2013 Self-Generation Incentive Program HANDBOOK

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

September 1, 2013

Center for Sustainable Energy® CALIFORNIA

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

Pacific Gas and Electric Company®

SDGE connected
A Sempra Energy utility™

Southern California Gas Company
A Sempra Energy utility®

V.2

What's New 2013 Self-Generation Incentive Program V2(SGIP)

In this version of the 2013 Handbook we have added additional clarifying language the following sections:

- Wind Turbine sizing and rating criteria §2.3.1, 4.4.1, 4.4.8
- AES Capacity Factors and Greenhouse Gas Emission Standards §3.2.4, 3.3.1, 4.2.9
- Ancillary loads §4.4.8
- System sizing for NEM participating customers §4.4.6

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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:	Self-Generation Incentive Program PO Box 7433 San Francisco, CA 94120
Overnight Mailing Address:	245 Market Street Mail Code N7R San Francisco, CA 94105-1797

California Center for Sustainable Energy (CCSE)

Website:	www.energycenter.org/sgip
Email Address:	sgip@energycenter.org
Telephone:	(858) 244-1177
Mailing Address:	California Center for Sustainable Energy Attn: Self Generation Incentive Program 9325 Sky Park Court, Suite 100 San Diego, CA 92123

Southern California Edison (SCE)

Website:	www.sce.com/SGIP
Email Address:	SGIPgroup@sce.commailto:
Telephone:	(866) 584-7436
Mailing Address:	Self-Generation Incentive Program Southern California Edison P.O. Box 800. Rosemead, CA 91770-0800

Southern California Gas Company (SoCal Gas)

Website:	www.socalgas.com/innovation/self-generation
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 California Center for Sustainable Energy (CCSE)[2].

1. Budget

1.1 Statewide Program Budget and Administrator Allocations

The annual statewide incentive budget for Program Year 2013 authorized by the CPUC totals $77,190,000. Allocations for each Program Administrator are as follows:

Pacific Gas and Electric Company	$33,480,000
Southern California Edison Company	$26,040,000
California Center for Sustainable Energy	$10,230,000
Southern California Gas Company	$7,440,000

1.2 Budget Allocation

The budget is divided into two categories:

1. Renewable and emerging technologies
2. Non-renewable fueled Conventional CHP projects

75% of the project funding budget will be dedicated to the renewable and emerging technology category and 25% will be dedicated to the non-renewable fueled conventional CHP project category. The previous year's carry-over funds for the respective budget categories will be added to current Program Year's funding for incentive reservations.

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

Biogas, AES and Fuel cells are all considered an emerging technology and will be funded from the renewable and emerging budget category. However, if an AES system is coupled with conventional CHP technologies operating on non-renewable fuel, they will be funded from the non-renewable budget category.

Although the Program Administrator may move funds from the non-renewable category to renewable and emerging technology category, the Program Administrator must seek approval from the CPUC through an advice letter prior to shifting funds from renewable and emerging technology category into the non-renewable category.

1.3 Incentive Levels by Eligible Technologies

Technologies eligible for the SGIP are grouped into three incentive levels[3] as shown in Table 1.3 below

Table 1.3 Base Incentive Levels for Eligible Technologies

Technology Type	Incentive ($/W)
Renewable and Waste Energy Recovery	
Wind Turbine	$1.19
Waste Heat to Power	$1.19
Pressure Reduction Turbine	$1.19
Non-Renewable Conventional CHP	
Internal Combustion Engine - CHP	$0.48
Micro-turbine – CHP	$0.48
Gas Turbine – CHP	$0.48
Emerging Technologies	
Advanced Energy Storage	$1.80
Biogas Adder[4]	$1.80
Fuel Cell – CHP or Electric Only	$2.03

[3] The SGIP incentive levels were reorganized by CPUC Decision 11-09-015 on September 8, 2011, to include Pressure Reduction Turbines, Waste Heat to Power technologies, Gas turbine, Microturbine and Internal Combustion Engine conventional fuel based CHP, stand alone Advanced Energy Storage and Biogas.

[4] The biogas incentive is an adder that may be used in conjunction with fuel cells or any conventional CHP technology.

2. Incentive Applications

2.1 Application Process

The SGIP is an annual incentive program. Each Program Year is run on a calendar basis (January 1 through December 31).The program will open and will begin accepting applications once the Program Year's Handbook and forms are approved and posted to the PAs websites. Any applications received after December 31 from previous program years will be returned with an encouragement to apply under the current Program Year.

SGIP funds are reserved on a first eligible basis. Reservations received after total funds have been committed for a calendar year will be placed on a wait list (refer to the *section 2.3.5* for further information). Reservations will follow the program rules of the year they were submitted, even if the Reservation is issued in the following year. Incentive rates are based on the year in which the application was submitted.

Only complete applications may receive an approved reservation.

2.1.1 Application Submission

Applicants can submit their SGIP applications either via regular mail, via email or via a combination of the two. All document submissions at any stage of the application process (RRF, PPM and/or ICF) can be delivered using any of these three methods.

Email submissions should meet the following requirements:

- Each document must be a separate file
- All documents must be submitted in ".pdf" format.
- Files must use the following naming convention: *Document Name* (as specified on the PA's websites)*_Host Customer Name*
    - Example: *Reservation Request Form_ John Doe*
- It is acceptable to submit 'legible' scanned copies of the original signed documents.
- Email subject line must be titled "SGIP Application-*Program Year-Host Customer Name*"
    - Example: *SGIP Application – 2011 – John Doe*
- Email size should not exceed 7MB in size. If total file sizes exceed 7MB additional emails may be sent containing the remaining files. Applicants can submit all or part of an application via regular mail. However, the Reservation Request will be considered incomplete until the documents sent via regular mail are received. Applicants must identify the documents that will be delivered via regular mail in their email.

Program Administrators do not assume any responsibility or liability for any deficiency in service on part of the delivery method the Applicant has chosen. To ensure confirmation of receipt, submit

documentation to the appropriate Program Administrator by certified or overnight mail. **No faxed or hand delivered applications will be accepted**.

2.1.2 Signatures

Original signed documents or scanned copies of original signed documents are acceptable for all required Program forms[5]. In the event that any signature is delivered by e-mail delivery of a ".pdf" format data file, such signature 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 ".pdf" 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 maintained 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 small (<10kW) non-residential Projects should follow the two-step application process. For non-residential projects larger than 10kW a three-step process is available. Larger projects may opt-into the two-step application process but all two-step requirements and timelines must be met.

[5] All forms requiring signatures from multiple parties must have all signatures submitted on one document.

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

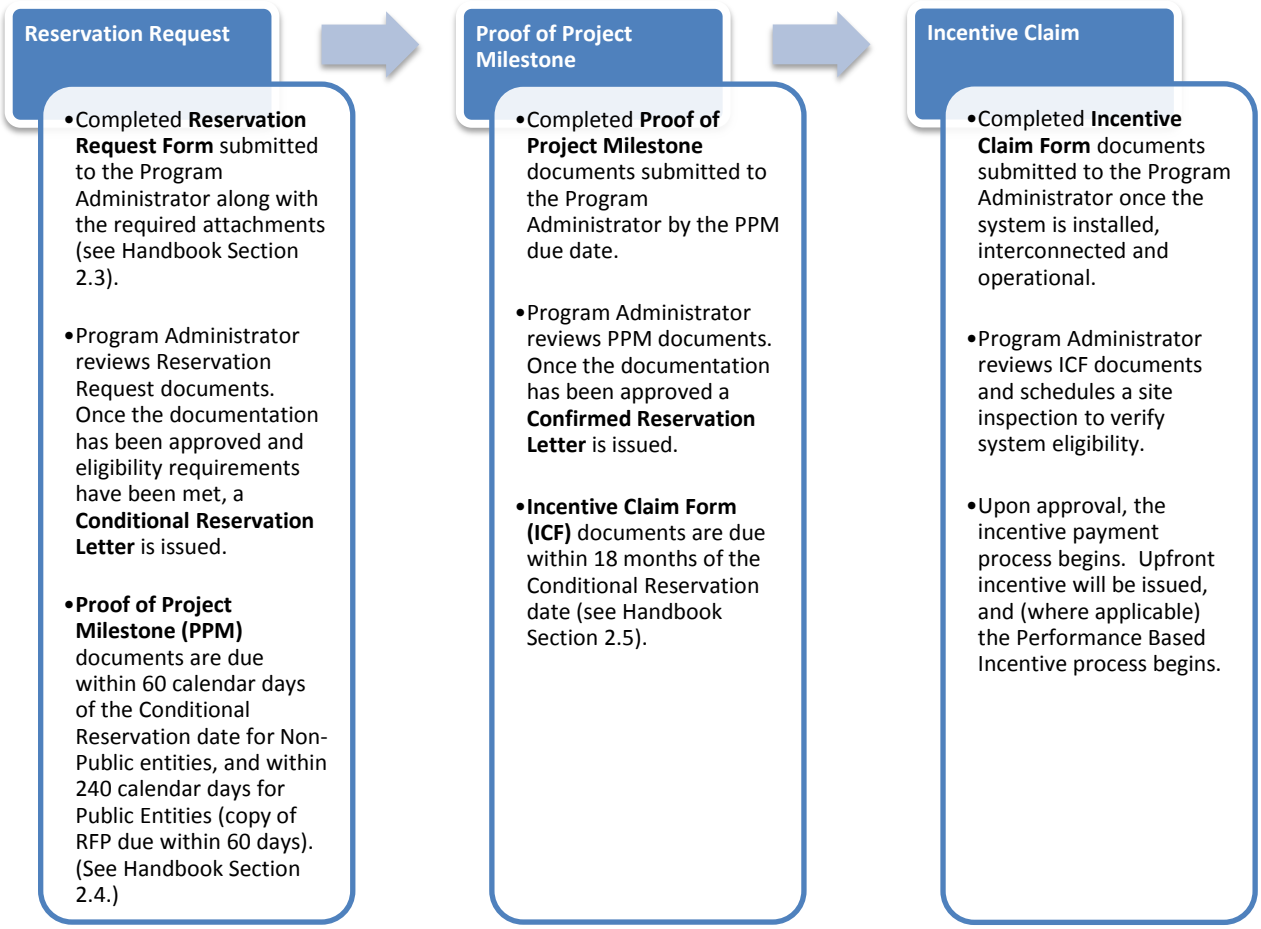
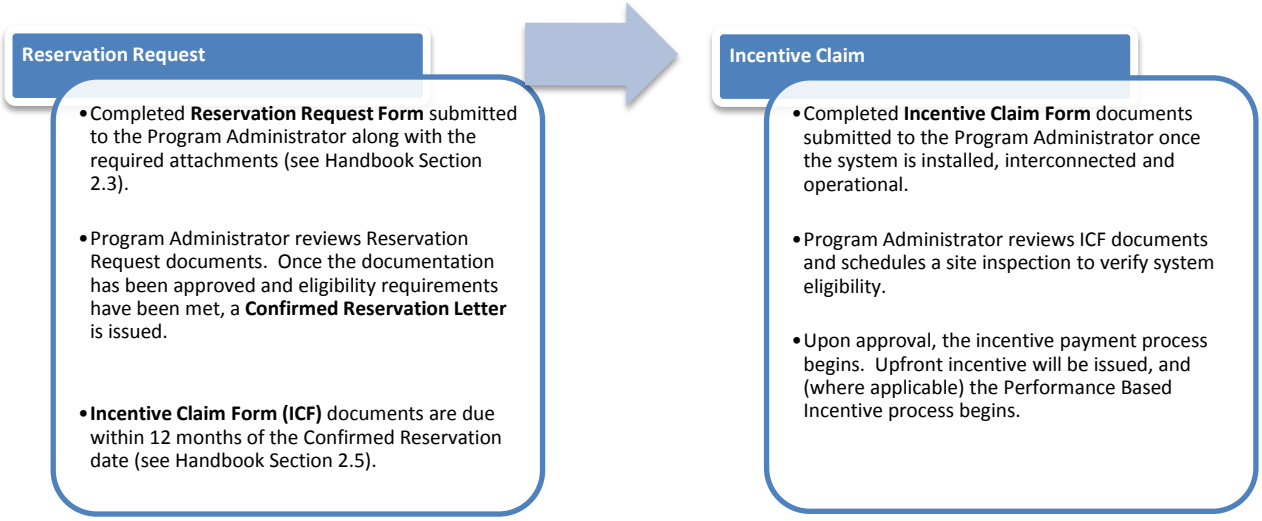


Figure 2.2-2: Two Step Application Process for All Residential and Non-Residential Entities <10kW



2.3 Reservation Request

To reserve a specified incentive amount, a Reservation Request Form must be submitted with required attachments and application fee; incentive funds are not reserved until the Program Administrator receives screens and approves these documents.

Projects that include multiple technologies must include one Reservation Request Form for each technology in the project.

2.3.1 Required Attachments

All applications must provide a copy of the following:

Table 2.3.1 Reservation Request Requirements

Required Materials
1. **Completed Reservation Request Form** *(All Projects)*
2. **Application Fee** *(All Projects)*
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/Back-up Documentation** *(Non-Renewable Fuel Projects Only)*
7. **Proof of Adequate Fuel or Waste Energy Resource** *(Renewable Fuel, Waste Energy, Waste Gas Projects Only)*

Two-Step Applications should also include all applicable Proof of Project Milestone Documents *(as outlined in section 2.4)* as part of their Reservation Request

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

   Required for all applications and must be completed and signed by the Applicant and representatives with signature authority for both the System Owner and Host Customer (if not Host Customer).

2. **Application Fee** *(All Projects)*

   Equal to 1% of the amount of requested incentive amount, due at the time of application, payable by check only and should reference the project by facility address. The application fee will be refunded upon completion and verification of the installed SGIP Project and incentive payment. Prior to project completion application fees are non-refundable once a Conditional Reservation

has been issued.[6] All forfeited application fees will be allocated to the Program Administrator's SGIP incentive Budget.[7]

3. **Equipment Specifications** *(All Projects)*

   Manufacturer equipment specifications stating nameplate capacity, rated capacity (kW) and, if necessary, fuel consumption and waste heat recovery rate.

   For Advanced Energy Storage, the manufacturer equipment specifications must include a capacity rate based on the average discharge power output over a two hour period.

   Proof of power factor eligibility is also required for Micro-turbines, Internal Combustion Engines & Gas Turbines 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, 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 or gas utility bill indicating the account number, meter number, Site address, and Host Customer name. For new construction, the Host Customer must receive confirmation from the serving utility that their Site is within the Program Administrator's service territory. In addition, all applications 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 the program sizing requirements. SDG&E customers may also be required to submit an Authorization to Receive Customer Information form, signed by the utility customer of record that authorizes CCSE to access utility account information.

   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:

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

[7] 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.

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.); 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.)

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.)

Two Step Applications will include (as part of their Reservation Request) a Proposed Monitoring Plan as outlined in *Section 2.4.1 Item 5*.

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

The Minimum Operating Efficiency Worksheet (MOEW) is used to determine if a projects meets the following operating efficiency and emission 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) System Efficiency and NOx Emission Qualification
d) Greenhouse Gas Emission Standard
e) Electrical Load Coincidence (Electrical Export Eligibility)

There are two versions of the Minimum Operating Efficiency Worksheet; one for residential systems and a second worksheet for all other systems. "Residential systems" are Projects installed at a residential Host Customer Site.

a) Minimum Operating Efficiency Calculations

All applications proposing CHP technologies must provide back-up documentation along with the MOEW including 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 Combined Heat and Power (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 application 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>System Efficiency and Proof of NOx Emission Qualification</u> *(Conventional CHP systems only)*

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[8] 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 D of this handbook.[9]

[8] Acceptable test methods include but not limited to CARB Test Method 100 and USEPA Test Method 7.

[9] 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.

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. See Appendix C for more information.

d) Greenhouse Gas Emission Rate Testing Protocol *(Electric-Only Fuel Cells)*

Electric-only Fuel Cells operating on non-renewable fuel must provide the ASME PTC 50-2002 test as back-up documentation to the MOEW. Please see *Section 4.2.9 f*or further information.

e) Electric Load Coincidence *(Electrical Export Eligibility)*

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

7. **Proof of Adequate Fuel or Waste Energy Resource** *(Renewable Fuel, Waste Gas & Waste Energy Projects)*

On-site Renewable Fueled Projects 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.

