [93]
    - Balance of system costs

[91] For projects located in front of the customer's electric meter, each customer may be automatically transferred to an SGIP-eligible TOU rate (if one is available to them) by the electric IOU, if one was not selected at interconnection.

[92] Host Customers that do not own the home and are applying as a renter must provide a letter that states they have approval from the landowner/homeowner to install the incentivized equipment.

[93] Are allowable costs for Equity Resiliency and Equity/RSSE Budget projects with a maximum reimbursement of $3,500 per project.

[93] Are allowable costs for Equity Resiliency and Equity/RSSE Budget projects with a maximum reimbursement of $3,500 per project.

- Storage: Any system or component required to complete the installation of the storage system unrelated to the battery and/or inverter
- Solar: Encompasses all components of a photovoltaic system other than the photovoltaic panels and inverter(s). This includes racking, wiring, switches, and mounting system, etc

- Name, address and contractor's license number of the company performing the system installation
- Site address for the system installation
- Description of the work to be performed
- Total agreed price to install the system
- Payment terms (payment dates and dollar amounts)
- Printed names and signatures of the purchaser and the company's authorized representative

- As part of the Executed Contract, all systems are required to include a minimum **10-year service warranty (wind turbine systems must have a minimum 20-year service warranty).** A service warranty ensures proper maintenance and continued project performance. The service warranty must cover the system maintenance to include (but not limited to) system support, problem diagnosis, on-site repair, and preventative maintenance. The warranty should also include language to guarantee the continued performance of the system over the warranty period. The System Owner must provide proof of warranty and maintenance contract and specify the warranty and maintenance contract start and end dates. An exception to the service warranty can occur when a developer has declared bankruptcy or gone out of business, and provided that the CPUC has approved the exception through the disposition of a Tier 2 Advice Letter submitted by the PAs.
- **For energy storage systems:** In lieu of the service warranty, all energy storage systems are required to have a minimum 10-year performance warranty[94] which guarantees at least 60 percent beginning of life (BOL) rated energy capacity remaining at year 10. The performance warranty must also outline 1) the cycle life or energy throughput and 2) the depth of discharge or usable energy storage capacity the battery can safely operate at to avoid voiding the warranty.

- **For solar systems:** SGIP requires the following:

[94] Performance warranty requirement can be found on the SGIP Public Equipment List: https://www.selfgenca.com/documents/verified_equipment/public_equipment_list

- All solar energy equipment for electricity generation (PV modules, inverters, tracking mechanisms) shall have a minimum 20-year performance warranty to protect against degradation of electrical generation output of more than 15% from their originally rated electrical output. This may require obtaining an extended warranty for some equipment.
- All contractors shall provide a minimum 10-year workmanship warranty to provide for no-cost repair and replacement of the system for any expenses not otherwise covered by the manufacturer. All contractors shall provide a minimum 20-year warranty to protect the purchaser against more than a 10% degradation of electrical generation output that may occur as a result of faulty installation. Meters must have a one-year warranty to ensure against defective workmanship, system or component breakdown, or degradation in electrical output of more than 15% from their originally rated electrical output during the warranty period. For meters that are integrated into the inverter, the inverter warranty requirement of 20 years will take precedence.

- **For projects claiming the ITC for equipment purchased after December 31, 2021:** Proof of purchase dated after December 31, 2021 for the energy storage equipment and its main components (battery, inverter, controls) is required.

3-step applications may submit the executed contract during the PPM stage.

6. ***Load Documentation*** *(*single-family storage projects > 15 kWh, multifamily projects > 12.5 kWh per tenant; *non-residential projects > 10 kW, single-family solar projects >5 kW, multifamily solar projects >5 kW per tenant)*

   Single family residential systems being sized based on new or future load growth (i.e., new construction or load growth due to facility expansion or other load growth circumstances), applications must include an engineering estimate with appropriate substantiation of the site's annual energy consumption forecast. This can be provided by using the Energy Storage Sizing Tool available on the selfgenca.com website [95]. Backup documentation such as green button data, monthly bills, PV generation data (such as output from NREL's PVWatts [96]) must also be provided in addition to a copy of a filled out (populated) version of this tool.

[95] https://www.selfgenca.com/documents/application_forms/storage_sizing

[96] *When using PV Watts to develop PV generation data for use with the Energy Storage Sizing Tool please use the PTC rating of the panels as the input to PV Watts rather than the STC rating. This allows PV Watts to model the PV generation with a more real-world expectation of the solar performance at the site. This is also in line with the use of the PTC rating in the EPBB calculator for the calculation of the solar incentive.*

For projects applying in CSE and SoCalGas territories, applications for technologies that discharge electricity to the on-site load must include documentation of the previous 12 months of electric consumption including maximum demand and kWh consumption to confirm that the participating generation system meets the program sizing requirements. Electric utility customers of SCE and PG&E are not required to submit their 12-month electric consumption and demand data.

SDG&E customers are also required to submit an Authorization to Receive Customer Information form, signed by the utility customer of record that authorizes CSE to access utility account information for non-residential systems greater than 10 kW, single-family systems over 15 kWh, or multifamily residential systems over 12.5 kWh per tenant.

Residential projects that require load justification are required to submit the results from the load sizing tool.[97] Electric SCE and PG&E customers are not required to submit this information.

If the system is being sized based on new or future load growth (i.e., new construction or load growth due to facility expansion or other load growth circumstances), applications must include an engineering estimate with appropriate substantiation of the site's annual peak demand forecast. Suggested methods of demonstrating load growth include Application for Service with corresponding equipment schedules and single-line diagram; building simulation program reports such as eQUEST, EnergyPlus, EnergyPro, DOE-2, and Visual DOE; or detailed engineering calculations.

Energy Storage Projects

Non-residential projects applying to the Equity Resiliency Budget or are otherwise receiving the Resiliency Adder for a system that is sized above peak load necessary due to modular component sizes to accommodate the customer's peak load must demonstrate proof of this need. An ad-hoc letter explaining the need for the larger system size to cover the customer's previous 12-month annual peak demand must be provided.

Large Thermal Energy Storage Projects

Must provide pre-installation monitoring data as outlined in Section 9.1.4 (Large TES Monitoring Requirements) during periods that occur during any 30 consecutive day period within the designated IOU summer period that contains at least nine days with a peak ambient air temperature of 90ºF or above, or within 10ºF of the peak ambient temperature in the TMY3 file for the project, with at least three of the peak temperature days being consecutive. Pre-monitoring should occur no greater than 18 months prior to the installation of the L-TES system.

Photovoltaic Projects

For incentivized solar systems in the Residential Solar Storage Equity budget, solar systems at 5 kW or less (and 5kW or less per tenant load assumption for Multifamily Projects) and are not being

[97] https://www.selfgenca.com/documents/application_forms/storage_sizing

oversized above 100% of the customer's annual onsite load due to future load growth are exempt from the load documentation requirement.

Multifamily Residential System Sizing:
To be eligible for SGIP incentives, the system must be sized so that the amount of electricity produced by the system primarily offsets the tenant area electrical needs at the Project Site. At least 51% of the system's electric output must directly offset tenant load and be provided to tenants in the form of VNEM bill credits. Unless additional load substantiation documentation is submitted, the estimated annual kWh production of the proposed system as shown on the EPBB Calculator (see Section *4.2.4.1*, EPBB Methodology) may not be higher than the annual site consumption for all eligible meters. This requirement not only applies to the system as a whole, but also to the common area portion and tenant area portion, distinctively.

Single Family Residential System Sizing:
To be eligible for SGIP incentives, the system must be sized so that the amount of electricity produced by the system primarily offsets the home electrical needs at the Project Site. Unless additional load substantiation documentation is submitted, the estimated annual kWh production of the proposed system as shown on the EPBB Calculator (see Section 4.3.1, Expected Performance Based Buydown (EPBB) Methodology) may not be higher than the annual site consumption for the residence's electrical meter.

Oversizing Attestation for Single Family or Multifamily Residential System Sizing Based on Future Load Growth:
In the case of Host Customers with new or expanded loads with no electric bill history or where the existing electric bill does not reflect the Host Customer's expected expanded consumption, the Applicant must include an estimate of the expected expanded consumption along with an attestation with the expected increase in usage that will correspond with this system size within 12 months of interconnection. Oversizing in these scenarios is limited to no more than 150% of the customer's on-site load. The engineering estimate must include the appropriate substantiation of the forecast of the Host Customer Site's annual energy use (in kWh) if the PV system size is based on future load growth, including load growth due to site expansion or other load growth circumstances. Justification for increasing the PV system size may include the planned completion of the following measures:

- Conversion of gas space heating (individual or central) to high efficiency electric
- Conversion of gas cooking, gas laundry drying, or gas pool heating to high efficiency electric
- Installation of electric vehicle charging stations on the property premises, which will be considered a common area load in multifamily residences as it relates to SGIP rebate calculations.

Suggested methods of demonstrating load growth include an application for electric service or interconnection with corresponding equipment schedules and a single line diagram; building simulation program reports such as eQUEST, EnergyPro, DOE-2, and VisualDOE; or detailed engineering calculations including lists of equipment with corresponding equipment schedules. The PA will verify the load growth predicted and may request further information prior to confirming a reservation and/or approving the increased system size based on future load growth at subsequent application milestones.

7. ***Preliminary Monitoring Plan*** *(energy storage projects paired with on-site renewable generators, projects subjected to PBI, and generation projects >=30kW)* [98]

Examples and a blank preliminary monitoring plan template can be downloaded from the www.selfgenca.com website.

Energy Storage Projects

The preliminary monitoring plan should demonstrate the following components:

- **Description of the proposed SGIP system:** Include a description of the system with an overview of the energy services to be provided by the system to the project site; the major components making up the system; and the intended operation of the system (e.g., demand charge management of the facility or specific end-use equipment, TOU energy arbitrage, shifting excess generation). Include photos and/or diagrams of the system if available.
- **Description of the backed-up loads:** Include a description of the loads at the site that will be backed up by the energy storage system.
- **Description of the metering system and metering approach:** Include an overview of the performance data to be collected and a simplified layout of the system showing major components and location of the proposed metering points and data to be collected at those points is required.
- **Description of the approach to be used for collecting, storing, and transferring the necessary performance data:**
    - The reasoning behind the selected metering points (for example, if electrical energy performance data is to be collected)
    - Frequency with which the data is to be collected (e.g., 15-minute intervals)
    - Data storage capability and approach for transfer of data (e.g., cell modem)
    - For all new non-residential systems, the frequency of reporting to PDP (e.g., daily, weekly), which could also include frequency for reporting of data to Program Administrators (e.g., monthly)

[98] A Preliminary Monitoring Plan is not required for RSSE single-family PG&E and Sacramento Municipal Utility District (SMUD) electric customers who submit executed contracts beginning with the 2026 SGIP Handbook v2 (released on March 18, 2026), as these customers have SGIP-Approved rate(s). A Preliminary Monitoring Plan may be required at PG&E's discretion.

- **Identification of the metering system components by performance data type (including manufacturer and model number):**
    - Electrical metering equipment (AC meters must meet the criteria for the applicable project type (see Section 9)
    - Thermal energy metering equipment
    - Data acquisition (i.e., logger) system
- **Systems Pairing with On-Site Renewable Generators:** Energy storage systems paired with on-site renewable generators must provide a description of:
    - The anticipated charge and discharge schedule of the system demonstrating that the system complies with ITC operational requirements or will be charged at least 75% from renewables.
    - The metering that will be used to verify that the system is being charged from renewables.
    - The ability to provide data to verify operation in the event of an audit.

Renewable Generation Projects

The preliminary monitoring plan should demonstrate the following components:

- **Description of the proposed SGIP system:**
    - Include a description of the system with an overview of the energy services to be provided (e.g., generation, waste heat recovery, storage) by the system to the project site; the major components making up the system; and the general operating schedule of the system (e.g., is it 24x7x365 or 10x6x365); the operating schedule is required to distinguish the system's intended operation as either an intermittent, dispatchable, or baseload generation resource. Include photos and/or diagrams of the system if available.
    - Break out subsystems such as solar panels, power conditioning equipment, and automatic transfer switches for solar generation projects and waste heat recovery systems for other renewable fuel generation projects to provide context for thermal energy metering systems. Provide similar descriptions for other important subsystems such as energy storage when combined with wind systems.
    - Include a description of the existing load at the site and identification of the sources of the fuel that would be displaced by operation of the SGIP system (i.e., electricity provided by XYZ utility or natural gas provided by ABC utility) and photos of the interface locations where the SGIP system would be located to displace the load.
- **Description of the metering system and metering approach:**
    - Include an overview of the performance data to be collected (e.g., electrical, useful thermal energy, fuel consumption) and a simplified layout of the system showing

major components (e.g., generator, waste heat recovery, storage) and location of the proposed metering points and data to be collected at those points (e.g., electrical, flow, temp, fuel) is required.

- Two-Step Applications will include (as part of their Reservation Request) a Proposed Monitoring Plan as outlined in Section 8.2.4.

8. ***Minimum Operating Efficiency Worksheet with Backup Documentation*** *(generation projects)*

The Minimum Operating Efficiency Worksheet (MOEW) is used to evaluate a project's technical ability to meet the following requirements:

- Minimum operating efficiency requirement which can either be satisfied by meeting:
  - Waste Heat Utilization, *or*
  - Minimum Electrical Efficiency Requirements
- Thermal Load Coincidence
- CHP System Efficiency and NOx Emission Qualification
- Electrical Load Coincidence (Electrical Export Eligibility)

Minimum Operating Efficiency Calculations

The MOEW is a spreadsheet used to evaluate the project's estimated minimum operating efficiency over 10-years. Additionally, the MOEW verifies the first-year minimum operational efficiency for Electric-only fuel cells and linear generators. All applications proposing renewable-fueled technologies must provide backup documentation along with the MOEW. CHP systems must additionally include engineering calculations with documented assumptions regarding the site's thermal load. All assumptions, backup documentation, hand calculations, models (with inputs and outputs), and custom spreadsheets used to develop the forecasts must be included in the documentation. Forecasts based solely on "professional experience" or subjective observation will be rejected.

Specifically, the following applicable documentation must be provided:

- **Generator & Thermal System Description:** The application must include the performance and capacity specifications for the proposed CHP system and all thermal system equipment that the CHP system interacts with or serves. This includes but is not limited to the generator system, heat recovery system, heat exchangers, absorption chillers, boilers, furnaces, etc. In addition, a thermal process diagram must be provided as part of the documentation package that shows the configuration of the generator(s), heat recovery system, pumps, heat exchangers, thermal load equipment, and the working fluid flow and temperatures in/out of each piece of major equipment at design conditions.

- **Forecast of Generator Electric Output**: The MOEW must include a forecast of the monthly generator electric output (kWh/month) for a 12-month period. The generator electric output forecast must be based on the operating schedule of the generator, historical or site electric load forecast, and maximum/minimum load ratings of the generating system, exclusive of any electric energy used in ancillary loads necessary for the power production process (e.g., intercooler, external fuel gas booster).
- **Forecast of Generator Thermal Output**: The application must include a forecast of the monthly generator thermal output (Btu/month) for a 12-month period. The generator thermal output forecast must be based on the electric output forecast of the generating system and the waste heat recovery rate specifications of the system.
- **Forecast of Generator Fuel Consumption**: The application must include a forecast of the generating systems monthly fuel consumption (Btu/month) for a 12-month period. The generator's fuel consumption forecast must be based on the generating system electric output forecast and the systems fuel consumption specifications.
- **Forecast of Thermal Load Magnitude**: The application must include a monthly Thermal Load forecast (Btu/month) for a 12-month period for the Thermal Load served by the CHP system. The forecast must be based on engineering calculations, thermal system modeling, historical fuel billing, measured data or a combination of these methods. The Thermal Load forecast must be independent of the generator operation forecast. If historical natural gas or other fossil fuel consumption records (e.g., billing records) are used, the combustion efficiency of the natural gas or fossil fuel fired equipment that is being displaced must be included. Historical fuel consumption must be discounted to account for equipment Thermal Load that will not be displaced by the prime mover's thermal energy.
- **Forecast of Useful Thermal Output**: The useful thermal output of the CHP system will be the lesser of the Thermal Load forecast, or the prime mover's thermal output coincident with the Thermal Load. The useful thermal output is the value used in calculating the Public Utilities Code 216.6 requirements.

Thermal Load Coincidence

Thermal load coincidence is calculated in the worksheet by comparing the waste heat recovered to the thermal load on an annual basis. The backup documentation listed above for the forecast of generator thermal output and forecast of thermal load magnitude will be sufficient to meet this operating efficiency requirement.

CHP System Efficiency and Proof of Nitrogen Oxides (NOx) Emission Qualification

Applications must include documentation substantiating that the generating system meets or exceeds the 60% minimum system efficiency and NOx emissions are at or below the applicable emission standard. One of the following documents must be included to determine the NOx emissions (lb/MWh) of the proposed system:

- Manufacturer emission specifications based on factory testing using California Air Resources Board (CARB), EPA, or local air district test methods for the proposed generating system as configured for the site
- CARB distributed generation certification
- Emission engineering calculations for the proposed generating system as configured for the site

Conversion of emissions concentration (ppm) to production-based emissions rates (lb/MWh) shall use the method found in Appendix B of this Handbook. Units that do not pass the emission standard may use emission credits. If the application claims NOx emissions credits for their waste heat utilization emission, credit calculation documentation based on the amount of waste heat utilized over a 12-month period must be provided.

Electric Load Coincidence *(Electrical Export Eligibility)*
The application must include the monthly electrical load for the previous 12 months. This information will be used in the MOEW to determine electrical load coincidence with electrical generation on an annual basis. If the generator is eligible to export electricity to the grid, the electrical generation will be compared to 125% of electrical load on an annual basis.

9. *Proof of Adequate Fuel or Waste Energy Resource* *(generation projects)*

- **On-site biogas projects (including on-site hydrogen)** must include an engineering survey or study confirming the renewable fuel (i.e., adequate flow rate) and the generating system's average capacity during the term of the project's required permanency period.
- **Biogas projects utilizing directed renewable fuel or hydrogen delivered via vehicle or dedicated pipeline** must include documentation of the forecasted fuel consumption of the generator over the life of project.
- **Proposed pressure reduction turbine applications** must include an engineering survey or study confirming adequate temperature, pressure, and flow within the piping system, and the generating system's rated capacity. The rated capacity must be based upon the average pressure drop across and flow through the turbine, when flow exists, as determined by historical flow and pressure data from the previous year if available, or from an engineering estimate if new construction or expanded load. Additionally, the survey or study must show that the capacity factor for the proposed project will be greater than or equal to 40% based upon conditions over the course of a full year, or from an engineering estimate for future conditions.
- **Proposed waste heat to power applications** must include an engineering survey or study confirming adequate waste heat production rate and temperature, and the generating system's rated capacity. The rated capacity must be based upon the average waste heat

production rate and temperature, when waste heat is available, as determined by historical waste heat and temperature data from the previous year if available, or from an engineering estimate if new construction or expanded load. Additionally, the survey or study must show that the capacity factor for the proposed project will be greater than or equal to 40% based upon conditions over the course of a full year, or from an engineering estimate for future conditions.

