PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

Pacific Gas & Electric Company
GAS (Corp ID 39)
Status of Advice Letter 4769G/6974E
As of July 31, 2023

Subject: Proposed Revisions to the Self-Generation Incentive Program Handbook Pursuant to Decision 23-04-045

Division Assigned: Energy

Date Filed: 06-28-2023

Date to Calendar: 07-03-2023

Authorizing Documents: D2304045

Disposition:	**Accepted**
Effective Date:	**06-28-2023**

Resolution Required: No

Resolution Number: None

Commission Meeting Date: None

CPUC Contact Information:

edtariffunit@cpuc.ca.gov

AL Certificate Contact Information:

Stuart Rubio
279-789-6210
PGETariffs@pge.com

PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

To: Energy Company Filing Advice Letter

From: Energy Division PAL Coordinator

Subject: Your Advice Letter Filing

The Energy Division of the California Public Utilities Commission has processed your recent Advice Letter (AL) filing and is returning an AL status certificate for your records.

The AL status certificate indicates:

Advice Letter Number
Name of Filer
CPUC Corporate ID number of Filer
Subject of Filing
Date Filed
Disposition of Filing (Accepted, Rejected, Withdrawn, etc.)
Effective Date of Filing
Other Miscellaneous Information (e.g., Resolution, if applicable, etc.)

The Energy Division has made no changes to your copy of the Advice Letter Filing; please review your Advice Letter Filing with the information contained in the AL status certificate, and update your Advice Letter and tariff records accordingly.

All inquiries to the California Public Utilities Commission on the status of your Advice Letter Filing will be answered by Energy Division staff based on the information contained in the Energy Division's PAL database from which the AL status certificate is generated. If you have any questions on this matter please contact the:

Energy Division's Tariff Unit by e-mail to
edtariffunit@cpuc.ca.gov

Pacific Gas and Electric Company

Sidney Bob Dietz II
Director
Regulatory Relations

Pacific Gas and Electric Company
300 Lakeside Drive
Oakland, CA 94612

June 28, 2023

Advice 4769-G/6974-E
(Pacific Gas and Electric Company ID U 39 M)

Advice 5059-E
(Southern California Edison Company U 338-E)

Advice 143-E
(Center for Sustainable Energy®)

Advice 6154-G
(Southern California Gas Company U 904-G)

Public Utilities Commission of the State of California

Subject: Proposed Revisions to the Self-Generation Incentive Program Handbook Pursuant to Decision 23-04-045

Purpose

Pacific Gas and Electric (PG&E), Center for Sustainable Energy® (CSE), Southern California Edison Company (SCE), and Southern California Gas Company (SoCalGas), collectively the Self-Generation Incentive Program (SGIP) Program Administrators (PAs), submit this Tier 1 Advice Letter (AL) to update the SGIP Handbook in accordance with Decision (D.) 23-04-045 Ordering Paragraph (OP) 9.

Discussion

In D.23-04-045 (the Decision), the CPUC 1) granted the PAs discretion to grant relief to the customers affected by Petersen Dean Inc.'s bankruptcy;[1] and 2) established a pathway, requiring CPUC approval, to provide similar relief to other customers who unexpectedly lose contact with their developers.

1) Relief for Petersen Dean Customers:
   For customers impacted by Petersen Dean's bankruptcy, the CPUC granted additional time to submit Incentive Claim documentation, provided relief from the service warranty requirements established in earlier Commission decisions,[2] and

[1] Filed in United States Bankruptcy Court, District of Nevada (Case No. 2:20-BK-12821), jointly administered with In Re: Beachhead Roofing and Supply Inc. (Bankr. D. Nev. 2:20-BK-12814).
[2] D.23-04-045, pp. 15, OP 5.

relieved the PAs of the obligation to enforce penalties against Petersen Dean in the event of non-compliance with program GHG rules.[3] This relief is effective immediately to Petersen Dean customers.

2) Relief for other customers who unexpectedly lose contact with their developer: If a customer loses permanent contact with their developer due to a future developer bankruptcy or the developer going out of business, the PAs are granted the authority to submit a Tier 2 Advice Letter to request additional time for Incentive Claim requirements and exceptions to the service warranty and developer GHG compliance enforcement requirements. Upon the CPUC disposition date of the Tier 2 Advice letter, the customers requesting relief would be granted an additional 90-day extension. For customers that have exhausted all available program extensions, this 90-day extension would commence upon the issuance date of the related Tier 2 Advice Letter.

Proposed Handbook Modifications

OP 9 of the Decision directs the SGIP PAs to "file [a] Tier 1 Advice Letter to implement the changes to the SGIP Handbook within 60 days of the issuance of this decision." Accordingly, the SGIP PAs submit this Joint Advice Letter with changes to the SGIP Handbook at the sections listed below and as reflected in Attachment A:

- Section 2.6.3 Extensions and Exceptions
- Section 5.4.2 Required Documentation for Proof of Project Milestone (Storage Projects)
    - (3) Executed Contract and/or Agreement for System Installation
- Section 6.9.2 Required Documentation for Proof of Project Milestone (Generation Projects)
    - (3) Executed Contract and/or Agreement for System Installation
- Section 9.1.7 Residential GHG Emissions Compliance
- Legislation and Regulatory Background

Protests

Anyone wishing to protest this submittal may do so by letter sent electronically via E-mail, no later than July 18, 2023, which is 20 days after the date of this submittal. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
E-mail: EDTariffUnit@cpuc.ca.gov

[3] D.23-04-045, pp. 8-9, 10-11, 15, OP 3.

Copies of protests should also be emailed to the CPUC's Energy Division Director.

In addition, protests and all other correspondence regarding this AL should also be sent electronically to the attention of:

For CSE: Sephra Ninow
Director, Regulatory Affairs
Center for Sustainable Energy®
E-mail: sephra.ninow@energycenter.org

For SoCalGas: Attn: Gary Lenart
Regulatory Tariff Manager
E-mail: Glenart@socalgas.com
E-mail: Tariffs@socalgas.com

For PG&E: Attn: Sidney Bob Dietz II
Director, Regulatory Relations
c/o Megan Lawson
E-mail: PGETariffs@pge.com

For SCE: Connor Flanigan
Managing Director, State Regulatory Operations
Southern California Edison Company
E-mail: AdviceTariffManager@sce.com

and

Tara S. Kaushik
Managing Director, Regulatory Relations
Southern California Edison Company
c/o Karyn Gansecki
E-mail: Karyn.Gansecki@sce.com

Effective Date

Pursuant to General Order (GO) 96-B, Rule 5.1, and OP 9 of D.23-04-045, this advice letter is submitted with a Tier 1 designation. PG&E requests that this Tier 1 advice submittal become effective upon date of submittal, which is June 28, 2023.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically to parties shown on the attached list and the parties on the service list for R. 10-05-004, R.12-11-005 and R.20-05-012. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For

changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Sidney Bob Dietz II
Director, Regulatory Relations
CPUC Communications

Attachments: Attachment A - Redlined SGIP Handbook

cc: Service List R.10-05-004
cc: Service List R.12-11-005
cc: Service List R.20-05-012

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (U 39 M)

Utility type:
- [x] ELC
- [x] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Stuart Rubio
Phone #: 279-789-6210
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: stuart.rubio@pge.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 4769-G/6974-E

Tier Designation: 1

Subject of AL: Proposed Revisions to the Self-Generation Incentive Program Handbook Pursuant to Decision 23-04-045

Keywords (choose from CPUC listing): Compliance

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.23-04-045

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date: 6/28/23

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission Energy Division Tariff Unit Email: EDTariffUnit@cpuc.ca.gov	Contact Name: Sidney Bob Dietz II, c/o Megan Lawson Title: Director, Regulatory Relations Utility/Entity Name: Pacific Gas and Electric Company Telephone (xxx) xxx-xxxx: (415)973-2093 Facsimile (xxx) xxx-xxxx: Email: PGETariffs@pge.com
	Contact Name: Title: Utility/Entity Name: Telephone (xxx) xxx-xxxx: Facsimile (xxx) xxx-xxxx: Email:

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

Attachment A

Redlined SGIP Handbook

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

The 2023 V3 Handbook has been updated to reflect the following changes:

- Added Language to Extension and Exceptions
  - § 2.6.3 Extensions and Exceptions
- Added Language to Required Documentation for Proof of Project Milestone
  - § 5.4.2 (3) Copy of Executed Contract and/or Agreement for Installation (Storage Projects)
  - § 6.9.2 (3) Copy of Executed Contract and/or Agreement for Installation (Generation Projects)
- Added Language to Residential GHG Emissions Compliance
  - § 9.1.7 Residential GHG Emissions Compliance
- Updated Legislation and Regulatory Background

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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:	www.energycenter.org/sgip
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, GT20B8 Los Angeles, CA 90013-1011

[1] Potential eligible projects located in the service territory of both Southern California Edison and the Southern California Gas Company can apply for incentive funding to either Program Administrator, but not to both.

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) emission 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 establishes 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. Any changes made to the SGIP will be published in revisions to this Handbook and/or posted at each Program Administrator's (PA's) website. The Program Administrators are Pacific Gas and Electric (PG&E), Southern California Edison (SCE), the Southern California Gas Company (SoCal Gas) and the Center for Sustainable Energy® (CSE).[2]

[2] CSE is the Program Administrator for SDG&E customers.

1 Budget

1.1 Statewide Program Budget and Administrator Allocations

Authorized incentive collections through the end of 2024 total $813,400,000.[3] Additional funds made available through attrition will be added to Program Administrators' budgets as they become available. Authorized incentive collections for each Program Administrator are as follows:

Pacific Gas and Electric Company	$360,000,000[4]
Southern California Edison Company	$280,000,000[5]
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 until all incentive funds have been fully allocated.[6]

The current budget, incentive rates, and incentive steps in each Program Administrator territory are posted on the Program Metrics page at www.selfgenca.com.

1.2 Budget Allocation

The budget is divided accordingly and described in detail below:

Energy Storage Technologies – 88% of funds

- Large-scale storage (greater than 10 kW) - 10%
- Small residential storage (equal to or less than 10 kW) – 7%
- Residential equity – 3%
- Non-residential equity – 0%[7]
- Equity resiliency (residential and non-residential) – 63%
- Heat pump water heaters (general) – 5%
- SJV Pilot budget – 0%[8]

[3] Available authorized incentives comprise of ratepayer collections from 2020 to 2024 pursuant to D.20-01-021.

[4] Please note, PG&E's funding allocation per D.20-01-021 does not include funding for administrative expenses.

[5] Please note, SCE's funding allocation per D.20-01-021 does not include funding for administrative expenses.

[6] Total available funding includes authorized incentive collections, funds from cancelled projects, and application fee forfeitures.

[7] 2020-2024 authorized collections suspend further collections for non-residential equity storage once existing carryover is exhausted.

[8] Pursuant to D.19-09-027, SJV Pilot Program has a $10 million set-aside funded from SCE and PG&E's unused non-residential equity budget.

Renewable Generation Technologies – 12% of funds

Energy Storage General Budget

The incentive budget allocates 88% to energy storage technologies, with 7% of the energy storage category carved out for small residential projects less than or equal to 10 kW. This budget category has added Steps 6 & 7 (with equal budget allocations of $28 million each per step) and continues the $0.05/Wh incentive step-down structure.

The incentive budget allocates 10% to large-scale storage (greater than 10 kW) for Steps 3 through 5.

Energy Storage Equity Budget

The incentive budget allocates 3% for residential energy storage equity budget for qualifying residential (single family and multifamily low-income housing) regardless project size. The incentive budget allocates 0% for the non-residential energy storage equity budget.

Renewable Generation Budget

The incentive budget allocates 12% to generation technologies, with no incentive step-down structure.

Equity Resiliency Budget

A $100 million Equity Resiliency Budget has been established using unspent funds from the Generation Technology budget.[9]

Heat Pump Water Heater Budget

$4 million has been established for equity projects. Additionally, the incentive budget allocates 5% to general market HPWHs.

SJV Pilot Budget

$10 million has been set aside from SCE and PG&E's unspent non-residential equity budget.

Fund Shifting Authority

Program Administrators have the option to transfer funds between technology incentive budgets after December 31, 2022 if it is likely that funds will remain unspent, allowing PAs the flexibility to better respond to market demands in SGIP.[10]

[9] Funds were transferred sequentially in order from the highest budgeted incentive step to the lowest. If any PA had insufficient funds in the Generation Technology budget to reach the budget levels required, the shortfall was transferred from the Large-Scale storage budget.

[10] Implemented pursuant to Ordering Paragraph 34 in D.20-01-021.

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. However, in the event that application submissions on a single day exceed available funding in a given Program Administrator's territory for a given budget and step, a lottery will be initiated. Lottery details are found in *Section 2.3.2*. Please refer to www.selfgenca.com for the most up-to-date information on current incentive steps, rates, and available funds.

2.1.1 *Application Submission*

All SGIP applications and required documents[11] at all stages of the application process must be submitted via the SGIP online application database at www.selfgenca.com. **Mailed, emailed, faxed or hand delivered applications will not be accepted.**

In order to submit an application and/or project documentation, companies or individuals must create an account and register users at www.selfgenca.com. Once the account has been confirmed, registered Applicants may create and edit applications.

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 will be rejected.[12] Applicants must agree to the Terms of Use pertaining to the SGIP online application database in order to submit an application. The Terms of Use can be found at www.selfgenca.com.

Once an application is entered into the SGIP database and submitted for consideration within a given step, it will be retained in the database. In the event a lottery is implemented and the application is *not* selected for the current step, the Applicant must update relevant documentation and resubmit the application in order to be considered in the next incentive step.

2.1.2 *Signatures*

Original signed documents or scanned copies of original signed documents are required for all program provided forms.[13] Electronic signatures and/or acknowledgments are acceptable for documents created by

[11] With the exception of the application fee check that is to be mailed directly to the Program Administrator. See *Section 5.4.1* and *Section 6.10.1* for more information.

[12] Duplicative applications are considered a program infraction. See *Section 9* for information on program infractions.

[13] Includes: Reservation Request Forms, Proof of Project Milestone Forms, Incentive Claim Forms, and all affidavits. All forms requiring signatures from multiple parties must have all signatures submitted on one document.

the Contractor or Host Customer, such as the installation contract.[14] 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.

2.1.3 *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.

2.2 Incentive Process Flowcharts

There are two application processes illustrated below:

- Three-Step Application Process - Figure 2.2-1
- Two-Step Application Process - Figure 2.2-2

All residential projects and non-residential projects less than 10 kW must follow the two-step application process. Non-residential projects greater than or equal to 10 kW must follow a three-step process.

[14] E-signatures may be acceptable for other program documents depending on Program Administrator territory. Please contact your Program Administrator for more information.

Figure 2.2-1: Three-Step Application Process for Public and Non-Public Entities ≥ 10 kW

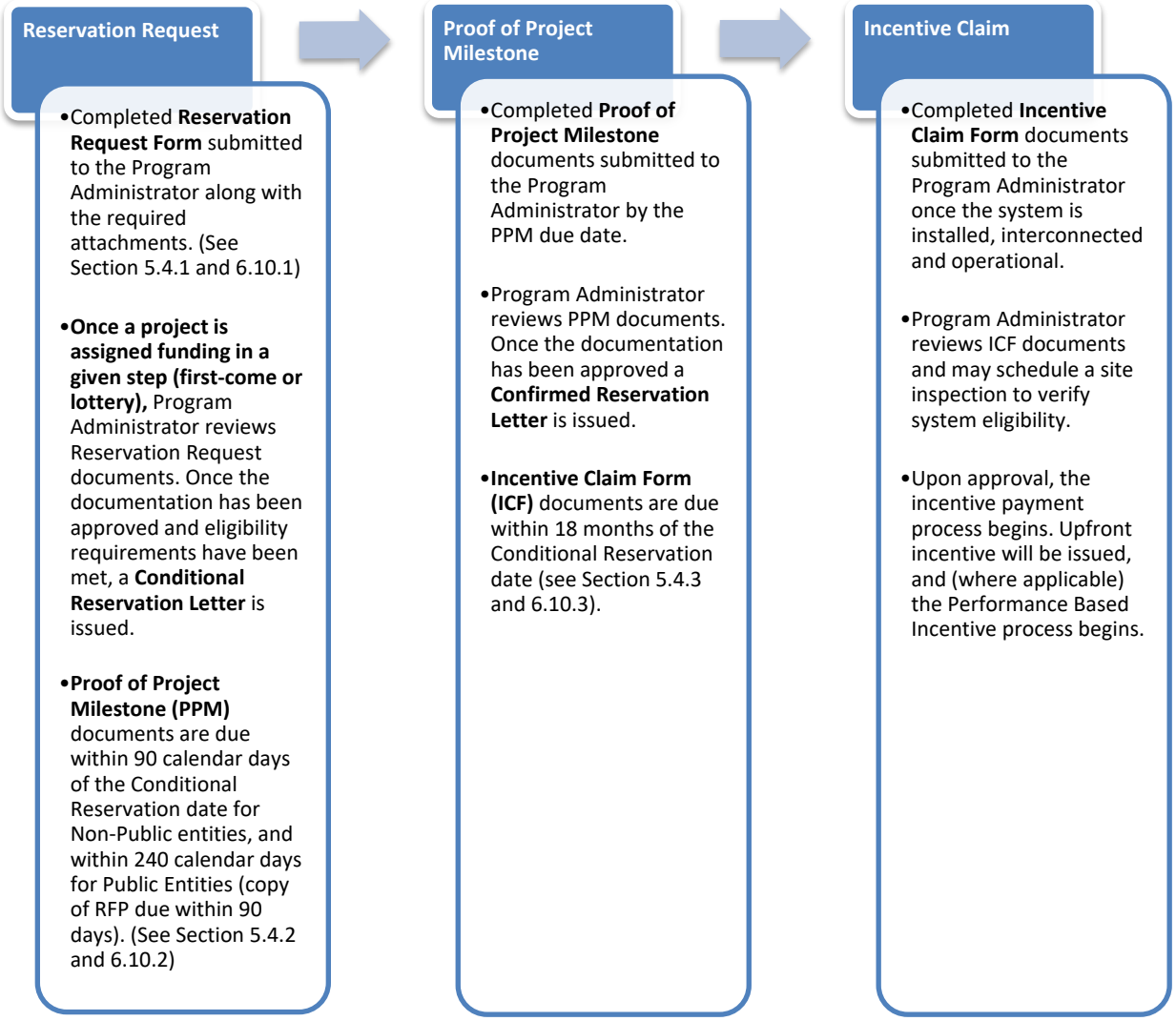
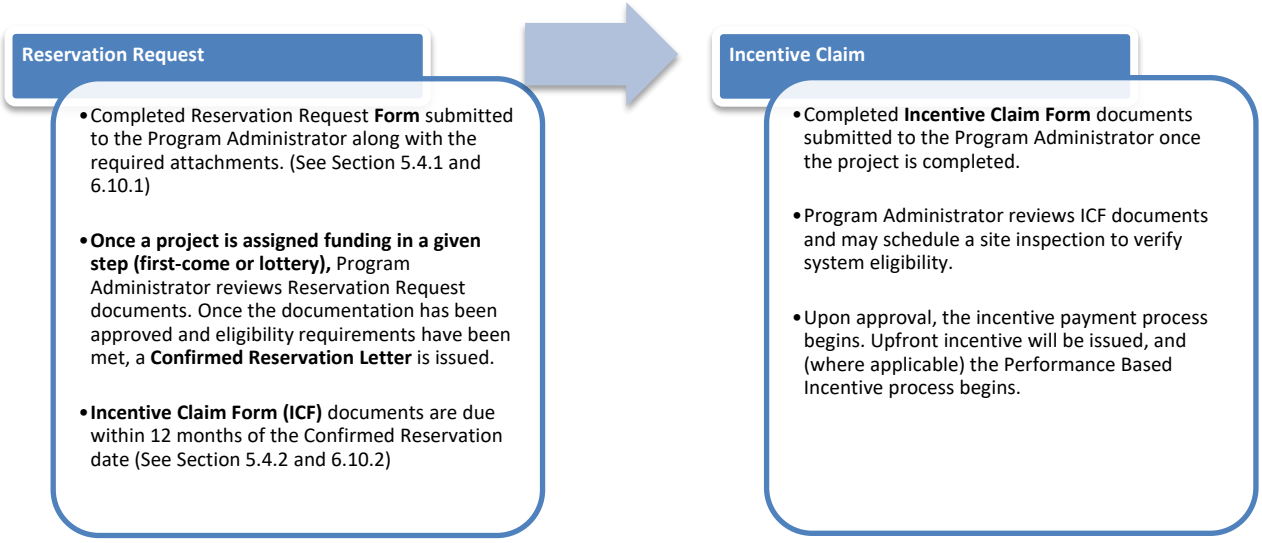


Figure 2.2-2: Two-Step Application Process for All Residential and Non-Residential Entities <10 kW



2.3 Reservation Request

To request an incentive, an online Reservation Request Form (RRF) must be submitted with required attachments. Non-residential projects are required to submit an application fee upon submittal of the RRF. (See *Section 5.4.1* and *6.10.1* for required attachments specific to storage and generation technologies.) Projects that include multiple technologies must submit separate applications for each technology.