Renewable Fueled Projects utilizing Directed Biogas must include documentation of the forecasted fuel consumption of the generator over the life of project.

Projects utilizing Waste Gas Fuel (Micro-turbines, Internal Combustion Engines & Gas Turbines Waste Gas Fuel Applications Only) must include an engineering survey or study confirming that there is adequate on-site Waste Gas fuel (i.e., adequate flow rate) for continuous operation of the self-generation unit for the term of the Project's required permanency period.

Proposed Pressure Reduction Turbine applications must include an engineering survey or study confirming adequate temperature, pressure and flow within the piping system, and the generating system's average capacity during the term of the Project's required permanency period.

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 average capacity during the term of the Project's required permanency period.

Proposed Wind projects must include an engineering survey or study confirming the annual average wind speed at the hub height of the wind turbine and the generating system's capacity at that wind speed during the term of the Project's required warranty/maintenance period. 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.

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 2.4*.

2.3.2 Submitting the Reservation Request

Once the Reservation Request Form is complete and all the required attachments are secured, Applicants may submit their application package to the appropriate Program Administrator. Once received, the Program Administrator will review the application package for completeness and to ensure that the project meets all incentive & program eligibility guidelines. Applications will be screened based on the date received.

2.3.3 Incomplete Reservation Request

All Reservation Request documents (including Application Fee) should be submitted as part of the complete application package. If an application is found to be missing *any* of the required documentation or requires additional clarification, the Program Administrator or their representative 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 Applicant has not submitted the requested information, the application will be cancelled. Returned Application Fees will also result in cancellation of the application. Resubmitted application packages will be treated as a new application (i.e. all required documents must be resubmitted) and processed in sequence along with other new applications.

2.3.4 Approval of Reservation Request

Upon approval by Program Administrator of the Reservation Request package (Reservation Request Form and required attachments), the Applicant and Host Customer will receive a Reservation Letter *if* funds are available. There are two types of "Reservation Notice Letters" and they are based on the type of application.

Conditional Reservation Letter (for 3 Step applications)

Upon verification and approval of the 3 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 and the Proof of Project Milestone 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 Notice Letter (for 2 step applications)

Upon verification and approval of the 2 Step Reservation Request package, the Applicant and Host Customer will receive a Confirmed Reservation Notice Letter if funds are available. The Confirmed Reservation Letter will list the reservation dollar amount and the reservation expiration date (12 months after the date of the original Conditional 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.

2.3.5 Wait List Procedures

If funds are not available for a particular reservation request while a Program Administrator is still accepting new applications, it will be assigned a place on a wait list upon receipt of the reservation request package (Reservation Request Form and required attachments). The Applicant and Host Customer will receive notification that their request is on a wait list until funding is made available or the project is withdrawn or cancelled. Should funds become available, wait list applications will be reviewed for Conditional Approval Letters (or Confirmed Reservation Letters for 2-step projects) in the order they were received until available funding is again exhausted.

If a wait list exists at the end of a Program Year, the Host Customer must promptly notify the Program Administrator if they wish to withdraw the application; otherwise pending wait list applications will become first projects reviewed for reserved incentives in the following approved Program Year.

2.3.6 Wait List Closure

If the wait list hits either of the following pre-determined limits, the wait list will be closed and new applications will no longer be accepted for a given quarter:

50 Projects

Or

Incentive requests resulting in more than 50% of the PA's annual incentive budget

At the beginning of each quarter the PAs will review any project attrition and allow new applications if funding is available.

2.4 Proof of Project Milestone

Two-Step Applications should submit all Proof of Project Milestone documents as part of their Reservation Request. For *Three-Step Applications, Non-Public Entities* have 60 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 60 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 the Conditional Reservation Letter.

2.4.1 Required Attachments

All Proof of Project Milestone submittals must include the following:

Table 2.4.1 Proof of Project Milestone Requirements

Required Materials
1. **Completed Proof of Project Milestone Form** *(All 3-Step Projects)*
2. **Copy of RFP or equivalent after 60 days** (*Public Entity Projects Only)*
3. **Copy of Executed Contract or Agreement for Installation** *(All Projects)* • Includes Required Warranty Documentation
4. **Energy Efficiency Audit** *(All Projects)*
5. **Proposed Monitoring Plan** *(All Projects >=30 kW)*
6. **Proof of Fuel Contract and Documentation** *(Renewable Fuel and Waste Gas Projects Only)* • Renewable Fuel Contract *(Directed Biogas Only)* • Directed Biogas Renewable Fuel Attestation – System Owner & Fuel Supplier *(Directed Biogas Only)* • Renewable Fuel Affidavit *(On-site Renewable Fuel Only)* • Fuel Clean-up *(On-site Renewable Fuel Only)* • Waste Gas Fuel Affidavit *(Waste Gas Fuel Only)*

1. **Proof of Project Milestone Form** *(All 3-Step Projects)*[10]

   The Proof of Project Milestone Form must be completed and signed by the Applicant and representatives with signature authority for both the System Owner and Host Customer (if not Host Customer). The form must identify updated project information including the installation contractor's name, telephone number and contractor license number. All systems must be installed by appropriately licensed California contractors in accordance with rules and regulations adopted by the State of California Contractors' State Licensing Board. Installation contractors must have an active A, B, or C-10 license.

2. **Request for Proposals (RFP) Documentation** *(Public Entities Only)*

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

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 60 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). 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 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.

4. **Energy Efficiency Audit** *(All Projects)*

An Energy Efficiency Audit (EEA) report issued within the last 5 years identifying the payback periods for all prescribed measures should be submitted. EEA reports must be issued by utility, PA, or qualified vendor/consultant. Any measures identified with a payback period of two years or less must be implemented prior to receipt of the upfront incentive payment. Implementation of the required measures will be verified during the field verification visit.

A Title 24 energy efficiency compliance report issued within the past three (3) years may also be used in lieu of an Energy Efficiency Audit. To verify that the requirements have been met, a copy of the Title 24 building permit documentation should be submitted.

5. **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.). 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.)

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.)

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 PAs, such as monthly]

Identification of the metering system components by performance data type (including manufacturer and model number)

- Electrical metering equipment
- Thermal energy metering equipment
- Fuel consumption metering equipment
- Data acquisition (i.e., logger) system

6. **Proof of Fuel Contracts and Documentation** *(Renewable Fuel and Waste Gas Projects Only)*

Copy of Executed Renewable Fuel Contract *(Directed Biogas Projects)*

The Contract should at a minimum include term (minimum of 10 years), cost, amount of renewable fuel injected 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 PA 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 at least 75% of the system's anticipated fuel consumption.

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 at least 75% renewable fuel, as measured annually.

Directed Biogas Renewable Fuel Attestation *(Directed Biogas Only)*

Attestation letter from the System Owner of the intent to notionally procure Renewable Fuel and Attestation from the Fuel Supplier that the fuel meets the applicable renewable portfolio standard eligibility requirements for biogas injected into a natural gas pipeline.

Renewable Fuel Use Affidavit *(On-site Renewable Fuel Projects)*

Application documentation must include a signed affidavit that projects will not switch to non-renewable fuel for a period of ten years for all technologies. The SGIP PA has the right to audit and verify the generator's renewable fuel consumption upon request over the life of the contract.

Fuel Cleanup Equipment Purchase Order *(On-site Renewable Fuel Projects)*

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.

Waste Gas Fuel Use Affidavit *(Waste Gas Only)*

When applicable, application documentation must include a signed affidavit that Projects will be fueled solely (100%) with Waste Gas for a period of ten years.

2.4.2 Submitting Proof of Project Milestone

Once the Proof of Project Milestone package is complete and all the required attachments are secured, the PPM package must be submitted to the appropriate Program Administrator via email or regular mail.

2.4.3 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 30 calendar days to respond with the necessary information. If after 30 calendar days the requested information has not been submitted, the application may be cancelled. Any forfeited application fees will be allocated to the Program Administrator's SGIP incentive budget.

2.4.4 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 self-generation project is complete, Applicants must request payment of the incentive amount using the Incentive Claim Form. A project is considered complete when the system is completely installed, interconnected, permitted, and capable of producing electricity in the manner and in the amounts for which it was designed, and the energy efficiency measures identified with a two year payback have been verified as installed or non-feasible. Payment will be dispersed after the Program Administrator verifies by field 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 described below.

2.5.1 Required Attachments

All applicable Incentive Claim documents must be submitted when requesting incentive payment:

Table 2.5.1 Incentive Claim Required Attachments

Required Materials
1. **Completed Incentive Claim Form** *(All Projects)*
2. **Proof of Authorization to Interconnect** *(All Projects)*
3. **Project Cost Affidavit and Breakdown Worksheet** *(All Projects)*
4. **Final Permits** • **Building Permit Inspection Report** *(All Projects)* • **Air Permit Documentation** (*Non-Renewable Fuel Only)*
5. **Substantiations:** • **New or Expanded Load** *(All Projects)* • **Renewable 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 Biogas Only)* • **Renewable Fuel Metering Specifications** *(Directed Biogas Only)*
6. **Planned Maintenance Coordination Letter** *(>=200 kW Conventional CHP Only)*
7. **Final Monitoring Schematic** *(All Projects >= 30 kW)*

1. **Incentive Claim Form** *(All Projects)*

   The Incentive Claim form information must be complete, accurate and represent the actual system 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** *(All Projects)*

   Host Customers and/or System Owners will be required to execute certain documents such as, but not limited to, an "Application to Interconnect a Generating Facility" and a "Generating Facility

Interconnection Agreement" with the local Electric Utility. A copy of the signed letter from their Electric Utility granting the Host Customer and/or System Owner permission to interconnect and operate in parallel with the local grid should be submitted as proof of Authorization to Interconnect.

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.~~ **Project Cost Affidavit and Breakdown Worksheet** *(All Projects)*

A signed Project Cost Affidavit substantiating the claimed eligible Project cost including a final Project Cost Breakdown Worksheet substantiating the claimed eligible Project cost (as defined in S*ection 3.3.3*).

4. **Final Permits**

Building Inspection Report *(All Projects)*

A copy of the final building inspection report (or proof of exemption) demonstrating that the Project meets all codes and standards of the permitting jurisdiction. Contact your local permitting jurisdiction to learn about permitting requirements.

Air Permitting Documentation *(Non-Renewable Fuel Only)*

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).

5. **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)*

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 Renewable Fuel Projects must include documentation substantiating the fuel cleanup skid cost.

Renewable Fuel Documentation & Contract Commencement *(Directed Biogas 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 PA for commencement of the contract. However, no incentive will be paid until the contract has commenced.

Renewable Fuel Metering Specifications *(Directed Biogas Only)*

Documentation should also be provided to include make, model, specifications and serial number of installed revenue grad electric NGOM and gas meters.

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

When applicable, applications with micro-turbine, internal combustion engine and gas turbine systems operating on non-renewable fuel 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.

7. **Final Monitoring Schematic** *(for projects that are 30 kW or larger)*

A final 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.) 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).

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 PA's discretion.

2.5.2 Submitting Incentive Claim

Once the Incentive Claim Form is complete and all the required attachments are secured, Applicants may submit their application package to the Program Administrator via email or regular mail.

2.5.3 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, the application may be cancelled. Any forfeited application fees will be allocated to the Program Administrator's SGIP incentive budget.

2.5.4 Field Verification Visit

Upon receipt of a complete Incentive Claim Form package, the Program Administrator will organize a field verification visit to verify that the Project system is installed as represented in the application, is

operational, interconnected and conforms to the eligibility criteria of the SGIP. Verification includes but is not limited to:

If the Project is 30 kW and larger, 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 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.

AES systems will be tested to indicate the average discharge power output over a two hour period. If the project involves an AES system coupled with a SGIP funded generating system, the electrical coupling of the two systems will be verified.

If the eligible system size depended on new construction or load growth, the required load will be confirmed.

Verify system capacity rating to confirm the final incentive amount.

Implementation of energy efficiency measures identified as having a less than two year payback in the Energy Efficiency Audit.

Failed Field Verification

If field verification results indicate that the system is not eligible, the Program Administrator will notify the Applicant, Host Customer and System Owner of the reasons for system ineligibility. The Applicant, Host Customer and System Owner will have 60 calendar days to bring the system into compliance. A subsequent inspection visit will be conducted to determine final approval. If the Applicant, Host Customer and System Owner fail to bring the system to full eligibility within the 60 days, 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 inspection or;
2. Wait for the Site load, renewable fuel or waste energy to materialize within 12-months from the date the Incentive Claim Forms 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.

2.5.5 Approval of Incentive Claim

Upon final approval of the incentive claim documentation and completed field verification visit, the Program Administrator will issue a final approval letter. The incentive payment will be made in approximately 30 days from the date the final approval letter was sent. Payment will be made to the Host Customer, System Owner, or a third party as indicated on the Incentive Claim Form and will be mailed to the address provided.

2.6 Modifications and Extensions

2.6.1 Modifying the Proposed Project

The Program Administrator will expect a system to be installed as described on the Reservation Request Form and ultimately the Incentive Claim Form but recognizes that changes may result during development of the project and/or during the installation and that substantive changes may be necessary under extraordinary circumstances.

In general, changes to the project should be approved by the Program Administrator; especially those changes pertaining to System Owner, Payee, Project location, changes in equipment type, and system capacity.

Modifications affecting installed system capacity require that a new incentive amount be calculated as follows:

When the newly calculated incentive is smaller than the one specified in the original Reservation Request Form, the Payee will receive the smaller incentive amount.

In general, if the incentive amount increases relative to the one stated in the original Reservation Request Form, the larger amount is granted and all incentive caps as described in *Section 3.3* apply. If adequate funds are not available, the Program Administrator cannot guarantee that the higher incentive amount will be granted.

Changes in equipment type, system capacity or other changes resulting in incentive changes must include new RRF and PPM documentation. Once the request has been approved, a new Reservation letter will be issued. Changes do not extend the Reservation Expiration Date.

2.6.2 Extensions and Exceptions

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

All projects will be limited to a maximum of two 6-month extensions of the Reservation Expiration Date, after which the reservation expires automatically. Extensions will be for special circumstances only. In addition, extensions will not be granted to projects that have not made satisfactory progress

toward completion in compliance with established milestones and requirements. Additionally, any request for a second extension of the Reservation Expiration Date will require SGIP Working Group approval.

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

3. Incentives

3.1 Incentive Rates

The incentive levels for the three categories of self-generation technologies are provided below.

Table 3.1 Incentive Levels by Category

Technology Type	Incentive ($/W)
Renewable and Waste Energy Recovery	
Wind Turbine	$1.19
Waste Heat to Power	$1.19
Pressure Reduction Turbine[11]	$1.19
Non-Renewable Conventional CHP	
Internal Combustion Engine - CHP	$0.48
Micro-turbine – CHP	$0.48
Gas Turbine – CHP	$0.48
Emerging Technologies	
Advanced Energy Storage	$1.80
Biogas Adder[12]	$1.80
Fuel Cell – CHP or Electric Only	$2.03

3.1.1 Incentives for Technologies from a California Supplier

An additional incentive of 20 percent will be provided for the installation of eligible distributed generation or Advanced Energy Storage technologies from a California Supplier. "California Supplier" means any sole proprietorship, partnership, joint venture, corporation, or other business entity that meets the following criteria:

A) The owners or policymaking officers are domiciled in California and the permanent principal office, or place of business from which the supplier's trade is directed or managed, is located in California.

Or

B) A business or corporation, including those owned by, or under common control of, a corporation that meets all of the following criteria continuously during the five years prior to providing eligible distributed generation technologies to an SGIP recipient:

[11] Pressure reduction turbine includes but is not limited to, any small turbine generator installed in an existing, man-made channel for delivery of water, steam or natural gas.

[12] The biogas incentive is an adder that may be used in conjunction with fuel cells or any conventional CHP technology.

i) Owns and operates a manufacturing facility located in California that builds or manufactures eligible distributed generation technologies.

ii) Is licensed by the state to conduct business within the state.

iii) Employs California residents for work within the state.

For purposes of qualifying as a California Supplier, a distribution or sales management office or facility does not qualify as a manufacturer.