- **Proposed wind projects** must include an engineering survey or study evaluating the annual average wind speed at the hub height of the wind turbine. The study must confirm that the average annual wind speed is equal to or greater than 10 mph (4.5 m/s). The wind resource can be verified using wind resource maps from NREL or the CEC and standard formulas for correcting differences in tower heights or by gathering wind data on site at the turbine's proposed hub height for one year.
  For wind projects less than 30 kW in capacity with tower heights less than 80 feet wind Turbine performance modeling results using wind turbine models such as NREL's SAM or the AgWind Wind Report must be provided in conjunction with the results from the NREL or CEC wind resource maps.

10. ***Proof of Equity Eligibility*** *(energy storage projects applying for an Equity Budget)*

- **Certification of Tax-Exempt Status – Government** *(Non-Residential Equity Budget)*: State and local government and non-profit entities are required to submit verification of their tax-exempt status.
- **Proof of Non-Profit Registration** *(non-profit organizations)*: Customers qualifying for the Equity Budget must provide proof of registration and good standing with the California Secretary of State as a domestic non-profit entity.
- **Proof of Eligibility under Proposition 39 or an Accredited Institution – Educational Institutions** *(Non-Residential Equity Budget)*: For educational institutions, Applicants must submit documentation proving eligibility under the California Energy Commission's Proposition 39 Program[99], or which confirm they are an accredited educational institution.
- **Small Business Affidavit – Small Business** *(Non-Residential Equity Budget)*: Application documentation must include a signed affidavit affirming that the Host Customer is a business or manufacturer, including affiliates, with average annual gross receipts of $15 million or less over the last three tax years.
- **Deed Restriction or Regulatory Agreement – Multifamily** *(RSSE and Equity Resiliency Budgets)*: For a multifamily residential complex financed with low-income housing tax credits,

[99] Proposition 39 eligibility guidelines can be found at http://www.energy.ca.gov/efficiency/proposition39/.

tax-exempt mortgage revenue bonds, general obligation bonds, or local, state, or federal loans or grants, a deed restriction on the property, or a regulatory agreement signed and executed between the Property Owner/Developer and entity issuing financing must be submitted.

- **SGIP Multifamily Low-Income Housing Documentation Cover Sheet – Multifamily (***RSSE and Equity Resiliency Budgets)*: To clearly outline how a project achieves Public Utilities Code Section 2852 low-income eligibility, Applicants are required to submit a cover sheet identifying key details within the deed restriction or regulatory agreement such as, but not limited to, property owner name, public entity/non-profit agency name, expiration date of low-income documentation, rent restriction description, and percent of households with incomes at or below 60% of the area median income. This will allow Program Administrators to determine more accurately and efficiently eligibility.

- **Proof of Income Qualification – Single Family** *(RSSE and Equity Resiliency Budgets *includes Indian Country and electric-pump well projects):* Provide documentation showing the Host Customer's household income is 80% of the area median income or less based upon a copy of the most recently available federal income tax documentation. Area median income is subject to annual changes based upon Housing and Urban Development's income guidelines.[100] Contact your Program Administrator for instructions on how to submit the appropriate documents for your application.

  A copy of the customer's most recent 1040 form should be provided. In the event the customer did not file a 1040 or comparable document to the IRS, the customer should work with the Program Administrator to determine an acceptable alternative document to prove the household income for their project.

- **Proof of Enrollment in MASH, SOMAH, SASH, DAC-SASH, CARE, FERA, or ESA Reservation Letter – Low-income** *(RSSE and Equity Resiliency Budgets)*: Customers must provide proof of eligibility status in the MASH, SOMAH, SASH, or DAC-SASH, CARE, FERA, or ESA program. CARE, FERA, and ESA documents must reflect income verification has been completed as a result of participation in the programs.

- **Proof of Indian Country Qualification** *(all Equity Budgets)*: A Native American tribal card or official document must be provided to be eligible for the expanded DAC requirement.

- **Proof that at least 50% of census tracts served are DACs or low-income communities** *(non-residential Equity Budget)*: Customers have the burden of providing any information that demonstrates a facility's eligibility.

[100] Area Median Income is subject to annual changes based upon Housing and Urban Development's income guidelines (https://www.huduser.gov/portal/datasets/il.html).

11. *Proof of Resiliency Eligibility* *(Equity Resiliency projects, Resiliency Adder projects, and projects opting into resiliency)*

Customer Resiliency Attestation - Energy Storage Projects [101] *(Equity Resiliency projects, Resiliency Adder projects, and projects opting into resiliency):*

A copy of the Customer Resiliency Attestation must be submitted including the following information to be provided by the Developer:

- Provide an estimate of how long a project's fully charged battery will provide electricity for the relevant facility average load during an outage.
- Indicate whether a project's critical loads can and will be isolated.
- Provide an estimate of how long the project's fully charged battery will provide electricity to critical uses during an outage.
- Provide an estimate of how long the project can operate in less-than favorable circumstances, such as if an outage occurs when the battery has been discharged or during the winter (if paired with solar).
- Summarize information given to the customer about how the customer may best prepare the storage system to provide backup power in the case of a PSPS or EPSS event announced in advance.
- Attest to the truth of the information provided.
- Provide an attestation from the customer indicating that they received this information prior to signing a contract.

Proof of Critical Facilities (*non-residential Equity Resiliency Budget and Resiliency Adder projects)*: The Program Administrators may request for proof of the type of critical facility the customer is claiming. The critical facilities that may require to submit proof are (including but not limited to):

- Cooling center designated by state, local, or tribal government
- Emergency operations center
- Location designated by an IOU to provide assistance during PSPS and/or EPSS events

Renewable Generation Projects

For generation projects applying for the Resiliency Adder incentive, it is required that generation:

- Provide an estimate of how long a project's generation system will provide electricity for the relevant facility average load during an outage.
- Indicate whether a project's critical loads can and will be isolated.

[101] A blank questionnaire form and optional Resiliency Attestation Tool can be downloaded from the Forms and Documents page of www.selfgenca.com. The Host Customer and Developer must sign the document after filling out the questionnaire.

- Provide an estimate of how long a project's generation system will provide electricity to critical uses during an outage.
- Provide an estimate of how long the generation system can operate in less-than favorable circumstances.
- Summarize information given to the customer about how the customer may best ensure operation of the generation system in the case of a PSPS or EPSS event announced in advance.
- Attest to the truth of the information provided.
- Provide an attestation from the customer indicating that he or she received this information prior to signing a contract.
- Demonstrate that an Authority Having Jurisdiction has approved plans showing that the system can operate in islanded mode, has inspected the system after installation, and has authorized operation.

Proof of Electric-Pump Well – Single Family *(Equity Resiliency Budget projects)*: Each electric pump well customer must submit the SGIP Electric Pump Well Attestation [102] that confirms the following:

- Site is the customer's primary residence.
- The customer does not have access to a public water source.

Documentation will also be requested at the discretion of the Program Administrator to verify the eligibility of the equipment. Acceptable documentation to verify eligibility may include (but is not limited to):

- Photographs of the pump and motor
- Photograph of the home and well
- A photograph showing the meter behind which the pump is installed and/or copy of the electric bill
- The pump is serving the residential load and is assigned a residential tariff

If a Program Administrator is unable to reasonably verify the presence and eligibility of the electric pump well, the project may be required to undergo an on-site inspection rather than be subjected to an inspection sampling by Developer.

Proof of Medical Baseline or Notification of Serious Illness or Condition – Single Family *(Equity Resiliency Budget projects)*: Each Medical Baseline customer and/or customer notifying their utility of a serious illness or medical condition that could become life-threatening in the event of an outage, must submit the SGIP Medical Baseline Attestation(s) that confirms the following:

  - Equity Resiliency Budget incentive will be used for energy storage equipment installed at the customer's primary residence; and

[102] Downloadable on Forms and Documents page of www.selfgenca.com.

- Customer is self-certifying that they have a serious illness or condition that could become life-threatening if service is disconnected.

The following documents may also be required to be submitted to show proof of Medical Baseline or Notification of Serious Illness or Condition:

- Documentation demonstrating that the customer has notified their electric utility that they have a serious illness or condition that could become life-threatening if service is disconnected
- Documentation from the electric utility demonstrating participation in a Medical Baseline program

12. ***Certification/Proof of Coordination with Local Government and California Office of Emergency Services*** *(Non-residential Equity Resiliency and Resiliency Adder applications)*

    Non-residential customers must demonstrate that they are coordinating with their local government and the California Office of Emergency Services if applying for Equity Resiliency or for a Resiliency Adder Incentive. Customers that cannot demonstrate this, will have their application deprioritized in favor of Applicants that can provide proof.

13. **Ineligibility for IRA Tax Credit** (*projects claiming ineligibility for IRA tax credit)*

    Provide documentation explaining why the project would be ineligible for the tax credit and why the credit could not otherwise be utilized or transferred by a third-party entity.

8.2 Proof of Project Milestone

Completed PPM Form and all required documents are due within 90 calendar days of the Conditional Reservation date for non-public entities, and within 240 calendar days for public entities (copy of RFP due within 90 days).

Completed PPM Form and all required documents are submitted to the Program Administrator. The Program Administrator reviews the PPM documents. Once the documentation has been approved, a Confirmed Reservation Letter is issued.

The Confirmed Reservation Letter will list the reserved incentive amount and the Reservation Expiration date (18 months after the date of the Conditional Reservation Letter). Upon project completion, and no later than the Reservation Expiration date, the completed Incentive Claim Form (ICF) must be submitted along with all the required documentation to request an incentive payment.

Required Documentation for Proof of Project Milestone

Three-Step Applications must provide a copy of the following:

Table 8.2: Proof of Project Milestone Requirements

Required Materials
1. **Online Proof of Project Milestone Form** *(all Three-Step projects)*
2. **Copy of RFP or Equivalent** *(public entity projects)*
3. **Copy of Executed Contract or Agreement for Installation** *(all Three-Step projects)* • Includes Required Warranty Documentation
4. **Proposed Monitoring Plan** *(generation projects >=30kW)*
5. **Proof of Fuel Contract and Documentation** *(generation projects)*

1. ***Online Proof of Project Milestone Form*** *(all Three-Step projects)* [103]

The Online PPM Form must identify if there are changes from the information that was presented in the RRF. If there have been changes from what was submitted in the RRF, the PPM Form must be signed by the Applicant and representatives with signature authority for both the System Owner and Host Customer (if not Host Customer). The online form must identify updated project information including the installation contractor's name, telephone number, and contractor license number. All systems must be installed by an appropriately licensed California contractor in accordance with rules and regulations adopted by the State of California Contractors State License Board (CSLB). [104]

If there have been no changes to the application from what was approved in the Conditional Reservation, a signed PPM Form is not required.

2. ***Request for Proposals Documentation*** *(public entity projects)*

Include Notice to Invite Bids, or similar solicitation issued for the installation, lease, and/or purchase for systems proposed for the SGIP. The RFP must include sufficient project details such as the scope of work, schedule, terms, budget, and/or system components desired. For Public Entities not issuing an RFP, alternative documentation such as an executed letter of intent to engage with a contractor on the Host Customer letterhead, an executed contract/agreement for system installation/lease, an equipment purchase order, or alternate System Ownership Agreement must instead be submitted within 90 calendar days of the date the Conditional Reservation Letter. PPM documentation must then be submitted within 240 days of the date of the Conditional Reservation Letter.

3. ***Executed Contract and/or Agreement for System Installation*** *(all projects)*

See section 8.1.1 #5 for more details.

4. ***Proposed Monitoring Plan*** *(generation projects >=30 kW)*

[103] Not required for Two-Step Applications as part of the Reservation Request Package.
[104] List of appropriate CSLB classifications can be found at www.selfgenca.com under the 'Forms and Documents' page.

The proposed monitoring plan should demonstrate the following components:

- **Description of the proposed SGIP system(s):** Description of the system(s) with an overview of the energy services to be provided (e.g., generation, waste heat recovery, storage) by the system(s) to the host site; the major components making up the system(s); and the general operating schedule of the system(s) (e.g., is it 24x7x365 or 10x6x365); the operating schedule is required to distinguish the system's intended operation as either a dispatchable or baseload generation resource. Include photos of the system(s) if available.

  Break out subsystems such as waste heat recovery systems to provide context for thermal energy metering systems. Provide similar descriptions for other important subsystems such as energy storage when combined with wind systems.

  A description of the existing load at the site and identification of the sources of the fuel that would be displaced by operation of the SGIP system(s) (i.e., electricity provided by XYZ utility or natural gas provided by ABC utility) and photos of the interface locations where the SGIP system would be located to displace the load.

- **Description of the metering system and metering approach:** An overview of the performance data to be collected (e.g., electrical, useful thermal energy, fuel consumption) and a simplified layout of the system showing major components (e.g., generator, waste heat recovery, storage) and location of the proposed metering points and data to be collected at those points (e.g., electrical, flow, temp, fuel) is required.
- **Description of the approach to be used for collecting, storing, and transferring the necessary performance data:**
  - The reasoning behind the selected metering points (for example, if useful thermal energy data is to be collected)
  - Frequency with which the data is to be collected (e.g., 15-minute intervals)
  - Data storage capability and approach for transfer of data (e.g., cell modem) and frequency of reporting to PDP (e.g., daily, weekly), which could also include frequency for reporting of data to Program Administrators (e.g., monthly)
- **Identification of the metering system components by performance data type (including manufacturer and model number):**
  - Electrical metering equipment (AC meters must be listed on the CEC's list of Eligible System Performance and Revenue Grade Meters to be found on https://solarequipment.energy.ca.gov/Home/MeterList
  - Thermal energy metering equipment
  - Fuel consumption metering equipment
  - Data acquisition (i.e., logger) system

5. ***Proof of Fuel Contracts and Documentation*** *(generation projects)*

- **Copy of Executed Renewable Fuel Contract** *(directed renewable fuel and hydrogen delivered via dedicated pipeline or vehicle):* The Contract should at a minimum include term (minimum of 10 years), cost, amount of renewable fuel injected or delivered monthly for the length of the contract, address of renewable fuel facility, location of pipeline injection site, name of pipeline owner, and facility address of Host Customer.

  The Program Administrator or designee has the right to audit and verify the generator's renewable fuel consumption upon request over the life of the contract.

  The Host Customer will consume the contracted renewable fuel for the sole purpose of fueling the SGIP project and the contract should include a forecast for the system's anticipated fuel consumption.

  Directed Renewable Fuel Contracts should include a quarterly true-up mechanism in which the customer and renewable fuel supplier agree to true-up based on actual deliveries of renewable fuel. Note that the fleet of SGIP systems will have its own revenue-grade, electric NGOM and gas meters that are accessible via internet by the Program Administrator or designee.

  - If less on-site fuel is consumed than renewable fuel is nominated into the pipeline, then parties agree to a financial make-whole provision.
  - If more on-site fuel is consumed than renewable fuel is nominated into the pipeline, then parties agree to a make whole provision, such that Customer Generator consumes renewable fuel, as measured annually.

- **Directed Renewable Fuel Attestation** *(directed renewable fuel and hydrogen delivered via dedicated pipeline or vehicle)*: Attestation letter from the Host Customer of the intent to notionally procure renewable fuel for the life of the system and attestation from the fuel supplier that the fuel meets the applicable renewable portfolio standard eligibility requirements for renewable fuel injected into a natural gas pipeline.
- **Renewable Fuel Use Affidavit** *(on-site renewable fuel including on-site hydrogen)*: Application documentation must include a signed affidavit that projects will not switch to non-renewable fuel. The Program Administrator has the right to audit and verify the generator's renewable fuel consumption upon request over the life of the SGIP contract.
- **Fuel Cleanup Equipment Purchase Order** *(on-site renewable fuel)*: When applicable, application documentation must include a purchase order for renewable fuel cleanup equipment that lists the fuel cleanup equipment as a separate invoice item.

8.3 Incentive Claim

Completed ICF and all required documents are submitted to the Program Administrator after the system is installed, interconnected, and operational. The Program Administrator reviews ICF documents and may schedule a site inspection. Upon PA approval, the incentive payment process begins. An upfront incentive payment will be issued, and (if applicable) the performance-based incentive (PBI) process begins.

Upon final approval of the Incentive Claim documentation and completed virtual or On-site Post-Installation Inspection (if the project is selected), the Program Administrator will issue a final ICF approval letter. The incentive payment will be made approximately 30 days after the final approval letter is sent. Payment(s) will be made to the assigned Payee as indicated on the ICF and will be mailed to the Payee address provided.

Required Documentation for Incentive Claim

SGIP applications must provide a copy of the following:

Table 8.3: Incentive Claim Requirements

Required Materials
1. **Completed Incentive Claim Form** *(all projects)*
2. **Proof of Authorization to Interconnect** *(all projects)*
3. **Building Permit Inspection Report** *(CSE and SoCalGas project applications)* • **AHJ Approved Grid Island Capable Plans** (*Equity Resiliency projects, Resiliency Adder projects, and projects opting into resiliency*) • **Air Permit Documentation** *(generation projects)*
4. **Substantiations:** • **New Construction or Expanded Load** • **Residential Projects Without Access to SGIP Approved TOU Rates** • **VNEM Projects** • **L-TES Post-Installation Monitoring Data** *(L-TES Projects that used Engineering Assumptions in lieu of Pre-Installation Data)* • **Renewable Fuel or Waste Resource** *(on-site renewable fuel and waste energy generation projects)* • **Fuel Cleanup Skid Cost** *(on-site renewable fuel generation projects)* • **Renewable Fuel Documentation/Contract Commencement** *(directed renewable fuel generation projects)* • **Renewable Fuel Metering Specifications** *(directed renewable fuel generation projects)* • **IRA Tax Credit Percentage Decrease Explanation** (TPO systems)
5. **Planned Maintenance Coordination Letter** *(combined heat and power generation projects >=200kW)*

Required Materials
6. **Final Monitoring Schematic** *(SCE, CSE and SoCalGas project applications)*
7. **RSSE Cost Verification** (*All RSSE applications Over 90% TEPC*)
8. **TEPC Attestation Form** (All RSSE applications Over 90% TEPC)

1. ***Online Incentive Claim Form*** *(all projects)*

   The ICF information must be complete, accurate and represent the actual system, project costs and/or fuel information as installed (including system size and type). It must also be signed by the Applicant, Host Customer, System Owner (if not the Host Customer), and Developer.