2.3.1 *Submitting the Reservation Request*

After all Reservation Request documents have been uploaded to the SGIP online application database, Applicants must submit their complete application package to the appropriate Program Administrator. Applicants may not submit applications in excess of the Developer cap for the active step. Once an application is assigned an incentive rate, the Program Administrator will review the application package to ensure the project meets all program requirements. Incentive funds may only be reserved after the Program Administrator receives and approves the Reservation Request documents.

2.3.2 *Lottery Process*

A lottery will be triggered **only** in the event that applications submitted on a single day exceed funds available for a given budget and step.[15] Lotteries are to be conducted separately for large scale energy storage technologies, small residential energy storage technologies less than or equal to 10 kW, and generation technologies by Program Administrator territory, as necessary. All applications not selected in the lottery will be rejected and must reapply in the next funding step in order to receive funding.

2.3.2.1 Priority Projects

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

[15] 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.

- Energy storage projects located within the service territory of Los Angeles Department of Water and Power.[16]

- 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. A lottery will be held for the projects in the priority or non-priority category that exceeds available funding in the active step.

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.

A lottery will be held for the priority category that exceeds available funding in the active step.

2.3.3 *Pause Period*

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

- 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 to verify projects identified with a locational priority.

- If required, the lottery is conducted.

- 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.

- If a lottery is conducted, a notification of the results of the lottery is sent to Applicants. Applications that were not selected for funding in the current step through the lottery will be instructed on 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.[17]

[16] All projects interconnecting into LADWP's electrical grid must abide by LADWP interconnection rules.

[17] Projects are not allowed to be assigned a "split incentive" across two or more incentive steps.

- The SGIP public website is updated with information on the new incentive rate(s), available funds and the date of the next application submission opportunity.

2.3.4 *Incomplete Reservation Request*

Reservation Request documents must be complete and submitted as part of the application package. If an application is found to be missing any required information or requires additional clarification, the Program Administrator or their representative will request the information necessary to process that application further. Applicants have 15 calendar days to respond with the necessary information[18]. If after 15 calendar days 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 for the same missing or uncorrected item. Cancelled applications may be resubmitted and will be treated as a new application (i.e. all required documents must be resubmitted) and processed in sequence along with other new applications. Funds from cancelled projects will be allocated 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.

2.3.5 *Approval of Reservation Request*

Upon Program Administrator approval of the Reservation Request package (Reservation Request Form and required attachments) the Applicant and Host Customer will receive a reservation letter. The two types of reservation notice letters are based on the type of application:

Conditional Reservation Letter (for Three-Step applications)

Upon approval of the Three-Step Reservation Request package, a Conditional Reservation Letter will be issued confirming that a specific incentive amount is conditionally reserved for project. The letter will list the approved incentive amount, the Proof of Project Milestone date, and the reservation expiration date. All reservations are conditional pending receipt of the Proof of Project Milestone documentation on or before the Proof of Project Milestone date.

Confirmed Reservation Letter (for Two-Step applications)

Upon approval of the Two-Step Reservation Request package, a Confirmed Reservation Letter will be issued. The Confirmed Reservation Letter will list the approved 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 Incentive Claim Form must be submitted along with all of the necessary documentation to request an incentive payment.

[18] D.20-10-025 allowed a 90-day suspension period for electric-pump well applications affected by the eligibility requirements direction in that Decision.

2.3.6 *Wait List and Program Closure*

Once funds have been fully allocated in the final incentive step of a Program Administrator's given budget, applications will be placed on a wait list to be funded as incentive funds become available throughout the remainder of the program. When there is enough attrition to fund wait-listed projects, wait listed projects will be assigned an incentive rate in the last step and reviewed in the order in which they were submitted. In the event that there are available funds and all wait-listed projects have been allocated funding, new applications will be subject to normal program procedures specified in *Section 2.1*. Program Administrators may continue accepting new applications until all incentive funds have been fully paid or until December 31, 2025[19], whichever comes first. [20]

2.4 Proof of Project Milestone

Two-Step Applications must submit all Proof of Project Milestone (PPM) documents as part of their Reservation Request. For *Three-Step Applications, Non-Public Entities* have 90 calendar days from the date of the Conditional Reservation Letter to satisfy all Proof of Project Milestone criteria. For *Three-Step Applications, Public Entities* must submit a copy of the issued Request for Proposal (RFP) or equivalent for purchase or installation of the system within 90 calendar days of the date of the Conditional Reservation Letter; Proof of Project Milestone documentation must then be submitted within 240 days of the date of the Conditional Reservation Letter.

2.4.1 *Submitting Proof of Project Milestone*

Once the Online Proof of Project Milestone is completed and all the required attachments are uploaded, the PPM package must be submitted to the appropriate Program Administrator via the online application database.

2.4.2 *Incomplete Proof of Project Milestone*

If the Proof of Project Milestone package is not received by the Proof of Project Milestone date, the application may be cancelled by the Program Administrator.

If the Proof of Project Milestone documentation is incomplete and/or requires clarification, the Program Administrator will request the information necessary to process that application further. Applicants will have 15 calendar days to respond with the necessary information. If after 15 calendar days the requested information has not been submitted or satisfied the eligibility requirement in question, the application may be cancelled. An application may not receive multiple requests for the same missing or uncorrected item. Any project attrition and forfeited application fees will be allocated to the current incentive step in the

[19] SB 700 extended rate payer collection to December 31, 2024, and SGIP administration through December 31, 2025.

[20] Applications that remain on the waitlist for step 5 when step 6 opens will be assigned to step 6 until the soft target is reached. Projects that remain on the waitlist once the target is met will be removed and the waitlist closed. Projects are welcome to apply to the next step provided they meet the current eligibility requirements.

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.

2.4.3 *Approval of Proof of Project Milestone*

Once Proof of Project Milestone requirements have been successfully met, the Program Administrator will issue a Confirmed Reservation Letter. The Confirmed Reservation Letter will list the reservation dollar amount and the reservation expiration date (18 months after the date of the original Conditional Reservation Letter). Upon project completion and no later than the reservation expiration date, the completed Incentive Claim Form must be submitted along with all of the necessary documentation to request an incentive payment.

2.5 Incentive Claim

Once the project is complete, Applicants must request payment of the incentive amount by submitting the Incentive Claim Form (ICF) and all applicable Incentive Claim documents to the Program Administrator via the online application database. A project is considered complete when the system is completely installed, interconnected (if applicable), permitted, and capable of operating in the manner for which it was designed. Payment will be dispersed after the Program Administrator verifies by Post-Installation inspection[21] (if the project is selected for a Post-Installation inspection) that the system meets all the eligibility requirements of the SGIP. The completed Incentive Claim Form must be submitted to the Program Administrator on or before the reservation expiration date together with the required attachments.

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). In order to administer this provision, upon the Program Administrator's request, the Applicant shall provide the Program Administrator with evidence satisfactory to the Program Administrator of (a) the date on which the Applicant filed its application for such permit, (b) the date on which it submitted its interconnection application, (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.[22]

2.5.1 *Submitting Incentive Claim*

Once the Incentive Claim Form is complete and all the required attachments are submitted, Applicants may submit their Incentive Claim package to the Program Administrator via the online application database.

[21] See Definition for *Inspections*.

[22] No wind project will be suspended beyond June 30, 2027 unless the Legislature authorizes additional revenue collections for SGIP purposes such that SGIP's sunset date is extended beyond the date of January 1, 2026 authorized in Senate Bill 700.

2.5.2 *Incomplete Incentive Claim*

If the complete Incentive Claim package is not received by the reservation expiration date, the application may be cancelled by the Program Administrator.

If submitted Incentive Claim documentation is incomplete and/or requires clarification, the Program Administrator will request the information necessary to process that application further. Applicants have 30 calendar days to respond with the necessary information. If after 30 calendar days the requested information has not been submitted or satisfied the eligibility requirement in question, the application may be cancelled. An application may not receive multiple requests for the same missing or uncorrected item. Any project attrition and forfeited application fees will be allocated to the current 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.

2.5.3 *Inspections*

Upon receipt of a complete Incentive Claim Form package, the Program Administrator may organize an On-site Post-Installation inspection (or virtual Post-Installation inspection for select residential applications) [23] to verify that the project's system is installed as represented in the application, is operational, is interconnected and conforms to the eligibility criteria of the SGIP. Verification includes but is not limited to:

- 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 systems will be tested to validate the discharge energy capacity. Energy storage projects will be inspected according to the Energy Storage Field Verification Protocol. HVAC-integrated S-TES systems will be tested to show they can provide enough thermal energy to turn off the compressor of the accompanying HVAC unit for the specified discharge duration period. Refrigeration TES systems will be tested to show they can 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.
- If the eligible system size depended on new construction or load growth, the required load will be confirmed.

[23] Refer to Energy Storage Field Inspection and Discharge Testing Protocol and Field Inspection Sampling Protocol at www.selfgenca.com.

- Verify system capacity rating to confirm the final incentive amount.

Energy storage inspections will follow the latest version of the Energy Storage Post-Installation Inspection and Discharge Testing Protocol found on www.selfgenca.com.

Failed Post-Installation Inspection

If the results of the Post-Installation inspection indicate that the project is not ready for approval, 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. 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 full eligibility within the requested time, the application may be cancelled.

If the site load, 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 Post-Installation inspection or;
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.

2.5.4 *Approval of Incentive Claim*

Upon final approval of the Incentive Claim documentation and completed virtual or On-Site Post-Installation Inspection (if the project is selected for a Post-Installation inspection), 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 will be made to the assigned Payee as indicated on the Incentive Claim Form and will be mailed to the address provided.

2.6 Modifications and Extensions

All projects are expected to be installed as described on the Conditional and Confirmed Reservation Letter. In the event that 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 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.

2.6.1 *Modifications Pre-ICF*

Changes pertaining to System Owner, Payee, equipment 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, additional incentive funding for an application may be allowed only when a project is assigned to the currently active step and adequate funding is available.

Changes in equipment type, system capacity, Applicant, installer or other substantial changes may require new RRF and/or PPM documentation. Once the request has been approved, a new reservation letter may be issued. Changes do not extend the reservation expiration date.

2.6.2 *Modifications Post-ICF*

In general changes to the completed project are not allowed. In the event that 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 projects adding generation see *Section 3.2.4*.

2.6.3 *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 6-month extensions of the reservation expiration date, after which the reservation expires automatically.[24] Extensions will be for special circumstances only. Additionally, extensions will not be granted to projects that have not made satisfactory progress toward completion in compliance with established milestones and requirements. Any request for a second or third extension of the reservation expiration date requires unanimous SGIP Working Group approval, and the SGIP Working Group shall notify Applicants of the SGIP Working Group's decision in writing within 30 days. When considering a request for a second or third reservation expiration extension, the SGIP Working Group 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.

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

Eligible energy storage SGIP projects may rely on the longer of the extension granted under D.14-05-033 or the third six-month extension granted in D.15-06-002.

Exception Request: Stay on Cancellations due to COVID-19 pandemic[25]:

Projects that have exhausted the maximum of three 6-month extensions and require additional time to complete the installation due to issues related to the COVID-19 pandemic may be granted a stay on the cancellation not to exceed one (1) year from the project's Reservation Expiration Date. Program participants seeking additional time due to COVID-19 delays must submit a written request with verifiable information that clearly demonstrates the project was progressing in a timely manner prior to the COVID-19 pandemic. Similar to a second or third extension request, any request for a stay of cancellation requires unanimous SGIP Working Group approval, and the SGIP Working Group shall notify Applicants within 30 days of a submitted request. When considering a request for a stay of cancellation, the SGIP Working Group will consider:

1) Whether the project's delay is due to COVID related impacts and was outside the control of the Host Customer.

- Review is to include documentation (provided as part of the formal request) to substantiate the specific COVID related restrictions and/or impacts that prohibited the completed installation of the project.

2) Whether the project has made significant progress toward completion and would otherwise have installed prior to the current reservation expiration date.

- Review is to include a revised timeline (provided as part of the formal request) showing the expected date of commissioning of the project and that interconnection of the project will be no greater than one (1) year from the project's reservation expiration date.

Exception Request: PBI Pause on Calculations due to COVID-19:

Projects not able to meet the performance obligations of the program due to COVID-19 restrictions may request to have their PBI calculations paused for no longer than one (1) year. A written request must be provided to the Program Administrator with verifiable justification that demonstrates the customer is unable to meet the PBI requirements due to COVID-19 related issues. Program Administrator exception review will include:

[25] CPUC Decision 21-03-009

1) Whether system performance is due to COVID related impacts and was outside the control of the Host Customer.

- Review is to include documentation (provided as part of the formal request) to substantiate the specific COVID related restrictions and/or impacts that prohibited the performance obligations of the system.

2) A revised timeline (provided as part of the formal request) showing the 'pause period' (no greater than 1 year) being requested and plan to re-establish the performance obligations of the system.

If the request is approved, the project's performance period will be extended by the number of months that the PBI period was paused to ensure performance obligations are met prior to full payment.

Any other procedure or documentation exceptions should be submitted to the appropriate Program Administrator and will be subject to Working Group approval.

Exception Request: 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.[26] 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.

[26] 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.

3 Incentives

3.1 Incentive Rates

The incentive rates for the two budget categories of the SGIP, renewable generation and energy storage, are provided below. Vendors/developers shall not sell a residential storage system that receives incentives for a total price (before incentives) that is greater than the price they sell a comparable system that does not receive incentives. [27]

3.1.1 ***Renewable Generation Incentive Rates***

Renewable generation projects incentive levels are $2.00/W with no step-down structure.

3.1.1.1 ***Renewable Generation Resiliency Adder***

A renewable generation resiliency adder incentive of $2.50/W for renewable generation projects. Combined with the base incentive of $2.00/W, this results in an incentive of $4.50/W for renewable generation projects intended for resiliency purposes. Customers eligible for the equity resiliency budget and general market customers with critical resiliency needs are eligible for the renewable generation resiliency adder.[28]

The renewable generation resiliency adder is not limited to only equity budget or equity resiliency customers and is also available to critical resiliency facilities that provide critical resiliency services to serving their communities during PSPS events.

3.1.2 ***Energy Storage Incentive Rates***

Total energy storage incentive funds are divided across five steps for large storage and seven steps for small residential storage. Energy storage incentives generally 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 to the next step for large-scale storage projects not claiming the ITC and the small residential carve-out will be $0.10/Wh rather than $0.05/Wh. The incentive for large-scale storage projects claiming the 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.[29]

The table below has been updated to reflect the accelerated incentive decline beginning in Step 2. **Please visit <u>www.selfgenca.com</u> for a list of <u>current incentive rates</u>.**

Table 3.1.2 Energy Storage Incentives per Watt-hour (Wh)

[27] D.19-09-027 at 38.

[28] As defined in D.20-01-021.

[29] A complete table of incentive rates for ITC and non-ITC-claiming large-scale projects is given in Appendix F.

	Step 1	Step 2	Step 3	Step 4	Step 5	Step 6	Step 7
Energy Storage General Budget	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**	**$/Wh**
Large Storage (>10 kW)	$0.50	$0.40	$0.35	$0.30	$0.25	N/A	N/A
Large Storage Claiming ITC	$0.36	$0.29	$0.25	$0.22	$0.18	N/A	N/A
Residential Storage (<=10 kW)	$0.50	$0.40	$0.35	$0.30	$0.25	$0.20	$0.15

3.1.2.1 ***General Market Non-Residential Storage Resiliency Adder***

General market non-residential customers with critical resiliency needs that provide critical facilities or infrastructure as outlined in section 4.1.1.3, with the exception of the equity requirement, qualify for the general market resiliency adder.

The non-residential general market resiliency adder is $0.15/Wh in addition to the current step incentive rate.

3.1.2.3 ***Equity and Equity Resiliency Incentive Levels***

The Equity Budget incentive for residential and non-residential customers is $0.85/Wh. [30]

For Residential and Non-Residential customers that meet the eligibility requirements of the Equity Resiliency Budget, as outlined in section 4.1.1.3, the incentive rate is $1.00/Wh.

Table 3.1.2.3 Energy Storage Incentives per Watt-hour (Wh)

Energy Storage Equity Budget	**$/Wh**
Equity	$0.85
Equity Resiliency	$1.00

[30] The equity budget step-up incentive structure and the linkage between the equity budget and step three of the general storage incentives adopted in D.17-10-004 is eliminated.

3.1.3 ***Incentives for Technologies from a California Manufacturer***

An additional incentive of 20 percent will be added to the technology incentive for projects in which the equipment used is manufactured in California.[31] In order for a project to be eligible for the 20 percent adder, it must demonstrate that at least 50% of its capital equipment value is manufactured by an approved California Manufacturer.