The 20 percent adder for using a California Supplier shall be calculated on the non-renewable incentive rate before adding the additional $1.80 per watt incentive for using biogas. The incentive for each project including the California Supplier Adder shall be capped based upon the Incentive Limitations outlined in *Section 3.3.*

3.1.2 Tiered Incentives and Incentive Decline

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 decline according to the following schedule:

Table 3.1.2-1 Tiered Incentive Rates

Capacity	Incentive Rate (Pct. of Base)
0 – 1 MW	100%
1 MW – 2 MW	50%
2 MW – 3 MW	25%

SGIP incentive levels will decline annually with the first reduction starting on January 1, 2013. The rate of annual incentive decline is provided in the following table:

Table 3.1.2-2 Incentive Decline

Technology Type	Yearly Incentive Decline Rate
Renewable, Waste Energy Recovery, Conventional CHP	5%
Emerging Technologies	10%

3.2 Incentive Calculation

Incentives for a proposed system are calculated by multiplying the rated capacity of the system[13] by the incentive rate for the appropriate technology type.

[13] For more information on rating criteria for system output, see section 4.4.8.

Incentive *= rated capacity * incentive rate*

*100kW Fuel Cell = 100,000 watts (rated capacity) * $2.03 = $203,000.00*

For biogas projects, the total incentive payment will be the total of the biogas incentive plus the proposed system incentive not to exceed the total project cost limit for SGIP systems.

3.2.1 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, 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 technologies within a single Incentive Level, the incentives are calculated in the order in which they appear in Table 3.1, from top to bottom.

3.2.2 Up-front Payments

Projects less than 30 kW in size will receive an upfront incentive upon project completion and verification.

3.2.3 Performance Based Incentive Payment (PBI)

For projects 30 kW and larger, 50% of the incentive will be paid 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 capacity factor 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 production*

total anticipated kWh production *= rated capacity * 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 over the previous 12 months.

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

3.2.4 Capacity Factors

The program assumes the following capacity factors:

Table 3.2.4 Assumed Capacity Factors

Technology Type	Capacity Factor
Advanced Energy Storage	10%
Wind Turbine	25%
All other Technologies	80%

Advanced Energy Storage Systems typically discharge during peak weekday periods and are unable to discharge during their charging period. For this reason 5,200 hours[14] per year will be used for the purposes of calculating the capacity factor for AES systems.

3.3 Incentive Limitations

Incentive amounts can be limited by a number of factors, including (but not limited to) Greenhouse Gas (GHG) emission reductions (for PBI projects), total eligible project costs, maximum project cap ($5 Million), minimum customer investment (40%), sizing limitations per Site (3MW), and funding from other ratepayer sponsored programs.

3.3.1 Limitations on PBI based on GHG Emissions Reductions

Non-Renewable Fueled Projects PBI payments will be reduced or eliminated in years that do not result in the required GHG emissions reductions. The following describes how PBI payments are affected:

- PBI payments will be reduced by half in years where a project's cumulative emission rate is equal to or greater than 398 kg CO_2/MWh but less than 417 kg CO_2/MWh (i.e., 10% higher than the GHG eligibility threshold).
- Projects that exceed a cumulative emissions rate of 417 kg CO_2/MWh in any given year will receive no PBI payments for that year.

$$emission\ rate\ \leq\ 398\ \frac{kg\ CO_2}{MWh} \rightarrow \text{No penalty assessed on PBI payment}$$

$$398\ \frac{kg\ CO_2}{MWh} \leq emission\ rate\ \leq\ 417\ \frac{kg\ CO_2}{MWh} \rightarrow \text{PBI payment reduced by 50\%}$$

$$emission\ rate\ >\ 417\ \frac{kg\ CO_2}{MWh} \rightarrow \text{No PBI payment for that year}$$

3.3.2 Maximum Incentive Amount

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

3.3.3 Total Eligible Project Costs

No Project can receive total incentives (to include any combination of the technology incentive, biogas adder, and/or California Supplier) that exceed the Total Eligible Project Costs. Submittal of Project Cost details is required to report total eligible Project Costs and to ensure that total incentives do not exceed out of pocket expenses for the System Owner. Equipment and other costs outside of the Project envelope are considered ineligible Project Costs but also must be reported.

The following costs may be included in total eligible Project cost:

1. Equipment capital costs
2. Engineering and design costs

[14] As per Resolution E-4519, Attachement A.

3. 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.
4. Engineering feasibility study costs
5. Interconnection costs, including:

a. Electric grid interconnection application fees

b. Metering costs associated with interconnection

6. Environmental and building permitting costs
7. Warranty and/or maintenance contract costs associated with eligible Project cost equipment (See *Section 2.4.1 Item 3* for full explanation of warranty requirements)
8. 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 to serve the distributed generation unit.
9. Sales tax and use tax
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. 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
13. 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.
14. 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.
15. 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.
16. 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.

3.3.4 Minimum Customer Investment

Customers must pay a minimum of 40% of eligible project costs. When calculating the Minimum Customer Investment Limit, the biogas adder is not included. This incentive limit applies only to the system equipment (generator and/or AES).

The limit on the system equipment will be dictated by the following equation:

$$I <= L*EPC$$

where

I = Incentive = incentive as calculated in Section 3.1 (excluding biogas incentive)

L = 1- applicable investment tax credit – 0.4

EPC = Eligible Project Costs

3.3.5 SGIP Incentive Limit for Biogas Projects

For projects using on-site biogas, the adder *does not* apply to the SGIP Minimum Customer Investment Calculation.

In the case of Directed Biogas projects, the adder is applied separately to the cost of the biogas contract and should not exceed the cost difference between the biogas contract and a similar contract for standard natural gas.

3.3.6 Calculating Incentives with Existing Systems

A system may be installed in addition to existing system 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. Advanced Energy Storage system capacity is not additive with generation capacity for purposes of calculating the tiered incentive. The incentive calculation and capacity limits are treated separately for Advanced Energy Storage and Generation Technologies.

3.3.7 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 receive incentives from the Self Generation Incentive Program (SGIP), California Solar Initiative (CSI), or the Energy Commission's Emerging Renewables Program (ERP) or has received incentive from the SGIP, CSI,

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 generator's rate capacity (kW)[15].

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 field verification inspection.

3.3.8 Incentives from other sources

Customers may not apply for SGIP incentives for the same self-generation equipment from more than one Program Administrator.[16]

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 Projects receiving self-generating incentives under other programs, the SGIP incentive may be reduced depending on the source of the other incentive, effectively allowing only part of the other program incentive in addition to the SGIP incentive.

- For other incentives funded 100% by Investor Owned Utility (IOU) ratepayers, the total incentive will be reduced by the full amount of the other incentive.
- For other incentives funded by Non-IOU Ratepayers, the total 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 6.1.***

3.3.9 Manufacturer Concentration Limit

Any single equipment manufacturer is limited to 40% of the annual statewide SGIP budget. In other words, the SGIP shall not issue conditional reservations to a project using a technology produced by a manufacturer that has already received reservations in a given year that total 40% of the SGIP statewide budget. The annual statewide SGIP budget is defined as the authorized budget allocation plus carry-over funds from previous program years. The manufacturer concentration limit will be established and posted at the opening of the Program Year and will remain the same throughout the year.

[15] All applicable Incentive Limitations apply. See Section 3.3.

[16] Duplicative application is considered a program infraction. See *Section 6.1* for Program Infractions.

3.4 Non-Renewable Generating Systems Converted to Renewable Fuel

Non-Renewable SGIP funded generating systems can be converted to Renewable Fuel if all eligibility program requirements are met and the conversion takes place no later than 1 year from the first SGIP incentive payment. However, these conversions are only eligible to receive the additional biogas adder; all project costs caps are still applicable.

3.5 Export to the Grid

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. Export to grid system sizing is explained in *Section 4.4.5*.

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.

3.6 PBI Assignment

If there is a change in ownership of the property which hosts the SGIP equipment the new owner/s may continue to receive the Performance-Based Incentives (PBI) and be eligible to receive future SGIP incentives if they complete a new interconnection agreement. If the seller(s) remove the equipment, they may continue to receive the PBI Incentive payments and be eligible to receive future PBI Incentives if the equipment they removed is installed within the same service territory within six months and they complete an interconnection agreement at the new address. In either case, the PBI payment sunset date will not be extended.

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 customer of PG&E, SCE, SoCal Gas or SDG&E is eligible to be the Host Customer and receive incentives from the SGIP. 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.

Any class of customer (industrial, agricultural, commercial or residential) is eligible to be a Host Customer in the SGIP. The Host Customer's Site must be located in the service territory of, and receive retail level electric or Gas Service[17] from, PG&E, SCE, SDG&E or SoCal Gas at the Site. Municipal utility customers also served by SCE, PG&E, SDG&E or SoCal Gas at the Site are eligible.

The Host Customer is the exclusive incentive reservation holder and has the right to designate the Applicant, energy services provider, and/or system installer. The Host Customer also has the right to change these parties at any given time with prior written notice to the Program Administrator. The Host Customer may also be the Applicant and/or System Owner. The Host Customer shall be party to the SGIP Contract.

4.1.2 System Owner

The System Owner is the owner of the SGIP incentivized equipment. 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. The System Owner shall be designated on the Proof of Project Milestone Form t and on the Incentive Claim Form. If known at that time, the System Owner may also be designated on the Reservation Request Form. If different from the Host Customer, the System Owner shall also be a party to the SGIP Contract. The Program Administrator may require documentation substantiating equipment ownership.

In the event that the System Owner 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 a new Reservation Request Form to the Program Administrator.

[17] "…retail level electric or Gas Service…" means that the Host Customer pays for and receives distribution services, as defined by their respective utility rate schedule.

4.1.3 Applicant

The Applicant is the 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 (e.g. a party other than the Program Administrator or the utility customer) to act as the Applicant on their behalf. Applicants may be third parties such as, but not limited to, engineering firms, installation contractors, equipment distributors, Energy Service Companies (ESCO), equipment lessors, etc. The Host Customer may elect to change the Applicant at their discretion.

4.1.4 Payee

The Payee is the person or company to whom the SGIP incentive check is made payable. The Program Administrator will issue payment upon approval of application documents and successful field verification of the equipment. The Payee may be any entity designated by the Host Customer as indicated on the Incentive Claim Form.

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.

Equipment must have at least one year of documented commercial availability at the time of Reservation Request. Alternatively, equipment may be eligible if system certification is obtained from a nationally recognized testing laboratory (NRTL) indicating that the technology meets the safety and/or performance requirements of a nationally recognized standard. Systems that are still in the process of certification with a NRTL may submit a SGIP Reservation Request application before the certification process is finalized. 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 by the Program Administrator.

4.2.2 Eligibility for New and Emerging Technologies

Systems consisting of new technologies *not* already included in the list of eligible SGIP technologies listed in *Section 1.3* may become eligible for the SGIP as an emerging technology if its first commercial installation occurred less than ten years prior to SGIP funding. Emerging technologies must meet all applicable eligibility and program requirements. Developers of such technologies

seeking eligibility through these criteria must follow the Program Modification Guidelines (PMG) as outlined in *Section 4.5*.

4.2.3 Interconnection

All systems receiving incentives under the SGIP 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.

AES systems must also be configured to operate in parallel with the grid. It can be charged from either the grid, an SGIP funded generator, or both and discharged to the on-site load.

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 for a reservation up to 12 months after receiving authorization to operate in parallel with the grid from the Electric Utility.

4.2.4 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.

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 of the generation system, 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.

4.2.5 Ineligible Equipment

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

- Back-Up systems intended solely for emergency purposes
- 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
- Equipment that has been interconnected for more than 12 months

4.2.6 Eligibility Requirements for Advanced Energy Storage

Advanced Energy Storage Projects may be stand-alone or coupled with other SGIP eligible technologies or Photovoltaic systems. All Advanced Energy Storage systems must have the capability to discharge its rated capacity for a minimum of 2 hours and must be capable of discharging fully at least once per day. Advanced Energy Storage systems coupled with wind generation must have the ability to handle hundreds of partial discharge cycles each day.

4.2.7 Minimum Operating Efficiency Requirements

Conventional CHP systems and Fuel Cells operating on non-renewable fuel 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

Each of these requirements is described in detail below and an example is provided in Appendix B.

To facilitate minimum operating efficiency requirements and determine system eligibility, a Minimum Operating Efficiency Worksheet is available for download from the Program Administrators' websites. For more information on the worksheet please refer to *Section 2.3.1 item 6*.

Waste Heat Utilization

To meet minimum waste heat utilization, combined heat and power systems must meet the requirements of Public Utilities Code 216.6, which are expressed in the following equations:[18]

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.

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

Minimum Electric Efficiency[19]

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 4.4.8*, 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.

4.2.8 NOx Emission & Minimum System Efficiency Standards

In addition to the minimum operating efficiency requirement, all **conventional CHP systems using non-renewable fuels** must not exceed a NOx emissions standard of 0.07 lbs/MW-hr and must meet the 60% minimum system efficiency requirement. The minimum system efficiency shall be measured as useful energy output divided by fuel input in higher heating value. The calculated minimum system

[18] PUC 216.6 - "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.

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

efficiency shall be based on 100 percent load. The following formula is to be used to determine the system efficiency:

System Efficiency = (E + T) / F_{HHV} ≥ 60%

Where:

E ≡ The generating system's rated electric capacity as defined in *Section 4.4.8*, converted into equivalent Btu/hr using the factor 3,414 Btu/kWh

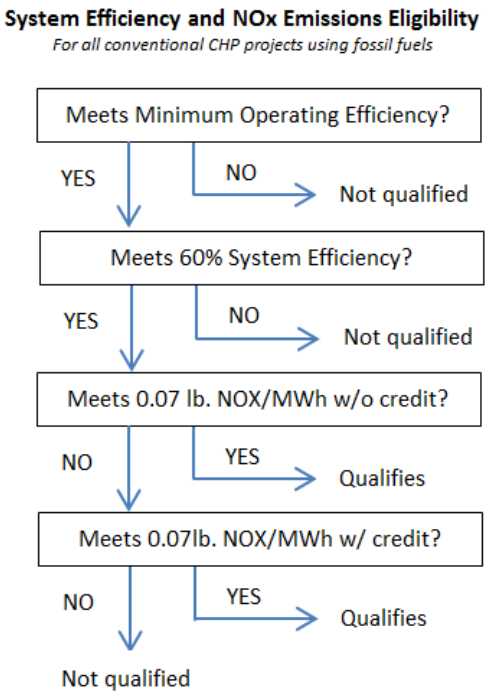
T ≡ The generating system's useful waste heat recovery rate (Btu/hr) at rated capacity.

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

For any conventional CHP systems using non-renewable fuels that fails to meet the emission standard but meets the 60% minimum system efficiency standard, an emission credit for waste heat utilization may be determined to adjust the final emissions determination of eligibility. For a detailed explanation of en emission credit calculation, please refer to *Appendix C*.

Conventional CHP systems operating solely on Waste Gas are exempt from the NOx emission requirements if the local air quality management district or air pollution control district, in issuing a Permit to Operate for the Project, provides in writing a determination that the operation of the Project will produce an on-site net air emissions benefit compared to permitted on-site emissions if the Project does not operate. Note that Waste Gas Systems, though exempt from NOx emission requirements, still must meet the minimum operating efficiency requirement.

Figure 4.2.8: System Efficiency and NOx Emissions Eligibility



4.2.9 Greenhouse Gas Emission Standards

- **Greenhouse Gas Emission Standards for CHP Projects**

Conventional CHP and Fuel Cell Projects operating on non-renewable fuels must not exceed an average Greenhouse Gas (GHG) emissions standard of 379 kg CO_2/MW-hr. The gross GHG output is calculated by multiplying the annual fuel consumption of the generator in MMBtus by an emission factor of 53.02 kg CO_2/MMBtu[20] for the conversion of natural gas to CO_2. The GHG savings from waste heat recovery are calculated by dividing the annual waste heat recovered in MMBtus by 80% which represents a nominal boiler efficiency and then multiplying by the 53.02 kg CO_2/MMBtu emission factor. The net GHG output of the generator is calculated by subtracting the GHG savings due to waste heat recovery from the gross GHG output. The GHG emissions rate for the generator is found by dividing the net annual GHG emissions by the annual electrical output of the generator in MWh and averaged over the years in operation.