2. ***Proof of Authorization to Interconnect*** *(all projects)*

   Host Customers and/or System Owners will be required to execute certain documents such as, but not limited to, an "Application to Interconnect a Generating Facility" and a "Generating Facility Interconnection Agreement" with the local electric utility. A copy of the signed letter from their electric utility granting the Host Customer and/or System Owner permission to interconnect and operate in parallel with the local grid is required to be submitted as proof of Authorization to Interconnect. PG&E and SCE Applicants are exempt from submitting an interconnection Permission to Operate (PTO) letter as proof of Authorization to Interconnect. PG&E and SCE will verify interconnection internally during the ICF review. [105]

   Applicants, Host Customers, and System Owners are solely responsible to submit interconnection applications to the appropriate electric utility interconnection department as soon as the information to do so is available to prevent any delays in system parallel operation.

3. ***Building Permit Inspection Report*** *(CSE and SoCalGas project applications)*

   Include a copy of the final building inspection report (or proof of exemption) demonstrating that the project has been inspected by the local Authorities Having Jurisdiction (AHJ), meets all codes and standards of the permitting jurisdiction, and has been authorized for operation. Contact your local permitting jurisdiction to learn about permitting requirements. SGIP Applicants to PG&E and SCE are exempt from submitting a building inspection report provided that a final building inspection report is submitted to PG&E and SCE, respectively, in connection with the project interconnection, pursuant to PG&E's and SCE's respective interconnection requirements. For PG&E and SCE the building inspection report will be verified during the PTO process. [106]

[105] The Program Administrator may request, at their discretion, a copy of the interconnection Permit to Operate (PTO) letter to be submitted by the Host / System Owner.
[106] A Building Inspection Report can be required at PG&E's or SCE's discretion.

- **AHJ Approved Grid Island Capable Plans** *(Equity Resiliency projects, Resiliency Adder, and projects opting into resiliency):* These projects must also show that an AHJ has approved plans (e.g., single-line diagram) showing that the system can operate in island mode and identifying if the project's critical loads are currently isolated. If the AHJ has indicated that they do not stamp plans as part of their review process, it is necessary for the Applicant to substantiate that the plans have been reviewed by the AHJ as part of the process leading to the signing of the inspection report.
- **Air Permit Documentation** *(generation projects):* For those projects that require an air permit from the local air district, the application must include a copy of the final documentation indicating compliance with all applicable air pollution regulations (or proof of exemption).

4. *Substantiations*

- **New Construction or Expanded Load**: For projects where Host Customer estimated the future load to justify system size, applications must include documentation demonstrating that the load forecast has materialized.
- **Residential Projects Without Access to SGIP Approved TOU Rates:** Customers that do not have access to an approved TOU rate may submit documentation as part of the incentive claim package that demonstrates the system is compliant with either solar-only charging (defined as a battery that begins charging at dawn and continues charging from the solar unit until fully charged, and that never charges from the grid) or has set relevant storage parameters to the appropriate manufacturer-certified functionalities at the time of installation to enable solar-self-consumption mode (defined as systems charging from solar generation and discharging the stored power only to meet on-site load).
- **VNEM Project:** Proof that project complies with the applicable residential or non-residential operational and GHG emissions reduction requirements must be provided as referenced in Section 3.3.
- **Large Thermal Energy Storage Post-Installation Monitoring Data** *(L-TES Projects that used Engineering Assumptions in lieu of Pre-Installation Data):* For Projects where the Host Customer used simulation data to estimate baseload energy consumption Applicants must include monitoring of the operating parameters of the chiller system(s), while the L-TES system remains idle, during periods that occur during any 30 consecutive day period within the designated IOU summer period that contains at least nine days with a peak ambient air temperature of 90ºF or above, or within 10ºF of the peak ambient temperature in the TMY3 file for the project, with at least three of the peak temperature days being consecutive (See Section 9.1.4 & Appendix G for monitoring parameters).
- **Renewable Fuel or Waste Energy Resource** *(on-site renewable fuel and waste energy generation projects)*: For projects where the Host Customer, Applicant, or System Owner

provided renewable fuel estimates or waste energy resource estimates, applications must include documentation demonstrating that the on-site renewable fuel or waste energy resource has materialized.

- **Fuel Cleanup Skid Cost Documentation** *(on-site renewable fuel generation projects)*: On-site biogas projects must include documentation substantiating the fuel cleanup skid cost.
- **Renewable Fuel Documentation & Contract Commencement** *(directed renewable fuel generation projects)*: Provide documentation from the supplier showing that the fuel is renewable and that it meets the quality standards to be injected into the local natural gas pipeline. Documentation should also be submitted showing that the contract has commenced, and the supplier has begun nominating the renewable fuel into the pipeline (e.g., one-month fuel invoice). The project will be given up to one year from the date the Incentive Claim was received by the Program Administrator for commencement of the contract. However, no incentive will be paid until the contract has commenced.
- **Renewable Fuel Metering Specifications** *(directed renewable fuel generation projects)*: Documentation should also be provided to include make, model, specifications and serial number of installed revenue grade electric NGOM and gas meters.
- **IRA Tax Credit Percentage Decrease Explanation** (TPO systems) Provide documentation explaining why the IRA tax credit percentage decreased

5. ***Planned Maintenance Coordination Letter*** *(combine heat and power generation projects >=200kW)*

   When applicable, applications with microturbine, internal combustion engine, gas turbine, and steam turbine CHP systems sized greater than 200 kW must include a maintenance coordination letter to the Host Customer's electric utility. The maintenance coordination letter shows the System Owner will schedule planned maintenance only between October and March and, if necessary, only during off-peak hours and/or weekends during the months of April to September.

6. ***Final Monitoring Schematic*** *(SCE, CSE, and SoCalGas project applications)*

   <u>Energy Storage Projects</u>

   The final monitoring schematic is an electrical single-line diagram (SLD) that includes the energy storage system, the inverter, the utility meter, the load panel and, when applicable, the PBI meter and on-site renewable generator with which the energy storage system is paired. Documentation must also be provided if there is a change in the make and model of the meters to be used (from what was submitted with the Preliminary Monitoring Plan at the Reservation Request). SGIP residential applications in PG&E's service area are exempt from the final monitoring schematic requirement provided that: (a) the project utilizes equipment from the Verified Equipment List; and (b) a final

monitoring schematic is submitted in connection with interconnection of the project pursuant to PG&E's interconnection requirements. PG&E will verify the Final Monitoring Schematic internally. [107]

For PBI projects, the Applicant must also provide the name of the Performance Data Provider (PDP) they are contracting with. A copy of the contract between the PDP and the Applicant may be requested at the Program Administrator's discretion.

Renewable Generation Projects

The final monitoring schematic includes an electrical single-line diagram (SLD) that includes the generator, the utility meter, and the load panel, and if applicable, the PBI meter. CHP projects must also include a Process and Instrumentation Diagram (P&ID) that shows the configuration of the generator(s), heat recovery system, pumps, heat exchangers, and thermal load equipment as well as the fuel and thermal metering points. Documentation must also be provided if there is a change in the make and model of the meters to be used (from what was submitted with the Proposed Monitoring Plan).

For PBI projects, the Applicant must also provide the name of the Performance Data Provider (PDP) with whom they are contracting. A copy of the contract between the PDP and the Applicant may be requested at the Program Administrator's discretion.

7. ***RSSE TEPC Verification***

RSSE projects reporting a TEPC above 90 percent of the maximum SGIP incentive for the system's size, must submit required documentation outlined in Section 4.5.2.

If an applicant chooses to reduce the reported TEPC, or if the PA must reduce the TEPC for a project because costs cannot be verified, the applicant must submit an amended contract signed by the host customer showing the lower TEPC.

8. **TEPC Attestation Form**

RSSE projects reporting a TEPC above 90% of the maximum SGIP incentive, are required to submit the TEPC Attestation Form.

9 Metering & Monitoring Requirements

9.1 Electrical Metering Requirements

PBI projects must install metering and monitoring equipment that measures net electrical output or offset from the system(s).

[107] The Final Monitoring Schematic may be requested at PG&E's discretion.

9.1.1 Minimum Electrical Metering Requirements for Energy Storage & Generation Projects

Electrical meters installed on the SGIP project provide data used to assess performance of the system, to analyze impact of the SGIP system on utility distribution systems, the peak system demand of the utility, and net GHG emission impacts.

The following table lists the electrical metering requirements for generation projects (30 kW and larger), small non-residential thermal and electrochemical energy storage projects (less than 30 kW), and large non-residential thermal and electrochemical energy storage projects (30 kW and larger).

Table 9.1.1: Minimum Electrical Metering Requirements for Energy Storage & Generation Projects

System Type	General	Meter Type	Acceptable Electrical Metering Points	Meter Accuracy	Meter Measurement and Time Granularity of Acquired Data	Meter Testing and Certification	Meter Display
Large Non-Residential Energy Storage Projects (30 kW and Larger)	Applies to: • All systems 30 kW and larger • Storage projects paired with and charging from on-site renewable generators Metering must: • Determine the amount of net system energy charge and discharge • Allows the System Owner to support system O&M	• A separate Interval Data Recording (IDR) meter(s), or • A complete onboard system that is functionally equivalent to an IDR meter • Records data no less frequently than every 15 minutes • Meters and service panels must meet all local building codes and utility codes (1) • AC electrical meters must be on CEC approved meters list (2)	AC Meters: • Installed on the AC side(s) of the energy storage device • Account for power delivery to all parasitic loads including thermal management and power conditioning DC Meters: • Installed on the DC output side of the energy storage device • Account for power delivery to all parasitic loads including thermal management and power conditioning (3) TES Systems: • One or more meters • Measuring the rate and quantity of charge (in kW/kWh) • Measuring the rate and quantity of discharge (in kW/kWh offset)	± 2% of actual system output (4)	Must Measure: • Net charge energy • Net discharge energy • Instantaneous power • Account for ancillary loads Granularity: • Logged no less than every 15 minutes Must Generate: • An accurate time/date stamp	AC Meters: • Tested to ANSI C-12 • Pertaining to kW and kWh • Certified by NRTL DC Meters: • Pertaining to kW and kWh • Certified by manufacturer (5)	Must be Visible: • Net charge energy • Net discharge energy • Measured instantaneous power Location: • On the meter or • On a remote device (6)

Generation Projects (30 kW and larger)	Applies to:
	• All systems 30 kW and larger
	
	Metering must:
	• Determine the amount of net system energy production
	• Allows the System Owner to support system O&M
			Separate Interval Data Recording (IDR) meter(s) must:
			• Be installed at the output of the generator
			• Account for power delivery to all parasitic loads
			
			Onboard Meters must:
			• Have multiple channels monitoring:
			  ○ Parasitic loads
			  ○ Generator output
			• Have net generation output reporting
					Must Measure:
					• Net energy generated (kWh)
					• Net real power delivered (kW)
					• Account for ancillary loads
					
					Granularity:
					• Logged no less than every 15 minutes
					
					Must Generate:
					• An accurate time/date stamp
							Must be Visible:
							• Net energy output or offset
							• Measured instantaneous power
							
							Location:
							• On the meter or
							• On a remote device (6)

Small Non-Residential Energy Storage Projects (Less than 30 kW)	Applies to: • All systems less than 30 kW • With an on-board inverter-based meter • With an on-board DC-DC converter-based meter • Receiving a PBI incentive	• Meter must meet minimum meter requirements for the applicable size • May have additional meter functionality requirements	• Same as AC Meters, DC Meters and TES Systems listed above	± 3% of actual system output	Must Measure: • Net charge energy • Net discharge energy Granularity: • Logged no less than every 15 minutes Must Generate: • Accurate time/date stamp		Must be Visible: • Net charge energy • Net discharge energy • Measured instantaneous power Location: • On the meter or On a remote device (6)

Notes:

(1) There may be additional metering considerations for projects subject to Performance-Based Incentives (PBI) such as meters and service panels must meet all local building codes and utility codes. The meter serial number must be visible after installation.
(2) California Energy Commission (CEC) approved meter list: https://solarequipment.energy.ca.gov/Home/MeterList
(3) Power conditioning such as DC to DC power conversion.
(4) Pertains to all systems receiving a PBI incentive. Applies to on-board electrical meters as well as external IDR meters.
(5) In the case of onboard meters, the certification must come from the DC-DC converter manufacturer.
(6) For PBI, if a remote device is the only visible access, the PA may ask for verification.

9.1.2 Small Thermal Energy Storage Technologies

Small TES systems must measure electrical energy when charging. HVAC-integrated S-TES systems must monitor and report the power (kW offset) and energy (kWh offset) that would have been consumed by the HVAC unit to provide the same amount of cooling provided by the S-TES system by monitoring outside air temperature and when the S-TES system turned off the compressor of the HVAC unit.

9.1.3 Refrigeration Thermal Energy Storage Technologies

Refrigeration TES systems must report the power (kW offset) and energy (kWh offset) that would have been consumed by the refrigeration system(s) to provide the same amount of cooling provided by the Refrigeration TES system by monitoring the operating set points of the refrigeration system(s), cooling load on the refrigeration system(s), and when the Refrigeration TES system turns off the compressor(s) and condenser(s) of the refrigeration system(s).

9.1.4 Large Thermal Energy Storage Technologies

Large TES systems must report the power (kW-AC offset) and energy (kWh-AC offset) that would have been consumed by the chiller system(s) to provide the same amount of cooling provided by the L-TES system by monitoring the operating parameters of the chiller system(s), which are described below during periods that occur during any 30 consecutive day period within the designated IOU summer period that contains at least nine days with a peak ambient air temperature of 90ºF or above, or within 10ºF of the peak ambient temperature in the TMY3 file for the project, with at least three of the peak temperature days being consecutive. Pre-monitoring should occur no greater than 18 months prior to the installation of the L-TES system. This data will be supplemented with post-installation data collected from the Host Customer’s facility at times during the L-TES idle periods and will include the winter and shoulder seasons in order to provide any necessary calibration of the baseline over the first year of operation.

If the chiller system(s) is being replaced along with the installation of the SGIP L-TES system making pre-install data of the new chiller not yet available at the time of RRF submission it is acceptable to estimate the kW/kWh offset of the TES system that will be paired with a newly installed chiller, with a building simulation model that uses 1-in-10-year ASHRAE temperature data. This estimate can be used to reserve the incentive and can then be verified at ICF, before releasing upfront payment, by pausing operation of the LTES system to collect monitoring data that includes the operational characteristics of the new chiller and using the approved UC Davis methodology (as outlined in Appendix F).

Exceptions: Should the timeline of the application not provide for the availability of one consecutive summer month of pre-installation data, the Applicant may request an exception to this requirement. Exceptions will be reviewed on a case-by-case basis by the PA and may require the L-TES system operation to be paused to confirm the application is sized correctly or to confirm baseline assumptions. Similarly, if monitoring data is deemed insufficient or missing, the PA may also request supplemental data from the Applicant.

See Appendix G for a list of pre- and post-installation monitoring parameters.

9.2 Thermal & Fuel Metering Requirements

SGIP generation technologies must measure fuel input into the generator(s). Additionally, CHP technologies must also install metering and monitoring equipment that measures and reports useful thermal energy delivered to the site from the CHP system.

The following table lists the thermal and fuel metering requirements.

Table 9.2: Thermal & Fuel Metering Requirements

Meter Type	General	Meter Type	Acceptable Metering Points	Meter Accuracy	Meter Measurement and Time Granularity of Acquired Data
Thermal	Applies to: • All CHP systems 30 kW and larger Metering must: • Determine amount of useful thermal energy production • Allows the System Owner to support system O&M • Assess thermal performance (7) • Assess impact of system on net GHG emission impacts and minimum system operating efficiency requirements (8)	• CHP systems that are 300 kW and smaller can use an on-board thermal metering system • Instrumentation to measure thermal energy production will vary depending on configuration and type of heat recovery system (9) • Common flow measuring devices: insertion type or ultrasonic flow meters • Temperature measurement can be done with thermocouples • Proposed meter and sensor types to be identified in Monitoring Plan for each individual project	• Proposed meter locations to be identified in Monitoring Plan for each individual project • Recommended for direct exhaust combined cooling heating and power (CCHP) systems that chilled water output, instead of measuring exhaust flows and temperatures, to calculate the useful thermal output	• ± 5% at design conditions and applies to both on-board and external metering systems • Monitoring system maintenance plans to be identified in Monitoring Plan to ensure compliance with accuracy requirement throughout the PBI period	Must Measure: • Useful heat recovery system performance/output data points (10) Granularity: • Data logged once every 15 minutes • Calculated values reported once every 15 minutes Reporting: • Heat transfer fluid specific heat and density reported at time of commissioning and reported again to PA if there is a change Must Generate: • An accurate time/date stamp
Fuel	Applies to: • All generation technologies 30 kW and larger (regardless of renewable fuel type) Metering must: • Determine the amount of renewable fuel consumption • Allows the System Owner to support system O&M	• Generation technologies that are 300 kW and smaller may use an on-board fuel metering system to minimize costs • Must measure fuel consumption by the generator • Proposed meter type to be identified in Monitoring Plan for each individual project External fuel gas flow measurements are typically done in one of three ways: 1. Mass flow meter 2. Calculated based upon continuous differential pressure measurements across an orifice 3. Utility gas meter	• Proposed meter locations to be identified in Monitoring Plan for each individual project External metering: • Before renewable fuel entry into the generator but downstream of any other loads On-board metering: • Fuel metered before any portion is consumed by the generator On-site renewable fuel projects: • Separate meters needed for the renewable fuel	Flow measurement must include: • Temperature and pressure compensation • Standard cubic feet (at 60°F and 1 atmosphere) Accuracy: • ± 5% of maximum flow for the generator at design conditions	Must Measure: • Generator system fuel input data points Granularity: • Data logged once every hour • Calculated values reported once every hour Units: • Recorded in standard cubic feet per minute Reporting: • Btu content and basis (HHV/LHV) of fuel reported during commissioning either through data provided by the gas company or determined by analysis and reported again to PA if there is a change Must Generate: • An accurate time/date stamp

Performance Notes:

(1) Includes assessing ability to meet on-site thermal energy demands (offsetting consumption of fossil fuels) and meet thermal energy efficiency requirements prescribed by Public Utilities Code 216.6.
(2) Thermal energy metering systems may also provide System Owners with a potential means of verifying carbon emissions and carbon emission reductions.
(3) Examples of heat recovery systems include: liquid, steam, and direct exhaust.
(4) The sum of four consecutive intervals would represent the industry standard rate of Useful Heat Recovery in units of MBtu/hr.