3.1.3.1 **California Manufacturer 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.

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:[32]

- 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.

3.1.3.2 **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:

Generation	Energy Storage
Generator/Prime Mover	Storage medium (i.e., battery)

[31] The incentive for each project including the California Manufacturer adder shall be capped based upon the Incentive Limitations outlined in *Section 5.2 and Section 6.6, 6.7 and 6.9.*

[32] This manufacturing processes list is not exhaustive, and PAs have authority to propose additional processes.

Ancillary equipment	Inverter
	Controller

3.1.3.3 **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.[33]

Example 1:

An energy storage project requests the California Manufacturer incentive adder. The project provides the following cost breakdown:

Equipment Type	Manufacturer[34]	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 the California Manufacturer incentive adder. The project provides the following cost breakdown:

Equipment Type	Manufacturer[35]	Cost	Manufacturing Location	Approved CA Manufacturer?
Energy Storage Medium	XYZ Company	$16,000	Philadelphia, PA	No

[33] 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.

[34] 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 3.1.3.1.

[35] 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 3.1.3.1.

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 = $29,000
- Cost Percentage of equipment components manufactured in California = 48%

Result: The Project is ineligible to receive the California Manufacturer Adder.

3.2 Incentive Limitations

Incentive amounts for both generation and storage projects can be limited by a number of factors, including maximum incentive amount, total eligible project costs, sizing limitations per site, and incentives from other sources. Please refer to *Section 5.2* and sections *6.6*, *6.7 and 6.9* for incentive calculations and limitations specific to energy storage and generation technologies, respectively.

3.2.1 ***Maximum Incentive Amount***

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

3.2.2 ***Total Eligible Project Costs***

No project can receive total incentives (to include any combination of the technology incentive, biogas adder, and/or California Manufacturer) that exceed the Total Eligible Project Costs. Submittal of Project cost details is required to report Total Eligible Project Costs 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 Total Eligible Project Cost:

1. Engineering feasibility study costs.
2. Engineering and design costs.
3. Environmental and building permitting costs.
4. Equipment capital costs.
5. 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.
6. 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 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.

7. 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.
8. Interconnection costs, including:
    a. Electric grid interconnection application fees
    b. Natural gas grid interconnection costs
    c. Metering costs associated with interconnection
9. 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.
10. System metering, monitoring and data acquisition equipment as well as additional on-board monitoring equipment and costs associated with the PDP contract.
11. Air emission control equipment capital cost.
12. Gas line installation costs, limited to the following:
    a. 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).
    b. 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.
    c. 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.
13. 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.
14. Electricity storage devices
15. Electrical and critical loads panel and wiring upgrades are allowable costs for equity resiliency and equity budget projects.
16. 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.
17. Sales tax and use tax.
18. 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.

19. 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.

3.2.3 ***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, with the lowest incentive rate ($/Watt) technology portion calculated first. For multiple generation technologies within a single incentive level, the incentives are calculated in the order in which they appear in Table 3.1.1, from top to bottom. When calculating the total eligible incentive for energy storage technologies, the incentives are to be calculated sequentially until the 6 MWh limit is reached.

3.2.4 ***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 when determining the current incentive. However, if the existing system is still in operation the existing capacity must be accounted in order to best determine new system size.

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.

3.2.5 ***Calculating Incentives for Replacement Generation***

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 incentive on the incremental increase above the existing system's rated capacity (kW for generation or kWh for energy storage). [36]

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.

3.2.6 ***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.

For all projects, the sum of the SGIP incentive and any other incentive received for the project may not exceed the total eligible project costs 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 projects (excluding Equity Budget projects) receiving incentives under other programs, the SGIP incentive may be reduced depending on the source of the other incentive.

- 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.
- For other incentives funded by Non-IOU Ratepayers, the total SGIP incentive will be reduced by 50% of the amount of the other incentive.

In order to protect against entities creating governance structures or affiliations that would allow them to achieve more funding than the capped amount, it is required that Host Customers, Applicants, and System Owners disclose information about all other incentives and eligible tax credits taken advantage of by them 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 9.***

3.2.7 ***Developer Cap***

Any single Developer is limited to 20% of the SGIP incentive funding for a given budget category in each statewide incentive step. The Developer cap will be calculated separately for generation projects, large scale energy storage projects, small residential energy storage projects, and equity budget projects. Applicants may not submit applications for Developers in excess of the statewide Developer cap for the active step, and Program Administrators shall not issue conditional 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

[36] All applicable Incentive Limitations apply. *See Section 5.2* and *Section 6.6, 6.7, 6.9.*

each budget step once the step is opened even if total available funds change.[37,38] Please see *Section 4.1.5* for the definition of a Developer.

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

3.2.8 Residential Storage "Soft Target"

A "soft target" is adopted such that half of the Step 6 and Step 7 general market residential incentive budget is reserved for residential customers living in Tier 3 or Tier 2 HFTDs, residential customers whose electricity has been turned off during two or more discrete PSPS events, or customers who have experienced one Public Safety Power Shutoff (PSPS) event and one de-energization or power outage from an actual wildfire that occurred on or after January 1, 2017.

The "soft target" shall be implemented by pausing acceptance of SGIP applications from residential customers who do not live in a Tier 3 or Tier 2 HFTD, who did not have their electricity turned off in two or more discrete PSPS events, or one discrete PSPS event and one outage from actual wildfire prior to January 1, 2017 prior to applying for SGIP incentives. Once the PAs have received reservations requests from such customers that have reached 50 percent of that PA's available funds for each residential incentive step.

3.3 **PBI Assignment**

If there is a change in ownership of the property which hosts the SGIP equipment, the new owner may continue to receive the Performance-Based Incentives (PBI) if the owner completes a new interconnection agreement. If the seller relocates the equipment, the owner 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 owner completes an interconnection agreement at the new address. In either case, the PBI payment sunset date will not be extended.

[37] The developer cap will take into account all authorized collections approved in D.14-12-033, D.17-04-017, and D.20-01-021 as well as all other funds made available through project cancellation before the step opens.

[38] Energy Division Disposition of Advice Letters (CSE Advice Letter 97-E-A, SoCalGas Advice Letter 5548, SCE Advice Letter 4114-E, and PG&E Advice Letter 4187-G/5699-E) approved the reallocation of funds from the Step 5 large-scale energy storage budgets to the Step 5 small residential budget carve-outs within each PA Territory resulting in an authorized, one-time adjustment of the Step 5 small residential budget Developer Cap on January 2, 2020.

4 Program Eligibility

In order to qualify for incentives, all program eligibility criteria must be satisfied. The following section details these requirements.

4.1 Program Participant Criteria

4.1.1 *Host Customer*

Any retail electric or gas distribution class of customer (industrial, agricultural, commercial or residential) of PG&E, SCE, SoCalGas, or SDG&E is eligible to be the Host Customer and receive incentives from the SGIP.[39] The Host Customer must be the utility customer of record at the site where the SGIP system is or will be located. In the event that the Host Customer's name is not on the utility bill, a letter of explanation is required that addresses the relationship of the Host Customer to the named utility customer. For multifamily buildings that are installing a system on behalf of tenants and are enrolled in a VNEM tariff, the property owner may be the Host Customer.

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.

The Host Customer is the exclusive incentive reservation holder who is party to the SGIP Contract. 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 with prior written notice to the Program Administrator.

4.1.1.1. Host Customer Eligibility for the Equity Budget

<u>Non-residential projects:</u>

For the Equity Budget, a non-residential project must meet one of the following customer criteria:

- Local governmental agency[40]
- State governmental agency[41]
- Tribal government agency[42]

[39] "…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.

[40] Public Contracts Code § 22161(f).

[41] Government Code §11000.

[42] 18 USC 1151: Except as otherwise provided in sections 1154 and 1156 of this title, the term "Indian Country," as used in this chapter, means (a) all land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation, (b) all dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state, and (c) all Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same.

- Educational institution[43]
- Non-profit organization[44]
- Small business[45]

Additionally, one of the following two criteria must be met:

a. the project site must be located in a disadvantaged, tribal, or low-income community[46] or document that at least 50% of the census tracts it serves are disadvantaged, tribal, or low-income communities.

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 percent of census tracts served are DACs or low-income communities.

A disadvantaged community is defined as 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 census tracts that score within the highest 5% of CalEnviroScreen's pollution burden, but do not receive an overall CalEnviroScreen score. A low-income community is defined as 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.

<u>Residential Projects:</u>

For the Equity Budget, residential projects are classified as 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 5.2.10.

Multifamily: Eligible multifamily housing is defined as

a. a multifamily residential building of at least five rental housing units that is operated to provide deed-restricted low-income residential housing[47] and is either

    i. located in a disadvantaged community or

[43] 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.

[44] An organization that is registered and in good standing with the California Secretary of State as a domestic non-profit entity.

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

[46] As defined in 39713(d)(2) of the Health and Safety Code.

[47] As described in clause (i) of subparagraph (A) of paragraph (3) of subdivision (a) of § 2852 of the Public Utilities Code.

ii. is a building where at least 80% of the households have incomes at or below 60% of the area median income[48]. Any customer account in such buildings will be eligible for the Equity Budget.

Single-family: The Equity Budget is available to customers living in single-family low-income residences sold at an affordable housing cost to a lower income household that is subject to:

a. income verification and[49]

i. a resale restriction[50] or;

ii. an equity sharing agreement, for which the homeowner does not receive a greater share of equity than described in paragraph (2) of subdivision (c) of Section 65915 of the Government Code, with a public entity or nonprofit housing provider organized under Section 501(c)(3) of the Internal Revenue Code that has as its stated purpose in its articles of incorporation on file with the office of the Secretary of State to provide affordable housing to lower income households.[51]

Additionally, the Equity Budget is available to residential customers who have participated or who are eligible for the SASH or DAC-SASH programs and for multifamily properties that have reserved funds in the MASH or SOMAH programs. Customers must provide a copy of their incentive reserved status for the SASH, DAC-SASH, MASH, or SOMAH program to demonstrate that they are eligible for one of these programs.

4.1.1.2. Inclusion of Indian Country in California

a) Indian Country in California, as defined in 18 USC 1151, is considered as being a disadvantaged community for purposes of the SGIP Equity Budget. Thus, projects in these areas are eligible for the Equity Budget. However, non-Indian residences or 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. Multifamily housing in California Indian Country is eligible for the Equity Budget if it demonstrates that it has at least five rental housing units where at least 80 percent of the households have incomes at or below 60 percent of the area median income. Any customer account in such buildings will be eligible for the Equity Budget. Single family residences in California Indian Country are eligible for the equity

[48] As defined in subdivision (f) of §50052.5 of the Health and Safety Code.

[49] Documentation showing the host customer's household income is 80 percent 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).

[50] Certain and specific "presumed resale restrictions" meet this requirement. See section 5.4.1 for more information.

[51] Subparagraph (c) of paragraph (3) of subdivision (a) of 2852 of the Public Utilities Code.

budget if the customer provides documentation showing that the host customer's household income is 80 percent of the area median income or less as required in Section [5.4.1],[52] Proof of Income Qualification.

4.1.1.3. Host Customer Eligibility for the Equity Resiliency Budget

Residential customers are eligible for the Equity Resiliency Budget if they meet each of the following:

a. Are located in a Tier 3 or Tier 2 HFTD[53], were subject to two or more discrete PSPS events prior to the date of application for SGIP incentives, or experienced one Public Safety Power Shutoff (PSPS) event and one de-energization or power outage from an actual wildfire that occurred on or after January 1, 2017, and

b. Are one of the following:

   i. Eligible for the SGIP Equity Budget; or

   ii. Medical Baseline customer[54]; or

   iii. A customer that has notified their utility of serious illness or condition that could become life-threatening if electricity is disconnected[55]; or

   iv. Rely on electric pump wells at their primary residence for water supplies. Customers must also meet the following criteria:[56]

      1. Demonstrate the residential household meets the income eligibility requirements required for the Equity Budget (4.1.1.1); and

      2. The storage installation site is a primary residence occupied by either a homeowner or tenant; and

      3. The residence is not provided water by a municipal or private utility.

Non-Residential customers are eligible for the Equity Resiliency Budget if they meet each of the following:

a. Located in a Tier 3 or Tier 2 HFTD;[57] or were subject to two or more discrete PSPS events prior to the date of application for SGIP incentives, and

[52] D.20.07-015 included the incorrect section of the 2020 SGIP Handbook, as Section 4.6.1.6 does not exist; Thus, we have included the correct section here in the proposed revision.

[53] https://ia.cpuc.ca.gov/firemap/

[54] Defined in D.86087, 80 CPUC 182.

[55] Defined in D12-03-054.

[56] Required for all applications that were submitted after August 17, 2020 and had not received a Confirmed Reservation Status by October 22, 2020.

[57] https://ia.cpuc.ca.gov/firemap/

b. Provides critical facilities or critical infrastructure during a PSPS event to at least one community[58] that is located at least partially in a Tier 3 or Tier 2 HFTD or were subject to two or more discrete PSPS events prior to the date of application for SGIP incentives, and

c. The community is also eligible for the equity budget. Emergency Feeding Organizations, homeless shelters, and independent living centers are exempt from this requirement;[59] and

d. The Non-Residential customer is one of the following:

i. Police stations; or

ii. Fire stations; or

iii. Emergency response providers[60] with the addition of tribal government providers; or

iv. Emergency operations centers; or

v. 911 call centers (also referred to as Public Safety Answering Points); or

vi. Medical facilities including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers and hospice facilities; or

vii. Public and private gas, electric, water, wastewater or flood control facilities; or

viii. Jails and prisons; or

ix. Locations designated by the IOUs to provide assistance during PSPS events (CRCs); or

x. Cooling centers designated by state, local or tribal governments; or

xi. Homeless shelters supported by federal, state, or local, or tribal governments; or

xii. 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; or

xiii. Independent living centers; or

xiv. Emergency Feeding Organization.[61]

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[58] Defined in D.17-10-004 (Table1).

[59] 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.

[60] Defined in D.19-05-042.

[61] The term "Emergency Feeding Organization" means a public or nonprofit organization that administers activities and projects (including the activities and projects of a charitable institution, a Food Bank, a food pantry, a hunger relief center, a soup kitchen, or a similar public or private nonprofit eligible recipient agency) providing nutrition assistance to relieve situations of emergency and distress through the provision of food to needy persons, including low-income and unemployed persons. This definition indicates that

4.1.2 *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.

In the event that 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 to the Program Administrator.

4.1.3 *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 SGIP 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.

4.1.4 *Payee*

A Payee is the person or entity to whom the SGIP incentive check is made payable. The Payee may be any person or entity designated by the Host Customer on the Incentive Claim Form.

4.1.5 *Entity*

Applications submitted to the Non-Residential Equity Budget are subjected to a $5 million cap per individual applicant entity.[62] For the purposes of SGIP, an individual applicant entity is defined as follows:

1. 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);
2. The various divisions and/or departments of a county shall together constitute an individual applicant entity (such as County Office of Emergency Services; County Sheriff);
3. Each unique state agency, municipal utility (such as a municipal water district), or joint powers authority shall constitute an individual applicant entity;
4. 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);
5. Each school district shall constitute an individual applicant entity and shall be considered separately from any county or city entity; and

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the term "Emergency Feeding Organization" includes any non-profit that is distributing food to relieve situations of emergency and distress either in an upstream capacity to other organizations or directly to individuals.

[62] 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.

6. All affiliates of a parent company and the parent company shall together constitute one individual applicant entity.

4.1.6 *Developer*

For applications received in Steps 1 and 2:

A Developer is the corporate entity that holds the contract for purchase and installation of the system, and/or alternative System Ownership Agreement (such as a Power Purchase Agreement) with the host customer and handles the project's development activities. The Developer must fully disclose their participation in developing the project and/or ownership in the project, or that of a combination of affiliated installers/developers. 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.

For applications received in Step 3 or later:

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.

An exclusive list of a project's development activities to be used for the purpose of applying this definition to the Program's developer cap is as follows:

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 SGIP administrators on incentive reservations
10. Liaising with the SGIP 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

For the purpose of this definition, the Program Administrators, with oversight from Energy Division, 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, a sufficient number of reservation requests for that participant shall be cancelled to bring the participant under its developer cap.

4.1.6.1 Developer Application Process

All SGIP projects must select a pre-approved Developer before the application may be submitted. A list of approved Developers will be available at www.selfgenca.com. Entities interested in becoming an approved SGIP Developer must submit the Developer Eligibility Application to the Program Administrators, containing the following information:

- 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
- The identity of the entity, if reasonably foreseeable, that will execute any of the following development activities if it is not the developer named in the Developer Eligibility Application:
    - Approaching or communicating with the host customer about the project and learning about its needs and energy profile
    - Developing the specifications for a system based on the customer's needs and interests
    - Soliciting bids from multiple manufacturers for the specified system
    - Gaining the customer's commitment to purchase the specified system, usually by signing a purchase order with a customer or other form of agreement; or owning the system during its lifetime and signing a lease or other similar agreement with the customer
    - Purchasing the specified system from the manufacturer to fulfill the obligation to provide a system to the customer
    - Securing permits for the system on behalf of the customer
    - Securing interconnection permission for the system on behalf of the customer
    - Filing SGIP applications
    - Liaising with the SGIP administrators on incentive reservations
    - Liaising with the SGIP administrators on data reporting requirements
    - Supplying project data to SGIP evaluators

    - Physically constructing the system at the customer's premises
    - Installing the system at the customer's premises

- 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 SGIP or reasonably foreseeable future projects that may be funded in whole or in part by SGIP.

Additionally, if requested by the Program Administrator, Developers must 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 participant per project can be determined by the Program Administrators or Energy Division to handle a substantial portion of the project's development activities.

Acceptance by the Program Administrators of a Developer Eligibility Application does not guarantee that a participant qualifies as a Developer of any given project.

The Developer must fully disclose its participation in developing the project and/or ownership in the project, or that of a combination of affiliated installers/developers. The Developer must disclose relationships with other SGIP participants in developing and/or owning any existing projects funded in whole or in part by SGIP or reasonably foreseeable future projects that may be funded in whole or in part by SGIP to the Program Administrators on an ongoing basis and in the Developer Eligibility Application. For example, if a Developer purchases the contract for purchase and installation of a system from another Developer, each Developer must describe the transaction in its Developer Eligibility Application, or inform the Program Administrators of the transaction if the Developer Eligibility Application has already been accepted. Note that the relationships between Developers to be disclosed to the Program Administrators include commercial or financial relationships between Developers that do not share the same majority ownership.

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.

In order 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 of 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.

4.2 Equipment Eligibility

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 section describes the specific equipment eligibility criteria for systems that want to participate in the SGIP.

4.2.1 *Commercial Availability*

Commercially available, factory-new equipment is eligible for incentives. "Commercially available" means that the major system components are acquired through conventional procurement channels.