- **Greenhouse Gas Emissions Testing for Electric-Only Technologies**

Electric-only technologies operating on non-renewable fuels must meet Greenhouse Gas (GHG) emission rates of 379 kg CO_2/MW-hr in the first ten years of operation. The only eligible electric-only technologies operating on non-renewable fuels are Fuel Cells. Fuel Cells operating under these conditions will be required to be tested according to the ASME PTC 50-2002 protocol. The ASME PTC 50-2002 will be used to determine the energy input to the Fuel Cell, the electrical power output, thermal and mechanical outputs, average net power, electrical efficiency, thermal effectiveness and heat rate under ISO test conditions. The average net power of the Fuel Cell coupled with the fuel input rate (HHV) will be used to calculate the annual power generation (MWh) and fuel consumption (MMBtu) based upon an assumed capacity factor of 80%. The GHG output is calculated by multiplying the annual fuel consumption of the Fuel Cell in MMBtus by the emission factor of 53.02 kg CO2/MMBtu for the conversion of natural gas to CO2. The GHG emissions rate for the generator is found by dividing the annual GHG emissions by the annual electrical output of the generator in MWh.

- **Greenhouse Gas Emission Standards for AES Projects**

AES systems, whether coupled with a generator or stand-alone, need to maintain round trip efficiencies equal or greater than 63.5% on an annual basis in order to be eligible under the SGIP[21]. Round trip efficiency is defined as the ratio of the AC electric energy discharged to the AC electric energy needed to charge the AES system. The charge and discharge of the AES will be metered per the requirements of *Section 5.1* of this Handbook.

[20] Unspecified natural gas conversion emission factor from Appendix A of Section 95112 of the mandatory GHG reporting regulation. Title 17 of the California Code of Regulations.

[21] Self Generation Incentive Program (SGIP) Working Group initially adopted a minimal round trip efficiency of 67.9% consistent with CPUC Staff Proposal September 2010 and D.11-09-015 from September 2011. Resolution E-4519 September 13, 2012 revised Round-Trip Efficiency requirement from 67.9% to 63.5%.

4.2.10 Reliability Criteria

Conventional CHP systems operating on non-renewable fuel must meet both of 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.

4.3 Eligible Fuels

Eligible fuels for participation in the SGIP are classified as renewable and non-renewable. Each type of eligible fuel is described below.

4.3.1 Renewable Fuel Requirements

A renewable fuel is a non-fossil fuel resource[22] that, for the purposes of the SGIP, can be categorized as one of the following: biodiesel or biogas derived from digester gas, landfill gas[23] or biomass. [24] A facility utilizing a renewable fuel to fuel an eligible SGIP technology qualifies for the renewable fuel incentive if it uses at least 75 percent renewable fuel annually, as determined on a total energy input basis for the calendar year.

The SGIP makes a distinction between those projects where a renewable fuel is being consumed at the location where it is being produced and those projects where the renewable fuel is obtained pursuant to a contract where biogas is nominated and delivered[25] to customers via a natural gas pipeline. The former is termed an on-site renewable fuel project and the latter is termed a Directed Biogas project. A summary of the requirements for both are outlined in detail below.

4.3.1.1 Renewable Fuel Requirements

To be considered an On-Site Renewable Fuel project under the SGIP, the project must meet the following eligibility requirements:

[22] Renewable fuel excludes those defined as conventional in Section 2805 of the Public Utilities Code.

[23] Based on AB4037, landfill gas is currently precluded from injection into California's natural gas pipelines.

[24] The utilization of resources such as wind, pressure and water to fuel eligible SGIP technologies are considered renewable for purposes of determining appropriate SGIP incentive levels.

[25] There is no means of ensuring the actual molecules of renewable gas are consumed at the customer's site. Thus, the gas is not literally delivered, but notionally delivered, as the biogas may actually be utilized at any other location along the pipeline route.

- Renewable fuel supplier facility must produce fuel that meets the SGIP definition of Renewable Fuels (see above).
- The project must prove the availability of an adequate average flow rate of Renewable Fuel to meet at least 75% of the generator's total fuel consumption for the duration of the required permanency period (10 yrs.). Evidence that an adequate Renewable Fuel resource exists will be verified during the field verification visit prior to approval of the incentive.

4.3.1.2 Directed Biogas Requirements

Eligible Directed Biogas projects must meet the following eligibility requirements and conditions:

- Renewable fuel supplier facility must produce fuel that meets the SGIP definition of Renewable Fuels (see above).
- The project must procure directed biogas to meet at least 75% of the generator's total fuel consumption for the duration of the required permanency period (10 years). Evidence that 75% of the generator's total fuel consumption is being procured with biogas will be verified via annual Directed Biogas audits (see below).
- The project must meet the currently applicable Renewable Portfolio Standard eligibility requirements for biogas injected into a natural gas pipeline (pipeline biomethane)
- Renewable fuel supplier facility must be located within California.
- The Host Customer and the renewable fuel supplier must install a revenue-grade fuel gas meter(s) that can be remotely monitored by the utility.
- If the Host Customer decides to change their renewable fuel supplier, or if the Customer's current renewable fuel supplier cannot meet the obligations to perform as set forth in their contract, the Host Customer is allowed to find a new supplier within 90 days. The Program Administrator must be made aware of the situation and during the transition period, the required minimum of 75% renewable fuel consumption on an annual basis must be maintained. Once the Host Customer finds a new supplier, they must then enter into a new contract that provides for at least 75% of the system's anticipated consumption. The Host Customer must provide to the Program Administrator all documentation requested in the bullets above, except for metering information, unless it has changed.

4.3.1.3 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 compliance with the requirement to procure renewable fuel to meet at least 75% of the generator's total fuel consumption.

The audit and verification approach will use a combination of metered fuel consumption data for SGIP Directed Biogas projects; invoices from SGIP participants for directed biogas purchases;

documentation/verification on any deliveries of directed biogas along the path from the SGIP participant back to the original directed biogas supply source; and documentation to verify the amount and energy content of directed biogas 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 biogas provider at the completion of each year after biogas contract start date.

If invoices show that nominated renewable fuel deliveries fell below 75% of the generator's fuel demand during any 1 year period, the SGIP Program Administrators will request that the System Owner refunds the full biogas SGIP incentive and reserve the right to request a refund of additional costs associated with administrative and legal fees incurred by the Program Administrators.

4.3.2 Non- Renewable Fuels

Non-Renewable Fuels include fossil fuels and synthetic fuels. For the SGIP, eligible fossil fuels are gasoline, natural gas and propane. Synthetic fuels are fuels derived from materials that are not Renewable Fuels or fossil fuels. Eligible synthetic fuels include, but are not limited to, the direct use or synthesis of fuels from sewage sludge, industrial waste, medical waste or hazardous waste.

4.3.2.1 Waste Gas Fuel

Waste Gas fuels used for conventional CHP technologies and Fuel Cells 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[26].

Incentives paid for Waste Gas fuel systems shall be subject to refund to the Program Administrator by the recipient if it is determined that the Project does not operate on Waste Gas for at least the required permanency period.

4.4 System Size Parameters

Generally, equipment may be sized up to the current or forecasted electrical load at the Site. For new construction or projects with future load growth, the load must be substantiated before the incentive can be paid. Systems that are rated at 5kW or less are exempt from the system sizing requirements.

4.4.1 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 back-up generators).

[26] This definition of Waste Gas is directly from AB 1684.

4.4.2 System Sizing for PRT, Waste Heat to Power, CHP and Fuel Cells

Pressure Reduction Turbine, Waste Heat to Power, Gas Turbine, Microturbine, Internal Combustion Engine 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 back-up generators) must be no more than the Host Customer's Maximum Site Electric Load.

In order to reduce GHG emissions and optimize system efficiency, non-renewable CHP projects must not exceed the on-site thermal load with the recovered waste heat on an annual basis.

4.4.3 System Sizing for Advanced Energy Storage

Stand-alone Advanced Energy Storage Projects may be sized up to the Host Customer's previous 12-month annual peak demand at the proposed Site.

Advanced Energy Storage Projects coupled with generation technologies must be sized no larger than the rated capacity of the PV or SGIP eligible technology it is operating in concert with. When coupled with a PV system, the rated capacity of the AES system can be no larger than the CEC-AC rating of the PV system, which is the rated AC output of the PV system including inverters.

4.4.4 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 following method:

Peak Demand (kW) = Largest Monthly Bill (kWh/month) / (Load Factor x Days/Bill X 24)

Residential Load Factor = .43

Commercial Load Factor = .55

Industrial Load Factor = .76

Agricultural Load Factor = .63

The resulting annual peak demand estimate should be used to determine system sizing for the proposed technology[27].

4.4.5 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

[27] Load factors determined from the California Energy Commission's 2012 Demand Forecast (Mid Case) http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/mid_case/

kWh) by 8760 hours and the expected capacity factor of the technology as stated in *Table 3.2.4*. There is an example provided in *Appendix B*.

4.4.6 System Sizing for Customers participating in RES-BCT and/or FC-NEM Tariffs

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 5MW cap per Site.

4.4.7 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 (DG) services (e.g. DG 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 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.

4.4.8 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 biogas, 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.

- For non-renewable fueled technologies, 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.
- For **on-site** renewable fueled technologies, the generating system capacity is the operating capacity based on the average annual available Renewable Fuel flow rate, including allowable non-renewable fuel at ISO conditions[28].
- 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.
- For Wind Turbine technologies less than 30 kW in capacity a minimum hub height of 80 feet is required unless a year's worth of wind data is provided at the turbine's proposed hub height, establishing its capacity at the site's annual average wind speed. No height limitation is imposed for turbines equal to or larger than 30 kW. For wind turbines of all sizes the wind turbine's rated capacity is based upon the highest electrical output from the manufacturer's power output curve (including inverter losses) at the annual average wind speed at the proposed site, at the turbine's hub height. For Advanced Energy Storage technologies, the rated capacity must be the average discharge power output (kW) over a two hour period.
- For Waste Heat to Power technologies, the generating system capacity is the operating capacity based on the average annual available waste heat production rate and temperature.
- For Pressure Reduction Turbine technologies, the generating system capacity is the operating capacity based upon the average annual pressure drop across the turbine and flow rate through the turbine.

Eligible technology system rated capacity must be substantiated with documentation from the manufacturer. Refer to *Section 2.3.1 Item 3* for detailed instructions on documentation requirements.

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

4.5 Program Modification Guidelines (PMG)

For the consideration of new technologies and/or SGIP rule changes, the following Program Modification Guidelines (PMG) 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 SGIP Working Group meeting.

All parties desiring a program modification will be required to meet with the SGIP Working Group at the 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 order.

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.34
- 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 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 Handbook will be made to capture the change.

  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 proposed program change, 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. Metering & Data Collection

This section contains detailed information on the minimum metering and monitoring requirements for SGIP projects with a capacity of 30 kW or larger. The meter data will be used to analyze the production, emissions, and efficiency performance of the installed equipment over a 5-year time frame following the initial commissioning of a project. The results of the analysis will be used to execute Performance Based Incentive (PBI) payments. Additionally the collected meter data will increase owner knowledge of system performance, foster adequate system maintenance, and thereby ensure ratepayer-funded incentives result in expected levels of self-generation.

All SGIP technologies 30 kW or larger must install metering and monitoring equipment that measures net electrical output from the system(s). Combined heat and power technologies operating on non-renewable fuels will in addition install metering and monitoring equipment that measures and reports useful thermal energy delivered to the Site from the CHP system as well as fuel input to the generator(s). Electric-only Fuel Cells will also be required to measure fuel input into the generator(s). Advanced Energy Storage systems, whether coupled with self-generation equipment or operating as a stand-alone system, must measure the net electrical energy during charge and discharge cycles.

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 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.

The following section details the metering and monitoring requirements as well as the data transfer protocols for PDPs under the SGIP.

5.1 Metering & Monitoring Requirements

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 5.2*.
- 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 (electrical, thermal, fuel).

5.1.1 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. For AES systems, a meter must be installed to measure the charge and discharge of the AES. Alternatively, one meter can be used with multiple channels that can monitor at these two points.

- **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 elevation at installation (feet above sea level) must be reported at the time of commissioning. This information may be gathered from a geological database. When monitoring AES systems, the PDP must measure 15 minute net energy for the AES system during charging and discharging and count the number of charge and discharge cycles during a 15 minute interval. The meter needs to generate an accurate time/date stamp.

- **Meter Testing and Certification**

± 2% 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).

- **Meter Display**

All meters must provide a display showing the meter's measured net generated energy output 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.

5.1.2 Minimum Thermal Metering Requirements

All Combined Heat and Power (CHP) systems 30 kW and larger running on non-renewable fuel 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[29] 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

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

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.

- **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.

5.1.3 Minimum Fuel Metering Requirements

All CHP systems and electric-only Fuel Cells 30 kW and larger must be installed with a fuel metering system which allows the System Owner and Program Administrator to determine the amount of fuel consumption and allows the System Owner to support proper system operation and maintenance. The recorded data will be used to calculate the minimum system operating efficiency and GHG emissions of the system. These calculated values will be used to monitor compliance with the Program's GHG emission limits and minimum system operating efficiency requirements.

- **Meter Type**

All CHP systems and electric-only Fuel Cells 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 fuel entry into the generator but downstream of any other loads (e.g., natural gas boiler, un-incentivized CHP system). For on-board metering systems, the fuel must be metered before any portion is consumed by the generator. 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 $\pm$ 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.

5.2 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 for AES 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.

5.2.1 Data Format

Meter data must conform to the SGIP program requirements as set forth in *Section 5.1* (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.[30]

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.

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

5.2.2 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.

5.2.3 Online Submission Process

All performance data will be submitted via the SGIP Online Database PDP Upload Portal. The portal will be accessed through www.selfgenca.com Files that are submitted via e-mail will not be accepted.[31]

5.2.4 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

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

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

5.2.5 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.

The Program Administrator will 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.

5.2.6 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.

5.2.7 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.

5.2.8 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.

5.2.9 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.

5.2.10 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.

5.3 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[32]. Note that the PDP Applicant may submit one application for statewide PDP services to either 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 database provider to set up an account for the PDP Upload Portal.

5.3.1 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 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

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

data services they are applying for (electrical, thermal and fuel) and submit the test files to the SGIP Online 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.

5.4 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.

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.

5.5 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.

5.5.1 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 field verification visits by the PA or its consultants (*see Section 2.5.4*), which are used to determine eligibility of the installed system and occur during the Incentive Claim stage of the application process.

5.5.2 M&E Metering Requirements

All SGIP systems require installation of metering devices to measure and record electrical output, waste heat, and fuel consumption for M&E purposes. For installations 30kW and larger, the PAs may collect this information from the data submitted by the Performance Data Providers (PDP) for PBI payment purposes. For projects under 30kW, the PA or the PA's independent third-party consultant will 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.

5.5.3 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.

6. 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.

6.1 Infractions

Infractions are any actions that intentionally circumvent program policy or have the intent to do so. The Program Administrators will exercise their judgment in assessing program infractions, which may include gross negligence or intentional submission of inaccurate project information in an attempt to collect more incentive dollars. Program infractions may be determined at any stage of the SGIP process. If it is determined that a program infraction has been committed, a reasonable sanction shall be imposed at the discretion of the Program Administrator, and may result in a suspension from the SGIP Program for a minimum of six months. The sanction maybe applicable to all parties involved in the project and is not limited to the Host Customer.

Definitions and Glossary

Advanced Energy Storage: Are technologies that convert electricity into another form of energy, stored and then converted back into electricity at another time.

AES: Advanced Energy Storage

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 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.

California Supplier: Is any sole proprietorship, partnership, joint venture, corporation, or other business entity that manufactures eligible distributed generation technologies in California and that meets the criteria outlined in Handbook *Section 3.1.1*

CCSE: California Center for Sustainable Energy

CEC: California Energy Commission

Coupled: Two technologies paired with each other and considered together on the same electrical circuit. For example, AES coupled with an eligible generating system; the energy from the generating system is used to charge the Advanced Energy Storage (AES).

CPUC: California Public Utilities Commission

Directed Biogas: A renewable fuel that is obtained pursuant to a contract where biogas is nominated and delivered to Host Customer's Project via a natural gas pipeline. There is no means of ensuring that actual molecules of renewable gas are consumed at the Host Customer's Site. Thus, the gas is not literally delivered, but notionally delivered, as the renewable fuel may actually be utilized at any other location along the pipeline route.

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

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 resulting in extremely low emissions and hot water or steam.

Gas Service: The gas line from the Utility's distribution main to the serving gas meter

Hybrid Project: Project on a Site that includes two or more different technologies. A separate application is required for each technology.

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.

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

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 (see Appendix –ES spec).

Non-Renewable Fuel: Includes fossil fuels and synthetic fuels not generated from a renewable resource.

Parallel Operation: The simultaneous operation of a self-generator with power delivered 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 third party 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.

Program Year: January 1 through December 31.

Project: For purposes of the SGIP, the "Project" is the installation and operation of the proposed eligible self-generation technology(ies), 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.[33]

Renewable Fuel: A Renewable Fuel is a non-fossil fuel resource other than those defined as conventional in Section 2805 of the Public Utilities Code that can be categorized as one of the following: solar, wind, gas derived from biomass, digester gas, or landfill gas. A facility utilizing a Renewable Fuel may not use more than 25 percent fossil fuel annually, as determined on a total energy input basis for the calendar year.

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

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.

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.

SoCal Gas: Southern California Gas Company

Stand-alone AES: Self-contained energy storage interconnected and is charged from the utility grid.

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

Thermal 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

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

exchangers, thermal storage tanks or vessels including pumps, cooling towers, and piping or any other ancillary equipment.

Waste Gas: Natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.

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.
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.

Date	Bill Number	Description
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.
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.

Date	Bill Number	Description
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 levels 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 • 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

Date	Bill Number	Description
	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

Appendix A - SGIP Contract

Self-Generation Incentive Program

Program Administrator

ENTER PA ADDRESS HERE

SELF-GENERATION INCENTIVE PROGRAM CONTRACT

BETWEEN **PROGRAM ADMINISTRATOR, HOST CUSTOMER,** AND **SYSTEM OWNER**

This Contract is made by and between Host Customer, organized and existing under California law, jointly and severally with System Owner, organized and existing under California law, and Program Administrator, a California corporation. If a separate System Owner is not designated, the Host Customer will be the designated System Owner for the purpose of this Contract. Capitalized terms not defined herein are given the same meaning as provided in the Glossary of the Self-Generation Incentive Program Handbook.

1.0 PROJECT DESCRIPTION - This Contract is limited to the Project described in the submitted Reservation Request Form. If all Program and Contract terms and conditions are complied with, Program Administrator will pay an incentive to the party designated on the submitted Incentive Claim Form. Program Administrator reserves the right to modify or cancel the incentive offer if the actual installation of Self-Generation (SG) Unit(s) differs from the proposed installation described in the Reservation Request Form. SG Unit(s) must also be installed by the date shown on the Incentive Claim Form to be issued by Program Administrator after all required Proof of Project Milestone items are submitted.

2.0 DOCUMENTS INCORPORATED BY REFERENCE - The following documents set forth additional terms, conditions and requirements of this Contract:

Self-Generation Incentive Program "Reservation Request Form" (RRF)

Self-Generation Incentive Program (SGIP) Handbook, Revision 0 dated April 5, 2012, or as subsequently amended.

Renewable Fuel Affidavit (if applicable)

Host Customer and System Owner each acknowledge having received and read, and agree to be bound by the aforementioned documents, copies of which are available to Host Customer and System Owner on the Program Administrator's website, and the terms of which are incorporated herein by reference as though set forth in full. Should a conflict exist between this Contract and any of these documents, this Contract shall control.

3.0 OTHER PROGRAM DOCUMENTS – The following forms set forth additional terms, conditions, and requirements of the Program:

Self-Generation Incentive Program "Incentive Claim Form" (ICF)

"Final Project Cost Affidavit" Form

Host Customer and System Owner each acknowledge having received copies of these forms, and that these forms, when completed, set forth additional Program terms and requirements. Host Customer and System Owner further acknowledge that the ICF and the Final Project Cost Affidavit contain certifications by Host Customer and System Owner, which certifications shall be true, accurate, and complete.

4.0 SUBMITTAL REQUIREMENTS FOR PAYMENT - As a condition of payment, the Host Customer or System Owner shall submit to Program Administrator, within the deadlines established by Program Administrator, the documents described in the SGIP Handbook. Each document requires review and Program Administrator's written approval before Host Customer and System Owner may move on to the next stage of the application process.

4.1 Reserving an Incentive - The Reservation Request Form ("RRF") describes the Project, lists the SG Unit(s) that will be installed in the Project, and estimates its size (system rated capacity according to the SGIP Handbook) and its costs (including interconnection fees and, in some cases, warranties costs). When Host Customer or System Owner submits the RRF to Program Administrator, it shall include the applicable items listed in the SGIP Handbook. Program Administrator will review the RRF and, if the Project appears to meet eligibility requirements, Program Administrator will make a conditional reservation of funds for the Project and will send Host Customer and System Owner a Conditional Reservation Letter, the description of which is provided in the SGIP Handbook.

4.2 Proof of Project Milestone - Within the prescribed number of days, as defined in the SGIP Handbook, of the date on the Conditional Reservation Letter, Host Customer or System Owner must submit the applicable Proof of Project Milestone ("PPM") items listed in SGIP Handbook, to demonstrate to Program Administrator that the Project is progressing and that there is a substantial commitment to complete the Project.
After Program Administrator reviews the PPM items and determines that the Project has met all of the necessary criteria, Program Administrator will send Host Customer and System Owner the Incentive Claim Form ("ICF"). The ICF will list the specific reservation amount and the Reservation Expiration Date.

4.3 Incentive Claim - Upon Project completion and prior to the Reservation Expiration Date, Host Customer and System Owner must complete and submit the ICF to request an incentive payment. In addition to the completed ICF, the Host Customer or System Owner must submit the applicable items listed in SGIP Handbook.

5.0 FIELD VERIFICATION BY INSPECTION - After complete, proper installation of the SG Unit(s) and submittal of the applicable items listed in SGIP Handbook, the Program Administrator or its authorized agent will schedule and complete a **Field Verification Visit** to verify that the SG Unit(s) have been installed and are operating in accordance with the RRF, ICF and required accompanying information. During the Field Verification Visit, Host Customer and System Owner must provide access to the SG Unit(s) and must demonstrate the operation of the SG Unit(s). In addition, access must be provided to verify all Energy Efficiency measures with a payback period of two years or less, as identified in the Energy Efficiency Audit (EEA). If the SG Units have a rated capacity that is 30 kW and larger, the metering system will be inspected, and it will be verified that it follows the proposed monitoring plan required under SGIP Handbook and meets the metering requirements of the SGIP as defined in SGIP Handbook. If the Project uses Renewable Fuel, the availability and flow rate of the Renewable Fuel will be demonstrated by 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. If the Project involves an Advanced Energy Storage (AES) system coupled with an SGIP-funded generating system or a photovoltaic system, the electrical coupling of the two systems will be verified at the time of the Field Verification Visit. In addition, the rated capacity of an AES system will be verified by allowing the system to discharge over a two-hour period and determining the average power output during that time. If the eligible system size depended on new construction or load growth, the required load will be confirmed at the time of Field Verification Visit. The Program Administrator also will verify system capacity rating to confirm the final incentive amount. During the Field Verification Visit, Host Customer and System Owner must ensure that someone is present for an interview that is knowledgeable about the SG Unit(s) and their operation, and must allow photographs of the Energy Efficiency measures and SG Unit(s) and their related systems to be taken. No incentive payment can be made until the final Field Verification Visit report has been satisfactorily completed.

6.0 MEASUREMENT & EVALUATION (M&E) ACTIVITIES - As a condition of receiving incentive payments, Host Customer and System Owner must ensure that Program Administrator or its authorized agent and the Program M&E consultant have access to the Project Site(s) for all Field M&E Visits and M&E data collection activities summarized below and described in detail in the SGIP Handbook.

6.1 The Host Customer and System Owner agree to participate in M&E activities, as discussed in SGIP Handbook. For systems with Host Customer, System Owner, and/or third party installed monitoring equipment; the Host Customer and System Owner agree to provide system monitoring data (including,

but not limited to, electric, gas, thermal and/or other relevant fuel input data) to the M&E consultant. Furthermore, the Host Customer and System Owner agree to cooperate with the installation of any additional monitoring equipment that the M&E consultant may deem necessary in its sole discretion.

6.2 Host Customer and System Owner agree to allow the Program Administrator or its authorized agent and the Program M&E consultant access to the Host Customer's Site to develop and implement a M&E Plan for the SG Unit(s) and its related systems in support of M&E activities discussed in SGIP Handbook.

7.0 PAYMENT - The incentive payment check will be made payable to the entity designated in writing by System Owner and Host Customer on the ICF only after the appropriate documents have been submitted (within the deadlines established by Program Administrator) and approved, and the Field Verification Visit report has been satisfactorily completed, in accordance with the Program rules set forth in the SGIP Handbook. Program Administrator's determination of the incentive amount is final, and the System Owner and Host Customer each agree to accept this determination. The incentive payment constitutes final and complete payment.

7.1 System Owner and Host Customer may designate in writing a third party to whom Program Administrator shall make the approved incentive payment.

8.0 REVIEW AND DISCLAIMER - Program Administrator's review of the design, construction, installation, operation or maintenance of the Project or the SG Unit(s) is not a representation as to their economic or technical feasibility, operational capability, or reliability. System Owner and Host Customer each agrees that neither of them will make any such representation to any third party. System Owner and Host Customer are solely responsible for the economic and technical feasibility, operational capability, and reliability of the Project and the SG Unit(s).

9.0 RENEWABLE FUEL LEVELS - For fuel cells utilizing renewable fuel, System Owner and Host Customer shall not, for ten (10) years or the life of the applicable SG Unit(s), whichever is shorter, use non-renewable fuel for more than 25% of its total annual fuel requirements for such SG Unit(s) in any calendar year.

9.1 In the event the System Owner or Host Customer fails to comply with Section 9.0 above, then System Owner and/or Host Customer shall, within thirty (30) days of receipt of a written demand from Program Administrator, reimburse Program Administrator for all incentive payments paid by Program Administrator pursuant to the Program and this Contract. Such reimbursement shall be in the form of a certified check or cash payable to Program Administrator.

9.2 In order to ensure payment in the event the System Owner or Host Customer fails to reimburse Program Administrator pursuant to Section 9.1 above, the Program Administrator may, in its sole discretion, require a bond or other forms of security acceptable to Program Administrator. Acceptable forms of security include cash deposit, irrevocable letter of credit, surety bond from an "A" rated company by A.M. Best, assignment of certificate of deposit, or corporate guarantee (guarantor subject to creditworthiness review).

10.0 WASTE GAS FUEL PROJECTS - For fuel cells projects running on waste gas fuel, System Owner and Host Customer shall, for the applicable ten (10) year warranty period or the life of the applicable SG Unit(s), whichever is shorter, operate the applicable SG Unit(s) solely on waste gas, *i.e.*, the total annual fuel requirements for such SG Unit(s) in any calendar year shall be 100% met by waste gas.

10.1 In the event Section 10.0 applies to Applicant or Host Customer's project and the System Owner or Host Customer fails to comply with Section 10.0 above, then System Owner and/or Host Customer shall, within thirty (30) days of receipt of a written demand from Program Administrator, reimburse Program Administrator all incentive payments paid by Program Administrator pursuant to the

Program and this Contract. Such reimbursement shall be in the form of a certified check or cash payable to Program Administrator.

10.2 In order to ensure payment in the event the System Owner or Host Customer fails to reimburse Program Administrator pursuant to Section 10.1 above, the Program Administrator may, in its sole discretion, require a bond or other forms of security acceptable to Program Administrator. Acceptable forms of security include cash deposit, irrevocable letter of credit, surety bond from an "A" rated company by A.M. Best, assignment of certificate of deposit, or corporate guarantee (guarantor subject to creditworthiness review).

11.0 TERM AND TERMINATION

11.1 The Term of this Contract shall begin on the date that the last party signs the RRF, and shall terminate no later than twice the length of the required warranty; unless terminated earlier pursuant to the operation of this Contract, or unless modified by order of the California Public Utilities Commission (CPUC) or by written agreement of the Parties.

11.2 The Contract may be terminated by Program Administrator in the event (a) System Owner or Host Customer fails to perform a material obligation under this Contract, and System Owner or Host Customer fails to cure such default within fifteen (15) days of receipt of written notice from Program Administrator of such failure to perform a material obligation; or (b) any statement, representation or warranty made by System Owner or Host Customer in connection with the Program or this Contract is false, misleading or inaccurate on the date as of which it is made.

11.3 The termination of this Contract shall not operate to discharge any liability, which has been incurred by either Party prior to the effective date of such termination.

11.4 Neither Party shall be liable in damages or have the right to terminate this Contract for any delay or default in performing any obligation under this Contract if such delay or default is caused by conditions beyond its control including, but not limited to, Acts of God, Government restrictions (including the denial or cancellation of any export or other necessary license), wars, insurrections and/or any other cause beyond the reasonable control of the Party whose performance is affected.

12.0 PERMANENT INSTALLATION - Equipment installed under this Program is intended to be in place for the duration of its useful life. Only permanently installed systems are eligible for incentives. This means that the System Owner and/or Host Customer must demonstrate to the satisfaction of the Program Administrator that the SG Unit(s) has both physical and contractual permanence prior to Program Administrator's payment of any incentive.

Physical permanence is to be demonstrated by the SG Unit(s)' electrical, thermal and fuel connections in accordance with industry practice for permanently installed equipment and its secure physical attachment 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 and/or platform will render the SG Unit(s) ineligible for incentives.

Contractual permanence, corresponding to a minimum of the applicable warranty period, is to be demonstrated as follows:

- System Owner agrees to notify the Program Administrator in writing a minimum of sixty (60) days prior to any change in either the Site location of the SG Unit(s), or change in ownership of the SG Unit(s).
- An additional agreement between the System Owner and the Program Administrator may be required at the Program Administrator's sole discretion in order to safeguard against the possibility of early removal and relocation of the generation system. This additional agreement, if required, must be negotiated to the satisfaction of the Program Administrator.

13.0 OTHER AGREEMENTS - All agreements involving the Project including, but not limited to, sales agreements, warranties, leases, energy service agreements, agreements for the sale of trade of Renewable Energy Credits (RECs), and/or energy savings guarantees, must be disclosed and provided to the Program Administrator as soon as they are available and in no event later than submission of the ICF.

14.0 ASSIGNMENT- System Owner and Host Customer consent to Program Administrator's assignment of all of Program Administrator's rights, duties and obligations under this Contract to the CPUC and/or its designee. Any such assignment shall relieve Program Administrator of all rights, duties and obligations arising under this Contract. Neither System Owner nor Host Customer shall assign its rights or delegate its duties without the prior written consent of Program Administrator or its assignee, if any, except in connection with the sale or merger of a substantial portion of its assets. Any such assignment or delegation without the prior written consent of Program Administrator or its assignee, if any, shall be null and void. Consent to assignment shall not be unreasonably withheld or delayed. System Owner and Host Customer must provide assurance of the success of a Project if assigned by providing any additional information requested by Program Administrator.

15.0 PERMITS AND LICENSES – System Owner and/or Host Customer, at their own expense, shall obtain and maintain all licenses and permits needed to successfully perform work on the Project.

16.0 ADVERTISING, MARKETING AND USE OF PROGRAM ADMINISTRATOR'S NAME – System Owner and Host Customer shall not use Program Administrator's corporate name, trademark, trade name, logo, identity or any affiliation for any reason, including soliciting persons to participate in the Project, without the prior written consent of Program Administrator. System Owner and Host Customer shall make no representations on behalf of Program Administrator.

17.0 INDEPENDENT CONTRACTOR - In assuming and performing the obligations of this Contract, System Owner and Host Customer are each an independent contractor and neither shall be eligible for any benefits which Program Administrator may provide its employees. All persons, if any, hired by System Owner and/or Host Customer shall be their respective employees, subcontractors, or independent contractors and shall not be considered employees or agents of Program Administrator.

18.0 INDEMNIFICATION

18.1 To the greatest extent permitted by applicable law, System Owner and Host Customer shall each indemnify, defend and hold harmless Program Administrator, its affiliates, subsidiaries, current and future parent company, officers, directors, agents and employees, from and against all claims, demands, losses, damages, costs, expenses, and liability (legal, contractual, or otherwise), which arise from or are in any way connected with any: (i) injury to or death of persons, including, but not limited to, employees of Program Administrator, Host Customer, System Owner, or any third party; (ii) injury to property or other interests of Program Administrator, Host Customer, System Owner, or any third party; (iii) violation of local, state or federal common law, statute, or regulation, including, but not limited to, environmental laws or regulations; or (iv) strict liability imposed by any law or regulation; so long as such injury, violation, or strict liability [as set forth in (i) - (iv) above] arises from or is in any way connected with this Contract or System Owner's or Host Customer's performance of, or failure to perform, this Contract, however caused, regardless of any strict liability or negligence of Program Administrator whether active or passive, excepting only such loss, damage, cost, expense, liability, strict liability, or violation of law or regulation that is caused by the willful misconduct of Program Administrator, its officers, managers, or employees.

18.2 System Owner and Host Customer each acknowledges that any claims, demands, losses, damages, costs, expenses, and legal liability that arise out of, result from, or are in any way connected with the release or spill of any hazardous material or waste as a result of the work performed under this Contract are expressly within the scope of this indemnity, and that the costs, expenses, and legal liability for environmental investigations, monitoring, containment, abatement, removal, repair, cleanup, restoration, remedial work, penalties, and fines arising from strict liability, or violation of any local, state, or federal law or regulation, attorney's fees, disbursements, and other response costs incurred as a result of such releases or spills are expressly within the scope of this indemnity.

18.3 System Owner and Host Customer each shall, on Program Administrator's request, defend any action, claim or suit asserting a claim which might be covered by this indemnity. System Owner and Host Customer shall pay all costs and expenses that may be incurred by Program Administrator in enforcing this indemnity, including reasonable attorney's fees. This indemnity shall survive the termination of this Contract for any reason.

19.0 LIMITATION OF LIABILITY - Program Administrator shall not be liable to System Owner, Host Customer or to any of their respective subcontractors for any special, incidental, indirect or consequential damages whatsoever, including, without limitation, loss of profits or commitments, whether in contract, warranty, indemnity, tort (including negligence), strict liability or otherwise arising from Program Administrator's performance or nonperformance of its obligations under the Contract.

20.0 VENUE - This Contract shall be interpreted and enforced according to the laws of the State of California. Sole jurisdiction and venue shall be with the courts in Los Angeles County, California.

21.0 INTEGRATION AND MODIFICATION - This Contract and its appendices constitute the entire Contract and understanding between the Parties as to its subject matter. It supersedes all prior or contemporaneous contracts, commitments, representations, writings, and discussions between System Owner, Host Customer, and Program Administrator, whether oral or written, and has been induced by no representations, statements or contracts other than those expressed herein.

NO AMENDMENT, MODIFICATION OR CHANGE TO THIS CONTRACT SHALL BE BINDING OR EFFECTIVE UNLESS EXPRESSLY SET FORTH IN WRITING AND SIGNED BY PROGRAM ADMINISTRATOR'S REPRESENTATIVE AUTHORIZED TO SIGN THE CONTRACT.

Notwithstanding the foregoing, this Contract is subject to such changes or modifications by the CPUC as it may, from time to time, direct in the exercise of its jurisdiction over Program Administrator. Furthermore, this Contract is subject to change or modification by the SGIP Working Group, as it may from time to time make to the Program in the exercise of its jurisdiction over the implementation of the Program. For purposes of this Contract, the "SGIP Working Group" shall constitute certain staff of each California investor-owned utility, the California Center for Sustainable Energy, California Energy Commission and the Energy Division of the CPUC.

22.0 NO THIRD PARTY BENEFICIARIES - This Contract is not intended to confer any rights or remedies upon any other persons other than the undersigned parties hereto.

By execution of this Contract, System Owner and Host Customer each certifies the Project meets all Program eligibility requirements, and that the information supplied in the Reservation Request Form is true and correct. System Owner and Host Customer further certify that System Owner and Host Customer have read and understand the Self-Generation Incentive Program documents described in the SGIP Handbook and agree to abide by the rules and requirements set forth in this Contract and in the RRF, the SGIP Handbook, the Renewable Fuel Affidavit and the ICF as applicable.

System Owner and Host Customer each declare under penalty of perjury under the laws of the State of California that: 1) the information provided in the RRF is true and correct to the best of my/our knowledge; 2) they have each read the Host Customer and System Owner Agreement set forth in the RRF and agree to terms therein; 3) any and all SG Unit(s) described in the RRF are new and intended to offset part or all of the Host Customer's electrical needs at the Site of installation; 4) the Site of installation is located within the Program Administrator's service territory; 5) the SG Unit(s) are not intended to be used solely as a backup generator; and 6) the Host Customer and the System Owner each has received a copy of this Contract and the completed RRF.

In witness whereof, the Parties have executed this Contract by executing the RRF as of the latest date on the RRF.

All communications under this Contract shall be forwarded directly to the appropriate Program Administrator.

Appendix B - System Calculation Examples

Efficiency Calculations

Example #1: 5 kW Residential Fuel Cell CHP System

A 5 kW fuel cell operating on natural gas is proposed to provide electricity and heat to a residential Host Customer. The fuel cell is sized to operate at an annual average 90% capacity factor. The residential Host Customer's Thermal Load consists of pool heating, domestic hot water and space heating. The Applicant used the Residential Minimum Operating Efficiency Worksheet (see Table A-1) and entered the following information:

- Rated Net Generating Capacity – The rated kW capacity of the proposed generating system
- Ancillary Generating System Loads – The rated kW size of all ancillary loads necessary for generator operation.
- Fuel Consumption Rate (LHV) – The lower heating value fuel consumption at rated capacity (Btu/hr).
- Fuel Consumption Rate (HHV) – The higher heating value fuel consumption at rated capacity (Btu/hr).
- Waste Heat Recovery Rate – The amount of recoverable heat from the generating system (Btu/hr)
- Zip Code of Residence – The zip code location of the Host Customer.
- Dwelling Living Area – The living area of the home (sq ft)
- Residential Space Heating – Check box indicating that recovered waste heat will be used for space heating.
    - Residential Type – Single family, town home or apartments
    - Vintage – When was the period the home was constructed.
- Pool Heating – Check box indicating that recovered waste heat will be used for pool heating.
    - Energy smart pools net load data entered into "Pool Heating" worksheets
- Domestic Hot Water - Check box indicating that recovered waste heat will be used for domestic hot water heating.
    - Household Size – The number of people living in the home.
- Generator Equipment Full Load Hours per Month

The fuel cell exceeds the PU Code 216.6. (a) and (b) requirements, therefore it meets the minimum operating efficiency requirement for the program. It is exempt from the NOx emissions eligibility and passes the GHG emissions eligibility. The thermal coincidence factor is less than 1.0 for every month of the year indicating that it is utilizing waste heat recovery effectively and since it is qualified for the feed-in-tariff the export factor indicates that it is exporting less than the program export limit which is 25% more than the site electrical load.

Table A-1 Residential Minimum Operating Efficiency Worksheet

Applicant:	ESCO	Date:	January 1, 2011
Host Customer:	Residential Customer	Application No.:	XX-XXX

Instructions: This spreadsheet determines if a proposed generating system meets the Minimum Operating Efficiency eligibility requirement of the Self-Generation Incentive Program for Residential customers. Applicants must provide documentation supporting all inputs including but not limited to system capacity, fuel consumption, waste heat recovery rate, operating schedule, equivalent full load operating hours and thermal load. See the 2011 SGIP Handbook for details of eligibility and documentation requirements. All yellow cells must be completed by Applicant/Host Customer.

Rated Net Generating Capacity =	5	kW	Full load net continuous rated capacity of the packaged prime mover/generator at ISO conditions.
Ancillary Generating System Loads =	0	kW	Any ancillary equipment loads necessary for the operation of the generator (e.g., fuel compressors, intercooler chillers, etc.) not accounted for in the Rated Net Generating Capacity.
Fuel Consumption Rate (LHV) =	42,844	Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on lower heating value of fuel.
Fuel Consumption Rate (HHV) =	47,511	Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on higher heating value of fuel.
Waste Heat Recovery Rate =	22,000	Btu/hr	Recoverable heat as specified by manufacturer of generator or waste heat recovery unit at full load conditions. This is not total waste heat of the unit. The value provided should be supported by Generating System specifications (if packaged unit), Waste Heat Recovery System specifications, or engineering analysis of recoverable waste heat.
Generator Emissions =	0.074	lbs/MWh	NOx emissions specifications for the proposed generating system as configured, including emissions controls, for the Host Customer Site at rated conditions. The value provided should be supported by factory testing, other installation source tests or engineering calculations.
Fuel Type =	Non-Renewable		Non-Renewable fuels are any fossil based fuels such as natural gas. Renewable fuels include landfill and digester gas. Waste gas are fuels 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.
Fuel Cell ?	☑ Yes		Is the proposed generator a fuel cell?
Feed-in Tariff Qualified?	☑ Yes		Is the proposed generator qualified for the Feed-in Tariff?

Zip Code of Residence =	94027	Weather Zone = 5	Electric Utility = PG&E	
Dwelling Living Area =	7,800 sqft	City = ATHERTON	Gas Utility = PG&E	

Applicable Thermal Loads
Check the residential thermal load(s) to be included

Residential Space Heating	☑	Residential Type = Single Family		Vintage = 1992-present	Vintage # = 5	
Pool Heating	☑	Enter Energy Smart Pools Net Load Data into "Pool Heating" Worksheet				
Domestic Hot Water	☑	Household Size = 2 Persons				

Month	Std Hours Per Month (hrs)	Generator Equivalent Full Load Hours per Month (hrs)	Capacity Factor	Generator Electric Output per Month (kWh)	Facility Electrical Load (kWh)	Recovered Waste Heat per Month (Btu)	Thermal Load per Month (Btu)	Thermal Load Coincidence Factor	Useful thermal energy output (Btu)	Fuel Input (LHV Btu)	Fuel Input (HHV Btu)	Gross GHG Generated (kg CO2)	GHG Savings from Heat Recovery (kg CO2)	Net GHG Emissions (kg CO2)
Jan	744	744	100%	3,720	3,164	16,368,000	85,387,670	0.2	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Feb	672	672	100%	3,360	3,209	14,784,000	70,323,418	0.2	14,784,000	28,791,168	31,927,392	1,693	980	713
Mar	744	744	100%	3,720	5,000	16,368,000	68,659,955	0.2	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Apr	720	720	100%	3,600	4,520	15,840,000	66,924,136	0.2	15,840,000	30,847,680	34,207,920	1,814	1,050	764
May	744	744	100%	3,720	3,721	16,368,000	53,428,187	0.3	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Jun	720	720	100%	3,600	3,599	15,840,000	38,922,630	0.4	15,840,000	30,847,680	34,207,920	1,814	1,050	764
Jul	744	744	100%	3,720	2,808	16,368,000	23,576,485	0.7	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Aug	744	744	100%	3,720	2,852	16,368,000	27,700,472	0.6	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Sep	720	720	100%	3,600	2,764	15,840,000	33,771,321	0.5	15,840,000	30,847,680	34,207,920	1,814	1,050	764
Oct	744	744	100%	3,720	2,540	16,368,000	51,170,604	0.3	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Nov	720	720	100%	3,600	2,852	15,840,000	67,552,174	0.2	15,840,000	30,847,680	34,207,920	1,814	1,050	764
Dec	744	350	47%	1,750	3,120	7,700,000	84,297,602	0.1	7,700,000	14,995,400	16,628,850	882	510	371
Annual Total	8,760	8,366	96%	41,830	40,149	184,052,000	671,714,655		184,052,000	358,432,904	397,477,026	21,074	12,198	8,876

Minimum Operating Efficiency Eligibility = PASS				
P.U. Code 216.6 (a) =	56.3%	≥ 5%	TRUE	Public Utilities Code 216.6(a) & 18CFR Part292
P.U. Code 216.6 (b) =	65.5%	≥ 42.5%	TRUE	Public Utilities Code 216.6(b) & 18CFR Part292
Minimum Electric Efficiency =	35.9%	≥ 40%	FALSE	Public Utilities Code 353.2 and 379.6
NOx Emissions Eligibility = EXEMPT				
AB 1685 Total Efficiency =	82.2%	≥ 60%	TRUE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/o CHP Credits	0.074	≤ 0.07 lb/MWh	FALSE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/ CHP Credits =	0.032	≤ 0.07 lb/MWh	TRUE	Public Utilities Code 379.6 and Calif. ARB, Guidance for the Permitting of Electric Generation Technologies, Appendix D:
GHG Emissions Eligibility = PASS				
GHG Emissions (kg CO2/MWh) =	212	< 379	TRUE	CPUC Decision 11-09-015
Coincidence of Thermal Load = PASS				
Max Thermal Load Coincidence	0.69	≤ 1.0	TRUE	CPUC Decision 11-09-015
Electrical Export Eligible = PASS				
Electrical Export Factor=	1.04	≤1.25	TRUE	CPUC Decision 11-09-015

Applicant:	ESCO	Date:	January 1, 2011
Host Customer:	Residential Customer	Application No.:	XX-XXX

Instructions: This spreadsheet determines if a proposed generating system meets the Minimum Operating Efficiency eligibility requirement of the Self-Generation Incentive Program for Residential customers. Applicants must provide documentation supporting all inputs including but not limited to system capacity, fuel consumption, waste heat recovery rate, operating schedule, equivalent full load operating hours and thermal load. See the 2011 SGIP Handbook for details of eligibility and documentation requirements. All yellow cells must be completed by Applicant/Host Customer.

Rated Net Generating Capacity =	5	kW	Full load net continuous rated capacity of the packaged prime mover/generator at ISO conditions.
Ancillary Generating System Loads =	0	kW	Any ancillary equipment loads necessary for the operation of the generator (e.g., fuel compressors, intercooler chillers, etc.) not accounted for in the Rated Net Generating Capacity.
Fuel Consumption Rate (LHV) =	42,844	Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on lower heating value of fuel.
Fuel Consumption Rate (HHV) =	47,511	Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on higher heating value of fuel.
Waste Heat Recovery Rate =	22,000	Btu/hr	Recoverable heat as specified by manufacturer of generator or waste heat recovery unit at full load conditions. This is not total waste heat of the unit. The value provided should be supported by Generating System specifications (if packaged unit), Waste Heat Recovery System specifications, or engineering analysis of recoverable waste heat.
Generator Emissions =	0.074	lbs/MWh	NOx emissions specifications for the proposed generating system as configured, including emissions controls, for the Host Customer Site at rated conditions. The value provided should be supported by factory testing, other installation source tests or engineering calculations.
Fuel Type =	Non-Renewable		Non-Renewable fuels are any fossil based fuels such as natural gas. Renewable fuels include land fill and digester gas. Waste gas are fuels strictly defined as natural gas that is generated as a by-product of petroleum production operations and is not eligible for delivery to the utility pipeline system.
Fuel Cell?	☑ Yes		Is the proposed generator a fuel cell?
Feed-in Tariff Qualified?	☑ Yes		Is the proposed generator qualified for the Feed-in Tariff?

Zip Code of Residence = 94027 | Weather Zone = 5 | Electric Utility = PG&E

Dwelling Living Area = 7,800 sqft | City = ATHERTON | Gas Utility = PG&E

Applicable Thermal Loads
Check the residential thermal load(s) to be included

Residential Space Heating	☑	Residential Type =	Single Family	Vintage =	1992-present	Vintage # = 5
Pool Heating	☑	Enter Energy Smart Pools Net Load Data into "Pool Heating" Worksheet				
Domestic Hot Water	☑	Household Size =	2 Persons			

Month	Std Hours Per Month (hrs)	Generator Equivalent Full Load Hours per Month (hrs)	Capacity Factor	Generator Electric Output per Month (kWh)	Facility Electrical Load (kWh)	Recovered Waste Heat per Month (Btu)	Thermal Load per Month (Btu)	Thermal Load Coincidence Factor	Useful thermal energy output (Btu)	Fuel Input (LHV Btu)	Fuel Input (HHV Btu)	Gross GHG Generated (kg CO2)	GHG Savings from Heat Recovery (kg CO2)	Net GHG Emissions (kg CO2)
Jan	744	744	100%	3,720	3,164	16,368,000	85,387,670	0.2	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Feb	672	672	100%	3,360	3,209	14,784,000	70,323,418	0.2	14,784,000	28,791,168	31,927,392	1,693	980	713
Mar	744	744	100%	3,720	5,000	16,368,000	68,659,955	0.2	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Apr	720	720	100%	3,600	4,520	15,840,000	66,924,136	0.2	15,840,000	30,847,680	34,207,920	1,814	1,050	764
May	744	744	100%	3,720	3,721	16,368,000	53,428,187	0.3	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Jun	720	720	100%	3,600	3,599	15,840,000	38,922,630	0.4	15,840,000	30,847,680	34,207,920	1,814	1,050	764
Jul	744	744	100%	3,720	2,808	16,368,000	23,576,485	0.7	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Aug	744	744	100%	3,720	2,852	16,368,000	27,700,472	0.6	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Sep	720	720	100%	3,600	2,764	15,840,000	33,771,321	0.5	15,840,000	30,847,680	34,207,920	1,814	1,050	764
Oct	744	744	100%	3,720	2,540	16,368,000	51,170,604	0.3	16,368,000	31,875,936	35,348,184	1,874	1,085	789
Nov	720	720	100%	3,600	2,852	15,840,000	67,552,174	0.2	15,840,000	30,847,680	34,207,920	1,814	1,050	764
Dec	744	350	47%	1,750	3,120	7,700,000	84,297,602	0.1	7,700,000	14,995,400	16,628,850	882	510	371
Annual Total	8,760	8,366	96%	41,830	40,149	184,052,000	671,714,655		184,052,000	358,432,904	397,477,026	21,074	12,198	8,876

Minimum Operating Efficiency Eligibility = PASS				
P.U. Code 216.6 (a) =	56.3%	≥ 5%	TRUE	Public Utilities Code 216.6(a) & 18 CFR Part 292
P.U. Code 216.6 (b) =	65.5%	≥ 42.5%	TRUE	Public Utilities Code 216.6(b) & 18 CFR Part 292
Minimum Electric Efficiency =	35.9%	≥ 40%	FALSE	Public Utilities Code 353.2 and 379.6
NOx Emissions Eligibility = EXEMPT				
AB 1685 Total Efficiency =	82.2%	≥ 60%	TRUE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/o CHP Credits	0.074	≤ 0.07 lb/MWh	FALSE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/ CHP Credits =	0.032	≤ 0.07 lb/MWh	TRUE	Public Utilities Code 379.6 and Calif. ARB, Guidance for the Permitting of Electric Generation Technologies, Appendix D:
GHG Emissions Eligibility = PASS				
GHG Emissions (kg CO2/MWh) =	212	< 379	TRUE	CPUC Decision 11-09-015
Coincidence of Thermal Load = PASS				
Max Thermal Load Coincidence	0.69	≤ 1.0	TRUE	CPUC Decision 11-09-015
Electrical Export Eligible = PASS				
Electrical Export Factor=	1.04	≤ 1.25	TRUE	CPUC Decision 11-09-015

	Enter **Net Total Monthly Pool Load (10^6 BTU's)** from Energy Smart Pools Base Analysis											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Load	73	61	59	59	46	33	19	23	29	45	60	74

Provide hardcopy of Energy Smart Pools Executive and Engineer Reports

	Enter **Net Total Monthly Pool Load (10^6 BTU's)** from Energy Smart Pools Base Analysis											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Load	73	61	59	59	46	33	19	23	29	45	60	74
Provide hardcopy of Energy Smart Pools Executive and Engineer Reports												

Example #2: Efficiency Calculations for 255 kW IC Engine CHP System

Three 85 kW internal combustion engines operating on natural gas are proposed to provide electricity and heat to a hospital. The internal combustion engines are sized such that they will operate at close to full load most of the year. Their output will be reduced in July and August so that the recovered waste heat does not exceed the thermal load. The hospital's Thermal Load consists primarily of domestic hot water and space heating. The Minimum Operating Efficiency Worksheet used for this application is similar to the residential version, but the Thermal Load and Electrical Load per Month must be calculated and justified separately and entered manually for each month. The internal combustion engines exceed the PU Code 216.6. (a) and (b) requirements, therefore they meet the minimum operating efficiency requirement for the program. They also pass the NOx emissions eligibility with CHP credits and pass the GHG emissions eligibility. Their thermal coincidence factor is less than 1.0 for every month of the year indicating that they are utilizing waste heat recovery effectively and since they are qualified for the feed-in-tariff the export factor indicates that they are exporting less than the program export limit which is 25% more than the site electrical load.

Table A-2 Minimum Operating Efficiency Worksheet

Applicant:	ESCO	**Date:**	January 1, 2011
Host Customer:	Commercial Customer	**Application No.:**	XX-XXXX

This spreadsheet calculates the operating system efficiency, system efficiency and emissions eligibility of generation systems applying to the Self-Generating Incentive Program for incentives. Applicants must provide documentation supporting all inputs including but not limited to system capacity, fuel consumption, waste heat recovery rate, baseline emissions, operating schedule, equivalent full load operating hours and thermal load. See the 2011 SGIP Handbook for details of eligibility and documentation requirements. All yellow cells must be completed by Applicant/Host Customer.

Rated Net Generating Capacity =	255 **kW**	**Full load net continuous rated capacity of the packaged prime mover/generator at ISO conditions.**
Auxiliary Generating System Loads =	5 **kW**	**Any auxiliary equipment loads necessary for the operation of the generator (e.g., fuel compressors, intercooler chillers, etc.) not accounted for in the Rated Net Generating Capacity.**
Fuel Consumption Rate (LHV) =	2,967,000 **Btu/hr**	**Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on lower heating value of fuel.**
Fuel Consumption Rate (HHV) =	3,263,700 **Btu/hr**	**Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on higher heating value of fuel.**
Waste Heat Recovery Rate =	1,470,000 **Btu/hr**	**Recoverable heat as specified by manufacturer of generator or waste heat recovery unit at full load conditions. This is not total waste heat of the unit. The value provided should be supported by Generating System specifications (if packaged unit), Waste Heat Recovery System specifications, or engineering analysis of recoverable waste heat.**
Generator Emissions =	0.074 **lbs/MWh**	**NOx emissions specifications for the proposed generating system as configured, including emissions controls, for the Host Customer Site at rated conditions. The value provided should be supported by factory testing, other installation source tests or engineering calculations.**
Fuel Type =	Non-Renewable	**Non-Renewable fuels are any fossil based fuels such as natural gas. Renewable fuels include landfill and digester gas. Waste gas are fuels 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.**
Fuel Cell ?	☐ Yes	**Is the proposed generator a fuel cell?**
Feed-in Tariff Qualified?	☑ Yes	**Is the proposed generator qualified for the Feed-in Tariff?**

Month	Std Hours Per Month (hrs)	Generator Equivalent Full Load Hours per Month (hrs)	Capacity Factor	Generator Electric Output per Month (kWh)	Facility Electrical Load (kWh)	Recovered Waste Heat per Month (Btu)	Thermal Load per Month (Btu)	Thermal Load Coincidence Factor	Useful thermal energy output (Btu)	Fuel Input (LHV Btu)	Fuel Input (HHV Btu)	Gross GHG Generated (kg CO2)	GHG Savings from Heat Recovery (kg CO2)	Net GHG Emissions (kg CO2)
Jan	744	710	95%	177,500	354,000	1,043,700,000	1,290,024,000	0.81	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Feb	672	640	95%	160,000	264,000	940,800,000	1,128,312,000	0.83	940,800,000	1,898,880,000	2,088,768,000	110,746	62,352	48,395
Mar	744	710	95%	177,500	347,000	1,043,700,000	1,117,080,000	0.93	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Apr	720	710	99%	177,500	353,000	1,043,700,000	1,068,048,000	0.98	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
May	744	690	93%	172,500	360,000	1,014,300,000	1,026,864,000	0.99	1,014,300,000	2,047,230,000	2,251,953,000	119,399	67,223	52,176
Jun	720	690	96%	172,500	400,000	1,014,300,000	1,024,992,000	0.99	1,014,300,000	2,047,230,000	2,251,953,000	119,399	67,223	52,176
Jul	744	655	88%	163,750	425,000	962,850,000	972,792,000	0.99	962,850,000	1,943,385,000	2,137,723,500	113,342	63,813	49,529
Aug	744	655	88%	163,750	421,000	962,850,000	974,016,000	0.99	962,850,000	1,943,385,000	2,137,723,500	113,342	63,813	49,529
Sep	720	690	96%	172,500	385,000	1,014,300,000	1,197,936,000	0.85	1,014,300,000	2,047,230,000	2,251,953,000	119,399	67,223	52,176
Oct	744	710	95%	177,500	321,000	1,043,700,000	1,259,280,000	0.83	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Nov	720	700	97%	175,000	309,000	1,029,000,000	1,281,024,000	0.80	1,029,000,000	2,076,900,000	2,284,590,000	121,129	68,197	52,932
Dec	744	710	95%	177,500	310,000	1,043,700,000	1,312,056,000	0.80	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Annual Total	8,760	8,270	94%	2,067,500	4,249,000	12,156,900,000	13,652,424,000		12,156,900,000	24,537,090,000	26,990,799,000	1,431,052	805,699	625,354

Minimum Operating Efficiency Eligibility = PASS

P.U. Code 216.6 (a) =	63.3% ≥ 5%	TRUE	Public Utilities Code 216.6(a) & 18CFR Part 292
P.U. Code 216.6 (b) =	53.5% ≥ 42.5%	TRUE	Public Utilities Code 216.6(b) & 18CFR Part 292
Minimum Electric Efficiency =	26.7% ≥ 40%	FALSE	Public Utilities Code 353.2 and 379.6

NOx Emissions Eligibility = PASS

AB 1685 Total Efficiency =	71.7% ≥ 60%	TRUE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/o CHP Credits =	0.074 ≤ 0.07 lb/MWh	FALSE	Public Utilities Code 353.2 and 379.6
NOx Emissions w CHP Credits =	0.027 ≤ 0.07 lb/MWh	TRUE	Public Utilities Code 379.6 and Calif. ARB, Guidance for the Permitting of Electric Generation Technologies, Appendix D: Quantifying CHP Benefits, July 2002.

GHG Emissions Eligibility = PASS

GHG Emissions (kg CO2/MWh) =	302 < 379	TRUE	CPUC Decision 11-09-015

Coincidence of Thermal Load = PASS

Max Thermal Load Coincidence Factor=	0.99 ≤ 1.0	TRUE	CPUC Decision 11-09-015

Electrical Export Eligible = PASS

Electrical Export Factor=	0.49 ≤1.25	TRUE	CPUC Decision 11-09-015

Applicant:	ESCO	Date:	January 1, 2011
Host Customer:	Commercial Customer	Application No.:	XX-XXXX

This spreadsheet calculates the operating system efficiency, system efficiency and emissions eligibility of generation systems applying to the Self-Generating Incentive Program for incentives. Applicants must provide documentation supporting all inputs including but not limited to system capacity, fuel consumption, waste heat recovery rate, baseline emissions, operating schedule, equivalent full load operating hours and thermal load. See the 2011 SGIP Handbook for details of eligibility and documentation requirements. All yellow cells must be completed by Applicant/Host Customer.

Rated Net Generating Capacity =	255 kW	Full load net continuous rated capacity of the packaged prime mover/generator at ISO conditions.
Ancillary Generating System Loads =	5 kW	Any ancillary equipment loads necessary for the operation of the generator (e.g., fuel compressors, intercooler chillers, etc.) not accounted for in the Rated Net Generating Capacity.
Fuel Consumption Rate (LHV) =	2,967,000 Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on lower heating value of fuel.
Fuel Consumption Rate (HHV) =	3,293,700 Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on higher heating value of fuel.
Waste Heat Recovery Rate =	1,470,000 Btu/hr	Recoverable heat as specified by manufacturer of generator or waste heat recovery unit at full load conditions. This is not total waste heat of the unit. The value provided should be supported by Generating System specifications (if packaged unit), Waste Heat Recovery System specifications, or engineering analysis of recoverable waste heat.
Generator Emissions =	0.074 lbs/MWh	NOx emissions specifications for the proposed generating system as configured, including emissions controls, for the Host Customer Site at rated conditions. The value provided should be supported by factory testing, other installation source tests or engineering calculations.
Fuel Type =	Non-Renewable	Non-Renewable fuels are any fossil based fuels such as natural gas. Renewable fuels include landfill and digester gas. Waste gas are fuels 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.
Fuel Cell ?	☐ Yes	Is the proposed generator a fuel cell?
Feed-in Tariff Qualified?	☑ Yes	Is the proposed generator qualified for the Feed-in Tariff?

Month	Std Hours Per Month (hrs)	Generator Equivalent Full Load Hours per Month (hrs)	Capacity Factor	Generator Electric Output per Month (kWh)	Facility Electrical Load (kWh)	Recovered Waste Heat per Month (Btu)	Thermal Load per Month (Btu)	Thermal Load Coincidence Factor	Useful thermal energy output (Btu)	Fuel Input (LHV Btu)	Fuel Input (HHV Btu)	Gross GHG Generated (kg CO2)	GHG Savings from Heat Recovery (kg CO2)	Net GHG Emissions (kg CO2)
Jan	744	710	95%	177,500	354,000	1,043,700,000	1,290,024,000	0.81	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Feb	672	640	95%	160,000	264,000	940,800,000	1,128,312,000	0.83	940,800,000	1,898,880,000	2,088,768,000	110,746	62,352	48,395
Mar	744	710	95%	177,500	347,000	1,043,700,000	1,117,080,000	0.93	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Apr	720	710	99%	177,500	353,000	1,043,700,000	1,068,048,000	0.98	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
May	744	690	93%	172,500	360,000	1,014,300,000	1,026,864,000	0.99	1,014,300,000	2,047,230,000	2,251,953,000	119,399	67,223	52,176
Jun	720	690	96%	172,500	400,000	1,014,300,000	1,024,992,000	0.99	1,014,300,000	2,047,230,000	2,251,953,000	119,399	67,223	52,176
Jul	744	655	88%	163,750	425,000	962,850,000	972,792,000	0.99	962,850,000	1,943,385,000	2,137,723,500	113,342	63,813	49,529
Aug	744	655	88%	163,750	421,000	962,850,000	974,016,000	0.99	962,850,000	1,943,385,000	2,137,723,500	113,342	63,813	49,529
Sep	720	690	96%	172,500	385,000	1,014,300,000	1,197,936,000	0.85	1,014,300,000	2,047,230,000	2,251,953,000	119,399	67,223	52,176
Oct	744	710	95%	177,500	321,000	1,043,700,000	1,259,280,000	0.83	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Nov	720	700	97%	175,000	309,000	1,029,000,000	1,281,024,000	0.80	1,029,000,000	2,076,900,000	2,284,590,000	121,129	68,197	52,932
Dec	744	710	95%	177,500	310,000	1,043,700,000	1,312,056,000	0.80	1,043,700,000	2,106,570,000	2,317,227,000	122,859	69,171	53,688
Annual Total	8,760	8,270	94%	2,067,500	4,249,000	12,156,900,000	13,652,424,000		12,156,900,000	24,537,090,000	26,990,799,000	1,431,052	805,699	625,354

Minimum Operating Efficiency Eligibility = PASS

P.U. Code 216.6 (a) =	63.3% ≥ 5%	TRUE	Public Utilities Code 216.6(a) & 18CFR Part 292
P.U. Code 216.6 (b) =	53.5% ≥ 42.5%	TRUE	Public Utilities Code 216.6(b) & 18CFR Part 292
Minimum Electric Efficiency =	26.7% ≥ 40%	FALSE	Public Utilities Code 353.2 and 379.6

NOx Emissions Eligibility = PASS

AB 1685 Total Efficiency =	71.7% ≥ 60%	TRUE	Public Utilities Code 353.2 and 379.6
NOx Emissions w/o CHP Credits =	0.074 ≤ 0.07 lb/MWh	FALSE	Public Utilities Code 353.2 and 379.6
NOx Emissions w CHP Credits =	0.027 ≤ 0.07 lb/MWh	TRUE	Public Utilities Code 379.6 and Calif. ARB, Guidance for the Permitting of Electric Generation Technologies, Appendix D: Quantifying CHP Benefits, July 2002.

GHG Emissions Eligibility = PASS

GHG Emissions (kg CO2/MWh) =	302 < 379	TRUE	CPUC Decision 11-09-015

Coincidence of Thermal Load = PASS

Max Thermal Load Coincidence Factor=	0.99 ≤ 1.0	TRUE	CPUC Decision 11-09-015

Electrical Export Eligible = PASS

Electrical Export Factor=	0.49 ≤1.25	TRUE	CPUC Decision 11-09-015

Incentive Calculations

Example #3: Single System Wind Turbine Technology

A Host Customer proposes to install an 800 kW wind turbine to provide a portion of their facilities' peak (maximum) electric demand. There are no other incentives included. The incentive for this technology is $1.19/Watt (or $1,190/kW) and the Project cost is $800,000 ($1,000/kW). Multiplying the incentive by the

capacity of the generation results in an incentive of $952,000. Assuming a 30% investment tax credit the incentive is limited to 30% of the project cost which is $240,000. $120,000 of the incentive would be received upfront and the remaining $120,000 would be paid based on expected kWh generation over five years, calculated as nameplate capacity x capacity factor x hours per year x five years.

Table A-3 Example of PBI Payment for an 800 kW Wind Turbine Operating at 25% Capacity Factor.

Year	Capacity (kW)	Capacity Factor	Hrs/Yr	kWh	Total kWh	PBI	Total PBI
1	800	25%	8760	1,752,000	1,752,000	$24,000	$24,000
2	800	25%	8760	1,752,000	3,504,000	$24,000	$48,000
3	800	25%	8760	1,752,000	5,256,000	$24,000	$72,000
4	800	25%	8760	1,752,000	7,008,000	$24,000	$96,000
5	800	25%	8760	1,752,000	8,760,000	$24,000	$120,000

Year	Capacity (kW)	Capacity Factor	Hrs/Yr	kWh	Total kWh	PBI	Total PBI
1	800	25%	8760	1,752,000	1,752,000	$24,000	$24,000
2	800	25%	8760	1,752,000	3,504,000	$24,000	$48,000
3	800	25%	8760	1,752,000	5,256,000	$24,000	$72,000
4	800	25%	8760	1,752,000	7,008,000	$24,000	$96,000
5	800	25%	8760	1,752,000	8,760,000	$24,000	$120,000

($120,000 performance payment)/8,760,00 kWh = 1.37 cents/kWh PBI

Because the wind turbine operated as expected, it receives the full and final PBI payment at the end of year five. If the turbine were to operate better than expected, it would receive the same $120,000 payment in a shorter time frame. Similarly if it generated fewer kWh than predicted by year five, it would not receive the full payment.

Table A-4 Example of PBI Payment for an 800 kW Wind Turbine with a Declining Capacity Factor

Year	Capacity (kW)	Capacity Factor	Hrs/Yr	kWh	Total kWh	PBI	Total PBI
1	800	25%	8760	1,752,000	1,752,000	$24,000	$24,000
2	800	25%	8760	1,752,000	3,504,000	$24,000	$48,000
3	800	25%	8760	1,752,000	5,256,000	$24,000	$72,000
4	800	20%	8760	1,401,600	6,657,600	$19,200	$91,200
5	800	20%	8760	1,401,600	8,059,200	$19,200	$110,400

Year	Capacity (kW)	Capacity Factor	Hrs/Yr	kWh	Total kWh	PBI	Total PBI
1	800	25%	8760	1,752,000	1,752,000	$24,000	$24,000
2	800	25%	8760	1,752,000	3,504,000	$24,000	$48,000
3	800	25%	8760	1,752,000	5,256,000	$24,000	$72,000
4	800	20%	8760	1,401,600	6,657,600	$19,200	$91,200
5	800	20%	8760	1,401,600	8,059,200	$19,200	$110,400

In the example shown in Table A-4 above, the capacity factor begins to decline in year four. This results in fewer kWh generated, and a correspondingly lower PBI for that year. Because the wind turbine did not maintain an average 25% capacity factor during the five years of PBI eligibility, this project would not receive the full SGIP incentive.

Example #4: Incentive Calculation for System Receiving Incentives from Other Programs

A Host Customer is installing a 1.0 MW fuel cell, operating on Renewable Fuel, which is estimated to cost $10 million ($10/Watt). The project received a previous rebate of 20% of the project costs ($2 million) from an IOU Ratepayer funded program. The SGIP incentive for this technology is $3.83/watt. Because the other incentive is IOU ratepayer funded, the SGIP incentive is adjusted. Given a 30% investment tax credit the SGIP incentive cannot exceed 30% of the eligible project cost. In addition, out-of-pocket expense of the System Owner must not be less than zero. The out-of-pocket expense of the system is the total eligible Project cost less any incentives including SGIP. Under the SGIP, this project would be eligible for an incentive of $1.83 million as follows:

Maximum SGIP Incentive based on System Size = 1,000,000 W x $3.83 / W = $3,830,000

Adjusted SGIP Incentive = $3,830,000 – 1.0 x $2,000,000 = $1,830,000

Project Cost Cap on SGIP Incentive = $10,000,000 x 30% = $3,000,000

Total Incentive = $2,250,000 (SGIP) + $2,000,000 (other IOU Ratepayer Program) = $4,250,000

Since the total Incentive ($4,250,000) is lower than the total eligible project cost of $10 million and the SGIP Incentive is lower than the project cost cap the SGIP incentive is $1,830,000.

Example #5: Incentive Calculation for Systems with Output Capacity above 1 MW and Receiving Incentives from Other Programs

A customer is installing a 2.2 MW fuel cell, operating on natural gas, which is estimated to cost $13 million. The incentives for this technology are $2.03/watt for the first 1.0 MW, 50% of $2.03/watt for the capacity greater than 1.0 MW up to 2.0 MW and 25% of $2.03/Watt for the capacity greater than 2.0 MW up to 3.0 MW. The project also received a $1 million rebate from a federal taxpayer funded program. Given a 30% investment tax credit the SGIP incentive cannot exceed 30% of the eligible project cost. Under the SGIP, the incentive would be calculated as follows:

Maximum SGIP Incentive = 1,000,000 Watt x $2.03/Watt + 1,000,000 Watt x 50% x $2.03/Watt + 200,000 Watt x 25% x $2.03/Watt = $3,145,000

Adjusted SGIP Incentive = $3,145,000 – 0.0 x $1,000,000 = $3,145,000

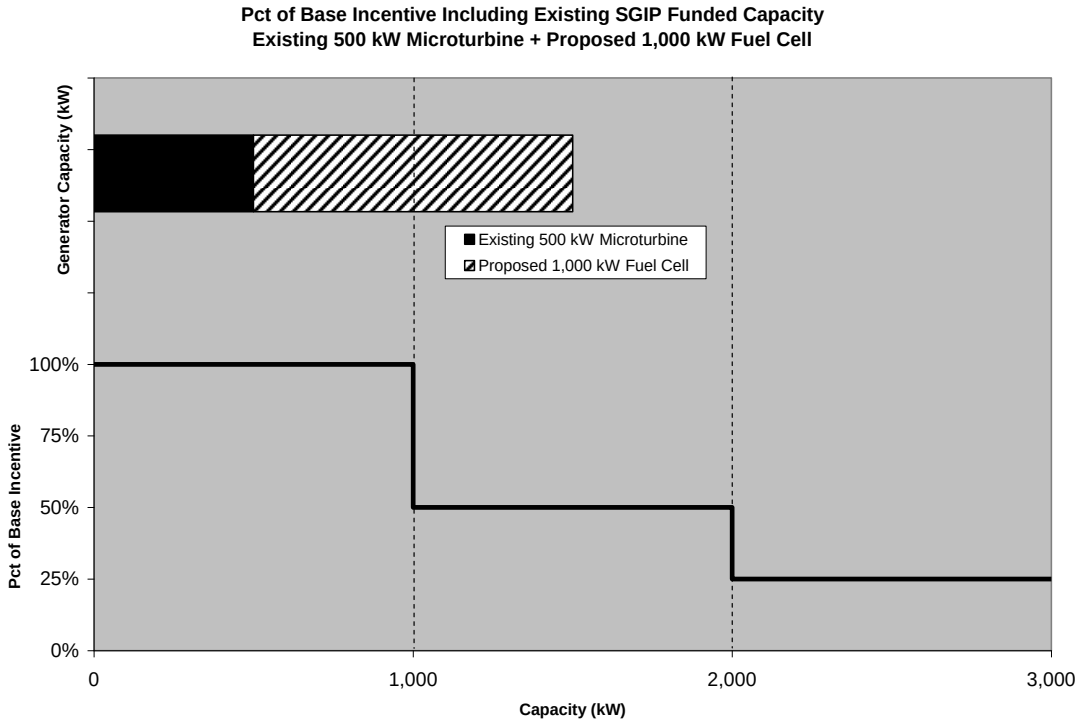
Project Cost Cap on SGIP Incentive = $13,000,000 x 30% = $3,900,000

Total Incentive = $3,145,000 (SGIP Incentive) + $1,000,000 (Federal Taxpayer Program) = $4,145,000

Since total incentive of $4,145,000 is lower than the total eligible project cost of $13 million and the SGIP incentive is lower than the project cost cap the SGIP incentive is $3,145,000.

Example #6: Incentive Calculation for System Added to Site with Existing SGIP Funded Capacity

A customer is installing a 1 MW fuel cell, operating on natural gas, which is estimated to cost $6 million. Under the SGIP, any existing generating capacity previously funded by SGIP is accounted for at that highest incentive as illustrated in the following chart. Because the customer Site has an existing 500 kW micro-turbine cogenerator, the proposed system receives 500 kW at $2.03/Watt and the remaining 500 kW at $1.015/Watt. Given a 30% investment tax credit (and based upon the formula in section 6.6) the SGIP incentive cannot exceed 30% of the eligible project cost.



The incentive would be calculated as follows:

Existing SGIP Funded Capacity = 500,000 Watt

Proposed Capacity = 1,000,000 Watt

Project Cost Cap on SGIP Incentive = $6,000,000 x 30% = $1,800,000

Maximum SGIP Incentive = 500,000 Watt x $2.03/Watt + 500,000 Watt x 50% x $2.03/Watt = $1,522,500

Since total incentive of $1,522,500 is lower than the total eligible project cost of $6 million and lower than the project cost cap of $1,800,000 the SGIP incentive is $1,522,500.

Example #7: Incentive Calculation for Advanced Energy Storage System

A customer proposes to install a 1 MW Advanced Energy Storage system and a natural gas fueled 1 MW fuel cell co-generator. The total project cost is $7 million. Given a 30% investment tax credit (and based upon the formula in section 6.6) the SGIP incentive cannot exceed 30% of the eligible project cost. Since the Advanced Energy Storage capacity is not additive with the companion fuel cell, the Advanced Energy Storage system receives $1.80/Watt for 1,000 kW of capacity and the fuel cell receives $2.03/Watt for 1,000 kW of capacity.

The incentive would be calculated as follows:

Advanced Energy Storage = 1,000,000 Watt

Fuel Cell = 1,000,000 Watt

Project Cost Cap on SGIP Incentive = $7,000,000 x 30% = $2,100,000

Maximum SGIP Incentive = 1,000,000 Watt x $1.80/Watt + 1,000,000 Watt x $2.03/Watt = $3,830,000

Since total incentive of $3,830,000 is higher than the Project cost cap the SGIP incentive is $2,100,000.

Example #8: Hybrid System Incentive Calculation

	Wind Turbine	**Non-Renewable Fuel Cell**	**Hybrid System Total**
1. Incentive Rate ($/Watt)	$1.19/W Wind Turbine (A)	$2.03/W Fuel Cell (B)	
2. Technology Capacity (kW)	800 kW (C)	300kW (D)	1,100 kW (E) C + D
3. Incented Capacity (kW)	800 kW (F) F = C	200 kW (G) = 1,000 - F + 100 kW (H) H = E - 1,000	1,100 kW (I) F + G + H

	Wind Turbine	Non-Renewable Fuel Cell	Hybrid System Total
4. Potential SGIP hybrid Incentive	$952,000 (J) J = A x F $1.19/W x 800,000 W	$406,000 (K) K = B x G $2.03/W x 200,000 W $102,000 (L) L = B x 50% x H $1.02/W x 100,000 W	**$1,460,000** J + K + L
5. Eligible Project Cost	$800,000	$1,650,000	**$2,450,000**
Project Cost Cap on SGIP Incentive (given 30% ITC)	$240,000	$495,000	**$735,000**
Maximum SGIP Incentive	$240,000	$495,000	**$735,000**

Example #9: Export to Grid

The following example demonstrates the SGIP incentive payments for a system that exports to the grid:

A 1.3 MW CHP system is designed to meet heat demand and is producing more electrical output than needed on site.

At an 80% assumed capacity factor, the CHP system would generate 9.1 GWh/year

*(1.3 MW * 80% * 8760 = ~9.1 GWh/ year)*

In the previous year, the facility only consumed 7 GWh, or ~3/4 of the expected output.

(7 GWh / 9.1 GWh = ~3/4)

Because the facility's electrical load is ~3/4 of the expected output, it would receive an SGIP incentive for ~3/4 of the system capacity which in this example is ~1 MW.

*(~3/4 * 1.3MW = 1 MW)*

The total incentive would be $480,000

*(1 MW * $.48/W = $480,000)*

$240,000 (50% of the total incentive) would be paid up-front.

The remaining $240,000 is spread over the next five years with an expected on-site load of 7 GWh per year, resulting in a PBI payment of 0.7 cents per kWh

($240,000 / 5 years / 7 GWh = ~0.7c per kWh)

Now assume that the actual capacity factor is 90% instead of 80%.

At a capacity factor of 90%, total generation is ~10.2 GWh

*(1.3 MW * 90% * 8760 = ~10.2 GWh/ year)*

On-site consumption remains constant at 7 GWh and the project still only receives an incentive for 1 MW

The 90% capacity factor increases incentivized on-site generation to 7.9 GWh.

*(1MW * 90% * 8760 = ~7.9 GWh)*

Due to the increase in generation, the project would receive an accelerated PBI payment of ~ $55,300

*(0.7c per kWh * 7.9 GWh = ~ $55,300)*

The project would receive the accelerated PBI payment even though 0.9 GWh of this amount attributed to "on-site" capacity was exported.

(7.9 GWh – 7 GWh = 0.9 GWh)

In this example, a total of 3.2 GWh would be exported

(10.2 GWh – 7 GWh = 3.2 GWh)

0.9 GWh of this total would be compensated under both the PBI and FIT tariff.

Appendix C – Combustion Emission Credit Calculation

Microturbine, internal combustion engine and gas turbine 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: [34]

$Lb/MWh_{w/credit} = Lb/hr_{EmissionRate} / (MW_{Rated} + MW_{ProcessHeat})$ ≡ 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 4.4.8.

$MW_{ProcessHeat} = (MMBtu/yr_{UtilizedWasteHeat} / 3.4\ MMBtu/MWh) / EFLH/yr$ ≡ 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 Waste Heat/AB1685 spreadsheet, 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[35]) 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 Non-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

34 Emissions credit calculation is based on the California Air Resources Board, Guidance for the Permitting of Electric Generation Technologies, Appendix D: Quantifying CHP Benefits, July 2002.

35 For natural gas, LHV ≈ HHV x 0.9

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 D - Conversion of Emissions PPM to Lb/MWH

Procedure for Converting Emission Data to lb/MW-hr

Engines

Engine emission standard 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

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[36]

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

Lean-burn Engines, natural gas fueled[37]

Pollutant	Factor
NOx	80
VOC	212
CO	123

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

[37] 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.