10 Performance Monitoring and Reporting Services for Solar Systems

Performance Monitoring and Reporting Service (PMRS) requirements were developed to increase owner knowledge of system performance and foster adequate system maintenance to ensure incentives result in expected levels of solar generation. PMRS is required for all multifamily solar projects, regardless of system size. The System Owner must contract with a PMRS provider for a minimum of 10 years to ensure transparency of the system's production for the Host Customer via login credentials to inverter original equipment manufacturer (OEM) or equivalent production software at the Incentive Claim stage. The Host Customer must attest on the Incentive Claim Form that they have secured a 10-year PMRS contract, and the PMRS provider name must be listed on the form. The SGIP PA reserves the right to request a copy of the PMRS agreement if needed. Additionally, Applicants must provide 15-minute interval production data to the SGIP PA via login credentials to inverter original equipment manufacturer (OEM) or equivalent production software at the Incentive Claim Milestone. A list of eligible PMRS providers may be found on the Go Solar CA website: https://www.energy.ca.gov/media/3770
Solar developers must use the California Distributed Generation Statistics public reporting site for incentivized projects.

11 Performance Data Provider (PDP)

It is the responsibility of the System Owners to contract with a Performance Data Provider (PDP) for a minimum of five years. This section describes the requirements for all new non-residential applications data reporting, PDP application process, data security, and measurement and evaluation activities.

11.1 Application Process

Any entity may choose to become a Performance Data Provider for the SGIP. Providers interested in becoming a PDP for the SGIP must submit information detailing their qualifications to become a PDP for the program. All PDPs must meet the requirements established herein in addition to the requirements set forth in the other metering sections of the SGIP Handbook. Interested parties may apply to qualify as a PDP for the SGIP program at any point in time.

To apply to qualify as a PDP, the Applicant completes the SGIP PDP Application and provides all documentation in the attached questionnaire.[108] Note that the PDP Applicant may submit one application for statewide PDP services to any of the Program Administrators. The Program Administrator will review the submitted documentation, determine if the PDP Applicant meets the program requirements and send the PDP Applicant a conditional approval letter if all requirements are met. Upon conditional PDP approval, the Applicant may contact the SGIP online application database provider to set up an account for the PDP Upload Portal.

11.2 Data Transfer Test

Once the prospective PDP has accumulated a month worth of data for the first SGIP project, they must contact the SGIP online application database provider to schedule a data transfer test. The prospective PDP must create, format, and validate Application Interval and Meter Interval Reports for all types of data services they are applying for (electrical, thermal and fuel, and/or energy storage) and submit the test files to the SGIP online application database via the PDP Upload Portal.

The Program Administrator will check the test files to ensure they comply with the SGIP guidelines. If the PDP Applicant fails the data transfer test and report approval, they will be given 2 weeks to resolve any technical or data format issues. Upon successful completion of the PDP data test procedures, the PDP will receive a final approval notice and will be qualified to provide PBI data to the Program Administrator for incentive payment.

11.3 Metering Requirements

Host Customers must install and maintain metering and monitoring equipment at their own cost and are responsible for the choice and installation of the metering hardware. For new non-residential projects 30 kW and larger, all AC electric meters must be listed on the CEC's list of Eligible System Performance and Revenue Grade Meters to be found on https://solarequipment.energy.ca.gov/Home/MeterList. New non-residential projects less than 30 kW must comply with the meter standards in Section 9.

PDPs will be tasked with recording performance data from the installed metering and monitoring equipment and submit it to the Program Administrators on a monthly basis.

[108] Please refer to The PDP Specification and the Program Administrators' websites for the PDP Application and detailed application instructions.

All installed electrical meters must fulfill the following requirements:

- Protocols for the minimum required performance/output data must enable any PDP to communicate with the meter and obtain the minimum required performance/output data from the meter and/or logger.
- All meters must have the capability to report their data remotely.
- Data reporting must occur on a daily basis.
- All meters must have the ability to retain collected data in the event of a power outage. Meters must have the capability to store seven days' worth of data.
- All meters must provide the PDP provider or defined list of authorized users with the ability to access and retrieve the minimum required data from the meter using the Meter Communication / Data Transfer Protocols described in Section 11.3.
- The meters will be inspected as part of the project inspection process.

11.4 Data Reporting and Transfer Rules

It is the responsibility of the System Owners to contract with a Performance Data Provider (PDP) and ensure that performance data is provided to the Program Administrator or their designee monthly for five years. A list of qualified PDPs can be found on www.selfgenca.com.

The following are the PDP's primary responsibilities:

- Manage meter reading/data retrieval schedule.
- Read and retrieve performance meter data.
- Post data on appropriate Program Administrator server on a consistent and reliable schedule, per Program Administrator requirements.
- Validate performance data prior to providing to the PA using the approved validation rules outlined in this document.
- Calculate annual production of generating system and net electrical energy discharged or offset for energy storage systems for incentive payment.
- Format data using an approved SGIP format.
- Troubleshoot and resolve communications issues.
- Store data in accordance with program requirements.
- Make historical performance data available to Program Administrators as requested.
- Provide technical support to Program Administrators as well as customer support.

- Communicate meter/device changes to the Program Administrator.
- Provide disaster recovery and data backup services as requested by respective Program Administrator.
- Manage data on PDP server.
- Ensure confidentiality of customer information and performance data.
- Possess technical expertise and capability.
- Comply with all State and Federal laws.

The purpose of the following section is to outline the data reporting requirements (format, delivery method) and schedule for submitting data reports to the Program Administrators.

11.4.1 Data Format

Meter data must conform to the SGIP program requirements as set forth in Section 11 (15-minute electrical and thermal data as well as hourly fuel data, when applicable).

The PDP is responsible for submitting the incoming meter data to the Program Administrators on a monthly basis in the following two formats: Meter Interval Report and Application Interval Report. The Application Interval Report will be used for calculating the Annual Performance-Based Incentive payments. The Meter Interval Report will be referenced as needed to support the data submitted for payment processing in the Application Interval Report. Both file types may be used for reporting and/or auditing purposes. [109]

The data file format for submission will be ".csv." The file formats are designed for bulk submission of data for any number of applications in a single calendar month. However, the file types (Meter Interval and Application Interval) must be submitted in separate files. If a Performance Data Provider is contracted to report data for more than one Program Administrator, they shall submit a separate file for each Program Administrator to maintain the confidentiality of the data.

11.4.2 Meter Reading and Data Submission Timeline

Meter data will be read remotely no less frequently than on a daily basis. In the event there is a communication problem between the PDP and the meter, and the 15-minute interval data is accumulated over a 24-hour period, it is acceptable to estimate the meter's 15-minute interval data. For more information, refer to The PDP Specification. Accumulated data for a period longer than 24 hours will not

[109] For a detailed description of the Meter and Application Interval Reports and submittal processes, please refer to The PDP Specification.

be accepted. Other than this exception, the Program Administrator is not responsible for, and will not pay any customer incentives based on missing, estimated, or invalid performance data.

Data for a SGIP project must be submitted in full calendar months. Once a month of data has been collected, the PDP has up until the 1st of the following month to validate, format, and submit the Meter and Application Interval data for that project. Annual PBI Payment amounts will only be processed after a full year of data has been submitted for the project.

For new SGIP projects, data recording for PBI Payment purposes should typically commence on the 1st of the month following the initial 50% Incentive Payment. Customers may choose to submit data since interconnection, if interconnection has occurred within the past six months. Any request for an alternate data collection commencement date will require Program Administrator approval.

11.4.3 Online Submission Process

All performance data will be submitted via the SGIP online application database PDP Upload Portal. The portal will be accessed through www.selfgenca.com. Files that are submitted via email will not be accepted. [110]

11.4.4 PDP Data Validation

The PDP must validate all data prior to submitting it to the PAs. The following data validation rules shall apply:

- Time Check of Meter Reading Device/System (all)
- Meter Identification Check (all)
- Time Check of Meter (all)
- Pulse Overflow Check (if applicable to metering system)
- Test Mode Check (if applicable to metering system)
- Sum Check
- Spike Check
- kVARh Check

Descriptions of these validation rules are included in The PDP Specification.

11.4.5 Data Audits & Payment Validation

The Program Administrators may, at their discretion, perform validations on incentive payments prior to issuing payments to customers participating in this program. The validations will compare actual yearly incentive payments with expected payments based on design specifications and expected performance data submitted with the approved incentive reservation documentation. If payments fall outside expected

[110] Please refer to The PDP Specification for a detailed description of the data submittal process.

ranges for the year, the incentive payment will be withheld until the Program Administrator determines to its satisfaction the reason for the discrepancy.

The PDP will work with the System Owner to resolve any discrepancies identified by the Program Administrator, which may include testing and/or recalibrating the meter/devices if deemed necessary. The Program Administrators are not responsible for the costs associated with investigating and resolving any such discrepancies (e.g., testing, meter replacement hardware, installation labor). However, if the Program Administrator requests an investigation that finds that the metering system is accurate, the Program Administrator will pay all reasonable and necessary costs for the investigation.

The Program Administrator may also perform random audits of PDP data to ensure accuracy and compliance with the requirements outlined in this document, or as part of the SGIP Measurement and Evaluation Program in accordance with the SGIP Handbook. Any PDP found to be in violation of any of these requirements will be subject to the penalties outlined later in this document. The Program Administrator, via the servicing local utility or its designated contractor may, at its discretion, inspect and test the performance meter or install separate metering in order to check meter accuracy, verify system performance, or confirm the veracity of monitoring and reporting services.

Any additional metering installed by or at the request of the Program Administrator will be paid for by the Program Administrator. However, in the event metering is installed during the course of an audit or investigation initiated by the Program Administrator where cheating or tampering is suspected and confirmed, the System Owner will be charged for these costs.

11.4.6 Performance Exemptions

The PDP is responsible for meeting the above noted program requirements and for consistently posting performance data in accordance with the Program Administrator's scheduling and data posting requirements. At its discretion, the Program Administrator may grant reasonable allowances for occasional issues or technical problems, as well as for large catastrophic events such as earthquakes.

11.4.7 Non-Performance

The Program Administrator will not issue incentive payments to customers based on estimated data from the PDP, nor will the Program Administrator estimate incentive payments under any circumstances. It is the PDP's responsibility to ensure timely and accurate posting of validated performance data so customer incentive payments can be made. Performance data also includes fuel consumption and useful thermal output data as this information will be used to verify compliance with program rules and impact PBI payments.

The following conditions may result in penalties, suspension of activity, or revocation of PDP approval from the Program Administrator:

- Data not posted by specified date
- Data not validated in accordance with program requirements

- Estimated data posted instead of actual data
- Meter change information not reported within 30 days of the meter change
- If an audit or investigation shows a discrepancy of ± 5% between the PDP reported data and Program Administrator check meter production data for one data report period. This discrepancy will trigger an audit schedule set by the Program Administrator for the PDP.

The PDP will be given a reasonable opportunity to correct problems identified by the Program Administrator. The Program Administrator will work with the PDP to correct any such problems and avoid unnecessary delays in issuing incentive payments to customers, to the extent feasible.

Upon receipt of a non-performance notice from the PA, the PDP must, as soon as reasonably practicable:

1. Perform a root-cause analysis to identify the cause of such a failure.
2. Provide the PA with a report detailing the cause of, and procedure for correcting such failure within three days of completion of such root-cause analysis.
3. Implement such procedure after obtaining the respective PA approval of such procedure.

PDP Providers that fail to submit data to the Program Administrators when requested by the PA or an authorized agent of the CPUC may be removed as an eligible PDP from the Program Administrators' approved list. It is the Host Customer and/or System Owner's responsibility to ensure the transfer of production data from the Performance Data Providers (PDP) to the Program Administrators. The System Owner is responsible for resolving any issues relative to PBI and PDP performance data.

Should the PDP disagree with a PA decision regarding a penalty, the PDP has the right to appeal to the SGIP Working Group for further consideration.

11.4.8 Data Retention

Monthly performance data must be retained in accordance with program requirements. The PDP must be prepared to post historical interval data at the Program Administrator's request. The Program Administrator audit will include raw interval data, which is to be maintained by the PDP for comparison with validated interval data transmitted to the Program Administrator. The PDP is also responsible for providing backup and disaster recovery services for 100% of the data.

11.4.9 Technical and Customer Support

The PDP must provide a technical support number to the Program Administrator for use during normal business hours (8 a.m. to 5 p.m. Pacific Time, Monday through Friday, except holidays) to help resolve any data availability, format or corruption issues, communication problems, server access problems, or other technical issues. Within those normal business hours, the PDP must respond to Program Administrator requests within two business days with a status report and plan for correcting the issues. The PDP must also provide a customer support number to respond to customer inquiries within two

business days from the initial customer contact. Program Administrators will have the discretion to set deadlines for the resolution of data transfer problems/issues.

11.4.10 Program Administrator Liability

Apart from the requirements identified herein, the PAs are not liable for the performance or non-performance of a PDP that may result in a delay of or incorrect amount of a PBI payment. The Program Handbook defines the criteria required for PDPs to participate in the Program only.

11.5 Data Privacy and Security

Protecting the privacy of System Owners and Host Customers is of the highest order. As such, data shall be collected, processed, and reported by the PDP to the System Owner and the Program Administrator in accordance with this section. The PDP is responsible for ensuring timely, consistent, and accurate reporting of performance data. Data must be located in a secure facility, on a secure server, and have firewall and equivalent protection. The PDP must protect the confidentiality of the customer information and performance data in accordance with all program guidelines. The PDP must also follow all applicable state and federal privacy and data security laws.

The PDP may provide data to third parties, including Contractors and Host Customers (if different than the System Owners), provided the System Owner has consented in writing to the release of such performance data. Electricity, thermal, and fuel meters shall be kept secure from Denial of Service (DOS) Attacks, Port Scanning, Unauthorized Access, and other security violations. To achieve this security, Communications Interfaces to all meters must be located in a physically secure location and include strong password protection with either a network firewall or encrypted connection to limit the meter's network access to the PDP and/or a defined list of authorized users. In addition, security measures may be implemented as needed to ensure data security including restriction of direct meter access for real time data to sequential access basis.

12 Measurement & Evaluation (M&E) Activities

As a condition of receiving incentive payments under the SGIP, System Owners and Host Customers agree to provide full access to site and system equipment and participate in Measurement and Evaluation (M&E) activities as required by the CPUC. M&E activities will be performed by the Program Administrator or the PA's independent third-party consultant and include, but are not limited to, periodic telephone interviews, site visits, review of documentation submitted by the project Developer or host site, installation of metering equipment or review/inspection of metering equipment installed by the project Developer or host site, collection and transfer of data from installed system monitoring equipment, whether installed by Host Customer, System Owner, a third party, or the PA. This data will be used to show the performance

of technologies by class (e.g., wind turbines) and may determine the performance of those technology classes as they see fit. Performance data from specific projects, however, will remain confidential. Energy Division, in consultation with the SGIP Working Group shall set an annual deadline for data submission for developers or manufacturers to ensure timely reporting well in advance of program evaluations. Once established, the date will be communicated to the developers or manufacturers by the evaluator.

12.1 M&E Field Visits

During the course of the project, the PA or the PA's independent third-party consultant may require one or more visits to the site for M&E purposes. These site visits can occur before, during, or after startup of the system for the purposes of developing a monitoring plan, installing additional M&E instrumentation, performing equipment operations inspection, and retrieving system data. These visits are separate and distinct from the Post-Installation Inspection visits by the PA or its consultants (see Section 2.1.1.3), which are used to determine eligibility of the installed system and occur during the Incentive Claim stage of the application process.

12.2 M&E Metering Requirements

All SGIP systems require installation of metering devices to measure and record electrical output or offset, waste heat, and fuel consumption for M&E purposes. The PAs may collect this information from the data submitted by the Performance Data Providers (PDP) for projects subject to PBI payments. For non-PBI projects, the PA or the PA's independent third-party consultant may install meters to collect M&E data at the Program's expense.

The Host Customer and System Owner agree to provide system monitoring data (15-minute interval data for electrical and thermal and hourly for fuel consumption) to the SGIP M&E consultant on a monthly basis as required by the CPUC.

12.3 Disposition of SGIP Metering Equipment

Upon completion of the SGIP M&E metering activities at the site, the Program Administrator will offer all M&E metering equipment installed by the Program to the System Owner for transference. The Program Administrator will provide an Equipment Transfer Agreement with a schedule of the SGIP M&E equipment located at the site. The Equipment Transfer Agreement must be signed by both the System Owner and the Program Administrator. If the System Owner does not wish to accept the M&E metering equipment, the Program Administrator or its independent third-party consultant will remove the M&E metering equipment. The Program Administrator shall pay the costs for the meter removal.

13 Dispute Resolution

All participants shall attempt in good faith to resolve any dispute arising out of, or relating to, this transaction promptly by negotiations between the Program Administrator or their designated representative and the Host Customer, System Owner, and/or Applicant or their designees. Either party must give the other party, or parties, written notice of any dispute. Within 30 calendar days after delivery of the notice, the parties shall meet, and attempt to resolve the dispute. If the matter has not been resolved within 30 calendar days of the first meeting, any party may pursue other remedies including mediation. All negotiations and any mediation conducted pursuant to this clause are confidential and shall be treated as compromise and settlement negotiations, to which Section 1152.5 of the California Evidence Code shall apply. Notwithstanding the foregoing provisions, a party may seek a preliminary injunction or other provisional judicial remedy if in its judgment such action is necessary to avoid irreparable damage or to preserve the status quo. Each party is required to continue to perform its obligations under this Contract pending final resolution of any dispute arising out of, or relating to, this Contract.

14 Participant Performance and Infractions

14.1 Participant Performance

All participants [111] are expected to follow program rules and eligibility requirements. Additionally, SGIP participants (including host customers, applicants, developers, and manufacturers) receiving AB 209 incentive funds are subject to all program and reporting requirements set by the Commission in its oversight role of funds allocated by the Legislature under the Greenhouse Gas Reduction Fund. This includes fulfilling requirements developed by CARB for state agencies that administer these funds. [112] Failure to do so will result in warnings and/or infractions. Please see Section 14.2.1 for additional information regarding warnings and infractions. Program Administrators will exercise their judgment in issuing warnings and assessing infractions.