All eligible technologies must be certified for safety by a nationally recognized testing laboratory (NRTL). An application may be submitted for a device that has not yet received certification from an NRTL if the certification process is underway, however proof of certification must be submitted at the latest with the Incentive Claim documents. 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 a 10-year warranty as consistent with Rule 21 interconnection standards. In the event that Rule 21 interconnection standards or NRTL certification do not require a separate manufacturer's warranty, a single 10-year service warranty is sufficient. If Rule 21 interconnection standards or NRTL certification require a separate 10-year manufacturer's warranty in addition to the 10-year service warranty, then the obligation for dual warranties must be met by the project.

4.2.2 *Interconnection*

All systems receiving incentives under the SGIP that discharge electricity[63] 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. The interconnection, operation, and metering requirements for the systems shall be in accordance with the local electric utility rules for customer generating facility interconnections. Energy storage systems must also be configured to operate in parallel with the grid. SGIP eligibility includes systems that interconnect to the local electric utility's distribution system under the requirements of a virtual net metering tariff.

In order to connect a system to the electric utility distribution system, 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. Written certification of interconnection and parallel operation to the Program Administrator prior to the Reservation Expiration date will be required. 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. For more information on electric grid and/or natural gas pipeline interconnections, please contact your local utility.

Systems will be eligible to receive a reservation up to 12 months after receiving authorization to operate in parallel with the grid from the electric utility.

4.2.3 *Permanent Installation*

The intent of the SGIP is to provide incentives for equipment installed and functioning for the duration of its useful life. Only permanently installed systems are eligible for incentives. This means that the system must demonstrate to the satisfaction of the Program Administrator adequate assurances of both physical and contractual permanence prior to receiving an incentive.

Physical permanence is to be demonstrated by electrical, thermal and/or fuel connections in accordance with industry practice for permanently installed equipment and be 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.

Additionally, 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.

[63] For example, TES does not discharge electricity and therefore does not require an interconnection agreement.

Contractual permanence, corresponding to a minimum of the length of the applicable warranty period (10 years), is to be demonstrated as follows:

- System Owner agrees to 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.
- All agreements involving the system receiving an incentive are to be provided to the Program Administrator for review as soon as they become available. 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.

4.2.4 *Ineligible Equipment*

The following equipment is not eligible for participation in the SGIP:

- Backup systems intended solely for emergency purposes[64]
- Any system/equipment that is capable of operating on, or switching to, diesel fuel or diesel cycle for start-up or continuous operation
- Field demonstrations for proof-of-concept operation of experimental or non-conventional systems partially or completely paid by research and development funds
- Rebuilt, refurbished or relocated equipment (e.g., second life batteries)
- Equipment that has been interconnected for more than 12 months

4.2.5 *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 most granular interval for which there is 12 months of available data should be used.

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 5.5kWh during the previous 12 months, then the peak demand estimate would be 5.5 kW. If the data revealed that the greatest consumption within a

[64] 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. Adopted Affidavit Form in CPUC Resolution E-4717.

15-minute interval was 5.5kWh during the previous 12 months, then the peak demand estimate 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.

4.2.6 *Eligibility for New Technologies*

Systems consisting of new technologies not already included in the list of eligible SGIP technologies listed in *Section 3.1.1 and Section 3.1.2* may become eligible for the SGIP if its first commercial installation occurred less than ten 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 4.2.7*.

4.2.7 *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 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 Working Group will review the PMR. If accepted, the Working Group will make the appropriate changes to the Handbook.
- If the Working Group needs more information, the party proposing the PMR would have the opportunity to present at the following Working Group meeting with additional information which supports its request for a program change.
- The 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 change and the Working Group recommendation(s) and rationale will be captured in the Working Group meeting minutes.

- If the party objects to the 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 Working Group will review the PMR and make a recommendation to support or oppose the PMR in the same meeting.
- The Working Group recommendation and rationale will be captured in the Working Group meeting minutes.
- Subsequent to the meeting, the Working Group will write up a summary of the discussion of the PMR at the Working Group meeting, a list of comments in support or against the PMR, as well as the 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 to Modify (PTM) for Commission review regardless of the Working Group's recommendation, but the Working Group's summary must be included in the PTM.
- The Energy Division participates in 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 Working Group's PMR review.
- Once the PTM is filed with the Commission, the normal PTM process will transpire, only it will have the benefit of the idea being somewhat vetted before submittal. All parties have a chance to comment on PTMs according to the Commission's Rules of Practice and Procedure.
- The Commission will review and address the PTM in a decision.

5 Energy Storage Technologies

The following sections outline the eligibility requirements, rating criteria, incentive calculation guidelines and 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.

5.1 Rating Criteria for Energy Storage Projects

5.1.1 *Rated Capacity (W)*

The rated capacity (W) 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 (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, etc.)
        - The continuous maximum power output capability of the system.[65] 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 D, based on the SEER rating and tonnage of the HVAC unit with which the S-TES system will be integrated and the climate zone in which the project is located.
- 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).

[65] Maximum continuous output might be determined by the maximum continuous discharge power/current of the system or by the continuous rated output of the inverter.

- Large TES: Calculate 1-in-10 Peak kW using the UC Davis methodology. The UC Davis methodology is provided in Appendix G to the Handbook.

5.1.2 *Energy Capacity (Wh)*

The energy capacity (Wh) 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 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, etc.)
- 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.
- 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 G. The energy capacity must be updated at ICF by calibrating the building simulation model using monitored data as described in section 5.5. 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 one 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 G)
        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

5.2 Eligibility Requirements for Energy Storage Projects

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 designed to ensure that all residential energy storage systems participating in the SGIP will be used for more than just back-up emergency purposes.

5.2.1 *Greenhouse Gas Signal*

A Greenhouse Gas (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.[66]

[66] Pub. Util. Code Section 379.6(b)(3).

- 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 kgCO2/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; and,
- 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.

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 fifteen minutes;
- One hour-ahead forecast, with five-minute granularity and updated every fifteen minutes;
- Day-ahead forecast, with five-minute granularity and updated every fifteen minutes;
- Longer Term Forecasts: 72-Hour Ahead, Month-Ahead and Year-Ahead

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

5.2.2 *Greenhouse Gas Emission Standards for new non-residential applications*

During the PBI term, non-residential 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 payment.

In order to calculate the GHG emissions, all new non-residential 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-min 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 projects should continue to annually reduce GHG emissions by five kg/kWh through the tenth year of their permanency period verified on a fleet basis. New non-residential 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 projects in years six through ten of their permanency periods, by developer. Large non-residential projects that are not otherwise part of a developer fleet are also subject to these requirements.

5.2.3 *Greenhouse Gas Emission Standards for non-residential legacy applications*

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

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 percent, with the exception that projects with a 260 per year cycling requirement may reduce this to 130 cycles per year.

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; or,
    - Enrollment in an approved storage rate including:
        - PG&E: Option S or A-1-STORE;
        - SCE: Option E or TOU-GS-1; and,
        - 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.[67]

Option 3: GHG Pathway- Operational Requirements

- Projects that select Option 3 that are within their ten-year permanency requirement are required to emit zero kg/kWh GHGs or less at the developer fleet level on an annual basis; and,
    - Must cycle a minimum of 130 times per year; and,
    - the annual RTE requirement is eliminated

Regardless of what option a non-residential 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 approval.

[67] 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.

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 the forthcoming calendar year.

5.2.4 *System Size Parameters*

System size requirements are applicable for systems that are rated above 10 kW. Systems that are rated at 10 kW or less are exempt from the sizing requirements.

Energy storage projects that are not receiving equity budget resiliency incentives or 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). Energy storage systems that are receiving equity budget resiliency 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 to accommodate the customer's peak load, and provided they demonstrate proof of this need 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.

Projects sizing to tenant loads may aggregate each tenant unit at an assumed 5 kW load. For example, a building with 10 residential units may assume a load of 50 kW 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).

5.2.5 *Operational Requirements*

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 equivalent of discharging the SGIP-incentivized energy capacity, whether it is during a single or multiple discharges.[68]

Legacy 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.

5.2.6 *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, if not claiming the ITC, charge a minimum of 75% from the on-site renewable generator.

5.2.7 *Demand Response Dual Participation*

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

5.2.8 *Upfront Eligibility Requirements for New Residential Projects*

All new residential systems, regardless of system size, must have a single cycle round trip efficiency (SCRTE) of 85% or greater.

Additionally, all new residential IOU and non-IOU customers are required to enroll in 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, if such rate is available. SGIP eligible customers may not utilize time-of-use (TOU) bill protection measures. 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.

A list of SGIP-approved residential rates can be found on www.selfgenca.com

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 onsite 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 onsite load).

[68] 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.

5.2.9 *Greenhouse Gas Emission Standards for Legacy Residential Projects*

Residential energy storage systems with an application approval date prior to April 1, 2020 are no longer subject to the round-trip efficiency requirements in place at the time the reservation letters were issued. The annual cycling requirement of 52 cycles per year must still be maintained for all legacy residential project completed. These projects are encouraged to enroll in an SGIP-approved rate as described in section 5.2.8.

5.2.10 *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.

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 percent 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 percent 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.

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 percent 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 percent 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.

5.3 Incentive Calculation for Energy Storage Projects

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*

5.3.1 *Incentive Declines Based on GHG Performance*

Non-residential energy storage systems must reduce GHG emissions by 5 kg CO_2/ 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.

5.3.2 *Incentive Declines Based on Storage Duration*

5.3.2.1 Incentives for Resiliency systems

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, such that systems with discharge duration capacities of four to six hours receive 50 percent of the base incentive rate. No incentive is provided for the discharge capacity greater than 6 hours.

Table 5.3.3 Energy Storage Incentive Duration Decrease (Projects with Backup Capability)

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

Example 1: Four-hour system at $.40/Wh incentive

100 kW discharge rating

400 kWh discharge capacity

400,000 Wh * $.40/Wh = $160,000

Example 2: Six-hour system at $.40/Wh incentive

100 kW discharge rating

600 kWh discharge capacity

400,000 Wh * $.40/Wh = $160,000

200,000 Wh * $.20/Wh = $80,000

$160,000 + $80,000 = $240,000

The Commission requires all equity budget, equity resiliency, and general market projects to meet all SGIP GHG emission 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.[69]

5.3.2.2 Incentives for Non-resiliency projects (Projects without backup capability)

For systems that have indicated on the RRF that they will not be installing a backup capable storage system, the 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, such that systems with discharge duration capacities of four to six hours receive 25 percent of the base incentive rate. No incentive is provided for the discharge capacity greater than 6 hours.

Table:5.3.4 Energy Storage Incentive Duration Decrease (Projects without backup capability)

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

Example 1: Four-hour system at $.40/Wh

100 kW discharge rating

400 kWh discharge capacity

200,000 Wh * $.20/Wh = $40,000

200,000 Wh * $.20/Wh = $40,000

$40,000 + $40,000 = $80,000

[69] D.19-09-027, Conclusion of Law 19.

Example 2: Six-hour system at $.40/Wh

100 kW discharge rating

600 kWh discharge capacity

200,000 Wh * $.40/Wh = $80,000

200,000 Wh * $.20/Wh = $40,000

200,000 Wh * $.10/Wh = $20,000

$80,000 + $40,000 + $20,000 = $140,000

5.3.3 *Incentive Declines and Caps Based on Energy Capacity (Wh)*

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

Table 5.3.4.1: Tiered Incentive Rates

Energy Capacity	Incentive Rate (Pct. of Base)
0 to 2 MWh	100%
Greater than 2 MWh to 4 MWh	50%
Greater than 4 MWh to 6 MWh	25%

5.3.4 *Performance-Based Incentive Payment (PBI)*

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[70] a project would receive the entire stream of performance payments in five years.

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*[71] ** five years*

For a 5-year period the PBI payment will be paid annually based on recorded kWh of electricity discharged or offset over the previous 12 months.

[70] See *Section 5.3.3.*

[71] For new non-residential projects only. If this was a residential project sized 30 kW or greater, 52 full discharges would be required.

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

Example PBI Payment for a two-hour system:

100 kWh system at $.50/Wh

*Total incentive: 100,000 Wh * $.50/Wh = $50,000*

Upfront payment: $50,000 / 2 = $25,000

Remaining payment to be recuperated through PBI: $50,000 / 2 = $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

*PBI payment per year assuming 104 full discharges: 10,000 kWh * $0. 480769230/kWh = $5,000*

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 5.3.1 for more details.

Large-scale Thermal Energy Storage Systems are subjected to a provisional one-year 30/70 PBI structure for L-TES, which would allow 30 percent 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 percent will be paid out, based on actual performance, over at most five years. [72]

5.4 Application Documentation Requirements for Energy Storage Projects

5.4.1 *Required Documentation for Reservation Request*

Energy storage applications must provide a copy of the following:

Table 5.4.1: Reservation Request Requirements

Required Materials
1. **Completed Reservation Request Form** *(All Projects)*
2. **Application Fee** *(Non-Residential Projects only)*
3. **Equipment Specifications** *(All Projects not currently on the SGIP Energy Storage Equipment List)*
4. **Proof of Utility Service/ Load Documentation** *(All Projects)*

[72] Resolution E-5106, Ordering Paragraph 3: 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. Concurrently, if after one year fewer than five successful L-TES reservations have been received, the 30/70 PBI structure shall remain. Thereafter, the SGIP 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 within 60 days of receiving the fifth successful L-TES reservation.

Required Materials
5. **Preliminary Monitoring Plan** *(All Non-Residential Applications and/or Residential projects paired with on-site renewable generators)*
6. Proof of Equity Budget Eligibility *(Equity Projects Only)* • Certification of Tax-Exempt Status *(Gov't and non-profit only)* • Proof of Eligibility under Proposition 39 or an Accredited Institution *(Educational Institutions Only)* • Small Business Affidavit *(Small business projects only)* • SGIP Multifamily Low-Income Housing Documentation Cover Sheet *(Multifamily only)* • Copy of Deed-Restriction or Regulatory Agreement *(Multifamily only)* • Proof of Income Qualification *(Single-family Equity Budget, California Indian Country, and Electric-Pump Well only)* • Proof of PU Code Section 2852 Compliance *(Single-family only)* • Copy of MASH, SOMAH, SASH or DAC-SASH Reservation Letter • Proof of Indian Country Qualification • Proof that at least 50 percent of census tracts served are DACs or low-income communities (Public agencies and tribal government agencies only)
7. Customer Resiliency Attestation *(All backup capable projects with a longer than two-hour duration and projects applying for a Resiliency Adder or Equity Resiliency Incentive)*
8. Certification/Proof of Coordination with Local Government and California Office of Emergency Services *(Non-Residential Equity Resiliency and Resiliency Adder Applications only)*
9. Proof of Electric-Pump Well at Primary Residence *(Residential Equity Resiliency projects)*
10. Proof of Medical Baseline at Primary Residence and Self-Certification *(Residential Equity Resiliency and General Market Resiliency Adder projects only)*

Two-Step Applications should also include all applicable Proof of Project Milestone Documents *(as outlined in Section 5.4.2)* as part of their Reservation Request

1. **<u>Online Reservation Request Form</u>** *(All Projects)*

All applicants are required to complete the online Reservation Request Form (RRF). This online form 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)[73] has been performed for the project site and they received and reviewed the findings of the audit.

Additionally, for storage systems not pursing 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.

[73] 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 printed and 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 only)*

The application fee 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.[74] The application fee is the only required document that must be mailed directly to the Program Administrator.[75] After a project is assigned to an incentive step, the application fee check must be mailed within 7 calendar days. If the check is not mailed within 7 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.[76] All forfeited application fees will be allocated to the Program Administrator's current incentive step.

3. **Equipment Specifications** *(All Projects not currently listed on the SGIP Energy Storage Equipment List)*

Equipment and/or component pairings that have been evaluated by the Technical Working Group can be found on the SGIP Energy Storage Equipment List at www.selfgenca.com. For 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[77] for the storage system must be provided. Equipment specifications may be submitted to any PA via email to the contact information listed on 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),

[74] 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.

[75] A single application fee check for each project is required.

[76] Application Fees will not be altered due to project changes that may result in a different incentive.

[77] AC-AC for AC systems and DC-DC for DC systems

- 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.[78] For DC systems, this is rated in DC, and for AC systems, this is rated in AC.

HVAC-integrated S-TES 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.

Refrigeration TES systems 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.

Large TES systems 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 compliant with ANSI/ASHRAE Standard 140-2017 and ASHRAE Standard 90.1 2016/2019 Appendix G.

Resiliency projects requesting to receive incentives 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.

4. **Proof of Utility Service & Load Documentation** *(All Projects)*

Participation in the SGIP is restricted to customers who are located in PG&E, SCE, SoCal Gas or SDG&E service territories and physically connected to the Electric Utility transmission and distribution system. All applications must include a copy of a recent electric utility bill, with the exception of PG&E,[79] indicating the account number, meter number, Site address, and Host Customer name.

[78] 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.

[79] A utility bill can be required at PG&E's discretion

Customers applying in PG&E and SoCalGas territory must also submit a copy of a recent gas utility bill. For new construction, the Host Customer must submit confirmation from the serving utility that their Site is within the Program Administrator's service territory.

For projects applying in CSE and SoCalGas territory, applications for technologies that discharge electricity to the onsite 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 systems greater than 10 kW or any other instance under CSE discretion if needed.

If the energy storage 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 VisualDOE; or detailed engineering calculations.

L-TES systems must provide pre-installation monitoring data as outlined in Section 5.5 (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.

For 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 5.2.10 for more information on how multifamily projects are classified. If the primary use case is determined to be residential, all benefiting tenant accounts will be required to be enrolled in an SGIP-eligible TOU rate.[80]

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

[80] 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.

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 of application to provide for discharging the battery to serve onsite load and to island.

5. **Preliminary Monitoring Plan** *(All Non-Residential Applications and/or Residential Projects Paired with On-Site Renewable Generators)*

The preliminary monitoring plan should demonstrate the following components:

Description of the proposed SGIP system:
Description of the system with an overview of the energy services to be provided by the system to the host 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 renewable generation, etc.); Include photos and/or diagrams of the system if available.

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:
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:

- For example, if electrical energy performance data is to be collected, the reasoning behind the selected metering points
- Frequency with which the data is to be collected (e.g., 15 min intervals)
- Data storage capability and approach for transfer of data (e.g., cell modem)
- For non-residential systems 30 KW and larger, the frequency of reporting to PDP (e.g., daily, weekly) [this could also include frequency for reporting of data to Program Administrators, such as monthly]

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 5.5)
- 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, for projects not claiming the ITC, 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.

6. **Proof of Equity Budget Eligibility** *(Equity Projects Only)*

Certification of Tax-Exempt Status *(Gov't and Non-profit Projects Only)*
State and local government and non-profit entities are required to submit verification of their tax-exempt status.

Proof of Eligibility under Proposition 39 or an Accredited Institution *(Educational Institutions Only)*
For educational institutions, applicants must submit documentation proving eligibility under the California Energy Commission's Proposition 39 Program[81], or which confirm they are an accredited educational institution.

Small Business Affidavit (*Small Business Projects Only)*
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 Projects Only)*
For a multifamily residential complex financed with low-income housing tax credits, 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.

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

SGIP Multifamily Low-Income Housing Documentation Cover Sheet *(Multifamily Projects Only)*

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 more accurately and efficiently determine eligibility.

Proof of Income Qualification *(Single-family Equity Budget, California Indian Country, and Electric-Pump Well Projects Only)*

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[82]. Contact your Program Administrator for instructions on how to submit these documents for review.

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 PU Code Section 2852 Compliance *(Single-family Projects Only)*

To demonstrate compliance with PU Code section 2852[83], applicants may submit a copy of a resale restriction or equity sharing agreement for which the homeowner does not receive a greater share of equity than described in paragraph (2) of subdivision (c) of Section 65915 of the Government Code. The resale restriction or equity sharing agreement must be between the homeowner and a public entity or a qualifying non-profit affordable housing provider. Additionally, a presumed resale restriction may also be demonstrated to meet the resale restriction eligibility requirement, such as single-family homes located in IRS-defined Qualified Census Tracts[84] and other designated areas eligible for the Single-Family Affordable Solar Homes (SASH) program.[85]

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[82] 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).

[83] As described in subparagraph (c) of paragraph (3) of subdivision (a).

[84] Qualified Census tracts are defined by Internal Revenue Code Section 143(j)(2) as "a tract in which 70 percent or more of the families have income which is 80 percent or less of the statewide median family income" https://www.huduser.gov/portal/sadda/sadda_qct.html

[85] Decision 15-01-027 allows presumed resale restrictions within the SASH program, such as those found in federally-designated Empowerment Zones, Enterprise Communities, certain Neighborhood Revitalization Areas, Targeted Employment Areas, and Qualified Census Tracts.

Copy of MASH, SOMAH, SASH or DAC-SASH Reservation Letter

Customers must provide a copy of their incentive reserved status of the MASH, SOMAH, SASH or DAC-SASH program that they are eligible for the program.

Proof of Indian Country Qualification

A Native American tribal card or official document must be provided to be eligible for the expanded DAC requirement.

Proof that at least 50 percent of census tracts served are DACs or low-income communities

Customers have the burden of providing any information that demonstrates a facility's eligibility.

Proof of Coordination with Local Government and California Office of Emergency Services

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.

7. **Customer Resiliency Attestation** *(All projects with a longer than two-hour duration and projects applying for a Resiliency Adder)*

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

(1) Estimate of how long a project's fully charged battery will provide electricity for the relevant facility average load during an outage
(2) Indicate whether a project's critical loads can and will be isolated
(3) Provide an estimate of how long the project's fully charged battery will provide electricity to critical uses during an outage
(4) 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)
(5) 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 event announced in advance
(6) Attest to the truth of the information provided; and
(7) Provide an attestation from the customer indicating that he or she received this information prior to signing a contract with the Developer.

Projects without backup capability (Equity and General Market Storage Budgets only)

Equity and General Market budget projects not intending to provide backup power can opt to apply via the incentive step-down structure in D.16-06-055.[86] Projects pursuing this incentive pathway are not required to fulfill the eight safety measures listed above; however, developers are required to demonstrate that host

[86] The incentive step down structure is a legacy pathway in D.16-06-055, Conclusion of Law 23.

customers have been informed their systems are not intended for backup capability by indicating it on the RRF.

8. **Certification/Proof of Coordination with Local Government and California Office of Emergency Services** (Non-Residential Equity Resiliency and Resiliency Adder Applications only)

9. **Electric-Pump Well Eligibility (Residential Equity Resiliency projects only)**

Each electric-pump well customer must submit the SGIP Electric-Pump Well Attestation that confirms the following:

i. The site is the customer's primary residence
ii. The customer does not have access to a public water source

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

i. Photographs of the pump and motor
ii. Photograph of the home and well
iii. 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 PA is unable to reasonably verify the presence and eligibility of the electric well pump, the project may be required to undergo an onsite inspection rather than be subjected to a developer's sampling.

10. Medical Baseline Primary Home and Self-Certification (Residential Equity Resiliency and General Market Resiliency Adder Project only)

Each Medical Baseline customer and/or customer self-certifying that they have notified 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 that confirms the following:

i. Equity Resiliency Budget incentive will be used for energy storage equipment installed at the customer's primary residence; and
ii. Customer is Self-certifying that they have a serious illness or condition that could become life-threatening if service is disconnected

Additional Requirements for Two Step Applications

All 2 step applications must include as part of their Reservation Request materials, all applicable requirements of the Proof of Project Milestone. *See Section 5.4.2*.

5.4.2 *Required Documentation for Proof of Project Milestone*

Energy storage applications must provide a copy of the following:

Table 5.4.2: Proof of Project Milestone Requirements

Required Materials (3-Step Projects)
1. **Online Proof of Project Milestone Form** *(All Projects)*
2. **Copy of RFP or equivalent after 90 days** (*Public Entity Projects Only)*
3. **Copy of Executed Contract and/or Agreement for Installation** *(All Projects)* • Includes Required Warranty Documentation

1. **Online Proof of Project Milestone Form** *(All 3-Step Projects)*[87]

The Online Proof of Project Milestone (PPM) Form must identify if there are changes from the information that was presented in the Reservation Request Form (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).

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 (RFP) Documentation** *(Public Entities Only)*

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. Proof of Project Milestone documentation must then be submitted within 240 days of the date the Conditional Reservation Letter.

3. **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) is required. The contract/agreement must be legally binding and clearly spell out the terms and scope of work. Purchase and/or installation

[87] Not required for 2-Step Applications as part of the Reservation Request Package.

agreements must also include system equipment and eligible system costs. All contracts/agreements must be signed by appropriate representatives (Host Customer, Installer, and/or System Owner) who are a party to the agreements of the SGIP reservation.

- As part of the Executed Contract, all storage systems are required to include a minimum *10 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.

5.4.3 *Required Documentation for Incentive Claim*

Energy storage applications must provide a copy of the following:

Table 5.4.3: Incentive Claim Requirements

Required Materials
1. **Completed Incentive Claim Form** *(All Projects)*
2. **Proof of Authorization to Interconnect** *(SCE, CSE and SoCalGas Project Applications)*
3. **Building Permit Inspection Report** *(SCE, CSE and SoCalGas Project Applications))* **Additional AHJ Grid Islanding Plan (Projects applying for Resiliency adder, Equity Resiliency, and Equity >2hr Projects Only)**
4. **Substantiations:** • New Construction or Expanded Load, • Residential Projects Without Access to Approved TOU Rates, • Equipment purchased after 2021, and • VNEM Projects • L-TES Post-installation monitoring data (L-TES Projects that used engineering assumptions in lieu of pre-installation data)
5. **Final Monitoring Schematic** *(SCE, CSE and SoCalGas Project Applications)*

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 and System Owner (if not the Host Customer).

2. **Proof of Authorization to Interconnect** *(Projects that interconnect with the electrical grid)*

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 should be submitted as proof of Authorization to Interconnect. PG&E customers are exempt from submitting an interconnection Permission to Operate letter as proof of Authorization to Interconnect. PG&E will verify interconnection internally during ICF review.[88]

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** *(SCE, CSE and SoCalGas Project Applications)*

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. PG&E customers are exempt from submitting a final building inspection report provided that a final building inspection report is submitted to PG&E in connection with interconnection of the Project pursuant to PG&E's interconnection requirements. PG&E will verify the Building Permit Inspection Report internally at ICF review.[89]

Projects applying for Resiliency adder, Equity Resiliency Projects, and Equity Projects with longer than two-hour discharge duration

A copy of the final building Inspection Report (or proof of exemption) demonstrating that the Project has been inspected by the local Authority (AHJ), meets all codes and standards of the permitting jurisdiction and has been authorized for operation. Additionally, 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.

4. **Substantiations** *(All Projects)*

- **New Construction or Expanding 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.

[88] 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.

[89] The Building Permit Inspection Report may be requested at PG&E's discretion.

- **Residential Projects Without Access to 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 onsite load).
- **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).
- **VNEM Projects:** Proof that project complies with the applicable residential or non-residential operational and GHG emissions reduction requirements must be provided.
- **Post-Installation (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 5.5 for monitoring parameters).

5. **Final Monitoring Schematic** *(SCE, CSE and SoCalGas Project Applications)*

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). 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.[90]

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.

5.5 Metering & Monitoring Requirements for Energy Storage Projects

PBI projects must install metering and monitoring equipment that measures net electrical output or offset from the system(s). Energy storage systems that discharge electricity must measure the net electrical energy during charge and discharge cycles. TES must measure electrical energy when charging. HVAC-

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

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. 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).

5.5.1 *Large TES Monitoring Requirements*

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).

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.

Pre & Post Monitoring Parameters:

<u>Pre-Monitoring</u>

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 shaded ambient DB sensor at project site, or

ii. 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 5 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

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:

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. 5-minute report Blocks are collected for the entire hour

3. Only 5-minute report Blocks collected when the TES system is in discharge are considered

4. For any 5-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.

The data reported on a monthly basis in the meter interval reports must follow the following format:

a. 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

1. GHG signal

2. Recharge GHG

a. Sum of measured kWh of all Recharge blocks in month x 5-minute GHG signal

b. Less sum of mean kWh of all block of same temp/status bin from current baseline x 5-minute GHG signal

c. Difference is net monthly Recharge GHG

3. Discharge GHG

a. Sum of kWh of all Discharge blocks in month of same temp/status bin from original calibrated baseline x 5-minute GHG signal.

b. Less sum of measured kWh of all Discharge blocks

c. Difference is net monthly Discharge GHG

4. Discharge GHG (saved) less Recharge GHG = Net total GHG impact

5. Net total GHG impact / sum of Discharge kWh = Net total GHG/ kWh for the month.

c. Detailed data

i. All 5-minute Blocks for month, including:

1. Time stamp

2. Discharge/Recharge/Normal operation status
3. Ambient air DB temperature
4. Occupied/unoccupied
5. 5-Minute GHG Signal

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. *Please see the Appendix for the full L-TES calculation methodology*.

System owners 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 http://www.gosolarcalifornia.ca.gov/equipment/index.html. New non-residential projects less than 30 kW must comply with the meter standards in section 5.5.1.2

It is also the responsibility of the System Owners to contract with a Performance Data Provider (PDP) for a minimum of five years. 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.

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 7 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 7.1*.

- The meters will be inspected as part of the project inspection process.

The following section details the minimum meter requirements per type of meter installed.

5.5.2 *Minimum Electrical Meter Requirements*

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.

5.5.2.1 Large Non-Residential Projects (30kW and larger)

All systems 30 kW and larger and/or storage projects paired with and charging from on-site renewable generators must be installed with a meter or metering system which allows the System Owner and Program Administrator to determine the amount of net system energy charge and discharge and allows the System Owner to support proper system operation and maintenance.

5.5.2.2 Small Non-Residential Projects (less than 30kW)

All systems less than 30 kW with an on-board inverter-based meter, receiving a PBI incentive must have a meter accurate to within ± 3% of actual system output.

± 3% AC on-board inverter electrical meters required for PBI must be tested according to all applicable ANSI C-12 testing protocols pertaining to the monitoring of power (kW) and energy (kWh).The accuracy rating of ±3% meters must be certified by an independent testing body (i.e., a NRTL such as UL or TUV). DC electrical meters must also have a ± 3% accuracy pertaining to the monitoring of power (kW) and energy (kWh), as specified by the DC-DC converter manufacturer.

- **Meter Type**

All systems are allowed to use on-board electrical meters, however, the meter must meet the minimum meter requirements for the applicable system size. For all systems receiving PBI payments, the installed meter(s) may be a separate Interval Data Recording (IDR) meter(s), or a complete onboard system that is functionally equivalent to an IDR meter, recording data no less frequently than every 15 minutes. Program Administrators may have additional meter functionality requirements for systems receiving PBI payments, as the Program Administrators will use these meters to process PBI payments, and system compatibility may be required. For example, meters and service panels must meet all local building codes and utility codes. The meter serial number must be visible after installation.

- **Acceptable Electrical Metering Points**

For AC energy storage systems, a meter(s) must be installed on the AC side(s) of the energy storage device and account for power delivery to all parasitic loads including thermal management and power conditioning. For DC electrical energy storage systems, a meter(s) must be installed at a point within

the electrical system to measure the charge and discharge of the energy storage device and account for power delivery to all parasitic loads, including thermal management and power conditioning (such as DC to DC conversion). For TES systems, one or more meters must be installed to directly meter or measure the data points necessary to calculate the rate and quantity of charge (in kW/kWh) and the rate and quantity of discharge (in kW/kWh offset).

- **Meter Accuracy**

All systems receiving a PBI incentive must install a meter accurate to within ± 2% of actual system output. This applies to on-board electrical meters as well as external IDR meters.

- **Meter Measurement and Time Granularity of Acquired Data**

Electric meters must measure the net energy charged and discharged (kWh) and net real power charged and discharged (kW)[91]. The PDP must log all required energy storage performance / output data points no less frequently than once every 15 minutes. The PDP must measure 15 minute energy and real power for the energy storage system during charging and discharging and account for all ancillary loads. The meter needs to generate an accurate time/date stamp.

- **Meter Testing and Certification**

± 2% AC electrical meters required for PBI must be tested according to all applicable ANSI C-12 testing protocols pertaining to the monitoring of power (kW) and energy (kWh).The accuracy rating of ±2% meters must be certified by an independent testing body (i.e., a NRTL such as UL or TUV). DC electrical meters must also have a ± 2% accuracy pertaining to the monitoring of power (kW) and energy (kWh), as specified by the meter manufacturer.

- **Meter Display**

All meters must provide a display capable of showing the measured net charge and discharge energy output and measured instantaneous power during charging and discharging. This display must be easy to view and understand and must be physically located either on the meter or on a remote device. For PBI, if a remote device is the only visible access, the PA may ask for verification.

[91] For AC systems, measured in AC. For DC systems, measured in DC.

5.6 San Joaquin Valley Affordable Energy Pilot Projects, Budget, Incentive Design, and Eligibility

$10 million in SGIP incentives is available for the San Joaquin Valley (SJV) pilot host communities within PG&E's and SCE's service territories.[92] Of the $10 million set-aside, $9.76 million is allocated for residential system incentives, and $240,000[93] is allocated for non-residential system incentives.[94].

Eligible SJV customers are located in Allensworth, Alpaugh, Cantua Creek, Ducor, Fairmead, Lanare, Le Grand, La Vina, Seville, West Goshen, and California City.

Eligibility for the approved residential SJV pilot incentives 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. Eligibility for the approved non-residential SJV pilot incentives is limited to nonresidential customers providing critical facilities or infrastructure as outlined in Handbook Section 4.1.1.3.

All participating SJV pilot customers must adhere to the GHG reduction requirements. 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.

The incentive level for SJV pilot communities is $1.00/Wh.

Approved project incentives must not exceed actual project costs.

SJV Budget Allocations by Program Administrator

PA	SJV Residential	SJV Non-Residential	Total
PG&E	$ 4,880,000.00	$ 120,000.00	$ 5,000,000.00
SCE	$ 4,880,000.00	$ 120,000.00	$ 5,000,000.00

[92] D.19-09-027, p. 78.

[93] If applications for non-residential projects exceed $240,000 within four years of issuance of this decision, then PGE and SCE may allocate an additional $240,000 towards SJV pilot non-residential system incentives.

[94] Unreserved funds remaining in the SJV set-aside after four years shall be reallocated to the residential equity budget.

Total	**$ 9,760,000.00**	**$ 240,000.00**	**$ 10,000,000.00**

Vendors / developers participating in SJV pilot projects shall not sell a residential storage system that receives incentives for a total price (before incentives) that is greater than the price they sell a comparable system that does not receive incentives.

6 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 sections 2, 3 and 4.

6.1 Operational Eligibility Requirements for Technologies Operating on Renewable Fuel

6.1.1 *Minimum Operating Efficiency Requirements*

All generation technologies must meet or exceed a minimum operating efficiency requirement. The systems can satisfy this requirement by either meeting:

1. Waste heat utilization requirements **OR**
2. Minimum electric efficiency

To facilitate minimum operating efficiency requirements and determine system eligibility, a Minimum Operating Efficiency Worksheet is available for download from the Program Administrators' websites.

Waste Heat Utilization

To meet minimum waste heat utilization, CHP systems must meet the requirements of Public Utilities Code 216.6, which are expressed in the following equations:[95]

P.U. Code 216.6 (a) => $T / (T + E) \geq 5\%$

And,

P.U. Code 216.6 (b) => $(E + 0.5 \times T) / F_{LHV} \geq 42.5\%$

Where:

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 ≡ the ***annual*** electric energy made available for use, produced by the generator, exclusive of any such energy used in the power production process.

[92] "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 percent 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 percent of any natural gas and oil energy input.

F_{LHV} ≡ the generating system's ***annual*** Lower Heating Value (LHV) non-renewable fuel consumption.

Minimum Electric Efficiency[96]

To meet the minimum electric efficiency criteria, the proposed generator's electrical efficiency must be equal or greater than 40%, which is expressed in the following equation:

Electrical Efficiency = $E / F_{HHV} \geq 40\%$

Where:

E ≡ the generating system's rated electric capacity as defined in *Section 6.1.5*, 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.

6.1.2 *NOx Emission & Minimum System Efficiency Standards*

IC Engines, microturbines and gas turbines must not exceed a NOx emissions standard of 0.07 lbs/MW-hr and/or must meet the 60% minimum system efficiency requirement.[97]

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 percent load. The following formula is to be used to determine the system efficiency:

CHP System Efficiency = $(E + T) / F_{HHV} \geq 60\%$

Electric only System Efficiency = $E/ F_{HHV} \geq 40\%$

Where:

E ≡ the generating system's rated electric capacity as defined in *Section 6.1.5*, converted into equivalent Btu/hr using the factor 3,414 Btu/kWh

T ≡ the generating system's useful waste heat recovery rate (Btu/hr) at rated capacity.

F_{HHV} ≡ the generating system's Higher Heating Value (HHV) fuel consumption rate (Btu/hr) at rated capacity.

CHP systems that fail to meet the NOx emission standard but meet the 60% minimum system efficiency standard may be eligible to receive an emission credit for waste heat utilization.

[93] This requirement was included as an alternative requirement to meeting Public Utilities Code 216.6 in compliance with AB 2778.

[97] An emission credit for waste heat utilization may be used to adjust the final emissions determination of eligibility.

6.1.3 *Ineligibility of IC Engines located in areas of federal nonattainment*

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 eight-hour ozone (O3) in the U.S. Environmental Protection Agency Green Book for any of the three years prior to the SGIP application date.