In an effort to ensure participant performance, all participants will be required to maintain a high level of performance in each of the following categories:

Table 14.1: Participant Performance

Category	Compliance Issue

[111] For the purpose of this section, participant is defined by an entity or group of entities submitting applications, data, or developing and/or installing SGIP projects.
[112] CARB Funding Guidelines for California Climate Investments, https://ww2.arb.ca.gov/sites/default/files/auction-proceeds/2018-funding-guidelines.pdf)

Application	• Providing purposefully incomplete, falsified, or inaccurate information • Missed deadlines • High attrition rate from cancelled or withdrawn projects • Excessive extension requests • Missed project milestone deadlines
Inspection	All projects: • List of compliance issues for inspections can be found in the Field Inspection Sampling Protocol [113] • Any unavailability for site inspection(s) [114]
	Generation Directed Renewable Fuel Projects Only: • Unavailable for periodic, random, no-warning spot-check inspections of directed biofuel sources • Findings from periodic, random, no-warning spot-check inspections of directed biofuel sources do not comply with SGIP
Data Reporting	• Past due submission of operational and performance data
	• Falsified, blank, or no submission of operational and performance data
SGIP Online Application Database Operation	• Non-compliance with SGIP database Terms of Use • Circumvention of application policies or procedures
Developer	• Developer does not fully and/or accurately disclose Developer and ownership information [115]

[113] Field Inspection Sampling Protocol can be located on www.selfgenca.com.
[114] Inspection may take place anytime during project's permanency period.
[115] See Section 3.6 for more details.

Residential GHG Emissions Compliance	Developers for Non-IOU Residential Customers Only: • Failure to produce documentation regarding customers' systems, rates, and charge and discharge patterns upon request All Developers: • If a Developer does not provide information within requested timeframe, they will receive an infraction. Any Developer with more than two infractions are subject to a six-month suspension. An exception to the GHG emissions compliance enforcement actions can occur when a developer has declared bankruptcy or gone out of business, and provided that the CPUC has approved the exception through the disposition of a Tier 2 Advice Letter submitted by the PAs. • For any new residential fleet that reports increased GHG emissions for two consecutive six-month periods, the Developer will be suspended for six months or until verified to be reducing GHG emissions, whichever is later. During which time, the Developer will also be required to bi-annually submit GHG emissions data for all projects in fleet until verified to be reducing GHG emissions. [116] • New Developers verified as having increased GHG emissions for submitting less than 90% of the meters of new fleet may be suspended for one year.

14.1.1 File Retention

Although "wet" signatures are not required on submitted documents, original signed documentation must be retained by the Applicant, Host Customer, and/or System Owner for at least five years from the date of submission. Program Administrators reserve the right to request original signed documents within the five-year period.

14.2 Infractions

Infractions are any actions that circumvent program policy or requirements, or have the intent to do so, in addition to low performance levels. Infractions can be issued to any participant, as defined in Section 3. The Program Administrators or Energy Division will evaluate program infractions, which may include

[116] Submit via the SGIP database.

gross negligence or intentional submission of inaccurate project information. Program infractions may be determined at any stage of the SGIP process and are applicable statewide. If it is determined that a program infraction has been committed, a reasonable sanction shall be imposed. The following sanctions may be applied:

- Suspension or expulsion from future program participation
- Cancellation of existing projects
- Application fee forfeitures
- Fiscal or programmatic audits

14.2.1 Issuance of Warnings and Infractions

If a Program Administrator determines that an infraction may be warranted, a notice will be sent to the violating participant. Participants may be issued one or more warnings before being issued an infraction; however, serious violations may result in an immediate infraction. Participants may receive no more than three warnings before an infraction is issued.

For renewable fuel generation projects, the Program Administrators will issue a single 30-day warning when renewable fuel use documentation is not provided as required or a verification spot-check of the directed biofuel source reveals a lack of compliance with SGIP requirements. Failure to bring the project into compliance within 30 days of issuance of the warning will result in the issuance of an infraction (excluding imposition of a fiscal or programmatic audit as a sanction).

All infractions will be reviewed by all Program Administrators and will be communicated to the participant. Notwithstanding any of the above, Energy Division may initiate an investigation of potential infractions, which may result in a penalty for any infraction determined to have occurred.

15 Program Modification Guidelines

For the consideration of new technologies and/or SGIP rule changes, the following Program Modification Guidelines as outlined in Decision 03-08-013 should be followed:

All Program Modification Requests (PMRs) must be submitted in writing, using the current PMR format to the SGIP Working Group for review at least 10 business days prior to the SGIP Working Group meeting or the request will roll over to the next monthly SGIP Working Group meeting.

All parties requesting a program modification will be required to meet with the SGIP Working Group during a monthly SGIP Working Group meeting to determine if the SGIP Working Group would support the PMR.

The SGIP Working Group will first determine whether or not the proposed PMR requires a modification to a prior Commission Decision. If the PMR is minor and non-substantive and does not require modifications to prior Commission orders, then:

- The SGIP Working Group will review the PMR. If accepted, the SGIP Working Group will make the appropriate changes to the Handbook.
- If the SGIP Working Group needs more information, the party proposing the PMR would have the opportunity to present at the following SGIP Working Group meeting with additional information which supports its request for a program change.
- The SGIP Working Group will make a decision to accept or deny the PMR based on the new information presented in the follow-up presentation.
- The proposed program changes and the SGIP Working Group recommendation(s) and rationale will be captured in the SGIP Working Group meeting minutes.
- If the party objects to the SGIP Working Group's decision to deny the PMR, the party may write a letter to Energy Division stating why their program change should be included in the SGIP. Information that supports the party's reasons to accept the program change must be included in the letter.
- Energy Division will then make a final decision on whether to approve the PMR.
- Energy Division will report its final decision at the following SGIP Working Group meeting, which will be captured in the SGIP Working Group meeting minutes.
- If the PMR is accepted, appropriate revisions to the SGIP Handbook will be made.

If the proposed change requires modification to a prior Commission order or if the PMR addresses large programmatic or substantive issues, then:

- The SGIP Working Group will review the PMR and make a recommendation to support or oppose the PMR in the same meeting.
- The SGIP Working Group recommendation and rationale will be captured in the SGIP Working Group meeting minutes.
- Subsequent to the meeting, the SGIP Working Group will write up a summary of the discussion of the PMR at the SGIP Working Group meeting, a list of comments in support or against the PMR, as well as the SGIP Working Group's overall recommendation with rationale, which will be presented to the Applicant.
- The party proposing the PMR has the choice to move forward and submit a Petition for Modification (PFM) for Commission review regardless of the SGIP Working Group's recommendation, but the SGIP Working Group's summary must be included in the PFM.
- The Energy Division participates in SGIP Working Group meetings and is welcome to participate in the discussion related to the PMR as well as in generating the "list of issues." The Energy

Division does not need to participate in the recommendation portion of the SGIP Working Group's PMR review.

- Once the PFM is filed with the Commission, the normal PFM process will transpire, only it will have the benefit of the idea being somewhat vetted before submittal. All parties have a chance to respond to PFMs according to the Commission's Rules of Practice and Procedure.
- The Commission will review and address the PFM in a Decision.

16 Third-Party Ownership Consumer Protections

To ensure adequate consumer protections for Host Customers participating in SGIP under a TPO model, the CPUC has adopted protections as guidance that a Developer must follow for TPO projects.

TPO Consumer Protections for SGIP:

1. Cover maintenance (includes, but not limited to, system support, problem diagnosis, on-site repair, and preventive maintenance), operations, inverter replacement, and monitoring;
2. Ensure that all costs are apparent and upfront and that there is no risk that the TPO deal would result in an additional financial burden to the customer (i.e., additional or hidden costs outside of what is agreed upon upfront in the sales contract, such as penalties for non-payment not previously disclosed);
3. Protect the customer against terms that could change after contract signing;
4. Require that TPO agreements note the potential for additional costs associated with the contract, if applicable;
5. Require the TPO provider to clearly explain that rate changes will affect the economies of a power purchase agreement or "PPA" (e.g., the financial impacts of a new successor tariff may have a different economic proposition; or impacts from rate escalators built into PPAs);
6. Require that TPO agreement include provisions that the TPO will notify the Host Customer in the event that the company owning the system defaults.

Definitions and Glossary

Alternating Current (AC): Electric current that reverses direction, usually many times per second. AC is the opposite of direct current (DC). Most electrical generators produce AC.

Amp-hour Capacity or Nominal Capacity (Ah for a specific C-rate): The total Amp-hours available when the battery is discharged at a continuous current over a specified period of time (specified as a C-rate) from 100% state-of-charge to a specified cut-off voltage.

Applicant: The entity, either the Host Customer, System Owner, or third party designated by the Host Customer responsible for the development and submission of the SGIP application materials. Functions as the main point of communication between the SGIP Program Administrator for a specific SGIP application.

Application Interval Report: Monthly meter data report provided by the Performance Data Provider (PDP). The Application Interval Report format will be the same for all PDPs and all applications as specified by the Program Administrators. The data in this file will be validated upon upload and used for the calculation of Annual PBI payments. An Entry in this file shall represent the combined data readings of all meters associated with a particular SGIP Application Code.

Azimuth: Horizontal angular distance between the vertical plane containing a point in the sky and true south. All references to azimuth within the SGIP, unless expressly stated otherwise, refer to true, not magnetic, azimuth.

Backup Generators: Operate as short-term temporary replacement for electrical power during periods of electric utility power outages. In addition to emergency operation, they ordinarily only operate for testing and maintenance. Backup generators do not produce power to be sold or otherwise supplied to the grid or provide power to loads that are simultaneously serviced by the electric utility grid. Backup generators only service customer loads that are isolated from the grid either by design or by manual or automatic transfer switch.

Baseload Resource (Generation Technology): Generation technologies (excluding Wind) expected to meet the minimum and ongoing (24 hour / 7 day a week) energy needs of a customer.

California Manufacturer: A California Manufacturer operates a manufacturing facility in California, is licensed to conduct business in California and is registered with a primary or secondary manufacturing NAICS code. Equipment is deemed to be manufactured in California if at least 50% of the value of the capital equipment has been made in a dedicated production line by an approved California Manufacturer.

Commercial: Commercial entities are defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions. For the purpose of SGIP, commercial sectors include agricultural and industrial customers.

CSE: Center for Sustainable Energy®

CEC: California Energy Commission

CPUC: California Public Utilities Commission

CEC-AC Rating: The SGIP Program Administrator will use the California Energy Commission's CEC-AC method to measure nominal output power of photovoltaic cells or modules to determine the system's rating in order to calculate the appropriate incentive level. The CEC-AC rating standards are based upon 1,000 watt/m2 solar irradiance, 20-degree Celsius ambient temperature, and one-meter/second wind speed. The CEC-AC watt rating is lower than the Standard Test Conditions.

Developer: A Developer is, if not individual homeowners applying for SGIP incentives for systems located on their own property, the corporate entity registered and in good standing with the Secretary of State of California that handles a substantial amount of the project's development activities.

Developer Fleet: Ten or more projects comprise a Developer Fleet. For compliance purposes, a Developer's legacy commercial fleet includes all legacy commercial projects within their 10-year permanency requirement, whose SGIP agreements list the same Developer. A Developer's legacy residential fleet includes all legacy residential projects whose SGIP agreements list the same Developer. A Developer's new commercial fleet includes all new commercial projects within their 10-year permanency requirement, whose SGIP agreements list the same Developer. A Developer's new residential fleet includes all new residential projects within their 10-year permanency requirement whose SGIP agreements list the same Developer.

Direct Current (DC): Direct current (DC or "continuous current") is the continuous flow of electricity through a conductor such as a wire from high to low potential. In direct current, the electric charges flow always in the same direction, which distinguishes it from alternating current (AC).

Directed Renewable Fuel: A directed renewable fuel is produced and captured at a different location than the project site of the electrical generation facility. The renewable fuel is delivered to the facility through a common carrier pipeline, which must be demonstrated through a procurement contract. Directed renewable fuel must be either injected into a common carrier pipeline system or interconnected to a common carrier pipeline system located within the state of California.

Disadvantaged Community: Any census tract that ranks in the statewide top 25% most affected census tracts in the most recently released version of the environmental health screening tool, CalEnviroScreen, plus those census tracts that score within the highest 5% of CalEnviroScreen's pollution burden, but do not receive an overall CalEnviroScreen score.

Discrete Public Safety Power Shutoff (PSPS) Event: For public safety, electric utilities may deem it necessary to turn off electricity when winds and dry conditions, combined with a heightened fire risk, are

forecasted. The utility may need to de-energize the grid for some number of hours or even days until the weather event has passed and it is safe to restore power.

For the purposes of SGIP, if the utility de-energizes a customer for safety and then restores power after the weather event has passed, this would count as one PSPS event – whether that PSPS event endured for the customer for only a few hours or some number of days. If power is restored for the customer and another weather event subsequently requires that the utility de-energize the same customer again – whether this occurred days, weeks or months later – this would count as the customer's second PSPS event.
In non-IOU territories, the applicable electric provider's definition of a discrete PSPS event will be used for SGIP eligibility purposes.

Dispatchable Resource (Generation Technology): Generation technologies (excluding Wind) that can be ramped up or shut off in a relatively short amount of time to meet the intermittent energy needs of a customer for the purposes of firming on-site intermittent renewables, providing peak load shaving, and/or supporting flexible load.

Education Institution: Any institution that would otherwise be eligible for funding through the California Clean Energy Jobs Act (Proposition 39), or a college or university accredited to operate in California.

Electric Utility: The Host Customer's local electric transmission and distribution service provider for their site.

Energy Capacity or Nominal Energy for DC/AC systems (Wh (for a specific C-rate)): The total watt-hours available when a storage system is discharged at a continuous current over a specified period of time (specified as a C-rate) from 100% state-of-charge to the cut-off voltage.

Energy Storage: Technologies able to store energy that can be discharged as useful energy at another time in order to directly supply electricity or offset electricity consumption. Unless specified otherwise, "energy storage" in the SGIP Handbook applies to all eligible storage technologies, including mechanical, electrochemical, or thermal energy storage.

Energy Storage Paired with and Charging from an On-site Renewable Generator: Energy storage system that is paired with an on-site generator and charges at a minimum 75% from the generator.

Environmental Attributes: All environmental benefits associated with an SGIP project, including any Renewable Energy Credits, and any carbon negative emission value associated with biofuels used in the project.

Energy Service Company (ESCO): a business entity that designs, builds, develops, owns, operates or any combination thereof self-generation projects for the sake of providing energy or energy services to a Host Customer.

Enhanced Powerline Safety Settings (EPSS): EPSS is a protective technology that reduces wildfire risk by enabling engineered device settings during periods of elevated wildfire risk. These devices de-energize downstream conductor in 100ms or less if a fault, such as a tree branch in contact with lines, is detected, overreach fuses to mitigate a wire-down back-feed condition, and provide higher impedance fault detection and de-energization. EPSS increases safety for PG&E customers and communities in High Fire Risk Areas (HFRA) and select HFRA-adjacent areas by mitigating potential ignitions that may otherwise result in a wide-spread, catastrophic wildfire.

Expected Performance Based Buydown (EPBB): The EPBB incentive methodology pays an up-front incentive based on a solar system's expected future performance. The SGIP incentive combines the performance benefits of performance-based incentives with the administrative simplicity of a one-time incentive paid at the time of project installation. The incentive will be calculated by multiplying the incentive rate by the system rating by the Design Factor.

Fuel Cell: A type of generation technology that produces electricity through an electrochemical reaction with a fuel source.

Gas Service: The gas line from the utility’s distribution main to the serving gas meter.

GHG signal: A digitally accessible data feed of current marginal greenhouse gas emissions rates (in units of kg/kWh) that updates at regular intervals (e.g., every five minutes) combined with additional data feeds that deliver regularly updated forecasts of grid conditions for use in the optimization of dispatch.

HVAC-integrated S-TES: Small thermal energy storage systems integrated to offset peak energy consumption of direct expansion refrigerant-based air conditioning units less than or equal to 20 tons.

Host Customer: An entity that meets all of the following criteria: 1) has legal rights to occupy the site; 2) receives retail level electric or gas distribution service from PG&E, SCE, SoCal Gas or SDG&E; or any CA resident for AB 209-funded projects; 3) is the utility customer of record at the site; 4) whose meter is connected to the electric grid; and 5) is the recipient of the net electricity generated from the self-generation equipment. Multifamily buildings that are installing a system on behalf of tenants and are enrolled in a VNEM tariff also qualify.

Inspection: An inspection can be conducted as an on-site Post-Installation Inspection by the Pas or their third-party consultant or as a virtual post-installation inspection executed by the Developer, System Owner, or Host Customer. For a description of the Post-Installation Inspection Protocol, please refer to the Energy Storage Post-Installation Inspection and Discharge Testing Protocol and SGIP Inspection

Sampling Protocol at www.selfgenca.com. In addition, general inspections can be conducted at any point during the permanency period.

Interconnection Agreement: Legal document authorizing the flow of electricity between the facilities of two electric systems. Under the SGIP Program, eligible renewable energy systems must be permanently interconnected and operating in parallel to the electrical distribution grid of the utility serving the customer's electrical load. Portable systems are not eligible. Proof of interconnection and parallel operation is required prior to receiving an incentive payment.

Inverter: Electric conversion device that converts direct current (DC) electricity into alternating current (AC) electricity.

Inverter Efficiency: AC power output of the inverter divided by the DC power input.

Investor-Owned Utility (IOU): For purposes of the SGIP, this refers to Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company.

ISO: International Standards Organization

ITC: Investment Tax Credit

Inverter Maximum Continuous Power Output Rating (kW): The maximum continuous power output rating of the solar inverter is listed on the inverter specification sheet and also on the California Energy Commission's list of Grid Support Solar/Battery inverters and is the maximum AC power output (in kW) allowed by the solar inverter under normal operating conditions.

Kilowatt (kW): Unit of electrical power equal to 1,000 watts, which constitutes the basic unit of electrical demand. The watt is a metric measurement of power (not energy) and is the rate (not the duration over which) electricity is used. 1,000 kW is equal to one megawatt (MW).

Kilowatt Hour (kWh): Use of 1,000 watts of electricity for one full hour. Unlike kW, kWh is a measure of energy, not power, and is the unit on which the price of electrical energy is based. Electricity rates are most commonly expressed in cents per kilowatt hour.

Large Thermal Energy Storage (L-TES): Large thermal energy storage systems integrated to offset peak energy consumption of direct expansion refrigerant-based and chilled water air conditioning systems larger than 20 tons.

Legacy Projects: Any project for which a completed SGIP reservation request was submitted before the GHG rules outlined in CPUC D.19-08-001 became effective.

Linear Generator: A type of generation technology that directly converts motion along a straight line into electricity using energy from a fuel source.

Local Governmental Agency: Any entity described by Public Contracts Code Section 22161 (f).