6.1.4 *Rating Criteria for System Output*

The generating system rated capacity is the net continuous power output of the packaged prime mover/generator under the conditions defined below for each technology. In order to determine the net continuous power output, all ancillary loads must be subtracted from the gross output of the generator. Ancillary loads are defined as equipment loads, added as part of the SGIP generator project, necessary for the operation of the generator (e.g. fuel compressors, intercooler chillers, pumps associated with waste heat recovery, blowers used to transport renewable fuel, fuel clean-up equipment). System capacity ratings are established at the time of Conditional Reservation Notification in order to determine the SGIP reservation dollar amount. If system modifications (i.e. changes in equipment make/model) are made after the Conditional Reservation Letter is sent, the system capacity must be re-rated using currently available published component information for the changed equipment. If the number of components has increased or decreased and there is no change in the make/model of the equipment used, system components can be re-rated using the same published information used at the time of the Conditional Reservation.

- Steam turbine CHP rated capacity 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.
- For on-site biogas projects, the generating system capacity is the operating capacity based on the average annual available renewable fuel flow rate at ISO conditions.[98]
- For directed biogas projects, the generating system rated capacity is the net continuous power output of the packaged prime mover/generator at ISO conditions operating on a non-renewable fuel.
- Pressure reduction turbine technologies rated capacity is 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. Eligible technology system rated capacity must be substantiated with documentation from the manufacturer.
- Wind turbine technologies, less than 30 kW in capacity, a minimum hub height of 25 feet is required. No height limitation is imposed for turbines equal to or larger than 30 kW. For wind turbines of all

[98] Industry standard conditions to measure output – temperature at 59 degrees Fahrenheit and altitude at sea level (0 feet).

sizes, the wind turbine's rated capacity is based upon the highest electrical output from the manufacturer's power output curve for wind speeds up to 30 mph including inverter losses.

- Waste heat to power technologies rated capacity is 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.

6.1.5 *Reliability Criteria*

CHP systems must meet the following reliability requirements:

1. The self-generating facility must be designed to operate in power factor mode such that the generator operates between 0.95 power factor lagging and 0.90 power factor leading. This design feature will be verified by reviewing the manufacturer's specifications at the time of application and as part of the field verification visit before incentive payment approval.
2. System owners with facilities sized greater than 200 kW must coordinate the self-generation facility planned maintenance schedule with the electric utility. This allows the utility to more accurately schedule load and plan distribution system maintenance. The system owner will only schedule a facility's planned maintenance between October and March and, if necessary, during off-peak hours and/or weekends during the months of April to September.

6.2 Capacity Factors

Generation systems are expected to operate at the following capacity factors:

Table 6.2: Assumed Capacity Factors

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

Wind Turbines are expected to operate at a 25 percent 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 percent capacity factor. Systems intended to operate as a dispatchable generation resource to firm onsite intermittent renewables, provide peak load shaving, and/or support flexible load are expected to operate at a 15 percent capacity factor.

6.3 Sizing Requirements for Generation Systems

The following system sizing requirements are applicable for systems that are rated above 5 kW.

6.3.1 *System Sizing for Wind Turbines*

Host customers with a previous 12-month annual peak demand that is less than 333 kW may size wind turbine projects up to 200% of the annual peak demand at the proposed site. If the Host customer's annual peak demand is greater than or equal to 333 kW, wind turbine projects may be sized up to 300% of the peak demand at the proposed site. 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).

6.3.2 *System Sizing for PRT, Waste Heat to Power, CHP, Linear Generators, and Fuel Cells*

Pressure reduction turbine, waste heat to power, steam turbine, gas turbine, microturbine, internal combustion engine, Linear Generators, and fuel cell projects may be sized up to the host customer's previous 12-month annual peak demand at the proposed site.

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.

6.3.3 *System Sizing for Projects Exporting Power to the Grid*

Systems that will be exporting power to the grid will size their generators based upon 125% of the last twelve months of electrical consumption (kWhs) at the site. The incentivized capacity of the generator will be based upon 100% of the last twelve months of electrical consumption at the site. 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 6.3*.

6.3.4 *System Sizing for RES-BCT Customers*

Any local governments participating in the RES-BCT tariff (AB 2466) or any customer participating in FC-NEM (fuel cell customers who have been determined by the CPUC to achieve reductions in emissions of greenhouse gases pursuant to subdivision (b) of PU Code § 2827.10, and meets the emissions requirements for eligibility for funding set forth in subdivision (c) of PU Code Section 379.6, and has commenced operation on or before January 1, 2015) may size their systems to the total annual electrical load at the site where the generating system is located and the benefiting site(s) combined. However, they are only eligible for incentives up to the total annual electrical load (kWh) at the site where the generating system is located. Local government sites participating in the RES-BCT tariff must comply with the 5 MW cap per site.

6.3.5 *System Sizing Limitations - Ineligible Host Customer Loads*

The following loads cannot be considered when sizing a system:

- Customers who have 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 and energy storage projects need not abide by this portion.*
- Publicly-owned or investor-owned gas, electricity distribution utilities or any electrical corporation (ref. Public Utility Code 218) that generates or purchases electricity or natural gas for wholesale or retail sales.

6.4 Eligible Fuel Requirements

Eligible fuels are those that produce useful energy when undergoing combustion or a chemical reaction and are classified as renewable.[99]

6.4.1 *Directed Biogas Project Requirements*

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.

6.4.2 *Directed Biogas Renewable Fuel Audits*

Program Administrators or a third-party designee will conduct an annual audit of the renewable fuel invoices for ten 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 from SGIP participants for directed renewable fuel purchases; documentation/verification on any deliveries of directed renewable fuel along the path from the SGIP participant back to the original directed renewable fuel supply source; and documentation to verify the amount and energy content of directed renewable fuel injected into the path. To complete the audit, 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.

[99] For the purposes of SGIP, renewable resources such as wind, pressure, waste heat, and water are not categorized as a fuel.

If invoices show that nominated renewable fuel deliveries fell below the generator's committed renewable fuel demand during any 1-year period, the SGIP Program Administrators may request that the system owner refunds the appropriate renewable fuel SGIP incentive amount and reserve the right to request a refund of additional costs associated with the administrative and legal fees incurred by the Program Administrators.

Any request to change the fuel provider during the 10-year fuel contract must be submitted to the SGIP Program Administrator for approval.[100]

SGIP Program Administrators will 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.

6.4.3 *On-site Biogas Projects - Gas Quality Standard*

Biogas fuel used in on-site internal combustion engine projects must meet a 96 percent methane gas quality standard. On-site biogas projects are required to self-certify to installation of equipment necessary to achieve this requirement which will be verified during the onsite on-site inspection and during subsequent measurement and verification assessments.

6.4.4 *Hydrogen Projects - Eligibility*

For the purposes of SGIP, technologies operating on Hydrogen are eligible for incentive if the hydrogen is produced at a SGIP project site, or delivered to a SGIP project site by vehicle or dedicated pipeline.

The types of 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 percent renewable electricity, as defined by the Renewables Portfolio Standard
- Hydropower, if the project is located onsite 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 is ineligible for use in SGIP incentivized projects.

[100] PAs shall respond to requests to change fuel supplier within 30 days.

6.4.5 *Renewable Fuel Commitment Modifications*

Customers are required to meet their renewable fuel commitment throughout the permanency period. In the event that modifications are made applicants are required to notify their Administrator.

- **Modifications Pre-ICF** – applicants must notify their administrator as soon as practical but no later than ICF. Increase of renewable fuel percent prior to the completion of the project may not automatically increase incentive amount.
- **Modifications Post-ICF –** applicants must notify their Administrator within 90 days of any changes made to the contract and amount of renewable fuel. Increase in amount of renewable fuel may not result in an incentive increase. Additionally, the host customer must provide to the Program Administrator with all pertinent documentation.

6.4.6 *Pressure Reduction Turbine Requirements*

Any steam turbine replacing a pressure reduction valve will be considered eligible under the pressure reduction turbine category.[101] 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.

6.5 Incentive Calculation for Renewable Generation Projects

Incentives for a proposed generation system are calculated by multiplying the rated capacity (W) of the system[102] by the incentive rate.

Incentive = *rated capacity * incentive rate*

For proposed generation systems that qualify for the resiliency incentive (as outlined in section 3.1.1.1):

Incentive = *rated capacity * (incentive rate + resiliency adder incentive rate)*

6.5.1 *Incentive Declines Based on Generation Capacity*

SGIP incentives are paid for up to 3 MW of capacity with tiered incentive rates. For projects that are greater than 1 MW, the incentives identified in Table 3.1.1 decline according to the following schedule:

Table 6.6.1: Tiered Incentive Rates

Capacity	Incentive Rate (Pct. of Base)
0 – 1 MW	100%
>1 MW – 2 MW	75%
>2 MW – 3 MW	50%

[101] 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.

[102] For more information on rating criteria for system output, see *Section 6.1.5*.

6.6 Performance-Based Incentive Payment (PBI)

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 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 * five years*

For a 5-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*

6.6.1 *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.

6.6.2 *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.

6.7 Renewable Generation Annual Payment Requirements

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

6.7.1 *Directed Renewable Fuel Verification*

The amount of directed renewable fuel procured will be verified prior to issuing annual PBI payments. For Directed Renewable Fuel users, applicant or Performance Data Provider (PDP) must provide monthly data of the amount of directed renewable fuel consumed on a monthly basis. This information must be provided through the SGIP database as part of the performance data requirements. Additionally, the applicant or PDP will be required to provide the source, path, and destination of the renewable fuel. Data reporting will commence one month after the initial payment. The following information and documentation must be provided on a monthly basis:

1. **Transportation Path and Energy Accounting**

The PDP must upload supporting documentation (i.e., invoices) reporting the amount of renewable fuel that was documented on the Directed Renewable Fuel Verification Form. Supporting documentation includes but not limited to:

- Documentation from the source showing the amount of directed biogas being moved onto the pipeline. Any non-renewable gas added at the source must be identified.
- Documentation from the gas transmission system showing:
- Receipt of directed biogas (from source, storage, or other pipelines)
- 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 utility receipt point

2. **Gas Fuel Consumption**

The PDP must provide gas fuel consumption documentation from the gas utility matching the directed renewable fuel receipts reporting the metered total energy input to the generator. Utility gas fuel consumption receipts must be reported on a quarterly basis.

It is the responsibility of the PDP 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.

6.7.2 *On-site Renewable Fuel Verification*

All on-site renewable fuel projects 30 kW and larger are required to install a fuel metering system that reports only renewable fuel consumption. The PDP is required to submit renewable fuel data on a monthly basis.

The System Owner must provide make, model, specifications, and serial number of installed revenue grade gas meters

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.

6.8 Incentive Limitations for Projects using Renewable Fuel

The following sections outline the incentive limitations for projects using renewable fuel. Additionally, all generation projects are subject to the general incentive limitations as outlined in *Section 3.2*.

6.8.1 *Limitations on PBI Adjustments based on Renewable Fuel Verification*

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.

6.9 Application Documentation Requirements for Generation Projects

Applications are required to meet all documentation requirements on time. Documents are based on the application timeline. The following sections describe the required documents based on the specific step.

6.9.1 *Required Documentation for Reservation Request*

Generation applications must provide a copy of the following:

Table 6.10.1: Reservation Request Requirements

Required Materials
1. Completed Reservation Request Form *(All Projects)*
2. Application Fee *(Non-Residential Projects only)*
3. **Equipment Specifications** *(All Projects)*
4. **Proof of Utility Service/ Load Documentation** *(All Projects)*
5. **Preliminary Monitoring Plan** *(All 3-Step Applications >=30 kW)*
6. **Minimum Operating Efficiency Worksheet w/Backup Documentation** *(Renewable Fuel Projects)*
7. **Proof of Adequate Fuel or Waste Energy Resource** *(All Projects)*
8. Customer Resiliency Attestation (Resiliency Projects)

Required Materials
9. Proof of Coordination with Local Government and California Office of Emergency Services *(Non-Residential Renewable Generation Resiliency Adder Applications only)*

Two-Step Applications should also include all applicable Proof of Project Milestone Documents *(as outlined in Section 6.10.2)* as part of their Reservation Request

1. **Online Reservation Request Form** *(All Projects)*

All applicants are required to complete the online Reservation Request Form (RRF). This online form is used to provide project details, contact information, and signed declarations.

As part of the RRF the project Host Customer must attest that an Energy Efficiency Audit (EEA)[103] has been performed for the project site and they received and reviewed the findings of the audit.

The RRF must be printed and signed by the applicant, 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 only)*

The application fee 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.[104] The application fee is the only required document that must be mailed directly to the Program Administrator.[105] After a project is assigned to an incentive step, the application fee check must be mailed within 7 calendar days. If the check is not mailed within 7 calendar days, the project may be cancelled. Application fee checks returned by the financial institution without payment may result in cancellation of the application.

[103] 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.

[104] 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.

[105] A single application fee check for each project is required.

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 a Confirmed Reservation has been issued.[106]

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 which case the Program Administrator Working Group shall approve such request 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.

All forfeited application fees will be allocated to the Program Administrator's current incentive step.

3. **Equipment Specifications** *(All 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.

4. **Proof of Utility Service & Load Documentation** *(All Projects)*

Participation in the SGIP is restricted to 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 must include a copy of a recent electric utility bill, with the exception of PG&E,[107] indicating the account number, meter number, site address, and Host Customer name. Customers applying in PG&E and SoCalGas territory must also submit a copy of a recent gas utility bill. For new construction, the Host Customer must submit confirmation from the serving utility that their site is within the Program Administrator's service territory. For projects applying in CSE and SoCalGas territory, applications for technologies that discharge electricity to the onsite load must include a copy of the previous 12-months of electric consumption including maximum demand and kWh consumption to confirm that the participating generation system meets

[106] Application Fees will not be altered due to project changes that may result in a different incentive.

[107] A utility bill can be required at PG&E's discretion

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 systems greater than 10 kW or any other instance under CSE discretion if needed.

If the generation 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 VisualDOE; or detailed engineering calculations.

5. **Preliminary Monitoring Plan** *(All 3 Step Applications >=30 kW)*

The preliminary monitoring plan should demonstrate the following components:

Description of the proposed SGIP system:

Description of the system with an overview of the energy services to be provided (e.g., generation, waste heat recovery, storage, etc.) by the system to the host site; the major components making up the system; and the general operating schedule of the system (e.g., is it 24x7x365 or 10x6x365, etc.); 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 if available.

Break out subsystems such as waste heat recovery systems in order 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 (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, etc.) and a simplified layout of the system showing major components (e.g. generator, waste heat recovery, storage etc.) and location of the proposed metering points and data to be collected at those points (i.e. electrical, flow, temp, fuel etc.) is required.

Two Step Applications will include (as part of their Reservation Request) a Proposed Monitoring Plan as outlined in *Section 6.10.2*.

6. **Minimum Operating Efficiency Worksheet w/Backup Documentation** *(Renewable Fuel Projects)*

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

a) Minimum operating efficiency requirement which can either be satisfied by meeting:
   Waste Heat Utilization *or*
   Minimum Electrical Efficiency Requirements
b) Thermal Load Coincidence
c) CHP System Efficiency and NOx Emission Qualification
d) Greenhouse Gas Emission Standard
e) Electrical Load Coincidence (Electrical Export Eligibility)

a) Minimum Operating Efficiency Calculations

The MOEW is a spreadsheet used to evaluate the project's estimated minimum operating efficiency. All applications 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 twelve-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 (i.e., intercooler, external fuel gas booster, etc.).

- *Forecast of Generator Thermal Output*
  The application must include a forecast of the monthly generator thermal output (Btu/month) for a twelve-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 twelve-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 twelve-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 P.U. Code 216.6 requirements.

b) <u>Thermal Load Coincidence</u>

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.

c) <u>CHP System Efficiency and Proof of NOx Emission Qualification</u>

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[108] 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 C 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 twelve-month period must be provided.

d) <u>Electric Load Coincidence</u> *(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.

7. **<u>Proof of Adequate Fuel or Waste Energy Resource</u>** *<u>(All Projects)</u>*

<u>On-site Biogas Projects (including on-site Hydrogen)</u> 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.

<u>Biogas Projects utilizing Directed Renewable Fuel or Hydrogen delivered via vehicle or dedicated pipeline</u> must include documentation of the forecasted fuel consumption of the generator over the life of project.

<u>Proposed Pressure Reduction Turbine applications</u> 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 for 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, wind speed data must be collected at the turbine's proposed on-site location and hub height for a minimum of 60 days, and a third party must correlate the data using local annual wind speed data (gathered at an airport and averaged over the past three years) to determine if the average annual wind speed is greater than 10 mph.

8. **Customer Resiliency Attestation (Resiliency Projects)**
For renewable generation projects applying for the resiliency adder incentive, we require that renewable generation:

A. Provide an estimate of how long a project's renewable generation system will provide electricity for the relevant facility average load during an outage;
B. Indicate whether a project's critical loads can and will be isolated;
C. Provide an estimate of how long a project's renewable generation system will provide electricity to critical uses during an outage;
D. Provide an estimate of how long the renewable generation system can operate in less-than favorable circumstances.
E. Summarize information given to the customer about how the customer may best ensure operation of the renewable generation system, in the case of a PSPS event announced in advance;
F. Attest to the truth of the information provided;
G. Provide an attestation from the customer indicating that he or she received this information prior to signing a contract; and

H. 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.

9. **Proof of Coordination with Local Government and California Office of Emergency Services**

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.

Additional Requirements for Two Step Applications

All 2 step applications must include as part of their Reservation Request materials, all applicable requirements of the Proof of Project Milestone. *See Section 6.10.2*.

6.9.2 *Required Documentation for Proof of Project Milestone*

Generation applications must provide a copy of the following:

Table 6.9.2: Proof of Project Milestone Requirements

Required Materials
1. **Online Proof of Project Milestone Form** *(All Projects)*
2. **Copy of RFP or equivalent after 90 days** (*Public Entity Projects Only)*
3. **Copy of Executed Contract and/or Agreement for Installation** *(All Projects)* • Includes Required Warranty Documentation
4 **Proposed Monitoring Plan** *(All Projects >=30 kW)*
5. **Proof of Fuel Contract and Documentation** *(All Projects)* • Renewable Fuel Contract *(Directed Renewable Fuel and Delivered Hydrogen)* • Directed Renewable Fuel Attestation – System Owner & Fuel Supplier *(Directed Renewable Fuel Only)* • Renewable Fuel Affidavit *(On-site Renewable Fuel Only)* • Fuel Clean-up *(On-site Renewable Fuel Only)*

1. **Online Proof of Project Milestone Form** *(All 3-Step Projects)*[109]

The Online Proof of Project Milestone (PPM) Form must identify if there are changes from the information that was presented in the Reservation Request Form (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.

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 (RFP) Documentation** *(Public Entities Only)*

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. Proof of Project Milestone documentation must then be submitted within 240 days of the date the Conditional Reservation Letter.

3. **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) 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, Installer, and/or System Owner) who are a party to the agreements of the SGIP reservation.

- As part of the Executed Contract, all generation systems are required to include a minimum *10 year service warranty* (with the exception of wind turbines which 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

[109] Not required for 2-Step Applications as part of the Reservation Request Package.

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.

4. **Proposed Monitoring Plan** *(All Projects that are 30 kW or larger)*

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, etc.) 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, etc.); 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 in order 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, etc.) and a simplified layout of the system showing major components (e.g., generator, waste heat recovery, storage, etc.) and location of the proposed metering points and data to be collected at those points (i.e., electrical, flow, temp, fuel, etc.) is required.

Description of the approach to be used for collecting, storing and transferring the necessary performance data

- For example, if useful thermal energy data is to be collected, the reasoning behind the selected metering points
- Frequency with which the data is to be collected (e.g., 15 min intervals)

- Data storage capability and approach for transfer of data (e.g., cell modem) and frequency of reporting to PDP (e.g., daily, weekly) [this could also include frequency for reporting of data to Program Administrators, such as 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 http://www.gosolarcalifornia.ca.gov/equipment/index.html)
- Thermal energy metering equipment
- Fuel consumption metering equipment
- Data acquisition (i.e., logger) system

5. **Proof of Fuel Contracts and Documentation** *(All 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 on a monthly basis 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 SGIP 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.

For Directed Renewable Fuel Contracts, the contract 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 system owner 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 SGIP 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 Only)*
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.

6.9.3 *Required Documentation for Incentive Claim*

Generation applications must provide a copy of the following:

Table 6.10.3: Incentive Claim Requirements

Required Materials
1. **Completed Incentive Claim Form** *(All Projects)*
2. **Proof of Authorization to Interconnect** *(SCE, CSE and SoCalGas Project Applications)*
3. **Final Permits** • **Building Permit Inspection Report** *(SCE, CSE and SoCalGas Project Applications)* • **Additional AHJ Grid Islanding Plan** (Equity Resiliency and Equity) • **Air Permit Documentation** (*All Projects)*
4. **Substantiations:** • **New or Expanded Load** *(All Projects)* • **Renewable Fuel or Waste Resource** *(On-site Renewable Fuel and Waste Energy Only)* • **Fuel Cleanup Skid Cost** *(On-site Renewable Fuel Only)* • **Renewable Fuel Documentation/Contract Commencement** *(Directed Renewable Fuel Only)* • **Renewable Fuel Metering Specifications** *(Directed Renewable Fuel Only)*
5. **Planned Maintenance Coordination Letter** *(>=200 kW CHP Systems Only)*
6. **Final Monitoring Schematic** *(All Projects)*
7. **PBI Setup Sheet** *(All Projects >= 30kW)*

1. **<u>Online Incentive Claim Form</u>** *(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 and system owner (if not the host customer).

2. **Proof of Authorization to Interconnect** *(Projects that interconnect with the electrical grid)*

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 should be submitted as proof of Authorization to Interconnect. PG&E customers are exempt from submitting an interconnection Permission to Operate (PTO) letter as proof of Authorization to Interconnect. PG&E will verify interconnection internally during ICF review.[110]

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. **Final Permits**

Building Inspection Report *(SCE, CSE and SoCalGas Project Applications)*

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. PG&E customers are exempt from submitting a building inspection report provided that a final building inspection report is submitted to PG&E in connection with interconnection of the Project pursuant to PG&E's interconnection requirements. PG&E will verify the building inspection report internally during ICF review.[111]

Air Permitting Documentation *(All 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 Added Load *(All Projects)*

For Projects where host customer estimated the future load to justify system size, applications must include documentation demonstrating that the load forecast has materialized.

Renewable Fuel or Waste Energy Resource *(On-Site Renewable Fuel and Waste Energy Only)*

[110] 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.

[111] A Building Inspection Report can be required at PG&E's discretion.

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 Only)*
On-site biogas projects must include documentation substantiating the fuel cleanup skid cost.

Renewable Fuel Documentation & Contract Commencement *(Directed Renewable Fuel Only)*
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 SGIP Program Administrator for commencement of the contract. However, no incentive will be paid until the contract has commenced.

Renewable Fuel Metering Specifications *(Directed Renewable Only)*
Documentation should also be provided to include make, model, specifications and serial number of installed revenue grade electric NGOM and gas meters.

5. **Planned Maintenance Coordination Letter** *(CHP Projects >=200 kW Only)*

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** *(All 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 at the Proof of Project Milestone).

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.

7. **PBI Setup Sheet** *(for projects 30 kW or larger)*

The PBI setup sheet must include information for all meter(s) installed for the purpose of monitoring system performance. The meter IDs listed on the PBI setup sheet must also match the meter IDs specified on the Final Metering Schematic.

6.10 Metering & Monitoring Requirements for Generation Projects

All SGIP technologies 30 kW or larger must install metering and monitoring equipment that measures net electrical output from the system(s). In addition to electrical output, fuel input metering into the generator(s) is required for all generation technologies. CHP technologies must also install metering and monitoring equipment that measures and reports useful thermal energy delivered to the site from the CHP system.

System owners must install and maintain metering and monitoring equipment at their own cost and are responsible for the choice and installation of the metering hardware. All AC electric meters must be listed on the CEC's list of Eligible System Performance and Revenue Grade Meters to be found on http://www.gosolarcalifornia.ca.gov/equipment/index.html.

It is also the responsibility of the System Owners to contract with a Performance Data Provider (PDP) for a minimum of five years. 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.

All installed meters (electrical, thermal and fuel) 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 7 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 7.1.*
- The meters will be inspected as part of the project Post-Installation inspection process.

The following section details the minimum meter requirements per type of meter installed (electrical, thermal, fuel).

6.10.1 *Minimum Electrical Meter Requirements*

All systems 30 kW and larger must be installed with a meter or metering system which allows the System Owner and Program Administrator to determine the amount of net system energy production and allows the System Owner to support proper system operation and maintenance.
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.

- **Meter Type**

All systems are allowed to use on-board electrical meters, however, the meter must meet the minimum meter requirements of this section. For all systems receiving PBI payments, the installed meter(s) may be a separate Interval Data Recording (IDR) meter(s), or a complete onboard system that is functionally equivalent to an IDR meter, recording data no less frequently than every 15 minutes. Program Administrators may have additional meter functionality requirements for systems receiving PBI payments, as the Program Administrators will use these meters to process PBI payments, and system compatibility may be required. For example, meters and service panels must meet all local building codes and utility codes. The meter serial number must be visible after installation.

- **Acceptable Electrical Metering Points**

The electrical metering system must meter delivered energy by having a meter at the output of the generator and after power delivery to all parasitic loads. When an on-board electrical metering system is used, the meter must have multiple channels in order to monitor parasitic energy consumption as well as generator output and report net generation output.

- **Meter Accuracy**

All systems receiving a PBI incentive must install a meter accurate to within ± 2% of actual system output. This applies to on-board electrical meters as well as external IDR meters.

- **Meter Measurement and Time Granularity of Acquired Data**

Electric meters must measure the net energy generated (kWh) and net real power delivered (kW). The PDP must log all required generator performance / output data points no less frequently than once every 15 minutes. The meter needs to generate an accurate time/date stamp.

- **Meter Testing and Certification**

± 2% meters required for PBI for AC systems must be tested according to all applicable ANSI C-12 testing protocols pertaining to the monitoring of power (kW) and energy (kWh). The accuracy rating of ±2% meters must be certified by an independent testing body (i.e., a NRTL such as UL or TUV). DC electrical meters must also have a ± 2% accuracy pertaining to the monitoring of power (kW) and energy (kWh), by the meter manufacturer.

- **Meter Display**

All meters must provide a display showing the meter's measured net generated energy output or offset and measured instantaneous power. This display must be easy to view and understand and must be physically located either on the meter or on a remote device. For PBI, if a remote device is the only visible access, the PA may ask for verification.

6.10.2 *Minimum Thermal Metering Requirements*

All CHP systems 30 kW and larger must be installed with a metering system which allows the System Owner and Program Administrator to determine the amount of useful thermal energy production and allows the System Owner to support proper system operation and maintenance. Thermal energy metering systems installed on the SGIP project provide data used to assess thermal performance of the system; including its ability to meet on-site thermal energy demands (thereby offsetting consumption of fossil fuels) and meet thermal energy efficiency requirements prescribed by PUC 216.6. Thermal energy performance data will also be used to assess impact of the SGIP system on net GHG emission impacts[112] and minimum system operating efficiency requirements.

- **Meter Type**

All CHP systems that are 300 kW and smaller will be allowed to use an on-board thermal metering system in order to minimize cost. The specific instrumentation required to measure useful thermal energy production will vary depending on the configuration and type of heat recovery system (e.g., liquid, steam, direct exhaust). Common flow measuring devices include insertion type or ultrasonic flow meters. Temperature measurement may be done with thermocouples. On-board thermal metering systems just as external thermal metering systems must measure useful thermal energy production. Proposed meter and sensor types shall be identified in a Monitoring Plan developed for each individual project. On-board meters must meet the same requirements as external meters which are outlined below.

- **Acceptable Thermal Metering Points**

Proposed meter and sensor locations shall be identified in a Monitoring Plan developed for each individual project. It is recommended for direct exhaust combined cooling heating and power (CCHP) systems, that the chilled water output be measured, rather than measuring exhaust flows and temperatures as a way to calculate the useful thermal output.

- **Meter Accuracy**

The accuracy of the metering system for useful thermal energy production must be within ± 5% at design conditions. This requirement applies to on-board as well as external thermal metering systems. The Monitoring Plan shall include a section describing monitoring system maintenance plans that will be implemented to ensure compliance with the accuracy requirement throughout the PBI period.

[112] Thermal energy metering systems may also provide SGIP System Owners with a potential means of verifying carbon emissions and carbon emission reductions.

- **Meter Measurement and Time Granularity of Acquired Data**

The PDP must log all required useful heat recovery system performance / output data points no less frequently than once every 15 minutes. Calculated values of useful heat recovery must be reported in 15 minute intervals. The sum of four consecutive intervals would represent the industry standard rate of Useful Heat Recovery in units of MBtu/hr. The heat transfer fluid specific heat and density must be reported at the time of commissioning and then reported again to the PA if there is a change. The meter needs to generate an accurate time date stamp.

6.10.3 *Minimum Fuel Metering Requirements*

All generation technologies 30 kW and larger and regardless of renewable fuel type must be installed with a fuel metering system which allows the System Owner and Program Administrator to determine the amount of renewable fuel consumption and allows the System Owner to support proper system operation and maintenance.

- **Meter Type**

All generation technologies that are 300 kW and smaller will be allowed to use an on-board fuel metering system to minimize cost. 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

On-board fuel metering systems, just as external fuel metering systems, must measure fuel consumption by the generator. The proposed meter type shall be identified in a Monitoring Plan developed for each individual project. On-board meters must meet the same requirements as external meters which are outlined below.

- **Acceptable Fuel Metering Points**

For fuel metering that is external to the generator, an acceptable metering point is before renewable fuel entry into the generator but downstream of any other loads. For on-board metering systems, the renewable fuel must be metered before any portion is consumed by the generator. For on-site renewable fuel projects, there must be separate meters for the renewable fuel. Proposed meter locations shall be identified in a Monitoring Plan developed for each individual project.

- **Meter Accuracy**

Flow measurement must include temperature and pressure compensation and must measure standard cubic feet (at 60 °F and 1 atmosphere) to within ± 5% of maximum flow for the generator at design conditions. This requirement applies to on-board as well as external fuel metering systems.

- **Meter Measurement and Time Granularity of Acquired Data**

The PDP must log all required generator system fuel input data points no less frequently than once every hour. Calculated values must be reported in one-hour intervals. Data must be recorded in units of standard cubic feet per minute. The Btu content and basis (HHV/LHV) of the fuel must be reported during commissioning either through data provided by the gas company or determined by analysis. Btu content of the fuel will need to be re-analyzed and reported to the PA when there is a reason to believe it has changed. The meter needs to generate an accurate time date stamp.

7 Metering & Data Collection

This section describes the requirements for data reporting, PDP application process, data security, and measurement and evaluation activities.

7.1 Data Reporting and Transfer Rules – Contract for PDP Services

It is the responsibility of the System Owners to contract with a Performance Data Provider (PDP) for a minimum of five years 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 the Program Administrators websites.

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.

7.1.1 *Data Format*

Meter data must conform to the SGIP program requirements as set forth in *Section 5.5* and *Section 6.11* (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.[113]

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.

7.1.2 *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 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 Incentive 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 6 months. Any request for an alternate data collection commencement date will require Program Administrator approval.

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

7.1.3 *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 e-mail will not be accepted.[114]

7.1.4 *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.

7.1.5 *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 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 (i.e., 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.

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

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.

7.1.6 *PDP 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.

7.1.7 *PDP 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 $\pm$ 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 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 3 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.

7.1.8 *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.

7.1.9 *Technical and Customer Support*

The PDP must provide a technical support number to the Program Administrator for use during normal business hours (8am to 5pm 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.

7.1.10 *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.

7.2 PDP 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[115]. 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.

7.2.1 *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.

7.3 Data Privacy and Security

Protecting the privacy of System Owners and Host Customer 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 to ensure 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.

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

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.

7.4 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 for five-years. M&E activities will be performed by the Program Administrator (PA) or the PA's independent third-party consultant and include, but are not limited to, periodic telephone interviews, Site visits, development of a M&E Monitoring Plan, review of monitoring plans developed 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.

7.4.1 *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 2.5.3*), which are used to determine eligibility of the installed system and occur during the Incentive Claim stage of the application process.

7.4.2 *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 for the duration of five years.

7.4.3 *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 meter removal. Dispute Resolution and Infractions

8 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 his or her 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 thirty (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 thirty (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.

9 Participant Performance and Infractions

9.1 Participant Performance

All participants[116] are expected to follow program rules and eligibility requirements. Failure to do so will result in warnings and/or infractions. Please see *Section 9.2* 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:

- Application
- Inspection
- Attrition and Extensions
- Data Reporting
- SGIP Online Application Database Operation
- Developer

9.1.1 *Application*

Applications must be submitted with complete and accurate documentation and must meet all deadlines. Applications with incomplete, falsified, or inaccurate documentation[117] or that do not meet required due dates may receive warnings and/or result in an infraction.

9.1.2 *Inspection*

All projects may be inspected at any time during a project's permanency period and are expected to meet document and operational requirements of the program. Failure to do so will count as a failed inspection. Participants with a high statewide inspection failure rate may forfeit future participation and/or all active applications/incentive.

For Directed Renewable Fuel Projects, all projects will be subject to periodic and random no-warning verification spot-check inspections of directed biofuel sources. If the inspection reveals a lack of compliance with SGIP requirements, a single 30-day warning will be issued prior to issuing an infraction.

9.1.3 *Attrition and Extensions*

Participants are expected to submit applications that are committed/viable projects. Cancelled or withdrawn applications will be counted towards attrition rate. Participants with a high attrition rate may forfeit future participation and/or all active applications/incentives.

[116] 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.

[117] Including criteria that would grant higher priority in the event of a lottery.

Participants are also expected to meet project milestone due dates as originally assigned. Excessive extension requests among a participant's applications may receive warnings and/or result in an infraction.

9.1.4 *Data Reporting*

Participants are required to submit all necessary operational and performance data. Participants submitting data past their designated due date may receive warnings. Participants that do not submit data at all for their projects may be subject to an infraction. Any falsified or blank submissions will result in an automatic infraction.

9.1.5 *SGIP Online Application Database Operation*

Participants are required to comply with the Terms of Use of the SGIP database for all accounts, applications, and PBI data submissions. Non-compliance with the Terms of Use or attempting to circumvent the SGIP database application policies or procedures will result in an automatic infraction.

9.1.6 *Developer*

An infraction may be issued if the Developer of a project does not fully and/or accurately disclose Developer and ownership information as listed in *Section 4.1.5*.

9.1.7 *Residential GHG Emissions Compliance*

Developers of IOU and non-IOU residential customers have a continuing obligation to produce documentation regarding participating customers' systems, rates and charge and discharge patterns upon request. Failure to do so shall be considered an infraction. Developers must also provide the PAs and SGIP evaluator with documentation on participating customers' systems upon request. Failure to do so shall be considered an infraction.

Additionally, the PAs will annually verify that new residential fleets are reducing GHG emissions using annual statistical sampling within the SGIP impact evaluation process and, if not, will take appropriate enforcement actions. Note: 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.

The Commission adopts four additional requirements for new residential fleet verification:

1. PAs may issue infractions for any new residential developer that does not provide the information requested by the PAs or the SGIP Impact Evaluator in the timeframe requested and to suspend any developer with two infractions for this reason for applying for new incentives for a period of six months.
2. PAs will suspend any developer with a new residential fleet verified as having increased GHG emissions for two successive six-month periods from applying for new SGIP incentives for six months, or until the developer's fleet is verified to be reducing GHG emissions, whichever is later.

3. PAs will require any developer verified as having increased GHG emissions to biannually submit GHG emissions data for all projects in the developer's new residential fleet using the existing SGIP online data upload portal until the fleet is verified to reduce GHG emissions
4. PAs may suspend any new residential developer verified as having increased GHG emissions for submitting data for less than 90% of the meters of the developer's fleet from applying for any additional incentives for a period of one year.

9.2 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 4.1.* The Program Administrators or Energy Division will evaluate program infractions, which may include 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 forfeiture
- Fiscal or programmatic audit

9.2.1 *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 SGIP 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 SGIP 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.

Definitions and Glossary

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 percent 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.

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

Developer: For applications received in Steps 1 and 2, a Developer is the corporate entity that holds the contract for purchase and installation of the system, and/or alternative System Ownership Agreement (such as a Power Purchase Agreement) with the host customer and handles the project's development activities.

For applications received in Step 3 and later, 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 ten-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 ten-year permanency requirement, whose SGIP agreements list the same developer. A developer's new residential fleet includes all new residential projects within their ten-year permanency requirement whose SGIP agreements list the same developer.

Directed: 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. A directed renewable fuel must be injected into a common carrier pipeline system that is either within the Western Electricity Coordinating Council (WECC) region or interconnected to a common carrier pipeline system located within the WECC region.

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 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. This is a Public Safety Power Shutoff (PSPS).

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 onsite 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 percent 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.

ESCO: 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.

Fuel Cell: Power plants that produce 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, 3) is the utility customer of record at the site 4) 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.

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

ISO: International Standards Organization

ITC: Investment Tax Credit

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

Linear Generator: Power plants that directly convert 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).

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.

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 SGIP program requirements.

New Projects: Any project submitting a complete SGIP application containing all required information on or after April 1, 2020 and any project submitting an SGIP application prior to April 1, 2020 that is not complete and for which all required information is not provided until or on April 1, 2020 that receives SGIP incentives. GHG emissions reductions requirements apply throughout a project's ten-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, 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: 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: 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

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, etc.) 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.[118]

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 all required documentation must be provided by.

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.

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 and Electric

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.

[118] Source: CALIFORNIA CODES - PUBLIC CONTRACT CODE, SECTION 21611.

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

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

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.

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.

TES: Thermal Energy Storage

Thermal Energy Storage: Technologies able to store energy and discharge it at a later time as thermal energy to offset electricity consumption.