LADWP: Los Angeles Department of Water and Power

Low-Income Community: Census tracts with median household incomes at or below 80% of the statewide median income or with median household incomes at or below the threshold designated as low-income by the Department of Housing and Community Development's list of state income limits adopted pursuant to Section 50093.

Low-Income Residential Customer: An individual customer living in a low-income residence, as described in subparagraph (C) of paragraph (3) of subdivision (a) of Section 2852 of the Public Utilities Code.

Low-Income Residential Housing: Multifamily residential building of at least five rental housing units that is operated to provide deed-restricted low-income residential housing, as described in clause (i) of subparagraph (A) of paragraph (3) of subdivision (a) of Section 2852 of the Public Utilities Code, and is either: 1) in a disadvantaged community; or 2) a building where at least 80% of the households have incomes at or below 60% of the area median income, as defined in subdivision (f) of Section 50052.5 of the Health and Safety Code.

Manufacturer: The entity responsible for the assembly and production of a substantial portion of the SGIP system.

Meter Interval Report: Monthly meter data report provided by the Performance Data Provider (PDP). The Meter Interval Report format will vary by PDP. The PDPs shall format their report so that it includes all meter and sensor data recorded over the measured interval at a minimum 15-minute frequency, with the exception of Fuel Consumption, which shall be measured and reported hourly. This report should be formatted as specified by the SGIP program requirements.

Module: The smallest complete environmentally protected assembly of interconnected photovoltaic cells. Modules are typically rated between 50 and 400 watts.

New Projects: Any project submitting on or after the GHG rules outlined in CPUC D.19-08-001 became effective. GHG emissions reductions requirements apply throughout a project's 10-year permanency period. The phrase "complete application" refers to the "application submitted" date not the "incentive claim form submitted" date.

Non-Residential: Any project for which the customer is not residential. This includes eligible agriculture, commercial, government, non-profit, and industry customers.

Non-Profit Organization: An organization registered and in good standing with the California Secretary of State as a domestic non-profit entity.

Non-Renewable Fuel: A non-renewable fuel includes fossil fuels and synthetic fuels. Synthetic fuels are fuels derived from materials that are not renewable or fossil fuels. SGIP eligible fossil fuels are gasoline, natural gas, and propane. SGIP eligible synthetic fuels include, but are not limited to, the direct use or synthesis of fuels sewage sludge, industrial waste, medical waste, or hazardous waste.

On-Site Renewable Fuel: An on-site renewable fuel is produced and captured at the same location as the site of the electrical generation facility. Additionally, the renewable fuel is delivered from the source to the generating system via a dedicated pipeline. A dedicated pipeline is defined as only physically capable of delivering gas to the generating facility.

Paired Systems: Two or more technologies located on the same electrical circuit and behind the same utility electrical meter.

Parallel Operation: The simultaneous operation of a self-generator with power delivered to or received by the electrical utility while interconnected to the grid. Parallel Operation includes only those generators that are interconnected with the electric utility distribution system for more than 60 cycles.

PDP: Performance Data Provider. A company that contracts with the SGIP Participant to read and communicate their metering data to the Program Administrators.

PG&E: Pacific Gas and Electric Company

Photovoltaic (PV): Technology that uses a semiconductor to convert light directly into electricity.

Power Purchase Agreements: An agreement for the sale of electricity from one party to another, where the electricity is generated and consumed on the Host Customer site. Agreements that entail the export and sale of electricity from the Host Customer site do not constitute Host Customer’s use of the generated electricity and therefore are ineligible for the SGIP.

Pressure Reduction Turbine: If a facility with a high-pressure fluid (e.g., steam, water) distribution network and pressure reduction valve(s), installs a turbine to replace or operate in parallel with these pressure reduction valve(s), then the application is considered a Pressure Reduction Turbine.

Program Year: A project’s program year is the year its incentive application was accepted by the Program Administrator.

Project: For purposes of the SGIP, the "project" is the installation and operation of the proposed eligible self-generation technology(ies) at a specific site, as described by the submitted Reservation Request documentation.

Public Entity: Includes the United States, the state and any county, city, public corporation, or public district of the state, and any department, entity, agency, or authority of any thereof. [117]

Rated energy capacity (kWh): The rated energy capacity (kWh) for DC/AC energy storage technologies as the nominal voltage multiplied by the amp-hour capacity multiplied by the applicable efficiency (VDC x Amp-Hours x Applicable Efficiency).

Refrigeration TES: Thermal energy storage systems integrated to offset peak energy consumption of direct expansion refrigerant-based refrigeration systems.

Renewable Fuel: A renewable fuel is a non-fossil fuel categorized as one of the following: biodiesel or gas derived from digester gas, landfill gas or biomass. SGIP projects can use one or more eligible renewable energy sources, as identified by the Renewable Portfolio Standard (RPS).

Reservation Expiration Date: The Reservation Expiration Date is the date the Incentive Reservation expires and by which all required documentation must be provided.

Round Trip Efficiency (RTE): The total kWh discharge of the system divided by the total kWh charge over some period of time or number of cycles.

Rule 21: Electric Rule 21 is a tariff that describes the interconnection, operating and metering requirements for generation facilities to be connected to an Investor-owned utility's distribution system.

Single-cycle roundtrip efficiency (SCRTE): The total kWh discharge of the system divided by the total kWh charge after one complete cycle. SCRTE is often verified in the factory and specified on a device's technical specifications sheet.

SCE: Southern California Edison

SDG&E: San Diego Gas & Electric

SGIP-Approved Rate: A time-varying rate with a peak period starting at 4 pm or later and with a summer peak to off-peak price differential of 1.69 or more. SGIP eligible customers may not utilize time-of-use (TOU) bill protection measures.

SGIP-Approved Qualified Demand Response (DR) Program: For the purposes of the program, a qualified DR program is one that provides verifiable load drop using the storage device supported by the

[117] Source: California Codes - Public Contract Code, Section 21611.

SGIP incentive. For SGIP participants in POUs, an SGIP approved qualified DR program is one that would use the storage device to (1) shift onsite energy use to off-peak time periods or reduces demand from the grid by offsetting or lowering some or all of the customer's onsite energy demand, (2) is not an emergency DR program; and (3) the load impact from the storage device can be accurately measured and evaluated.

Single Business Enterprise: For purposes of defining a site, a Single Business Enterprise is a business that has a unique taxpayer or employer identification number. Two or more businesses with the same taxpayer or employer identification number, as a group, are a Single Business Enterprise.

Site: A Single Business Enterprise or home located on an integral parcel or parcels of land undivided by a public road or thoroughfare regardless of the number of meters serving that site; or if divided by a public road or thoroughfare, served by a single electric utility meter. Separate business enterprises or homes on a single parcel of land undivided by a highway, public road, thoroughfare, or railroad would be considered for purposes of the SGIP as separate sites.

Small Business: A business or manufacturer, including affiliates, with average annual gross receipts of $15 million or less, over the last three tax years.

SoCalGas: Southern California Gas Company

Solar Irradiance: Radiant energy emitted by the sun, particularly electromagnetic energy. In the SGIP Program the CEC-AC rating standards are based upon 1,000 watt/m2 solar irradiance, 20-degree Celsius ambient temperature, and one meter/second wind speed. The CEC-AC watt rating is lower than the Standard Test Conditions, a watt rating used by manufacturers.

Stand-alone Energy Storage: An energy storage system located on a Host Customer project site that does not also host a generating technology.

Standard Test Conditions (STC): Watt rating used by manufacturers of photovoltaic cells or modules. The CEC-AC watt rating used in SGIP is lower than the Standard Test Conditions.

State Governmental Agency: Any entity described by Government Code Section 11000.

Steam Turbine CHP: If a facility with a steam distribution network installs a steam turbine that is placed between the boiler and the steam distribution network, and steam pressure is increased, then the application is considered a Steam Turbine CHP. Pressure can be increased either through the purchase of new boilers or by increasing the pressure on existing boilers. In either case, boiler fuel usage per unit of steam production increases with boiler pressure.

Surface Orientation Factor (SOF): Ratio of the annual incident solar radiation on a surface for a specific tilt and orientation (MJ/m2/year) divided by the annual incident solar radiation on a surface for a south-facing surface with optimal tilt (MJ/m2/year).

System Owner: The owner of the SGIP system at the time the incentive is paid. For example, in the case when a vendor sells a turnkey system to a Host Customer, the Host Customer is the System Owner. In the case of a leased system, the lessor is the System Owner.

Thermal Energy Storage (TES): Technologies able to store energy that can be discharged at a later time as thermal energy to offset peak electricity consumption. In the SGIP Handbook, TES systems are categorized as Large Thermal Energy Storage (L-TES), HVAC-integrated S-TES, or Refrigeration TES.

Thermal Load: Host Customer heating process(es) including but not limited to industrial process heating, space heating, domestic hot water heating and/or heat input to an absorption chiller used for space cooling or refrigeration.

Thermal Load Equipment: Thermal end-use equipment such as but not limited to absorption chillers (indirect or direct fired), boilers, water heaters, space heaters, furnaces, dryers, secondary heat exchangers, thermal storage tanks or vessels including pumps, cooling towers, and piping or any other ancillary equipment.

Tribal Government Agency: Any entity described by Title 18 United States Code Section 1151.

Waste Gas: Waste Gas fuels used for generation technologies are strictly defined as natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.

Waste Heat to Power: If a facility discarding heat as a result of commercial or industrial processes installs a turbine driven by the discarded heat, then the application is considered a Waste Heat to Power system. These systems typically involve a heat recovery system, which transfers the waste heat to a working fluid which drives the turbine.

Wildfire: Wildfires are unplanned fires that burn in natural areas like forests, grasslands, or prairies.

Appendix A – Combustion Emission Credit Calculation

Micro-turbine, internal combustion engine, gas turbine, and steam turbine CHP projects that do not meet the applicable NOx emission standard (.07 lb/MWh) may receive emission credits for waste heat utilization.

Credit shall be at the rate of 1 MWh for each 3.4 million British thermal units (Btu) of heat recovered.

The following formula is used to modify the emissions rating for a generating system by giving credit for waste heat utilization:

Table 1: Formula to Modify the Emissions Rating for a Generating System by Giving Credit for Waste Heat Utilization

Formula to Modify the Emissions Rating for a Generating System by Giving Credit for Waste Heat Utilization		
Parameter Description	**Calculation**	**Result**
$Lb/MWh_{w/credit}$	$Lb/hr_{EmissionRate}$ / (MW_{Rated} + $MW_{ProcessHeat}$)	System emissions with thermal credit
$Lb/hr_{EmissionRate}$	$Lb/MWh_{w/o_credit}$ X MW_{Rated}	NOx emission rate at the system's rated capacity
$Lb/MWh_{w/o_credit}$	System's verified emissions without thermal credits	
MW_{Rated}	System's Rated Capacity as defined in Section 7.3.	
$MW_{ProcessHeat}$	($MMBtu/yr_{UtilizedWasteHeat}$ / 3.4 MMBtu/MWh) / EFLH/yr	Capacity credit for useful thermal energy
$MMBtu/yr_{UtilizedWasteHeat}$	Annual utilized waste heat	
3.4 MMBtu/MWh	Heat recovered conversion factor	
EFLH/yr	System's annual equivalent full load hours of operation	

All assumptions, backup documentation, hand calculations, models (with inputs and outputs), and custom spreadsheets used to develop the forecasts must be included in the documentation. Forecasts based solely on "professional experience" or subjective observation will be rejected. Applications must include a completed Minimum Operating Efficiency Worksheet, available from the Program Administrators' websites, that calculates the waste heat utilization, minimum system efficiency, and emissions requirements.

Example #1: Emissions Credit for 360 kW IC Engine Generator

A 360 kW IC engine generator set is proposed to supply electric power and heat to a furniture manufacturing facility. The system utilizes an intercooler chiller that is rated at 10 kW. Its full load fuel consumption is 4.4 MMBtu/hr LHV (4.8 MMBtu/hr HHV106) and its full load waste heat recovery rate is 2.6 MMBtu/hr.

Source testing documentation for the same generating system make/model and configuration, but from another site, indicate that the NOx emissions from this unit are 0.16 lb/MWh. The generator is fueled with a renewable fuel and is not a fuel cell. The generator electric output follows the load of the Host Customer's facility but shuts down when the load falls below 40 kW, the minimum load of the generator. The Host Customer's annual peak demand is approximately 400 kW. Waste heat from the generating system is used to deliver hot water for manufacturing process, equipment cleanup and space heating.

Detailed analysis of the system and Host Customer load reveals that the system will be generating 1,715,000 kWh/yr at a capacity factor of 56%. The system will produce 12,730 MMBtu/yr of recovered waste heat to serve 12,400 MMBtu/yr of thermal load, however only 8,255.8 MMBtu/yr of waste heat is actual useful thermal output because of non-coincident monthly load. The system consumes 21,521 MMBtu/yr LHV and 23,673 MMBtu/yr HHV of fuel. See Section 7.1 of legend for equations.

Table 2: Example #1 Calculations

Description	Equation	Result	Determination
P.U. Code 216.6 (a)	$T / (T + E_{ELEC}) \geq 5\%$	8,255,800,000 [Btu/yr] / {(1,715,000 [kWh/yr] x 3,413 [Btu/kWh]) + 8,255,800,000 [Btu/yr]} = **58.5%**	≥ 5% ***Passes***
P.U. Code 216.6 (b)	$(E_{ELEC} + 0.5 \times T) / F_{LHV} \geq 42.5\%$	{(1,715,000 [kWh/yr] x 3,413 [Btu/kWh]) + 0.5 x 8,255,800,000 [Btu/yr]} / 21,520,800,000 [Btu/yr] = **46.4%**	≥ 42.5% ***Passes***
AB 2778 Minimum Electric Efficiency	$E / F_{HHV} \geq 40\%$	(360 [kW] x 3,414 [Btu/kWh]) / 4,831,200 [Btu/hr] = **25.4%**	≤ 40% ***Fails***
AB 1685 Minimum System Efficiency	$(E + T_{WHR}) / F_{HHV} \geq$ 60%	{(360 [kW] x 3,414 [Btu/kWh]) + 2,598,000 [Btu/hr]} / 4,831,200 [Btu/hr] = **79.2%**	≥ 60% ***Passes***
AB 1685 NOx Emissions w/o Waste Heat Credit	NOx Emissions ≤ 0.07 lb/MWh	**0.16 [lb/MWh]**	≤ 0.07 lb/MWh NOx ***Fails***
AB 1685 NOx Emissions w/ Waste Heat Credit	$Lb/hr_{EmissionRate} / (MW_{Rated} + MW_{ProcessHeat})$ ≤ 0.07 lb/MWh	{0.16 [lb/MWh] x .360 [MW]} / {.360 [MW] + (8,256 [MMBtu/yr] / 3.4 [MMBtu/MWh]) / 4,900 [EFLH/yr]} = **0.067 lb/MWh**	≤ 0.07 lb/MWh NOx ***Passes***

Source: Emissions credit calculation is based on the California Air Resources Board, Guidance for the Permitting of Electric Generation Technologies, Appendix D: Quantifying CHP Benefits, July 2002.

The Minimum Operating Efficiency worksheet is designed to perform this calculation. Applications must include in their application a completed Minimum Operating Efficiency worksheet, which is available from the Program Administrators' websites. Note that for biogas LHV ≈ HHV x 0.9.

Appendix B – Conversion of Emissions PPM to Lb/MWH

Procedure for Converting Emission Data to lb/MWh

Engines

Engine emission standards are typically expressed in terms of ppmv or in grams per brake horsepower-hour (g/bhp-hr). Given below are factors to convert from ppm to g/bhp-hr and from g/bhp-hr to lb/MWh.

The resulting answers will be approximate values since various default assumptions were used to develop natural gas default factors. The efficiency of the engine has the greatest effect on the concentration (ppmvd) to mass emission rate conversion (g/bhp-hr), which can vary from 20–40%. In the calculations below, the efficiency is proportional to the engine brake specific fuel consumption.

ppm TO g/bhp-hr

Concentration in exhaust by volume (dry)(ppmvd) = 10 x volume of pollutant (Vp) / volume of exhaust (Ve), where:

Vp = emission factor (g/bhp-hr) x horsepower x (1/molecular weight) x molar volume x conversion factors

Ve = F-factor for exhaust volume x excess air correction x engine brake specific fuel consumption x horsepower x conversion factors

These factors can be reduced to: ppmvd = (gm/bhp-hr) * factor

Table 1: Reciprocating Engines, Natural Gas Fueled Factors

NOx	57-59
VOC	163-170
CO	93-97

Source: California Air Pollution Control Officers Association (CAPCOA) report: Portable Equipment Rule Piston IC Engine

Table 2: Lean Burn Engines, Natural Gas Fueled Factors

NOx	80
VOC	212
CO	123

Source: Factors provided by Waukesha

g/bhp-hr to lb/MWh

gm/bhp-hr x 3.07 = lb/MWh

• Includes 95 % factor for generator efficiency

• Conversion factors for grams to pounds and brake horsepower to watts

Gas Turbines
lb/MW-hr = (emission rate [lb/MMBtu]) x (3.413 [MMBtu/MWh]) / (efficiency)

Table 3: Emission Rate for Gas Turbines

Pollutant	ppmvd	lb/MMBtu
NOx	2.5	0.0093
VOC	2	0.0027
CO	5	0.013

Source: California Air Resources Board, Guidance for the Permitting of Electric Generation Technologies, Appendix B: Procedure for Converting Emission Data to lb/MWh, July 2002.

Efficiency for central station power plant is 50%

Appendix C – Conversion Tables for HVAC-Integrated S-TES

Before 1984 8 SEER	kW Offset Table with Source Multiplier of 1. Equipment Nominal Tonnage (In Tons)															
Climate Zone	1	1.5	2	3	3.5	4	5	6	7	7.5	8.5	9	10	12.5	15	20
1	1.0	1.6	2.3	3.5	4.2	4.8	6.1	7.3	8.6	9.2	10.5	11.1	12.4	15.5	18.7	25.0
2	1.4	2.3	3.1	4.8	5.6	6.5	8.2	9.8	11.5	12.4	14.1	14.9	16.6	20.8	25.0	33.4
3	1.3	2.1	2.9	4.5	5.3	6.0	7.6	9.2	10.8	11.5	13.1	13.9	15.5	19.4	23.3	31.2
4	1.4	2.2	3.0	4.6	5.4	6.2	7.8	9.5	11.1	11.9	13.5	14.3	15.9	20.0	24.0	32.1
5	1.4	2.2	3.0	4.6	5.4	6.2	7.8	9.4	11.0	11.8	13.4	14.2	15.8	19.8	23.8	31.8
6	1.4	2.2	3.0	4.7	5.5	6.3	7.9	9.6	11.2	12.0	13.7	14.5	16.1	20.2	24.3	32.5
7	1.4	2.2	3.1	4.7	5.5	6.4	8.0	9.7	11.3	12.1	13.8	14.6	16.3	20.4	24.5	32.8
8	1.4	2.2	3.1	4.7	5.5	6.4	8.0	9.7	11.3	12.1	13.8	14.6	16.3	20.4	24.5	32.8
9	1.4	2.2	3.0	4.7	5.5	6.3	7.9	9.6	11.2	12.0	13.7	14.5	16.1	20.2	24.3	32.5
10	1.5	2.3	3.2	4.9	5.8	6.7	8.4	10.1	11.9	12.7	14.5	15.3	17.1	21.4	25.7	34.4
11	1.5	2.4	3.3	5.1	6.0	6.9	8.6	10.4	12.2	13.1	14.9	15.7	17.5	22.0	26.4	35.3
12	1.4	2.3	3.1	4.8	5.7	6.5	8.2	9.9	11.6	12.5	14.2	15.0	16.7	21.0	25.2	33.7
13	1.4	2.2	3.1	4.7	5.5	6.4	8.0	9.7	11.3	12.1	13.8	14.6	16.3	20.4	24.5	32.8
14	1.5	2.3	3.2	4.9	5.8	6.7	8.4	10.1	11.9	12.7	14.5	15.3	17.1	21.4	25.7	34.4
15	1.6	2.5	3.4	5.2	6.1	7.0	8.9	10.7	12.5	13.4	15.3	16.2	18.0	22.5	27.1	36.2
16	1.4	2.2	3.0	4.6	5.4	6.2	7.8	9.5	11.1	11.9	13.5	14.3	15.9	20.0	24.0	32.1

1984 - 1991 8.9 SEER	kW Offset Table with Source Multiplier of 1. Equipment Nominal Tonnage (In Tons)															
Climate Zone	1	1.5	2	3	3.5	4	5	6	7	7.5	8.5	9	10	12.5	15	20
1	0.9	1.5	2.0	3.2	3.8	4.3	5.5	6.6	7.8	8.3	9.5	10.1	11.2	14.1	16.9	22.7
2	1.3	2.0	2.8	4.3	5.1	5.9	7.4	8.9	10.4	11.2	12.7	13.5	15.0	18.9	22.7	30.3
3	1.2	1.9	2.6	4.0	4.7	5.5	6.9	8.3	9.7	10.5	11.9	12.6	14.0	17.6	21.2	28.3
4	1.2	2.0	2.7	4.2	4.9	5.6	7.1	8.6	10.0	10.8	12.2	13.0	14.5	18.1	21.8	29.2
5	1.2	1.9	2.7	4.1	4.8	5.6	7.0	8.5	9.9	10.7	12.1	12.9	14.3	18.0	21.6	28.9
6	1.2	2.0	2.7	4.2	4.9	5.7	7.2	8.7	10.1	10.9	12.4	13.1	14.6	18.3	22.0	29.4
7	1.2	2.0	2.7	4.2	5.0	5.7	7.2	8.7	10.2	11.0	12.5	13.2	14.7	18.5	22.2	29.7
8	1.2	2.0	2.7	4.2	5.0	5.7	7.2	8.7	10.2	11.0	12.5	13.2	14.7	18.5	22.2	29.7
9	1.2	2.0	2.7	4.2	4.9	5.7	7.2	8.7	10.1	10.9	12.4	13.1	14.6	18.3	22.0	29.4
10	1.3	2.1	2.9	4.5	5.2	6.0	7.6	9.2	10.7	11.5	13.1	13.9	15.5	19.4	23.3	31.2
11	1.4	2.2	3.0	4.6	5.4	6.2	7.8	9.4	11.0	11.9	13.5	14.3	15.9	19.9	24.0	32.0
12	1.3	2.1	2.8	4.4	5.1	5.9	7.5	9.0	10.5	11.3	12.9	13.6	15.2	19.0	22.9	30.6
13	1.2	2.0	2.7	4.2	5.0	5.7	7.2	8.7	10.2	11.0	12.5	13.2	14.7	18.5	22.2	29.7
14	1.3	2.1	2.9	4.5	5.2	6.0	7.6	9.2	10.7	11.5	13.1	13.9	15.5	19.4	23.3	31.2
15	1.4	2.2	3.1	4.7	5.5	6.4	8.0	9.7	11.3	12.2	13.8	14.7	16.3	20.4	24.6	32.9
16	1.2	2.0	2.7	4.2	4.9	5.6	7.1	8.6	10.0	10.8	12.2	13.0	14.5	18.1	21.8	29.2

1992 - 2005 9.7 SEER	kW Offset Table with Source Multiplier of 1. Equipment Nominal Tonnage (In Tons)															
Climate Zone	1	1.5	2	3	3.5	4	5	6	7	7.5	8.5	9	10	12.5	15	20
1	0.8	1.3	1.9	2.9	3.5	4.0	5.1	6.1	7.2	7.7	8.8	9.3	10.4	13.0	15.7	21.0
2	1.2	1.9	2.6	4.0	4.7	5.4	6.8	8.2	9.7	10.4	11.8	12.5	13.9	17.4	21.0	28.1
3	1.1	1.7	2.4	3.7	4.4	5.0	6.4	7.7	9.0	9.7	11.0	11.7	13.0	16.3	19.6	26.2
4	1.1	1.8	2.5	3.8	4.5	5.2	6.6	7.9	9.3	10.0	11.3	12.0	13.4	16.8	20.2	27.0
5	1.1	1.8	2.4	3.8	4.5	5.1	6.5	7.8	9.2	9.9	11.2	11.9	13.2	16.6	20.0	26.7
6	1.1	1.8	2.5	3.9	4.6	5.3	6.6	8.0	9.4	10.1	11.4	12.1	13.5	16.9	20.4	27.3
7	1.1	1.8	2.5	3.9	4.6	5.3	6.7	8.1	9.5	10.2	11.6	12.2	13.6	17.1	20.6	27.5
8	1.1	1.8	2.5	3.9	4.6	5.3	6.7	8.1	9.5	10.2	11.6	12.2	13.6	17.1	20.6	27.5
9	1.1	1.8	2.5	3.9	4.6	5.3	6.6	8.0	9.4	10.1	11.4	12.1	13.5	16.9	20.4	27.3
10	1.2	1.9	2.7	4.1	4.8	5.6	7.0	8.5	9.9	10.7	12.1	12.8	14.3	17.9	21.6	28.9
11	1.2	2.0	2.7	4.2	5.0	5.7	7.2	8.7	10.2	11.0	12.5	13.2	14.7	18.4	22.2	29.6
12	1.2	1.9	2.6	4.0	4.8	5.5	6.9	8.3	9.8	10.5	11.9	12.6	14.0	17.6	21.2	28.3
13	1.1	1.8	2.5	3.9	4.6	5.3	6.7	8.1	9.5	10.2	11.6	12.2	13.6	17.1	20.6	27.5
14	1.2	1.9	2.7	4.1	4.8	5.6	7.0	8.5	9.9	10.7	12.1	12.8	14.3	17.9	21.6	28.9
15	1.3	2.1	2.8	4.4	5.1	5.9	7.4	9.0	10.5	11.3	12.8	13.6	15.1	18.9	22.8	30.4
16	1.1	1.8	2.5	3.8	4.5	5.2	6.6	7.9	9.3	10.0	11.3	12.0	13.4	16.8	20.2	27.0

2006-2009 12 SEER	kW Offset Table with Source Multiplier of 1. Equipment Nominal Tonnage (In Tons)															
Climate Zone	1	1.5	2	3	3.5	4	5	6	7	7.5	8.5	9	10	12.5	15	20
1	0.6	1.1	1.5	2.4	2.8	3.3	4.2	5.1	5.9	6.4	7.3	7.7	8.6	10.8	13.0	17.4
2	0.9	1.5	2.1	3.3	3.9	4.5	5.6	6.8	8.0	8.6	9.8	10.4	11.5	14.5	17.4	23.3
3	0.9	1.4	2.0	3.1	3.6	4.2	5.3	6.4	7.5	8.0	9.1	9.7	10.8	13.5	16.3	21.8
4	0.9	1.5	2.0	3.2	3.7	4.3	5.4	6.6	7.7	8.3	9.4	10.0	11.1	13.9	16.8	22.5
5	0.9	1.4	2.0	3.1	3.7	4.2	5.4	6.5	7.6	8.2	9.3	9.9	11.0	13.8	16.6	22.2
6	0.9	1.5	2.0	3.2	3.8	4.3	5.5	6.6	7.8	8.3	9.5	10.1	11.2	14.1	16.9	22.7
7	0.9	1.5	2.1	3.2	3.8	4.4	5.5	6.7	7.9	8.4	9.6	10.2	11.3	14.2	17.1	22.9
8	0.9	1.5	2.1	3.2	3.8	4.4	5.5	6.7	7.9	8.4	9.6	10.2	11.3	14.2	17.1	22.9
9	0.9	1.5	2.0	3.2	3.8	4.3	5.5	6.6	7.8	8.3	9.5	10.1	11.2	14.1	16.9	22.7
10	1.0	1.6	2.2	3.4	4.0	4.6	5.8	7.0	8.2	8.8	10.1	10.7	11.9	14.9	17.9	24.0
11	1.0	1.6	2.2	3.5	4.1	4.7	6.0	7.2	8.5	9.1	10.3	11.0	12.2	15.3	18.4	24.7
12	0.9	1.5	2.1	3.3	3.9	4.5	5.7	6.9	8.1	8.7	9.9	10.5	11.7	14.6	17.6	23.6
13	0.9	1.5	2.1	3.2	3.8	4.4	5.5	6.7	7.9	8.4	9.6	10.2	11.3	14.2	17.1	22.9
14	1.0	1.6	2.2	3.4	4.0	4.6	5.8	7.0	8.2	8.8	10.1	10.7	11.9	14.9	17.9	24.0
15	1.0	1.7	2.3	3.6	4.2	4.9	6.1	7.4	8.7	9.3	10.6	11.3	12.5	15.7	18.9	25.3
16	0.9	1.5	2.0	3.2	3.7	4.3	5.4	6.6	7.7	8.3	9.4	10.0	11.1	13.9	16.8	22.5

2010-2014 13 SEER	kW Offset Table with Source Multiplier of 1. Equipment Nominal Tonnage (In Tons)															
Climate Zone	1	1.5	2	3	3.5	4	5	6	7	7.5	8.5	9	10	12.5	15	20
1	0.4	0.8	1.1	1.8	2.1	2.4	3.1	3.8	4.4	4.8	5.5	5.8	6.5	8.1	9.8	13.2
2	0.6	1.1	1.5	2.4	2.9	3.3	4.2	5.1	6.0	6.5	7.4	7.8	8.7	10.9	13.2	17.6
3	0.6	1.0	1.4	2.3	2.7	3.1	3.9	4.8	5.6	6.0	6.9	7.3	8.1	10.2	12.3	16.5
4	0.6	1.0	1.5	2.3	2.8	3.2	4.1	4.9	5.8	6.2	7.1	7.5	8.4	10.5	12.7	17.0
5	0.6	1.0	1.5	2.3	2.7	3.2	4.0	4.9	5.7	6.1	7.0	7.4	8.3	10.4	12.5	16.8
6	0.6	1.1	1.5	2.4	2.8	3.2	4.1	5.0	5.8	6.3	7.1	7.6	8.4	10.6	12.8	17.1
7	0.6	1.1	1.5	2.4	2.8	3.3	4.1	5.0	5.9	6.3	7.2	7.7	8.5	10.7	12.9	17.3
8	0.6	1.1	1.5	2.4	2.8	3.3	4.1	5.0	5.9	6.3	7.2	7.7	8.5	10.7	12.9	17.3
9	0.6	1.1	1.5	2.4	2.8	3.2	4.1	5.0	5.8	6.3	7.1	7.6	8.4	10.6	12.8	17.1
10	0.7	1.1	1.6	2.5	3.0	3.4	4.3	5.3	6.2	6.6	7.6	8.0	8.9	11.2	13.5	18.1
11	0.7	1.2	1.6	2.6	3.1	3.5	4.5	5.4	6.4	6.8	7.8	8.3	9.2	11.6	13.9	18.6
12	0.7	1.1	1.6	2.5	2.9	3.4	4.3	5.2	6.1	6.5	7.4	7.9	8.8	11.0	13.3	17.8
13	0.6	1.1	1.5	2.4	2.8	3.3	4.1	5.0	5.9	6.3	7.2	7.7	8.5	10.7	12.9	17.3
14	0.7	1.1	1.6	2.5	3.0	3.4	4.3	5.3	6.2	6.6	7.6	8.0	8.9	11.2	13.5	18.1
15	0.7	1.2	1.7	2.7	3.1	3.6	4.6	5.6	6.5	7.0	8.0	8.5	9.4	11.9	14.3	19.1
16	0.6	1.0	1.5	2.3	2.8	3.2	4.1	4.9	5.8	6.2	7.1	7.5	8.4	10.5	12.7	17.0

6/2014 After 14 SEER	kW Offset Table with Source Multiplier of 1. Equipment Nominal Tonnage (In Tons)															
Climate Zone	1	1.5	2	3	3.5	4	5	6	7	7.5	8.5	9	10	12.5	15	20
1	0.4	0.8	1.1	1.8	2.1	2.4	3.1	3.8	4.4	4.8	5.5	5.8	6.5	8.1	9.8	13.2
2	0.6	1.1	1.5	2.4	2.9	3.3	4.2	5.1	6.0	6.5	7.4	7.8	8.7	10.9	13.2	17.6
3	0.6	1.0	1.4	2.3	2.7	3.1	3.9	4.8	5.6	6.0	6.9	7.3	8.1	10.2	12.3	16.5
4	0.6	1.0	1.5	2.3	2.8	3.2	4.1	4.9	5.8	6.2	7.1	7.5	8.4	10.5	12.7	17.0
5	0.6	1.0	1.5	2.3	2.7	3.2	4.0	4.9	5.7	6.1	7.0	7.4	8.3	10.4	12.5	16.8
6	0.6	1.1	1.5	2.4	2.8	3.2	4.1	5.0	5.8	6.3	7.1	7.6	8.4	10.6	12.8	17.1
7	0.6	1.1	1.5	2.4	2.8	3.3	4.1	5.0	5.9	6.3	7.2	7.7	8.5	10.7	12.9	17.3
8	0.6	1.1	1.5	2.4	2.8	3.3	4.1	5.0	5.9	6.3	7.2	7.7	8.5	10.7	12.9	17.3
9	0.6	1.1	1.5	2.4	2.8	3.2	4.1	5.0	5.8	6.3	7.1	7.6	8.4	10.6	12.8	17.1
10	0.7	1.1	1.6	2.5	3.0	3.4	4.3	5.3	6.2	6.6	7.6	8.0	8.9	11.2	13.5	18.1
11	0.7	1.2	1.6	2.6	3.1	3.5	4.5	5.4	6.4	6.8	7.8	8.3	9.2	11.6	13.9	18.6
12	0.7	1.1	1.6	2.5	2.9	3.4	4.3	5.2	6.1	6.5	7.4	7.9	8.8	11.0	13.3	17.8
13	0.6	1.1	1.5	2.4	2.8	3.3	4.1	5.0	5.9	6.3	7.2	7.7	8.5	10.7	12.9	17.3
14	0.7	1.1	1.6	2.5	3.0	3.4	4.3	5.3	6.2	6.6	7.6	8.0	8.9	11.2	13.5	18.1
15	0.7	1.2	1.7	2.7	3.1	3.6	4.6	5.6	6.5	7.0	8.0	8.5	9.4	11.9	14.3	19.1
16	0.6	1.0	1.5	2.3	2.8	3.2	4.1	4.9	5.8	6.2	7.1	7.5	8.4	10.5	12.7	17.0

Appendix D – Calculation of Minimum Roundtrip Efficiency

Table 1: Minimum Roundtrip Efficiency Calculation

Line Loss On Peak	10.3%
Line Loss Off Peak	5.3%
Degradation Rate	1.0%
First-Year RTE	69.6%
Ten-Year Avg RTE	66.5%
Sum of Ann'l GHGs	0

Table 2: GHGs Over a 10-Year Period

Year	Off-Peak ER	On-Peak ER	GHG Emitted	GHG Avoided	Net GHG per MWh
1	382	544	580	606	-27
2	382	544	585	606	-21
3	382	544	591	606	-15
4	382	544	597	606	-9
5	382	544	603	606	-3
6	368	524	587	584	3
7	368	524	593	584	9
8	368	524	599	584	15
9	368	524	605	584	21
10	368	524	611	584	27

Appendix E – Incentive Rate for Large-Scale Storage Projects Claiming the ITC at All Incentive Levels

Table 1: Large-Scale Storage Budget Incentive Rates with and without ITC

	$/Wh	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**
Non-ITC	0.50	0.45	0.40	0.35	0.30	0.25	0.20	0.15	0.10
ITC	0.36	0.32	0.29	0.25	0.22	0.18	0.14	0.11	0.07

Appendix F – Large Thermal Energy Storage UC Davis Methodology for Determining 1-in-10 Year Peak

Large TES Calculation Methodology

1. Existing Air-Cooled Equipment
    a. Developing Baseline
        i. General
            1. Measurements are taken during 2 separate periods
            2. With ambient temperatures 85°F or greater
            3. With greater than 4°F differential between measurement points
        ii. IPLV elimination
            1. Track supply air temperature leaving the unit (Direct expansion) or Chilled Water Leaving Temperature (Chiller)
            2. Progressively increase outside air fraction until supply temperature begins to rise
    b. Measurement
        i. Measure true power at the point where temperature begins to rise
        ii. If 100% outside air is incapable of producing a rise in supply temperature, additional supplementary heat can be added to the ventilation air intake or return air system
    c. Calculation
        i. Establish the 1-in-10-year dry bulb temperature from the applicable ASHRAE temperature file for the nearest weather station
        ii. Derive the ratio between temperature change and power change from the power measurements taken in terms of KW increase per 1°F
        iii. Calculate the difference between the ASHRAE 10-year high temperature and the highest temperature measured
        iv. Using the highest measured temperature and the temperature/power change ratio described above, calculate the KW of the system at ASHRAE 1-in-10 ambient air temperature
2. Existing Water-Cooled Equipment
    a. Developing Baseline
        i. General
            1. Measurements are taken during 2 separate periods
            2. With ambient temperatures 85°F or greater
            3. With greater than 4°F differential between measurement points
        ii. Cooling Tower Manufacturer to provide expected condensing water temperature given

1. Using the chiller manufacturer's data for heat load rejected and
2. ASHRAE Dry Bulb and Wet bulb data for 1-in-10 conditions

iii. IPLV elimination

1. Cooling tower
    a. Raise condenser water inlet temperature to the chiller to anticipated 1-in-10 temperature by controlling cooling tower air flow
    b. Maintain full mass flow of condenser water
2. Track Chilled Water Leaving Temperature
3. Progressively increase outside air fraction until supply temperature begins to rise

b. Measurement

i. Measure true power at the point where temperature begins to rise

ii. If 100% outside air is incapable of producing a rise in supply temperature, additional supplementary heat can be added to the ventilation air intake or return air system

c. Calculation

i. Establish the 1-in-10-year dry bulb temperature from the applicable ASHRAE temperature file for the nearest weather station

ii. Derive the ratio between temperature change and power change from the power measurements taken in terms of KW increase per 1°F

iii. Calculate the difference between the ASHRAE 10-year high temperature and the highest temperature measured

iv. Using the highest measured temperature and the temperature/power change ratio described above, calculate the KW of the system at ASHRAE 1-in-10 ambient air temperature

3. New Equipment

a. Applicant to submit a declaration of the schedule of equipment that would have been used if the program did not exist

i. Manufacturers attesting to this performance must declare that the values calculated at the given temperatures are interpolated values from physically tested values measured in tests in a controlled environment

b. From have manufacturer's provide data on equipment KW at ASHRAE 1-in-10 ambient heat values for

i. Default equipment

ii. Proposed equipment

c. The difference between the 2 equipment schedules is the peak KW differential

Appendix G – Large Thermal Energy Storage Upfront and PBI Incentive Calculation Methodology

Estimating the kW Offset

1. Model building as per former PLS program
2. Analyze model data as follows:
    a. Existing system
        i. Divided into 1°F bins based upon ambient DB temperature,
        ii. Further divided into separate occupied and unoccupied bins
    b. Proposed system
        i. Model KW of Proposed System Configurations
            1. TES System off (8760)
            2. TES System recharging (8760)
            3. TES System discharging (8760)
        ii. Divide each Configuration into 1°F bins for each occupancy type
            1. Occupied
            2. Unoccupied
            3. Bin to represent 1 hour of time
        iii. Interpolation
            1. Extend bins
                a. From highest modeled temperature (TMY3 worst hour)
                b. To 1-in-10 worst hour
            2. Number of bins
                a. One bin for 1-in-10 worst hour
                b. Two bins for next lower temperature
                c. Continue this extension, with number of bins never less than two nor higher than the number of hours at highest DB in TMY3 file
            3. Straight line estimate
                a. Delta KW between
                    i. 1-in-10 high KW
                    ii. Highest hour
                b. Divided by number of °F between 1-in-10 and TMY3
                c. Applied equally to each bin between high and low

Pre & Post Monitoring Parameters for PBI Calculations

3. Pre-Monitoring
    a. Monitor total KW of all affected HVAC equipment

i. Water cooled chiller
    1. Chiller
    2. Condenser water pumps
    3. Cooling tower fans/Pumps
    4. Chilled water pumps
ii. Air cooled Chiller
    1. Chiller
    2. Chilled water pumps (if separate)
iii. Air Cooled DX units (if replaced with Chilled water)
    1. All units being upgraded

b. Ambient DB Air temp
    i. From nearest National Weather Service recognized weather station
c. Monitoring location
    i. Typically, at unit
    ii. Where one sub panel serves HVAC equipment exclusively, can be monitored at that panel
    iii. Monitoring plan to show where metering is located
d. Data requirements
    i. Peak KW as described in UC Davis methodology
    ii. kWh
        1. Hourly Bins
            a. By occupied/unoccupied
            b. Per 1°F
            c. Average for hour
                i. Temp
                ii. KW
        2. Data collection
            a. Collected every 4 seconds
            b. Stored locally
            c. Averaged
            d. Reported/recorded as a “Block” by PDP every five minutes
        3. Data Required for each “Block”
            a. Time stamp
            b. Ambient air temp
            c. KW of all HVAC equipment to be impacted by installation
            d. CPUC GHG signal (once available)
        4. Minimum 240 reported Blocks @ >90°F

e. Pre-monitoring reporting
    i. KW monitoring points to be reported to PA in advance
    ii. PA to approve or reject monitoring points plan w/in 10 business days of submission
    iii. Applicant to inform PA when monitoring equipment is in place
f. Model kWh Calibration
    i. Collected KW data averaged per bin
    ii. Model data averaged per bin
    iii. If model average KW per bin is over/under by >10% for any individual bin, or >5% for any four consecutive 1°F bins, model to be calibrated to match measured data
g. Data set editing
    i. Where the number of hours in the TMY3 file for a given °F are less than half of the two adjacent hours, the following method shall be used
        1. Average the number of hours for the next higher and lower ambient air temps to derive the adjusted number of slots for that bin
        2. Average the mean KW for the next higher and lower ambient air temps to derive the adjusted KW for that bin

Large TES systems also have post installation monitoring and reporting requirements during the PBI period.

These are described in the section below:

4. Post Monitoring
    a. Duration: five years from start-up
    b. Monitored points
        i. Baseline points remain the same
            1. KW of HVAC equipment
            2. Ambient DB air temp
            3. Occupied/unoccupied
        ii. Additional TES operation related bins added
            1. TES Discharge
            2. TES Recharge
    c. Monitoring frequency remains same
    d. Analysis of kWH
        i. Full Discharge hours
            1. A full discharge hour is any hour where the TES system is in operation for all 60 minutes
            2. All 12 report Blocks are averaged for
                a. KW

b. Ambient air temp in °F

3. Average KW for this hour is compared to the average KW of the current baseline system for that temperature and status combination
4. The difference between the Average hourly KW of the baseline system and the average hourly KW of the TES system in discharge mode will be the attributable kWh for that hour

ii. Partial discharge hours

1. In cases where the TES system is not discharged starting at the top of a given hour, the following pro-rated process is used
2. Five-minute report Blocks are collected for the entire hour
3. Only five-minute report Blocks collected when the TES system is in discharge are considered
4. For any five-minute report that is divided between discharge / recharge / normal operation states, the state with the most 4 second measurements shall be the reported state, with KW averaged across those all measurements of that state for the reporting period
5. The difference between the Average hourly KW of the baseline system and the average hourly KW of the TES system for all reports in discharge mode times the fraction of the hour the system was in discharge mode will be the attributable kWh for that hour.

e. Current baseline updating

i. The initial baseline will be populated from the calibrated pre-monitoring baseline as mentioned above
ii. Each individual temperature/status bin will have the number of hour “slots” that it had in the initial 8760 TMY3 based model + any “extension” hours added to get to the 1-in-10 temperature
iii. As actual post installation data is acquired, it displaces the original modeled data.
iv. The process is continuous over life of project, so that the non-discharge baseline is continuously reset with actual data
v. Actual Baseline updating occurs after the end each month to set the updated baseline for the next month

f. Original baseline retention and use

i. The original calibrated baseline is retained.
ii. The original baseline is NOT used for calculating Performance Based Incentives
iii. The original baseline is retained and used for calculating the GHG impacts of the installation Example 1: There are 48 hours at 97°F for a given location in a given TMY3 file. The number of “slots” in the occupied/97°F bin is fixed at 48. In Year 1

there are 55 hours at 97°, and in Year 2 there are 39 hours at this temperature. As each new “measured” hour is added to the database it pushes an originally modeled hour out. In such a case, all the modeled data would all be pushed out of this bin before the end of Year 1, while by the end of Year 2 the slots in that bin would be almost all from Year 2.

5. Reporting
    a. Monthly reports in PDF and data to be provided in Excel or CSV format
    b. Data Summary
        i. Location
        ii. Project identifying information
        iii. Discharge kWh shifted
            1. Used for PBI purposes
            2. kWh
                a. Sum of measured kWh of all Discharge blocks in month
                b. Less sum of mean kWh of all block of same temp/status bin from current baseline
                c. Difference is net monthly Discharge kWh
        iv. Net GHG impact/kWh
        v. GHG signal
            1. Recharge GHG
                a. Sum of measured kWh of all Recharge blocks in month x five-minute GHG signal
                b. Less sum of mean kWh of all block of same temp/status bin from current baseline x five-minute GHG signal
                c. Difference is net monthly Recharge GHG
            2. Discharge GHG
                a. Sum of kWh of all Discharge blocks in month of same temp/status bin from original calibrated baseline x five-minute GHG signal.
                b. Less sum of measured kWh of all Discharge blocks
                c. Difference is net monthly Discharge GHG
            3. Discharge GHG (saved) less Recharge GHG = Net total GHG impact
            4. Net total GHG impact / sum of Discharge kWh = Net total GHG/ kWh for the month.
    c. Detailed data
        i. All five-minute Blocks for month, including:
            1. Time stamp
            2. Discharge/Recharge/Normal operation status

3. Ambient air DB temperature
4. Occupied/unoccupied
5. Five-Minute GHG Signal (once available)

ii. Current Baseline

1. Current Baseline for this month (from last monthly update)
2. Updated Current Baseline
    a. For next month
    b. incorporating the insertion of the reporting month's data into the baseline database
    c. displacing older data from the database

Data rolled up from the meter interval report into the app interval report must follow the format specified by the SGIP database manager in the latest file format spec.

Appendix H – Incentive Calculation Examples

Energy Storage Incentive Duration Decrease Examples

Table 1: Energy Storage Incentive Duration Decrease (Projects with backup capability) Calculation

Example 1: Four-hour system at $.40/Wh incentive rate with a discharge rating of 100 kW and a discharge capacity of 400 kWh (400,000 Wh)	
Given	Calculation
Discharge Rating: 100,000 W Total Duration: 4 hours Total Discharge Capacity: 400,000 Wh Incentive Rate: $0.40/Wh	**Step 1** *Calculate incentive for the first 2-hr discharge duration (0-2hrs) in a 4-hr system:* 100,000 W × 2h × $0.40/Wh × 100% = $80,000 **Step 2** *Calculate incentive for the second 2-hr discharge duration (2-4hrs) in a 4-hr system:* 100,000 W × 2h × $0.40/Wh × 100% = $80,000 **Step 3** *Calculate total incentive:* $80,000 + $80,000 = **$160,000**

Table 2: Energy Storage Incentive Duration Decrease (Projects with backup capability) Calculation

Example 2: Six-hour system at $.40/Wh incentive rate with a discharge rating of 100 kW and a discharge capacity of 600 kWh (600,000 Wh)	
Given	Calculation
Discharge Rating: 100,000 W Total Duration: 6 hours Total Discharge Capacity: 600,000 Wh Incentive Rate: $0.40/Wh	**Step 1** *Calculate incentive for the first 2-hr discharge duration (0-2hrs) in a 6-hr system:* 100,000 W × 2h × $0.40/Wh × 100% = $80,000 **Step 2** *Calculate incentive for the second 2-hr discharge duration (2-4hrs) in a 6-hr system:* 100,000 W × 2h × $0.40/Wh × 100% = $80,000 **Step 3** *Calculate incentive for the third 2-hr discharge duration (4-6hrs) in a 6-hr system:* 100,000 W × 2h × $0.40/Wh × 50% = $40,000 **Step 4** *Calculate total incentive:* $80,000 + $80,000 + $40,000 = **$200,000**

Table 3: Energy Storage Incentive Duration Decrease (Projects without backup capability) Calculation

Example 1: Four-hour system at $.40/Wh incentive rate with a discharge rating of 100 kW and a discharge capacity of 400 kWh (400,000 Wh)	
Given	Calculation
Discharge Rating: 100,000 W Total Duration: 4 hours Total Discharge Capacity: 400,000 Wh Incentive Rate: $0.40/Wh	**Step 1** *Calculate incentive for the first 2-hr discharge duration (0-2hrs) in a 4-hr system:* 100,000 W × 2h × $0.40/Wh × 100% = $80,000 **Step 2** *Calculate incentive for the second 2-hr discharge duration (2-4hrs) in a 4-hr system:* 100,000 W × 2h × $0.40/Wh × 50% = $40,000 **Step 3** *Calculate total incentive:* $80,000 + $40,000 = **$120,000**

Table 4: Energy Storage Incentive Duration Decrease (Projects without backup capability) Calculation

Example 2: Six-hour system at $.40/Wh incentive rate with a discharge rating of 100 kW and a discharge capacity of 600 kWh (600,000 Wh)	
Given	Calculation
Discharge Rating: 100,000 W Total Duration: 6 hours Total Discharge Capacity: 600,000 Wh Incentive Rate: $0.40/Wh	**Step 1** *Calculate incentive for the first 2-hr discharge duration (0-2hrs) in a 6-hr system:* 100,000 W × 2h × $0.40/Wh × 100% = $80,000 **Step 2** *Calculate incentive for the second 2-hr discharge duration (2-4hrs) in a 6-hr system:* 100,000 W × 2h × $0.40/Wh × 50% = $40,000 **Step 3** *Calculate incentive for the third 2-hr discharge duration (4-6hrs) in a 6-hr system:* 100,000 W × 2h × $0.40/Wh × 25% = $20,000 **Step 4** *Calculate total incentive:* $80,000 + $40,000 + $20,000 = **$140,000**

Table 5: Energy Storage Performance-Based Incentive (PBI) Payment Calculation Example (5-Year Period)

Example PBI Payment for a Two-Hour System: 100 kWh system at $.50/Wh		
Description	**Calculation**	**Result**
Total incentive	= 100,000 Wh * $.50/Wh	$50,000
Upfront payment	= $50,000 * 50%	$25,000
Remaining payment to be recuperated through PBI	= $50,000 * 50%	$25,000
Total anticipated kWh discharged/offset	= 100 kWh * 104 full discharges * 5 years	52,000 kWh
$/kWh for anticipated kWh discharged/offset	= $25,000 / 52,000 kWh	$0.480769230/kWh
$/kWh for anticipated kWh discharged/offset	= 100 kWh * 104 full discharges * $0.480769230/kWh	$5,000

Table 6: Energy Storage Performance-Based Incentive (PBI) Payment Calculation Example (2-Year Period)

Example PBI Payment for a Two-Hour System: 100 kWh system at $.50/Wh		
Description	**Calculation**	**Result**
Total incentive	= 100,000 Wh * $.50/Wh	$50,000
Upfront payment	= $50,000 * 50%	$25,000
Remaining payment to be recuperated through PBI	= $50,000 * 50%	$25,000
Total anticipated kWh discharged/offset	= 100 kWh * 104 full discharges * 2 years	20,800 kWh
$/kWh for anticipated kWh discharged/offset	= $25,000 / 20,800 kWh	$1.201923077 ⁄kWh
$/kWh for anticipated kWh discharged/offset	= 100 kWh * 104 full discharges * $1.201923077/kWh	$12,500

California Manufacturer Total Value of Capital Equipment Calculation Examples

Example 1

An energy storage project requests the California Manufacturer [118] incentive adder. The project provides the following cost breakdown:

Table 7: California Manufacturer Total Value of Capital Equipment Calculation Examples

Equipment Type	Manufacturer	Cost	Location Manufactured	Approved CA Manufacturer
Energy Storage Medium	ABC Company	$12,000	Los Angeles, CA	Yes
Inverter	Lizard Inverters	$3,000	San Diego, CA	Yes
Balance of System	Nick Controllers	$2,000	South Korea	No

- Total system cost = $17,000
- Cost percentage of equipment components manufactured in California = 88%

Result: The project is eligible to receive the California Manufacturer Adder.

Example 2

An energy storage project requests incentive adder. The project provides the following cost breakdown:

Table 8: California Manufacturer Total Value of Capital Equipment Calculation Examples

Equipment Type	Manufacturer	Cost	Manufacturing Location	Approved CA Manufacturer?
Energy Storage Medium	XYZ Company	$16,000	Philadelphia, PA	No
Inverter	Lizard Inverters Company	$3,000	San Diego, CA	Yes
Balance of System	Golden Gate System Company	$11,000	San Francisco, CA	Yes

- Total system cost = $30,000
- Cost Percentage of equipment components manufactured in California = 46.7%

Result: The project is ineligible to receive the California Manufacturer Adder.

HVAC-integrated S-TES System Energy Capacity Calculation Examples

Example 1: Systems that fully avoid compressor(s) run-time during its entire discharge duration

[118] The manufacturer must be the entity responsible for the assembly and manufacturing of a substantial portion of the assembly of the final product, as described in Section 4.4.1.

Calculate the rated capacity of a HVAC-integrated S-TES system for a 5-ton HVAC unit with a 12 SEER rating in Climate Zone 10. During the S-TES system's discharge duration, the HVAC unit's compressor is entirely substituted for the full 180-minute duration.

1. Using the Conversion Table in Appendix C, the peak kW Offset is 5.8 kW.
2. Energy Capacity = 5.8 kW x 180 minutes x (1 hour / 60 minutes) = 17.4 kWh

Example 2: Systems with compressor(s) running a percentage of time during its discharge duration

Calculate the rated capacity of a HVAC-integrated S-TES system for a 5-ton HVAC unit with a 12 SEER rating in Climate Zone 10. During the S-TES system's discharge duration, the HVAC unit's compressor is running 60 minutes of the 180-minute duration with the maximum compressor operation being five minutes in every 15-minute interval.

1. Using the Conversion Table in Appendix C, the peak kW Offset is 5.8 kW.
2. The compressor runtime during TES system's discharge duration is 60 minutes (180 minutes x 5 / 15 minutes)
3. The minimum avoided compressor run-time is 120 minutes (180 minutes - 60 minutes)
4. Energy Capacity = 5.8 kW x 120 minutes x (1 hour / 60 minutes) = 11.6 kWh

HVAC-integrated S-TES System Rated Capacity Calculation Example

Example 1: Systems with compressor(s) running a percentage of time during its discharge duration

Calculate the rated capacity of a HVAC-integrated S-TES system for a 5-ton HVAC unit with a 12 SEER rating in Climate Zone 10. During the S-TES system's discharge duration, the HVAC unit's compressor is running 60 minutes of the 180-minute duration, where the maximum compressor operation is five minutes in every 15-minute interval.

1. Using the Conversion Table in Appendix C, the peak kW Offset is 5.8 kW.
2. The compressor runtime during S-TES discharge duration is 60 minutes (180 minutes x 5 / 15 minutes)
3. The minimum avoided compressor run-time is 120 minutes (180 minutes - 60 minutes)
4. Rated Capacity = 5.8 kW x 120 minutes / 180 minutes = 3.87 kW