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.

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.

Legislation and Regulatory Background

Date	Bill Number	Description
9/6/2000	AB 970	Assembly Bill required the CPUC to initiate load control and distributed generation activities.
3/27/2001	D 01-03- 073	CPUC Decision complying with Assembly Bill 970 and establishing the Self Generation Incentive Program. Implementation of PU Code Section 399.15(b), Paragraph 4-7; Load Control and Distributed Generation Initiatives.
06/01/2001	D. 01-06-035	CPUC Decision establishing waste heat recovery standards for SGIP. Requires Energy Branch to develop reliability criteria.
01/18/2002	Letter on Reliability Criteria	CPUC Energy Branch Letter establishing reliability criteria requirements for level 3 technology applications received after January 1, 2002
02/07/2002	D. 02-02-26	CPUC Decision addressing eligibility of customers served by electric municipalities, maximum size and annual program budget.
04/04/2002	D. 02-04-004	CPUC Decision clarifying Applicant's ability to receive incentive funding from multiple sources. Addressing SCAQMD's PTM of Decision 01-03-073
09/19/2002	D. 02-09-051	CPUC Decision adding technology level 3-R, which establishes a new level of incentives. Contains specific requirements for projects using renewable fuels for level 3-R. Addressing Capstone's PTM
10/12/2003	AB 1685	• Extended the SGIP through 2007 • Required that projects commencing January 1, 2005 meet a NOx emission standard • Required that projects commencing January 1, 2007 meet a more stringent NOx emission standard and a minimum system efficiency standard. • Established a NOx emission credit that can be used by combined heat and power (CHP) units to meet minimum system efficiency standard
9/22/2004	AB 1684	Exempts certain projects from NOx emission standards set forth in AB 1685 that meet waste gas fuel and permitting requirements.

Date	Bill Number	Description
12/16/2004	Decision 04-12-045	Modified SGIP to incorporate provisions of AB 1685: • Eliminates maximum percentage payment limits • Reduces incentive payments for several technologies • Expands opportunities for public input regarding developing a declining incentive schedule, developing an exit strategy and adopting a data release format • Required an application fee for all projects received after 1/1/2005 in order to deter against "phantom projects". This requirement was removed beginning in 2007 except in the case of new technologies that are in the process of certification.
1/12/2006	Decision 06-01-047	Established the California Solar Initiative (CSI) and ordered changes in the 2006 SGIP to accommodate the transition of solar program elements to the CSI beginning January 1, 2007.
9/29/2006	AB 2778	• Extended SGIP until January 1, 2012 • Limited eligible technologies beginning January 1, 2008 to fuel cells and wind systems that meet emissions standards required under the distributed generation certification program adopted by the State Air Resources Board • Requires that eligibility of non-renewable fuel cell projects be determined either by calculating electrical and process heat efficiency according to PU Code 216.6 or by calculating overall electrical efficiency
4/24/2008	Decision 08-04-049	Removed the 1 MW cap on incentives for 2008 and 2009 allowing projects to receive lower incentives on a tiered structure for the portion of a system over 1 MW.
9/28/2008	AB 2267	Requires an additional 20% incentive for the installation of eligible distributed generation resources from a California Supplier. This additional incentive is applied only to the technology portion of the incentive; the additional incentive for renewable fuels is not included in calculating the 20%.
11/21/2008	Decision 08-11-044	• Determined that Advanced Energy Storage systems coupled with eligible SGIP technologies will receive an incentive of $2/watt of installed capacity. • Revises the process for the review of SGIP program modification requests
9/09/2009	Decision 09-09-048	Grants a petition to modify SGIP policies expanding eligibility for Level 2 incentives to include "directed biogas" projects where renewable fuel is nominated via contract.

Date	Bill Number	Description
2/25/2010	Decision 10-02-017	• Revises Decision 08-11-044 so that Advanced Energy Storage systems coupled with fuel cells must meet the site specific requirements for on-site peak demand reduction and be capable of discharging fully at least once per day in order to be eligible for the $2/watt incentive from the self-generation incentive program. • Determines that Advanced Energy Storage systems coupled with eligible technologies under the SGIP must install metering equipment capable of measuring and recording interval data on generation output and Advanced Energy Storage system charging and discharging.

09/08/2011	CPUC D.11-09-015	• Adds eligibility requirements based upon greenhouse gas reductions. • Establishes an on-site emission rate that projects must beat to be eligible for SGIP participation of 379 kg CO2/MWh. • Adds Waste Heat to Power, Pressure Reduction Turbine, Internal Combustion Engine – CHP, Microturbine – CHP, Gas Turbine – CHP, Stand-Alone AES technologies to the list of eligible technologies. • Revises the incentive rates for all technologies and adds a $2.00/Watt biogas adder. • Directs that Directed Biogas can only be procured from in-state suppliers. • Eliminates maximum size restrictions given a project meets on-site load. Sets a 30 kW minimum for wind and renewable fueled fuel cell projects. • Adopts a hybrid payment structure with 50% upfront, 50% PBI based on kWh generation of on-site load for projects 30 kW and larger. Projects under 30 kW will receive the entire incentive upfront. • Adopts the following assumed capacity factors to be used in PBI calculations: 10% for AES, 25% for wind, and 80% for all other distributed energy resources. • Implements incentive decline in the following manner 10% per year for emerging technologies and 5% per year for all other technologies, beginning 1/1/2013. • Adopts a supplier concentration limit where no more than 40% of the annual statewide budget available on the first of a given year may be allocated to any single manufacturer's technology during that year. • Establishes a maximum project incentive of $5 million. • Establishes that the minimum customer investment in a project must be 40% of eligible project costs. • Establishes an SGIP incentive budget allocation of 75% for renewable and emerging technologies, and 25% for non-renewable technologies. • Determines that the Program Administration Budget will be reduced to 7%. • Establishes that projects exporting to the grid are eligible for SGIP incentives as long as they do not export more than 25% on an annual net basis. • Makes an energy efficiency audit mandatory for participation in SGIP unless an extensive audit has been conducted within five years of the date of the reservation request. • Establishes an application fee that is 1% of the amount of incentive requested

Date	Bill Number	Description
		• Limits all projects to one six-month extension. Request for a second extension may be made to the Working Group. Extends the warranty period to 10 years
	ADVICE LETTER 4410-G	ADVICE LETTER COMPLYING WITH RESOLUTION E-4519Proposed Amendments to the Self-Generation Incentive Program Handbook to Conform to Resolution E-4519. Changes to the RTE for AES technologies and elimination of certain data formatting requirements for PDP providers
	ADVICE LETTER No. 3253-G/3940 –E	Proposed Revisions to the Self-Generation Incentive Program Handbook to Implement Decision (D.) 11-09-015: Implementation of the Hybrid-Performance-Based Incentive Payment Structure; Metering and Monitoring Protocols; Other Amendments.
	ADVICE LETTER No 3253-G-A/3940–E-A	Supplemental Filing: Proposed Revisions to the Self-Generation Incentive Program Handbook to Implement Decision (D.) 11-09-015: Implementation of the Hybrid-Performance-Based Incentive Payment Structure; Metering and Monitoring Protocols; Other Amendments
5/24/2012	Decision 12-05-037	• Orders that all technologies previously eligible for the Emerging Renewables Program should be immediately eligible for the SGIP Determines that consolidating the ERP and SGIP programs now is preferable to perpetuating two competing programs that serve the same types of technologies and policy purposes

Date	Bill Number	Description
5/20/2014	SB 861	• Extended SGIP funding through 2019 and extended SGIP administration until January 1, 2021 • Directed the Commission to update the factor for avoided greenhouse gas emissions based on the most recent data available to the State Air Resources Board • Established eligibility requirements for distributed technologies that: reduce demand from the grid by offsetting some or all of the customer's onsite load, are commercially available, safely utilize the existing T&D system, and improve air quality by reducing criteria air pollutants • Specified that SGIP incentive recipients are subject to data collection and site inspections upon request • Directed the Commission to develop a capacity factor for each technology in the SGIP • Directed the Commission to consider the cost of greenhouse gas emissions reductions, peak demand reductions, system reliability benefits, and other measurable factors when allocating program funds between eligible technologies • Change the California supplier requirement to "manufactured in California" • Specified that the SGIP will be evaluated on the following performance measures: reductions of GHGs, reductions of air pollutants, amount of energy reductions measured in energy value, reductions of customer peak demand, capacity factor, value to T&D system measured in avoided cost of upgrades and replacement, ability to improve onsite electricity reliability
09/27/2014	AB 1478	• Clarified that eligible technologies can shift onsite energy use to off-peak times
12/18/2014	Decision 14-12-033	• Decision authorizing Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and Southern California Gas Company to continue to collect funds for the Self-Generation Incentive Program pursuant to Public Utilities Code Section 379.6 as amended by Senate Bill 861
	ADVICE LETTER 47-A	• Advice Letter to propose modifications to the SGIP Handbook to include revised capacity rating methodologies for Pressure Reduction Turbine (PRT) and Waste Heat to Power (WHP) technologies • Included conventional topping cycle Steam Turbines in the program.

Date	Bill Number	Description
6/11/2015	Resolution E-4717	• Approval of Advice Letter No. PGE 3552-G/4563-E, CSE 55, SCE 3165-E, SCG 4741, filed January 20, 2015, to incorporate Residential AES Operational Requirements Affidavit into the SGIP Handbook.
6/11/2015	D.15-06-002	• Approval of Program Administrator's Petition for Modification to allow a maximum of three six-month extensions, filed November 13, 2014.
7/1/2015	Advice Letter No. CSE 60, PG&E 4663-E, SCE 3242-E, SCG 4828.	• Compliance Advice Letter to incorporate third six-month extension into the SGIP Handbook.
7/17/2015	Disposition Letter for Advice Letter CSE 56	• Approval of CSE Advice Letter 56, filed on February 17, 2015, to incorporate kW, kWh offset methodologies, and other associated changes for HVAC-Integrated Small TES systems.
11/19/2015	D.15-11-027	• Decision Revising the GHG Emissions Factor to Determine Eligibility to Participate in the SGIP. • GHG Emissions Factor revised to 350 kg $CO2_2$/MWh averaged over 10 years for non-renewable generation technologies. • For technologies that are subject to a 1% annual degradation rate, the first-year GHG Emissions Factor for Electric-Only Fuel Cells is set at 334 kg $CO2_2$/MWh., assuming a 1% annual degradation rate. • Storage devices should demonstrate an average round trip efficiency of at least 66.5% over ten years to qualify for SGIP, which is equivalent to a first-year round trip efficiency of 69.6%.
12/16/2015	Advice Letter No. CSE 66, PG&E 4759-E, SCE 3327-E, SCG 4904	• Advice Letter to incorporate kW, kWh offset methodology and other associated changes for refrigeration TES. • Advice Letter became effective January 15, 2016.
12/17/2016	D.15-12-027	• Decision Partially Suspending Disbursement of 2016 Program Year Funds and Acceptance of New Applications for the Self-Generation Incentive Program. • Half of 2016's program year funds are available to fund new applications at the beginning of the year. • The PAs shall not disburse any additional funds authorized for program year 2016 until further ordered by the Commission.
12/21/2015	Advice Letter No. PG&E 3663-G/4763-E, CSE 67, SCE 3331-E, SCG 4907	• Compliance Advice Letter incorporating the GHG Emissions Factor from D.15-11-027 into the SGIP Handbook. • Advice Letter became effective January 1, 2016.
6/23/2016	D.16-06-055	• Decision Revising the SGIP Pursuant to SB 861, AB 1478, and Implementing Other Changes

Date	Bill Number	Description
		• Divided SGIP budget 75% storage, 25% generation • Created renewable and small residential storage carve-outs. • Revised incentive rates for all SGIP technologies. • Made several substantial changes to the SGIP. • Resolved several petitions for modifications regarding Distributed Wind Energy Association, pressure reduction turbines and biogas incentive, PowerTree's request to extent deadlines, and Maas Energy's request to investigate the February 23, 2016 program opening.
4/6/2017	D.17-04-017	• Decision revising the SGIP pursuant to AB 1637 and CALSEIA's Petition for Modification • Authorized doubling authorized SGIP collections for years 2017-2019
10/12/2017	D.17-10-004	• Decision establishing Equity Budget for Self-Generation Incentive Program • Beginning in Step 3, 25% of the funds collected for energy storage projects shall be reserved for the SGIP Equity Budget, which will be awarded only to projects that meet specific criteria.
08/01/2019	D.19-08-001	• Decision establishing a Greenhouse Gas signal and compliance rules for legacy and new projects. • Established PBI for all non-residential projects.

9/19/2019	D.19-09-027	• Decision establishing new rates for Equity projects, establishing:
		  ○ Equity Resiliency Budget
		  ○ HPWH Budget
		  ○ SJV Pilot Budget
		  ○ ME&O Plan
		  ○ Updated budget and using accumulated unused funds

1/16/2020	D. 20-01-021	• Decision revising SGIP pursuant to SB 700.
7/15/2020	D.20-05-041	• Decision required changes for Medical Baseline customers who do not have access to an approved Medical Baseline TOU rate in their territory.
7/16/2020	D.20-07-015	• Decision addressing CALSSA's Petition for Modification of D.19-09-027 and D.20-01-021 clarifying SGIP eligibility requirements for equity and equity resiliency budget.
10/22/2020	D.20-10-017	• Decision addressing CESA's Petition for Modification of D.20-01-021 and D.16-06-055 to transfer funds between technology budgets.
10/22/2020	D.20-10-025	• Decision revising and clarifying the Equity Resiliency Budget electric-pump well customer eligibility requirements adopted in D.20-01-021.

Date	Bill Number	Description
11/05/2020	Resolution E-5106	• Rejection of the large thermal energy storage incentive calculation methodology proposal for the SGIP and proposed updates to the Handbook.
03/02/2021	D.21-03-002	• Decision revising definition of "Food Bank" to "Emergency Feeding Organization" in order to include certain types of emergency food and nutrition relief organizations.
03/04/2021	D.21-03-008	• Decision allowing projects not able to meet the performance obligations of the program due to COVID-19 restrictions may request to have their PBI calculations paused for no longer than one (1) year.
3/04/2021	D.21-03-009	• Decision allowing projects that require additional time beyond the third 6-month extension granted to complete the installation and have been unable to do so due to issues related to the COVID-19 pandemic may be granted a stay on the cancellation of a project not to exceed one (1) year from the project's third Reservation Expiration Date.
06/04/2021	D.21-06-005	• Decision revised program requirements for SGIP renewable generation technologies, removed pause on generation projects with capture/use/destroy baselines, Equity Resiliency Budget eligibility, and other items.
02/10/2022	Resolution E-5182	• Approves with modifications CA Manufacturer Eligibility clarifications to energy storage mediums, such as treatment of imported battery cells.
02/10/2023	D.23-02-004	• Reduce the assumed annual capacity factor to 15% for eligible dispatchable renewable fuel projects that do not operate as baseload resources and to limit annual PBI payments to no more than 25% of the expected total annual PBI payment for all eligible SGIP generation projects.
04/27/2023	D. 23-04-045	• Approves exception to service warranty and GHG fleet compliance obligations for developers who have declared bankruptcy or gone out of business. • Added 90-day extension to SGIP applications that have been approved for an incentive and had the project installed but are unable to complete required documentation to receive the incentive due to the developer declaring bankruptcy or going out of business.

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 one 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: [119]

$Lb/MWh_{w/credit} = Lb/hr_{EmissionRate} / (MW_{Rated} + MW_{ProcessHeat})$ ≡ System emissions with thermal credit

Where:

$Lb/hr_{EmissionRate} = Lb/MWh_{w/o_credit} \times MW_{Rated}$ ≡ 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 6.1.5*.

$MW_{ProcessHeat} = (MMBtu/yr_{UtilizedWasteHeat} / 3.4\ MMBtu/MWh) / EFLH/yr$ ≡ 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 HHV_{106}) 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 Customers facility, but shuts down when the load falls below 40 kW, the minimum load of the generator. The Host Customer 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 8,256 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. Thus -

Minimum Operating Efficiency Requirement

P.U. Code 216.6 (a)

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)

{(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

(360 [kW] x 3,414 [Btu/kWh]) / 4,831,200 Btu/hr = 25.4 ≥ 40%

Fails

Air Emissions Requirement

AB 1685 Minimum System Efficiency

{(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

0.16 [lb/MWh] ≤ 0.07 lb/MWh NOx ***Fails***

AB 1685 NOx Emissions w/ Waste Heat Credit

{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***

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.

Appendix B - Conversion of Emissions PPM to Lb/MWH

Procedure for Converting Emission Data to lb/MW-hr

Engines

Engine emission standards are typically expressed in terms of ppmv or in grams/brake horsepower-hour. Given below are factors to convert from ppm to grams/brake horsepower-hour and from grams/brake horsepower-hour to pound/megawatt hour.

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 to 40 percent. IN the calculations below, the efficiency is proportional to the engine brake specific fuel consumption.

PPM TO GM/Bhp-hr

$$\text{Concentration in exhaust by volume (dry)(ppmvd)} = \frac{\text{volume of pollutant (Vp)}}{\text{volume of exhaust (Ve)}} \times 10$$

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

Reciprocating Engines, natural gas fueled[120]

Pollutant	Factor
NOx	57-59
VOC	163-170
CO	93-97

Lean-burn Engines, natural gas fueled[121]

Pollutant	Factor
NOx	80
VOC	212
CO	123

[120] Values taken from California Air Pollution Control Officers Association (CAPCOA) report: Portable Equipment Rule Piston IC Engine Technical Reference Document, 1995.

[121] Factors provided from Waukesha

GM/Bhp-hr to Lb/MW-hr

Gm/Bhp-hr x 3.07 = lb/MW-hr

- 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)

2.5 ppmvd = 0.0093 lb/MMBtu for NOx

2 ppmvd = 0.0027 lb/MMBtu for VOC

5 ppmvd = 0.013 lb/MMBtu for CO

Efficiency for central station power plant is 50%

Source: California Air Resources Board, Guidance for the Permitting of Electric Generation Technologies, Appendix C: Procedure for Converting Emission Data to lb/MW-hr, July 2002.

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

Calculation of Minimum Roundtrip Efficiency

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				

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 D – Incentive rate for large-scale storage projects claiming the ITC at all incentive levels

	$/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 E – L-TES Incentive Calculation Methodology

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

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
Braun Blaising Smith Wynne, P.C.
California Community Choice Association
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell
Downey Brand LLP
Dish Wireless L.L.C.

East Bay Community Energy Ellison Schneider & Harris LLP
Engineers and Scientists of California

GenOn Energy, Inc.
Green Power Institute
Hanna & Morton
ICF
iCommLaw
International Power Technology
Intertie

Intestate Gas Services, Inc.

Johnston, Kevin
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McClintock IP
McKenzie & Associates

Modesto Irrigation District
NRG Solar

OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Public Advocates Office

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.

Resource Innovations

SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Stoel Rives LLP

Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy