 Date of Issuance 9/16/2011

Decision 11-09-015 September 8, 2011

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues.	Rulemaking 10-05-004 (Filed May, 6, 2010)

DECISION MODIFYING THE SELF-GENERATION INCENTIVE PROGRAM AND IMPLEMENTING SENATE BILL 412

TABLE OF CONTENTS

Title **Page**

TABLE OF CONTENTS
(Cont'd)

DECISION MODIFYING THE SELF-GENERATION INCENTIVE PROGRAM AND IMPLEMENTING SENATE BILL 412

1. Summary

By this decision we modify the Commission's Self-Generation Incentive Program (SGIP) to conform the program to Senate Bill 412 (Stats. 2009, ch. 182). In addition, we modify several aspects of the SGIP to improve program outcomes and facilitate program implementation. Among other issues, we modify the eligibility criteria for participation in the program, incentive amounts and payment structures for eligible technologies, metering and warranty requirements, and budget allocation among eligible technologies.[1]

Eligibility for participation in the SGIP will now be based on greenhouse gas emissions reductions. SGIP technologies that achieve reductions of greenhouse gas emissions pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code) will be eligible to participate in the SGIP.[2] The eligible technologies include wind turbines, fuel cells, gas turbines, micro-turbines and internal-combustion engines, organic rankine cycle/ waste heat capture, combined heat and power (CHP), advanced energy storage, and pressure reduction turbines.

Eligible technologies will receive up-front and performance-based incentives (PBI). However, PBI payments will be reduced or eliminated in years that a project does not achieve cumulative greenhouse gas reductions.

---

1 Attachment A sets forth a summary of all the program changes.

2 Any combustion-operated DG project using fossil fuel must meet the emission standards stated in the Air Resources Board's Distributed Generation Certification Program, which can be found in section 94200, et seq. Title 17, California Code of Regulation.

The incentives will apply only to the portion of the generation that serves a project's on-site electric load. The maximum total incentives per watt of capacity that each technology may receive are shown in Table 1 below:

Table 1. - SGIP Incentive Levels Category[3]

Technology Type	Incentive ($/W)
Renewable and Waste Heat Capture	
Wind Turbine	$1.25
Bottoming-Cycle CHP	$1.25
Pressure Reduction Turbine	$1.25
Conventional Fuel-Based CHP	
Internal Combustion Engine – CHP	$0.50
Microturbine – CHP	$0.50
Gas Turbine – CHP	$0.50
Emerging technologies	
Advanced Energy Storage[4]	$2.00
Biogas[5]	$2.00
Fuel Cell – CHP or Electric Only	$2.25

The changes in this decision will only apply to SGIP projects going forward.[6] In other words, existing SGIP projects will continue to receive the same incentives they were receiving prior to this decision and will continue to operate under the existing SGIP rules. Eligible projects that were completed

---

[3] Any onsite renewable fuel which meets RPS guidelines should be considered an eligible onsite renewable fuel and be eligible for the OSB based incentive levels. This recommendation allows for onsite biodiesel or waste vegetable oil to qualify.

[4] Stand-alone or paired with solar PV or any otherwise eligible SGIP technology.

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

[6] We note, however, that current rules allow changes to existing program guidelines through advice letters and with staff approval.

between January 1, 2011 and the effective date of this decision shall be subject to the program rules that were in place during that time.

The SGIP PAs shall file Tier 2 advice letters proposing handbook revisions necessary to implement this decision. The SGIP is currently suspended. Upon approval of the advice letters, the SGIP suspension will be lifted and the PAs will resume accepting reservation requests for the SGIP.

2. Background

In Decision (D.) 01-03-073, the Commission established the Self-Generation Incentive Program (SGIP) to encourage the development and commercialization of new distributed generation (DG) technologies. For purposes of this decision, DG refers to generation technologies installed on the customer's side of the utility meter that provide electricity for all or a portion of that customer's onsite electric load. The program is available to customers of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas). PG&E, SoCalGas and SCE administer their own programs, and the California Center for Sustainable Energy (CCSE) administers the program in SDG&E's service territory.

The SGIP provides funding to qualifying technologies.[7] Incentives offered under the SGIP vary based on the technology and whether the DG facility uses renewable fuel. From 2007 through 2010, SGIP provided incentives as follows:

---

[7] At its inception, the SGIP funded solar PV, wind turbines, fuel cells, microturbines, small gas turbines, internal-combustion (IC) engines and combined heat and power (CHP) plants. Pursuant to Pub. Util. Code § 379.6, the SGIP is currently limited to wind and fuel cell technologies.

- For renewables: $1.50 per watt incentive for wind turbines and $4.50 per watt incentive for renewable fuel cells;
- For non-renewables: $2.50 per watt incentives for non-renewable fuel cells; and
- For advanced energy storage (AES) coupled with eligible self-generation technology: $2.00 per watt.

The program administrators (PAs) administer the SGIP and implement the program rules contained in the SGIP Program Handbook (Handbook).

Senate Bill (SB) 412 (Stats. 2009, ch. 182) authorizes the Commission, in consultation with the California Air Resources Board (CARB), to determine what technologies should be eligible for the SGIP based on greenhouse gas (GHG) emissions reductions. SB 412 also extends the sunset date of the SGIP from January 1, 2012 to January 1, 2016. An Administrative Law Judge (ALJ) Ruling issued on November 13, 2009, posed several questions regarding implementation of SB 412, and requested comments from parties. The ALJ Ruling also scheduled a workshop for January 7, 2010 to address the questions posed in the ruling.

Following the January 7 workshop, Energy Division Staff analyzed potential participating SGIP technologies. Based on the Energy Division's analysis, and after consultation with California Energy Commission (CEC) Staff, Energy Division developed a Staff proposal with recommendations on how to modify the SGIP to comply with SB 412 (SGIP Staff Proposal, Part I).[8] In the months following the issuance of the Staff proposal, Staff worked with the CARB to ensure that CARB concurs with Staff analysis.

---

[8] SGIP Staff Proposal, Part I was attached to the ALJ ruling, dated September 10, 2010.

A second ALJ ruling issued on September 10, 2010, requested comments from interested stakeholders on the workshop report and the SGIP Staff Proposal, Part I. To help parties understand the Staff proposal, Energy Division Staff conducted another workshop on November 14, 2010. Subsequently, parties filed comments and reply comments on the proposed modifications to the SGIP.

The SGIP Staff Proposal noted that the cost-effectiveness recommendations in the proposal were preliminary, and Energy Division Staff planned to update them after the results of the cost-effectiveness evaluation of SGIP became available later in the year. The cost-effectiveness study was finalized on February 9, 2011 (The Cost-Effectiveness Report). Accordingly, Staff updated the recommendations in the SGIP Staff Proposal, Part I and issued a revised SGIP Staff Proposal (Staff Proposal, Part II), which was attached to the ALJ Ruling, dated April 21, 2011. The April 21, 2011 ALJ Ruling requested comments on the revised SGIP Staff Proposal, Part II. Comments and reply comments were received on May 2, 2011 and May 9, 2011. Comments and reply comments on the Cost-Effectiveness Report were also received on May 11, 2011 and May 17, 2011. All comments were reviewed and incorporated into this decision, but due to the large volume of recommendations and in the interest of brevity, we make broad references to the comments as is relevant to our determination of the issues, but do not discuss the comments individually.

3. Ratification of the Assigned Commissioner's Ruling

On February 10, 2011, the assigned Commissioner in this proceeding issued an Assigned Commissioner's Ruling (ACR) directing the PAs to suspend accepting new SGIP reservation requests.

We support the rationale for temporarily suspending issuing new SGIP applications and ratify the ACR that directed the PAs to suspend accepting new

SGIP reservation requests. The SGIP has limited funding, and the funding could have been depleted before the Commission implemented SB 412. The modifications we adopt today could result in a greater variety of technologies, and a broader range of customers and projects participating in SGIP in the future. Moreover, some of the modifications we adopt today help ensure that ratepayers receive a greater benefit from the incentives provided to the SGIP recipients. Thus, the temporary suspension of the program preserved the SGIP's limited funds and ensured that the limited budget was not exhausted while the Commission considered which additional technologies should be eligible to participate in the SGIP.

4. Proposed SGIP Modifications

4.1. Statement of Purpose and Program Principles

Staff proposes a Statement of Purpose for the SGIP program to assist the Commission and the parties with the program implementation. The Statement of Purpose states that the SGIP should contribute to:

- GHG emissions reductions in the electricity sector;
- Demand reduction and reducing customer electricity purchases;
- Electric system reliability through improved transmission and distribution system utilization; and
- Market transformation for distributed energy resources (DER) technologies.

In addition to the Statement of Purpose, Staff proposes the following eight guiding principles to help with evaluating new technologies and informing program design modifications:

1. The SGIP should only support DER technologies that are cost-effective, or represent the potential to achieve cost-effectiveness in the near future.

2. The SGIP should only support technologies that produce fewer GHG emissions than they avoid from the grid.
3. The SGIP incentives should provide sufficient payment to stimulate DER technology deployment without overpaying. The SGIP incentives should not be provided to technologies that do not need them to earn a reasonable return on investment.
4. The SGIP should support behind the meter "self-generation" DER technologies, which serve the primary purpose of offsetting some or all of a host-customer's on-site demand.
5. The SGIP should only support commercially available technologies.
6. The SGIP should target best of class DER by paying for performance.
7. The SGIP incentives should focus on projects that efficiently utilize the existing transmission and distribution system.
8. The SGIP should complement the structure of and be coordinated with existing ratepayer supported programs, especially the California Solar Initiative (CSI), which is aimed at transforming the market for renewable DG by driving down prices and increasing performance of DER.

Parties generally support the proposed statement of purpose and the guiding principles, but several parties recommend including peak load reduction as one of the SGIP's guiding principles. These parties contend that peak load reduction was the original primary purpose of the program. They argue that "SB 412 did not reverse, or eliminate the importance of emphasis on peak load reduction that still remains in [Public Utilities Code Section] 379.6…."[9]

---

[9] See, e.g., Opening Comments of Ice Energy, Inc. on Administrative Law Judge's Ruling Requesting Comments on Staff Proposal regarding Modifications to the Self-Generation Incentive Program (Ice Energy Comments), November 15, 2010, at 4.

Discussion:

Clear program purpose and principles are essential to the successful implementation of any program. We agree that the proposed Statement of Purpose captures the key objectives of the SGIP and will help guide the PAs, the SGIP participants and the Commission Staff through the process of future program implementation. Accordingly, we adopt Staff's proposed Statement of Purpose.

We agree with PG&E that given the limited budget and timeline required by SB 412, the Commission should strive to keep the SGIP program expansion as simple and straight forward as possible. Given that the proposed changes to the SGIP are to fulfill the statutory requirements of SB 412, and since SB 412 specifically requires that eligibility for receiving the SGIP incentives be based on GHG emissions reductions, requiring that SGIP systems funded under SGIP achieve GHG reductions emissions should be a priority. Accordingly, we adopt guiding principle 2, which requires that technologies must show GHG reductions. However, we agree that this requirement should be an additional guiding principle to the peak load management goals of the SGIP. As parties correctly point out, peak load reduction was originally the primary purpose of the program. We believe it should remain important in the SGIP and should be included in the list of the SGIP guiding principles. Accordingly, we add the following as a new guiding principle:

- Encourage the deployment of DER in California to reduce peak electric demand.

In addition, given that many of the initiatives supporting DG in California are fundamentally market transformation programs, we believe that market transformation should be added as a guiding principle of the SGIP. Accordingly, we add market transformation as a new guiding principle.

With respect to the other proposed guiding principles, we adopt guiding principle 2 and 4 through 8 because we find that they are beneficial to California and consistent with stated policies towards DG.

We are, however, concerned that guiding principles 1 and 3 would impose unnecessary requirements that might result in slowing down development of DER in California. That outcome would not serve the public interest. We therefore, do not adopt guiding principles 1 and 3. A more detailed discussion of why we do not adopt guiding principles 1 and 3 is presented under the "technology eligibility test" section below.

4.2. SGIP Eligibility Requirements

4.2.1. Technology Eligibility Test

In the Staff Proposal, Part I, Staff recommended that the Commission adopt three screens for SGIP eligibility:

1. GHG reductions: A product or a technology must produce fewer GHG emissions than it avoids from the grid;

2. Cost-effectiveness: A technology must be cost-effective or represent the potential to be cost-effective in the near future; and

3. Need for financial incentives: the SGIP incentives should provide sufficient payment to stimulate DER technology deployment without overpaying, and the SGIP incentives should not be provided to technologies that do not need them to earn a reasonable return on investment of 15%.

After reviewing the results of the Cost-Effectiveness Report, Staff altered its recommendation and proposed that the Commission only use cost-effectiveness and GHG emission reductions screens in determining the eligibility for incentives. The need for the financial incentives screen would be used only as an aid in setting incentive levels.

Staff also slightly modified the cost–effectiveness approach. The Cost-Effectiveness Report examined both current and future cost-effectiveness from the societal and participant perspective. In the Staff Proposal, Part II, Staff recommends that only technologies which show cost-effectiveness on a total resource cost (TRC) basis in 2010 should be funded. Staff argues the future cost-effectiveness results are considerably more uncertain due to projections that rely on assumed cost-reduction curves which may change due to external factors or unforeseen events. Therefore, to maximize the societal benefit of ratepayer funds, Staff recommends that technologies with a TRC value of >1.0 in the Statewide Average 2010 Commercial Results be deemed "cost-effective" and pass the TRC screen.[10] According to the recommendations in the Staff Proposal, Part II, a technology would need to pass both the GHG screen and the TRC screen to be recommended for inclusion in the SGIP program.

Discussion:

Achieving GHG reductions through SGIP projects is a requirement, as stated in Public Utilities Code Section 379.6 ((b):

> Eligibility for incentives under the [SGIP] program shall be limited to distributed energy resources that the commission, in consultation with the State Air Resources Board, determines will achieve reductions of greenhouse gas emissions pursuant to the California Global Warming Solutions Act of 2006

[10] SGIP Cost-Effectiveness of Distributed Generation Technologies Final Report, at 5-3.

(Division 25.5 (commencing with Section 38500) of the Health and Safety Code).

As stated above, SB 412 authorizes the Commission to determine eligibility for the SGIP based on achieving GHG emissions reductions. Thus, it is appropriate to make the GHG emissions reduction requirement the primary screen for establishing technology eligibility for the SGIP. We will not impose the additional requirements that technologies pass the cost-effectiveness test or pass the need for financial incentives test as prerequisites to receiving SGIP incentives. SB 412 does not contain such eligibility requirements. Although SB 412 provides that the Commission may consider other public policy interests in determining program eligibility, these suggested requirements do not contribute to the development of additional alternative energy technologies. In fact, they could slow investment in the SGIP and hamper market transformation for technologies that could contribute to reducing grid emissions.

Moreover, the financial incentives test for SGIP eligibility can be complex and administratively difficult to implement, as financial performance of systems is tied to physical characteristics of the site and tax status of the customer. Finally, in some cases this requirement could increase the costs for customers to participate in the program, and thereby discourage customer participation. As PG&E states, this would be counter to our stated purpose of facilitating development of DER.

As for the cost-effectiveness test, it also could be difficult to implement because of inadequate cost data to establish a reliable and accurate cost-effectiveness model. Currently, there are limited cost data available for most DER technologies. Furthermore, some information is proprietary and may be difficult to obtain. This is especially true of forecasted price information, which either does not exist or can only be derived through assumption-driven modeling. In addition, as stated by the parties, there are too many variables and assumptions that could lead to inconsistent results in calculating the cost-effectiveness of various technologies. For example, technology costs for DERs are frequently site-specific and vary significantly with capacity. Given all these uncertainties about the DER cost data, we find that a cost-effectiveness screen might not yield reliable results.

Furthermore, one of the purposes of the SGIP is to contribute to market transformation and facilitate DER development. Excluding technologies that are likely to have an impact on GHG emissions in California from participating in the program because they cannot meet the cost-effectiveness or the need for incentive tests would be contrary to the intent of SGIP and the state's goal of GHG reductions. Furthermore, additional support from the SGIP incentives could help technologies achieve future cost-effectiveness. To that end, it is appropriate that SGIP provide support to technologies that are GHG reducing and may potentially be cost-effective in the future.

We next address Staff's proposal on how to use the GHG reduction screen and whether the GHG screen should be applied on a project-by-project or technology specific level.

4.2.1.1. Avoided GHG Emissions from the Grid

Staff Proposal, Part I proposes that a DER be considered to reduce GHG if the resource would avoid more emissions than it would produce. Staff's determination of whether AES and fossil-fueled DER technologies are GHG-reducing was presented in the SGIP GHG Analysis Workbook, which was released concurrently with the Staff Proposal, Part I. For technologies to be considered GHG-reducing by Staff, they must generate electricity at an emission rate lower than the emission rate of electricity purchased from the grid over a ten-year time span. Staff's analysis of fossil-fuel based DER technologies rested on a few key assumptions: 1) the electrical conversion efficiency of all technologies degrades at a rate of 1% per year, 2) the total system efficiency of CHP technologies is 62%, which is the minimum required for CHP FiT eligibility, 3) the useful thermal output provided by CHP technologies would otherwise be provided by an 80% efficient boiler, and 4) average transmission and distribution losses are 7.8%.

While parties generally support the approach used in Staff's analysis, some are opposed to the use of Staff's avoided GHG emission factor of 349 kg CO2e/megawatt-hour (MWh) as an estimate of the emissions avoided from reduced consumption of electricity from the grid baseline. These parties argue that the proposed GHG factor is too aggressive and would result in the exclusion of many technologies that meet the CEC's required efficiency for GHG reducing technologies. They suggest the use of the CARB factor of 437 Kg CO2e/MWh, which is the factor CARB developed to estimate the GHG reductions achieved by various renewable energy and energy efficiency measures adopted as part of the AB 32 Scoping Plan. Staff's proposed number is CARB's factor adjusted by 20% to account for renewable resources as required under the Renewables Portfolio Standard (RPS) program.[11] California Clean DG Coalition (CCDC) contends

---

[11] Originally, the RPS program required investor-owned utilities, electric service providers, and community choice aggregators to increase procurement from eligible renewable energy resources by at least 1% of their retail sales annually, until they reach 20% by 2010. Although this requirement was increased to 33% by 2020 by SB X1- 2 ((Stats. 2011, ch.1), it occurred after the issuance of the Staff Proposal, Part I. However, we do not propose adjusting the CARB factor to reflect the higher RPS goal at this time.

Staff's number is erroneous because it ignores several factors, including the fact that some renewables were already accounted for in CARB's factor. In addition, CCDC argues that DG could displace fossil fuel generation with higher GHG emissions or displace only some renewables.

We believe the adjusted emissions factor represents a reasonable proxy for calculating the avoided GHG emissions at this time and adopt it here. First, we believe that the GHG emissions factor should reflect the fact that DG displaces a mix of resources including renewable resources as required by the RPS statute. CARB's factor is simply the weighted emission rate of all in-state gas-fired generation from 2002 through 2004 and does not include any renewable generation.

Second, Staff adjusted CARB's factor by 20% while the State has adopted a 33% RPS mandate. It is likely that accounting for the 33% goal will require even further reduction to Staff's estimate in the future.

Third, because the CARB AB 32 Scoping Plan emission factor value is based on the emission rate of gas-fired power plants from 2002 to 2004, it does not reflect the lower emission rate of newer gas-fired units that SGIP projects may avoid going forward. Given these factors, we believe Staff's proposal to adjust CARB's factor by only 20% is reasonable.

We also agree that GHG reductions are expected to be achieved on average during the first ten years of operations. PG&E also recommends that we apply the same requirement to projects that receive all up-front incentives. We agree it is reasonable to require GHG reductions to occur at a minimum over the first ten years of project operation, even with the expected system performance degradation.

We also believe that to encourage long-term investment in DER, the GHG screen should be applied, whenever possible, on a technology basis instead of project-by-project. Applying the GHG screen on a technology basis will provide a clear signal to market participants and developers in making investment decisions. However, because the GHG performance of fossil-fired CHP projects depends on site-specific factors, eligibility for these projects must be assessed on a project-by-project basis. We require the PAs to propose methods to determine, based on CHP technologies' operating specifications and site-specific thermal loads, the amount of waste heat capture for each project necessary to qualify the project as GHG reducing. The PAs shall propose these methods within 30 days of the effective date of this decision in advice letters.

4.2.2. Eligible Technologies

Staff applied the GHG reduction and cost-effectiveness screens identified above to determine eligibility. A technology that passed both the GHG screen and the TRC screen was recommended for inclusion in the SGIP. These technologies include wind, fuel cell CHP, gas turbine CHP greater than 3.5 MW, microturbine and IC engine CHP with onsite biogas, organic rankine cycle, and pressure reduction turbines.

Because we reject Staff's recommendation to use a cost-effectiveness screen, we focus only on the GHG screen. Applying this screen as discussed above, we find wind, pressure reduction turbines, bottoming-cycle CHP, and projects using the RPS-required minimum of 75% biogas to be eligible technologies for SGIP.

All fossil-fuel consuming CHP technologies are conditionally eligible but must be evaluated on a project-specific basis to ensure that they are GHG reducing. Electric-only technologies seeking SGIP incentives for projects that operate on fossil fuels must meet GHG emission rates below 379 kgCO_2/MWh[12] under realistic field conditions in the first ten years of operation. PAs, in consultation with CARB, will develop criteria and procedures for showing compliance with this GHG emission rate.

We require the PAs to propose modifications to the current waste heat emissions worksheet as necessary to reasonably ensure that an SGIP funded non-renewable CHP project will reduce GHG emissions compared to the adopted grid emission factor and the heating (or cooling) technology the SGIP project is displacing. The PAs must work closely with parties to develop an assessment tool that is rigorous and transparent but not unduly complex and must submit the modified worksheet as an advice letter for Commission approval within 30 days of the effective date of this decision.

In cases where a DER changes fuel, the corresponding effect on emissions must be considered. Thus, if a generator initially uses renewable fuel but later switches to natural gas, that project's eligibility for SGIP could be affected unless the customer can demonstrate that the efficiency was high enough to achieve GHG reductions operating on natural gas.

In response to comments on proposed decision, we wish to clarify that SGIP eligibility is limited to projects that do not use re-manufactured parts. While we acknowledge the environmental benefits of re-using equipment, there is not enough information in the record of this proceeding to provide assurance that allowing the use of re-manufactured equipment would not affect the quality

---

[12] The avoided emission factor described previously does not account for avoided transmission and distribution losses. The actual on-site emission rate that projects must beat to be eligible for SGIP participation is 379 Kg CO_2/MWh.

and reliability of equipment receiving SGIP incentives. However, we will direct Staff to discuss this option with the SGIP Working Group, and the PAs may file an advice letter to amend the Handbook to permit the use of re-manufactured equipment with appropriate conditions and ratepayer protections.

4.2.3. Other Advanced or Emerging Technologies

AES, fuel cells, pressure reduction turbines (PRT) and waste heat to power[13] are considered advanced or emerging technologies. However, the Commission recognizes that other clean DER technologies currently under development may soon be commercially available. Accordingly, new technologies may become eligible for inclusion in SGIP as an emerging technology if their first commercial installation is less than ten years prior to SGIP funding and if they meet program goals of GHG and peak load reduction. Developers of such technologies should seek a letter of support from the SGIP Working Group for SGIP eligibility. Developers of technologies that do not receive a support letter from the SGIP Working Group may file a Petition to Modify (PTM) requesting inclusion of their technology.

4.2.3.1. Advanced Energy Storage (AES)

In addition to the above technologies, Staff also considered AES technologies. Staff recommends AES coupled with intermittent DG, which is currently eligible for the SGIP, continue to be included in the SGIP. Staff, however, does not support including stand-alone AES in the SGIP, because it did

---

[13] The proposed decision referred to bottoming-cycle CHP. In comments on the proposed decision, parties recommended we change the bottoming-cycle CHP category to waste heat to power to clarify that all sources of waste heat are eligible for SGIP incentives.

not show positive TRC results. The California Energy Storage Alliance (CESA) and Ice Energy argue that stand-alone AES should be eligible for SGIP incentives. The Division of Ratepayer Advocates (DRA) opposes AES eligibility. DRA argues that through the Commission's Demand Response programs, utilities have initiated programs for permanent load shifting (PLS) resources that provide incentives for resources that permanently shift load from on-peak to off-peak times, including energy storage resources. Therefore, DRA opposes allowing stand-alone storage to participate in SGIP before the results of the utilities' PLS program are available. CESA, however, urges us not to wait for the PLS pilot program results, since any expansion of scope or pace of implementation for these pilot programs is entirely unknown at the present.

We will grant eligibility to stand-alone AES. As CCSE states "the SGIP is an excellent platform for technologies such as AES, which is relatively new to the marketplace, has significant positive benefits, and needs market support to increase deployment and become more fully commercial."[14] Stand-alone AES may reduce peak demand and GHGs. As such, even though it is not generation, it fulfills two important SGIP goals. Both the demand response and the storage proceedings are in preliminary stages of developing a program for storage. Therefore, AES should receive interim support while the Commission considers various proposals related to this technology in other proceedings.

We note the concerns raised by DRA and we clarify that if a future Commission decision in another proceeding provides comparable funding for incentives to customer-sited AES, or a particular subcategory of AES, the

[14] CCSE Reply Comments, May 9, 2011 at 3.

incentives provided to AES (or subcategory thereof) under the SGIP should be removed so as to prevent multiple incentives encouraging the same resource, just as incentives for solar photovoltaic (PV) were transferred to a dedicated incentive program. The same caveat applies to other SGIP-eligible technologies.

4.2.3.2. Pressure Reduction Turbines (PRT) and Waste Heat to Power Technologies

Staff recommends that PRTs or "in-conduit hydro" and organic-rankine cycle plants be included in the SGIP. Staff notes that these technologies are consistent with the goals of the program.[15]

We agree that PRTs – which do not require fuel – do reduce GHGs and can also reduce peak load. Because they require little or no additional fuel for generation, waste heat to power units are also considered renewable for purposes of determining the appropriate SGIP incentive levels. Including PRT and waste heat to power technologies in the SGIP will help promote these technologies as viable options for clean DG and achieve the market transformation goal articulated above.

4.2.3.3. Fuel Cells

Fuel cells are another emerging technology with the potential for significant cost reductions in the future. The Cost-Effectiveness Report found that of all technologies, residential fuel cells have the highest projected cost reductions between now and 2020.[16] Because the SGIP provides support for

---

[15] The Staff Proposals refer to Organic Rankine Cycle (ORC) technologies, but as suggested in comments, other waste heat to power technologies are likely to be GHG-reducing, not just ORCs. Thus, we clarify that all waste heat to power technologies are eligible for SGIP.

[16] *See* the Cost-Effectiveness Report, Figure A-2.

commercially available yet emerging technologies, the Commission should continue to offer SGIP incentives to fuel cell applications.

4.2.3.4. Onsite Biogas (OSB) and Directed Biogas (DBG) Fuel Considerations

Staff proposes that we allow OSB in the SGIP but that we raise the requirement for percentage of renewable fuel consumed from 75% for only the first five years of operation to 100% for the life of the project. Staff also recommends that we exclude DBG from the SGIP. Staff is concerned about the potential for gaming associated with fuel use for these projects and the administrative challenges in verifying their fuel usage. Staff suggests that if we were to continue to allow DBG to qualify for incentives, we address issues related to the quantity, the timing, and verification of delivery of the renewable fuel. In particular, Staff recommends that DBG projects that have received incentive reservations but are not yet completed be required to demonstrate a ten-year contract for 100% of fuel from biogas. In addition, Staff suggests that PAs audit these projects in order to enable them to litigate for the return of previously-approved incentives if these projects are unable to verify continued DBG fuel purchase.

Given the concerns raised regarding the ability to verify out-of-state directed biogas, as well as the lack of local environmental benefits to California ratepayers, we will exclude it from SGIP eligibility. We also note that the two conditions for granting a Petition to Modify the SGIP to allow eligibility of directed biogas in D.09-09-048 were that the SGIP had an excess of unused carryover funds and that an in-state biogas market would develop as a result. SGIP no longer has an excess of funds, and there has been no significant development of in-state biogas supplies since we granted the petition. However, using renewable biogas and developing California's biogas industry remain important objectives as California transitions to a low-carbon future. For these reasons, we will retain a separate incentive for biogas utilization for SGIP projects that use biogas from in-state sources. This eligibility applies to both on-site biogas and directed biogas produced within California. For customers using directed biogas, we adopt Staff's recommendation of a ten-year contract, but we only require that 75% of the fuel be from a renewable source, consistent with the RPS eligibility requirement.

Many parties voice concerns about changing rules for DBG projects with existing reservations. We agree that projects that are already receiving SGIP incentives or have existing reservations should not be subject to new changes since these projects entered into contracts under the existing rules. Accordingly, the changes we adopt here will only apply to new projects with reservation requests submitted after the effective date of this decision.

TURN and BP Energy Company (BP) raised a potential Commerce Clause challenge to our distinction between OSB and DBG. BP, in its comments, enumerated cases which govern one of the analytical frameworks of the Dormant Commerce Clause doctrine. All the cases cited by BP were initiated by a tax/surcharge or burden on the out-of-state entity wanting to enter or partake in a certain marketplace.[17]

---

[17] *Oregon Waste System, Inc. v. Dept. of Environmental Quality of the State of Oregon, et al.*, 511 U.S. 93 (1994) (at issue, surcharge imposed by Oregon on in-state disposal of solid waste generated in other states); *National Solid Waste Mgmt. v. Pine Belt Regional Solid Waste Mgmt. Auth'y*, 389 F.3d 491 (5th Cir. 2004) (at issue, ordinances that required that all solid waste collected within the counties and cities be disposed of at facilities owned by the waste management authority); *Wyoming v. Oklahoma,* 502 U.S. 437 (1992) (at issue, Oklahoma statute requiring all coal-fired electric utilities to burn mixture

Footnote continued on next page

The Commerce Clause states that "Congress shall have [the] [p]ower…to regulate Commerce with foreign [n]ations, and among the several [s]tates."[18] The Dormant Commerce Clause limits the ability of individual states to impede the flow of interstate commerce.[19] This doctrine focuses on preventing economic protectionism.[20]

Here, the SGIP is a self-selecting incentive mechanism funded by California ratepayers. It is a program for eligible distributed generation technologies to receive incentives to offset the cost of their systems. The distinction between OSB and DBG is an added incentive which is not a condition for being eligible to receive the base level incentives for the technologies or systems at the crux of this incentive program. The added incentive for OSB is not a tax, surcharge, bar, nor a condition for entering into a specific marketplace. Technologies/systems eligible to receive SGIP incentives can use OSB or DBG and all others wishing to enter the California biogas market can do so. This adder does not in any way impede the flow of interstate commerce nor is it based on economic protectionism. To the contrary, incentivizing the capture of

---

containing at least 10 percent Oklahoma- mined coal); *Chemical Waste Mgmt Inc. v. Hunt*, 504 U.S. 334 (1992) (at issue, disposal fee imposed by Alabama on hazardous waste generated out of state, but not on waste generated in state); *Hunt v. Washington Apple Advertising Comm'n*, 432 U.S. 333 (1992) (at issue, state's statute prohibiting closed containers of apples shipped into the state from bearing any grade other than the applicable United States grade); *Granholm v. Heald*, 544 U.S. 460 (2005) (at issue, state laws that allowed in-state wineries to sell wine directly to in-state consumers but barred out-of-state wineries from doing so--or made such sales economically impractical).

[18] U.S. Const. art. I, § 8, cls. 1, 3.

[19] *H.P. Hood & Sons, Inc. v. Du Mond*, 336 U.S. 525, 533-536 (1949).

[20] *City of Philadelphia v. New Jersey*, 437 U.S. 617, 623-624 (1978).

fugitive methane in California provides local air quality benefits and ensures that directed biogas used for the program meets the environmental standards that biogas produced in California must meet, in addition to alleviating concerns about tracking and verifying directed biogas.

4.2.4. System Size

The SGIP currently has a minimum size requirement of 30 kilowatts (kW) for wind turbines and renewable fueled fuel cells. There is no minimum size for non-renewable fueled fuel cell projects. In addition, all eligible projects are capped at a maximum size of five megawatts (MW) and the program requires that projects be sized to meet onsite load.

Staff recommends that the minimum size requirement for wind and renewable fuel cells remain in place only as long as the Emerging Renewables Program (ERP) continues to provide incentives for these technologies. If the ERP program is discontinued or interrupted at any time, Staff recommends that wind and renewable-fueled fuel cells technologies under 30 kW that have not received ERP incentives should automatically be eligible to receive SGIP incentives without additional Commission action. For all other technologies, Staff recommends that there be no minimum size requirement. Staff also recommends eliminating the maximum size restriction of 5 MW for all technologies participating in SGIP. Staff does not propose any changes to the program requirement that projects be sized to meet onsite load.

Discussion:

The 30 kW minimum size requirement was intended to minimize overlap between the SGIP and the CEC’s ERP, which offers incentives for projects with the same technologies as the SGIP that are sized at less than 30kW. We agree that as long as ERP exists, the minimum requirement for SGIP projects is appropriate. To the extent the ERP program is interrupted or eliminated, we agree all wind and renewable-fueled fuel cells should automatically be eligible for the SGIP incentives.

For other technologies, removing the minimum size requirement would ensure that customers with smaller load such as residential and small commercial customers also have access to incentives. Removal of the size requirement would also be consistent with SB 412, which requires the Commission to ensure that incentives under this program be available to all customers. We therefore adopt this Staff recommendation.

Similarly, we eliminate the maximum size limit for SGIP systems. Eliminating the maximum size will be consistent with the policies of SB 412 as it will open up the program to large energy users and allow these customers to more effectively participate in SGIP. Additionally, removing the size cap will benefit the program by enabling systems greater than five MW, which may not be financially viable without the incentives available for the first three MW, to become eligible to participate in SGIP. Authorizing the participation of larger projects may also allow certain technologies to achieve wider adoption without any additional cost to the program. We believe the tiered incentive structure (*see* Section 4.4.4 below), which only provides incentives for the first three MW of a project's capacity, and the requirement that projects be sized to meet a customer's onsite-load, obviates the need for the maximum size limitation.

4.3. Incentive Design

The Commission must decide three issues with respect to incentive design. First, we must determine whether to continue the practice of providing technology-differentiated incentives to SGIP projects. Next, we must determine the structure of the incentive, i.e., whether the incentive should be upfront or based on actual system performance. Finally, we must determine the level of incentives for each technology. Below, we discuss these factors as well as additional aspects of the incentive design.

4.3.1. Technology-Based Incentive

Originally, Staff recommended that we continue the practice of providing technology-specific SGIP incentives. Staff noted that although the development of some technologies has progressed more slowly than others, almost all the recommended SGIP technologies have demonstrated that they can be successfully developed at the current technology-based incentive levels. Moreover, Staff was concerned that a single incentive structure for all SGIP technologies would not accurately reflect differences in capital and operating costs, as well as performance.

After the Cost-Effectiveness Report was published, Staff changed its recommendation from a technology-based incentive to a more technology-neutral incentive structure differentiated only according to whether a project uses renewable or non-renewable technology. Staff proposed that SGIP provide a $1.25/watt incentive rate to all renewable technologies and $0.50/watt to all non-renewable technologies. Staff's recommendation is based on the observation that rates of return may vary widely from project to project depending on project specific characteristics and utility territory. In Staff's view, even if incentive levels are differentiated by technology, they cannot adequately take into account all of the variations in utilities' rates and other specific factors.

UTC Power Corporation (UTC) objects to incentives that are not differentiated by technology. UTC argues differences in technology performance require different incentive across technologies. UTC further argues incentive levels based only on the underlying fuel sources, rather than other technology attributes, would create a very uneven playing field in which mature technologies would receive preferential treatment over newer technologies that have significant potential for cost reduction on the horizon. UTC therefore recommends that the higher incentive be offered to "less mature technologies with higher cost per kW today and strong prospect for future cost reduction."[21] In response, California Large Energy Consumers Association (CLECA) maintains it is unclear how the Commission would predict which technologies have the greatest prospect for future cost reduction or how it would choose winners and losers.[22]

Discussion:

One of the adopted statements of purpose is market transformation for DERs. Storage, biogas, and fuel cells are three emerging technologies that have previously been eligible to receive SGIP incentives, and which have the potential to play an important role in California's energy future. The SGIP may play a similar role for these technologies as the SGIP and the CSI have played in promoting the maturity of the solar industry in California. Therefore, we will adopt higher incentives for these emerging technologies than we do for more mature technologies. In addition, because the program is intended to encourage development of clean DG, it is appropriate to adopt an incentive structure that reflects the nature of the fuel used rather than just the technology. Based on the state's policy objective of promoting renewable energy and reducing GHGs, we will generally provide higher incentives for zero- and low-GHG technologies than for technologies consuming fossil fuels.

---

21 Opening comments of UTC Power on Staff Proposal, Part II at 5.

4.3.2. Structure of PBI Payments – A Hybrid-PBI

Staff proposes a hybrid PBI, where a portion of the overall payment is provided up-front and the remainder is provided over time based on customers' system performance. The up-front payment is capacity-based and would constitute 25% of the incentive. The rest of the payments would be based on measured energy deliveries and would vary depending on actual system output during the year, the base incentive amount, and the capacity factor for each technology. The Staff Proposal, Part I recommended that payments be made according to the following:

- Upfront Capacity-Based Payment = 25% of incentive
  - This payment would be made when a project is commissioned, consistent with the existing rules of the SGIP program.
- Annual Performance Payments = approximately 15% of incentive
  - This payment would be paid based on kWh generation each year for a maximum of five years.
  - Payments would be based on actual measured performance of a SGIP system during the previous 12-month period.
  - Annual performance payments would be made only to projects that meet and maintain the technology-specific minimum operating performance requirements during the year for which the payment is due. All projects would be required to monitor and report actual operating efficiency on a quarterly basis to the program administrator. A project must perform within 2 percentage points of the predicted operating efficiency over the year to be eligible for the incentive. Expected efficiency would be established on an upfront basis at the time a project is approved for its first upfront capacity-based payment.

---

[22] Reply Comments of CLECA on Staff Proposal, Part II at 3.

Staff notes that payment based on energy deliveries may create an incentive for energy storage technologies to discharge more than is necessary or beneficial. Therefore, Staff recommended that energy storage technologies receive annual payments based on availability during peak hours. Energy storage technologies would have to meet certain operational requirements and would have to be available during peak weekday hours (or semi-peak hours during winter months), at least 80% of the time during the year and 90% of the time during the summer peak period. Availability would be defined as days in which the energy storage device discharged at least partially during peak hours.

Discussion:

Staff's recommendation to implement a PBI approach is based on prior measurement and evaluation studies, which indicate that many projects that received incentives in the past have not maintained performance at the minimum program efficiency requirements over the life of the project. In several cases, the capacity factor and/or generator availability were lower than expected. Several parties have also expressed the same concern and question the performance of some systems. They endorse a hybrid PBI to prevent program abuse. Some parties who are generally supportive of a hybrid structure advocate for a different initial incentive. Tecogen Inc. (Tecogen) suggests increasing the initial incentive to 50% or 60% to make a bigger impact on potential participants' decision making. Capstone Turbine Corporation (Capstone) suggests 50% upfront incentive with two additional payments of 25%. Bloom Energy Corporation (Bloom) recommends a larger initial payment of 80% of the total incentive.

Some parties argue against performance-based incentives. SDG&E and SoCalGas believe such a mechanism is too complicated and could impede the progress of the SGIP. Rather than a hybrid PBI, Foundation Windpower LLC (Foundation) suggests an incentive recovery clause, which would require that the incentive recipient return 100% of the SGIP funding in the event the project falls below 75% of its operational availability.

In light of the findings of previous impact evaluation studies, we will replace the current upfront, capacity-based incentive mechanism with some form of PBI mechanism to ensure long-term performance of projects that receive SGIP incentives. One criticism of the current incentive design is that it fails to incentivize a project's long-term performance because the project receives the entire SGIP incentive upfront. Recent results of some SGIP studies indicate that several SGIP projects have not performed as expected or have failed to maintain performance at the minimum efficiency requirements during the project life. A project that receives SGIP incentives must perform at the expected levels of production and operate over the expected project lifetime in order for the ratepayers to realize the benefits of their investment. Therefore, a PBI should be part of the overall incentive structure to ensure continued project operation during the life of the project.

We disagree with SDG&E's and SoCalGas' contention that a PBI mechanism is complicated and cannot be implemented without significant costs. Our past experience with implementing a PBI mechanism in CSI has been successful. Given that the SGIP PBI mechanism introduces a similar concept on a much smaller scale, we expect the knowledge obtained from administering the CSI program will be useful and can be applied in implementing a successful PBI mechanism for the SGIP.

At the same time, we recognize that upfront incentives play an important role in the owners' decisions to invest in projects. An upfront incentive will encourage development of new projects by reducing owners' initial capital costs, which many identify as one of the main barriers to deploying SGIP technologies. Customers will be more motivated to invest in SGIP projects when the program offers upfront incentives.[23] Therefore, an upfront incentive should also be a part of the incentive structure. Given our findings that the incentive structure should contain a combination of upfront incentives and PBI, we adopt a hybrid incentive structure. We believe a hybrid structure will be most effective in encouraging investments in clean DER and protect ratepayer-supported funds against non-performing or under performing projects.

In comments on the proposed decision, PG&E states that a PBI approach is not appropriate for smaller projects and recommends projects less than 30 kW not be subject to the PBI mechanism.[24] We agree that the complexities of a PBI program coupled with the fact that the cost of monitoring and reporting for smaller projects could consume an excessive share of their SGIP incentives, making a PBI structure unsuitable for small projects. Accordingly, while projects 30 kW and larger will be paid using the hybrid PBI mechanism, projects under 30 kW should receive only an upfront incentive.

We now address what portion of the incentive should be paid upfront. As noted earlier, several parties urge us to adopt a larger upfront capacity-based incentive coupled with a shorter period for annual performance payments. They recommend an upfront capacity payment of 50% or more. Some also argue that

---

[23] SDG&E Comments to Staff proposal, November 15, 2010.

[24] PG&E Comments on the proposed decision, August 8, 2011 at 9.

the proposed five-year period for annual performance payments is too long and may add risk and uncertainty to a project's returns.

We believe a 25% upfront capacity payment may not be sufficient to assist many technologies to overcome the first cost hurdle. However, we decline to adopt Bloom's request to pay 80% of the overall incentive upfront. This approach would reduce the amount of incentive that would be subject to performance verification over time, thereby increasing the risk to ratepayers of overpayment to a project that does not perform as expected. We agree with PG&E that a large portion of the overall payment should be performance-based. Therefore, we adopt 50% as the share of the incentive to be paid upfront.[25]

In comments on the proposed decision, PG&E requests clarification on whether PBI payments should be adjusted for systems that do not perform at sufficient efficiencies to generate electricity below the GHG eligibility threshold.[26] In order to ensure that SGIP provides incentives to projects that achieve GHG reductions, we require that PBI payments be reduced or eliminated in years that cumulative GHG reductions do not occur. Because many factors may lead to a project performing below expected levels of efficiency, we will provide a 5% exceedance band before penalties kick in. In other words, no penalty will be assessed if the actual cumulative emissions rate does not exceed 398 kg CO_2/MWh. However, PBI payments will be reduced by half in years

---

[25] We also decline to adopt Bloom's other suggestion that technologies with less than 10 years of commercial deployment be exempt from PBI. We agree with The Utility Reform Network (TURN) that being a less mature technology does not justify a differential payment. Indeed, less established technologies may pose a greater risk of underperformance.

[26] PG&E Comments on the proposed decision, August 8, 2011 at 9 – 10.

where a project's cumulative emission rate is equal to or greater than 398 kg CO2/MWh but less than 417 kg CO_2/MWh (i.e., 10% higher than the GHG eligibility threshold). Projects that exceed cumulative 417 kg CO2/MWh in any given year will receive no PBI payments for that year.

4.3.3. Incentive Levels

4.3.3.1. Incentive Rates

In the Staff Proposal, Part I, Staff recommends incentives of $1.25/watt for renewable technologies and $0.50/watt for non-renewable technologies, including AES systems paired with eligible SGIP technologies.

Table 2. – SGIP Incentive Levels by Technology and Fuel Type Recommended in the Staff Proposal, Part II

Technology	Fuel[27]	Total Resource Cost (TRC) Value[28]	Incentive ($/W)
Renewable Fuel (Plus Waste Heat Capture)			
Wind	n/a	1.40	$1.25
Organic Rankine Cycle	n/a	1.54	$1.25
Pressure Reduction Turbine	n/a	n/a	$1.25
Fuel Cell – CHP	OSB	1.02	$1.25
Gas Turbine (>3.5MW) – CHP	OSB	1.18	$1.25
Microturbine – CHP	OSB	1.25	$1.25
IC Engine (0.5 MW) – CHP	OSB	1.51	$1.25
IC Engine (1.5 MW) – CHP	OSB	1.83	$1.25
Non-Renewable Fuel			
Fuel Cell – CHP	NG	1.05	$0.50
Gas Turbine (>3.5MW) – CHP	NG	1.11	$0.50
Storage (paired with eligible DG technologies)			
Advanced Energy Storage[29]	n/a	n/a	$0.50

Discussion:

Staff acknowledges that the proposed incentive levels are lower than the incentives historically offered by SGIP but given the limited budget, Staff believes that lowering the incentives would allow the program to support more capacity.

---

27 Fuel types are OSB = onsite biogas, or NG = natural gas. Staff recommends that, in addition to OSB, any onsite renewable fuel which meets RPS guidelines should be considered an eligible onsite renewable fuel and be eligible for the OSB based incentive levels. This recommendation allows for onsite biodiesel or waste vegetable oil to qualify.

28 Results shown are same as Table 1.

29 Paired with any otherwise eligible SGIP technology.

Although we earlier declined to adopt the financial need and cost-effectiveness screens recommended in the Staff Proposal, Part I, we agree with the general principle that the incentives should be high enough to stimulate the adoption of self-generation technologies without providing incentives far in excess of what is needed. With this principle in mind, we consider the appropriate incentives for those technologies we have identified as emerging technologies.

Since 2007 the incentive level for fuel cells has been $2.50 per watt. From 2002 through 2009, relatively few fuel cell projects applied for SGIP funds. This indicates that $2.50 per watt was insufficient to stimulate much demand for fuel cells during that time. However, completed or currently active applications for fuel cell projects increased from 13 MW in 2009 to nearly 72 MW in 2010. Much of this investment was driven by the combination of the fuel cell and biogas incentives, but over one-third of the 2010 reservation requests by fuel cell projects were for projects using standard natural gas. Thus, it appears that fuel cell costs have fallen to a level at which fuel cells are economically viable in many applications with the SGIP incentives currently in effect. In light of the rapid increase in fuel cell project applications in 2010, we will adopt a lower incentive than the $2.50 per watt currently in effect.

Regarding the incentives for biogas, some parties opposed the reduction suggested by Staff. The difference in incentive levels between projects using biogas and natural gas suggested by Staff yields an implicit incentive for biogas of $0.75 per watt. While the number of SGIP applications seeking incentives for biogas increased sharply in 2010 (46 MW compared to 10 MW in 2009), the vast majority of the requested incentives were for directed biogas contracts of five years' duration. A much smaller amount of capacity was reserved for onsite biogas projects. Because we adopt Staff's recommendation to increase the minimum contract length for directed biogas to ten years, a sizeable reduction in the incentive level now is likely to prove insufficient to promote further biogas development. SoCalGas encouraged the retention of the current incentive level for biogas, and we agree that with the more stringent requirements in place for directed biogas it would be prudent to maintain the incentive at $2.00 per watt.

Storage technologies have seen relatively little activity in the SGIP. In 2010, AES applications accounted for only eight MWs, or roughly 8% of the total capacity reserved in 2010. As CESA noted, Staff has previously determined that $2.00 per watt is necessary for AES to be financially attractive. The low participation of AES in the SGIP to date suggests that it would be premature to reduce the incentive level for these technologies at this time. Thus, we will maintain the current incentive level of $2.00 per watt for AES.

Aside from the emerging technologies, we agree with Staff that the SGIP should incentivize the maximum amount of DG possible at the lowest cost to ratepayers. Accordingly, for technologies other than the emerging technologies, it is reasonable to set the minimum incentive level necessary and allow the market to determine which technologies are installed based on their costs and the benefits they provide to participants. However, due to the state's strong interest in reducing GHGs and local air pollutants, and promoting renewable energy, the SGIP should offer higher incentive levels for renewable and waste heat recovery technologies.

Pressure reduction turbines and waste heat to power systems have not been eligible for SGIP in the past. As a result, we do not have actual cost data available to inform our decision regarding incentives for these technologies.

Because of this lack of program data, we will base our renewable and waste heat capture incentives on our experience with wind turbines.

Like fuel cells, wind turbines also saw a large increase in SGIP activity in 2010, with over 23 MW requesting reservations in 2010 compared to 1.6 MW in 2009. This increase in wind applications in 2010 demonstrates that $1.50 per watt has proven sufficient to attract investment. We note that, based on reported total installed costs in SGIP, $1.50 per watt covers over one-third of installed costs in most cases and as much as half of installed costs for a couple of projects. Combined with the 30% ITC for which wind turbines are also eligible, the $1.50 per watt incentive may result in ratepayers overpaying to induce these investments. Therefore, we will adopt the reduced incentive for wind turbines of $1.25 per watt as recommended in the Staff Proposal, Part II, and we will also use this value for pressure reduction turbines and waste heat to power technologies.

Conventional fuel-based CHP technologies have not been eligible for SGIP funds since 2006. At the time the program was revised to restrict eligibility to wind and fuel cells, the incentive levels for these technologies was $0.80 per watt for turbines/microturbines and $0.60 per watt for IC engines. These incentive levels appear to have been adequate to incentivize several MW of installations of these technologies, particularly IC engines. Moreover, the SGIP Cost-Effectiveness report shows the cost of these technologies falling generally in the $2 to $3 per watt range. Given the relatively low cost of these technologies and the 10% ITC available to them, we will adopt Staff's recommended incentive level of $0.50 per watt.

Table 3 below summarizes the incentive levels adopted for each technology. We note that the biogas incentive is an adder that may be used in conjunction with fuel cells or any conventional CHP technologies.

Table 3. – Adopted SGIP Incentive Levels Category[30]

Technology Type	Incentive ($/W)
Renewable and Waste Heat Capture	
Wind Turbine	$1.25
Waste Heat to Power	$1.25
Pressure Reduction Turbine	$1.25
Conventional Fuel-Based CHP	
Internal Combustion Engine – CHP	$0.50
Microturbine – CHP	$0.50
Gas Turbine – CHP	$0.50
Emerging Technologies	
Advanced Energy Storage[31]	$2.00
Biogas	$2.00
Fuel Cell – CHP or Electric Only	$2.25

4.3.3.2. Tiered Incentive Rate

Staff recommends that the Commission maintain the current tiered incentive rates:

0-1 MW = 100 %
1-2 MW = 50 %
2-3 MW = 25 %

Staff believes this tiered incentive structure is compatible with the hybrid performance-based incentive structure.

---

[30] Any onsite renewable fuel which meets RPS guidelines should be considered an eligible onsite renewable fuel and be eligible for the OSB based incentive levels. This recommendation allows for onsite biodiesel or waste vegetable oil to qualify.

[31] Stand-alone or paired with solar PV or any otherwise eligible SGIP technology.

Discussion:

Except for Foundation Windpower, which advocates that we apply 100% to the first 1.5 megawatts of capacity, most parties support maintaining the tiered incentive rates. Foundation's request to increase the capacity eligible for 100% of the incentive stems in part from the lower rates that large industrial customers pay as well as other factors unique to large-scale wind turbines. However, the tiered incentive rates are designed to ensure that SGIP funds are available to a larger number of potential beneficiaries. As explained above, we have determined that it would be overly complicated to tailor SGIP incentives to specific utility rates and other project-specific factors. Similarly, we will not deviate from the tiered incentive structure currently in effect to accommodate different technologies according to the rates that potential project hosts are likely to face. Therefore, we will maintain the current tiered structure as recommended by Staff.

4.3.3.3. Incentive Decline

The CSI program has a declining incentive structure in which incentives decrease for new projects as certain capacity milestones are reached. Staff supports applying a declining incentive structure to the SGIP, but does not recommend that incentives for the SGIP decline in the same manner as CSI. Staff notes that a declining incentive structure like the one adopted for CSI would be difficult to implement for the range of SGIP technologies. Instead, Staff recommends an annual 10% decline in the incentives for SGIP technologies, starting on January 1, 2013. Under the Staff's proposal, the reduced incentives would apply on a going-forward basis to projects whose reservation requests are received on or after the date that an incentive decline kicks in.

SoCalGas supports a gradual "ramp down" of incentives over a period of years, using the CSI as a model. Fuel Cell Energy (FCE) supports this approach, with the caveat that the "step down" structure should be designed (as it was in the case of the CSI) on a technology-specific assessment of current market maturity and the expected trajectory for market growth.[32]

Bloom recommends an annual 15% reduction in the incentive level, effective immediately upon re-opening the program. FCE also recommends a reduction in the incentive level, but a less aggressive reduction schedule of 10% every two years. Similarly, UTC suggests a fixed annual percentage reduction of 10% per year.[33]

Discussion:

In D.04-12-045, the Commission stated that "a declining incentive structure will gradually reduce the market's reliance on a subsidy" (D.04-12-045 at 12.) The Staff analysis also shows the CSI, which includes a declining incentive structure, has been successful in promoting development of solar projects and the CSI continues to receive record numbers of applications. Although a declining incentive structure was ultimately not implemented for the SGIP, we affirm the principle that SGIP incentives should gradually decline rather than end abruptly in order to ensure that the technologies supported by SGIP transition toward a self-sustaining level of maturity that is no longer dependent on ratepayer subsidies.

Given the success of the declining incentive structure in the CSI, we find that a declining structure similar to the CSI "would promote consistent incentive

---

32 Reply Comments of FCE at 4.

design structure among the Commission's DG programs and would follow a successfully implemented model." [34] We believe a declining incentive structure for the SGIP will facilitate self-sufficiency and promote cost reductions in the market for the SGIP technologies.

In comments on the proposed decision, Foundation urges us to reject any decline in incentives for wind projects, arguing that unlike emerging technologies, the cost of wind turbines used in wind projects is unlikely to decline materially over the next few years.[35] CCSE also notes that a 10% annual reduction across the board for all technologies may not be appropriate for the SGIP.[36]

In light of these comments, we will adopt a 10% annual reduction for emerging technologies and lower 5% annual reduction for all other technologies, with the first reduction starting on January 1, 2013.

4.3.4. Calculation of SGIP Incentive

The SGIP Staff Proposal, Part I recommended a five-year payment plan based on expected performance, with penalties for not achieving the planned generation. With respect to the performance-based portion of the incentive, we find that it is appropriate to require that each project be paid based on the actual performance of the system in a given 12-month period. Under this approach, customers who may encounter slower than expected business in one year will not be penalized if they produce less in that year because they will still receive a

---

33 Reply Comments of UTC on Staff Proposal, Part II at 3.

34 DRA comments November 15, 2010, at 4.

35 Foundation Comments on the proposed decision at 4.

36 CCSE Comments on the proposed decision at 3.

portion of their incentives based on the actual production of their system. Similarly, customers whose systems perform better than expected could receive all of their performance-based payments in less than five years. In order to limit the amount of time that PAs are obligated to continue administering the SGIP, the maximum amount of time allowed for earning the performance portion of the SGIP payment should be set at five years. This approach will provide some flexibility for projects whose hosts experience fluctuating levels of performance while ensuring that on average, systems are incentivized to perform as expected.

This approach will also allow systems that operate efficiently, but at lower than the target capacity factor, to receive some SGIP incentives rather than no incentives. Otherwise, as CCDG explains, these systems may install heat dump capability to allow them to operate even when the site thermal loads are satisfied. We agree with CCDG that such a practice will result in outcomes that are contrary to the goals of SB 412. To prevent such a practice, the metering and monitoring protocols should ensure that the exhaust heat from topping-cycle CHP systems serves a useful thermal load and that total system efficiencies remain high enough that these systems reduce GHGs.

We also adjust the expected capacity factors for wind and AES. The proposed decision recommended a capacity factor of 30% for wind and 20% for AES projects. In comments on the proposed decision, Foundation argues that capacity factor for wind projects are often below 30% and recommends using an availability factor of 85% or a capacity factor of 20%. CESA also argues that the 20% capacity factor for AES is too high given that energy storage is only required to discharge between 2-4 hours per day during peak load months to effectively reduce peak demand. CESA argues for calculating the energy payment based on availability factor rather than capacity factor. We do not believe availability factors are appropriate for calculating energy payments to SGIP projects because ratepayers should receive the maximum reasonable output from the SGIP projects they subsidize. However, we agree that the capacity factors for wind and AES should reflect practical standards suited to the location and performance characteristics of SGIP-funded projects. Accordingly, we reduce the assumed capacity factor for wind to 25% and for AES to 10%.

We also reduce the current SGIP requirement that an AES must be able to discharge its rated capacity for a minimum of 4 hours to 2 hours. In comments on the PD, Primus Power argues that this practice is not economically optimal and may penalize new, innovative, shorter duration energy storage systems. Moreover, Primus Power argues that a four-hour minimum would exclude about 40% of California's market whereas a two-hour minimum includes over 90% of the market.

Each incentive level would be based on capacity to meet on-site electric load and then converted into a cents per kWh payment (paid over five years) based on the expected capacity factor of the technology.

Under this arrangement, each project would have a performance expectation established during the incentive claim phase of the project review. Kilowatt hour-based payments would be structured so that under the expected capacity factor, a project would receive the entire stream of performance payments in five years. Each project would be paid a performance payment once a year based on the kWh of production for that 12 month period.

The following table provides an example for a wind turbine with a capacity factor of 25% that would be eligible for a $1 million dollar incentive with $500,000 received upfront and the remaining $500,000 paid based on expected kWh generation over five years, calculated as nameplate capacity * capacity factor[37] * hours per year * five years.

Table 4. – Example of PBI Payment for an 800 kW Wind Turbine Operating at a 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	$100,000	$100,000
2	800	25	8760	1,752,000	3,504,000	$100,000	$200,000
3	800	25	8760	1,752,000	5,256,000	$100,000	$300,000
4	800	25	8760	1,752,000	7,008,000	$100,000	$400,000
5	800	25	8760	1,752,000	**8,760,000**	$100,000	**$500,000**

* Assuming $1.25/W incentive payment with 50% upfront and 25% capacity factor, dividing total PBI by total kWh yields a PBI payment of 5.7 cents/kWh.

<u>($500,000 performance payment)</u>/8,760,000 kWh = 5.7 cents/kWh PBI

Because the wind turbine in Table 4 operated as expected, it received 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 $500,000 payment in a shorter time frame. Similarly, if it generated fewer kWh than predicted by year five, it would not receive the full payment.

[37] Capacity factor is defined as the percentage of time a generator is producing at the nameplate capacity.

Table 5. – 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	$100,000	$100,000
2	800	25	8760	1,752,000	3,504,000	$100,000	$200,000
3	800	25	8760	1,752,000	5,256,000	$100,000	$300,000
4	800	20	8760	1,401,600	6,657,600	$80,000	$380,000
5	800	20	8760	1,401,600	**8,059,200**	$80,000	**$460,000**

In the example shown in Table 5 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.

CHP applications, though they have not tended to perform well compared to their maximum potential efficiencies, do present an opportunity to reduce GHGs and electrical load. However, actual performance has been disappointing so far because customers focus on maximizing electricity production instead of matching the heat load. To appropriately value these savings and ensure efficient use of waste heat, we adopt a two-pronged approach: pre-screening and on-going monitoring that serves as a conditional basis for any ongoing performance payments.

Pre-screening of CHP efficiency could be accomplished by an improved waste heat utilization worksheet,[38] one of the documents used in the SGIP application process. Developers would be required to demonstrate the base

---

[38] *See* for example: http://www.pge.com/includes/docs/word_xls/shared/selfgenerationincentive/waste_heat_emission_worksheet.xls.

thermal load of a site, along with forecasted fluctuations and future changes due to changing business conditions. Additionally, they would be required to show the coincidence of thermal and electric load. This demonstration of base thermal load, fluctuations, and coincidence of demand would help ensure that only facilities with an appropriate heat demand are incentivized. Staff notes that for participation in the CHP FiT per AB 1613, customer sites must document their thermal load. This load is then used to determine the maximum eligible generator size, so that CHP projects are sized to the thermal and not electric load.

Monitoring will also be necessary to ensure the on-going performance of applications approved under the pre-screen. Natural gas input will be monitored by the utility, and kWh output monitored for PBI payment. Waste heat monitors would be the only additional piece of equipment needed, and they generally cost less than $20,000 – a small percentage of a typical SGIP project cost. Reviewing project efficiency will enable PAs to verify that a project is utilizing waste heat as predicted in the waste heat utilization worksheet.

Determining the kWh avoided from the use of thermal storage technologies involves complex engineering calculations. The record in this proceeding has not been adequately developed on this subject for us to determine how the PAs would calculate the capacity equivalence of thermal storage systems or how they would pay the PBI incentives based on the kWh avoided (rather than generated) by the reduced demand for chilling or space conditioning. While we believe that there may be significant potential for thermal storage to reduce peak loads, we do not wish to delay the recommencement of SGIP while the technical specifications and measurements are being developed to enable these technologies to participate. The PAs, after consultation with the Energy Division and stakeholders, may file a subsequent advice letter to incorporate capacity equivalence and avoided peak kWh estimates for thermal storage into the SGIP Handbook.

We will direct the PAs to file advice letters with the details of the PBI payment structure, including any variations by technology and updates to the waste heat utilization worksheet, within 30 days of the final decision. Once the advice letters are approved, the PAs would incorporate all of the details into the SGIP Program Handbook.

4.3.5. Incentive Allocation per Technology Manufacturer

Staff suggests the SGIP annual budget on a statewide basis be capped at 50% for a single technology manufacturer or installation contractor. Staff notes that this will serve to diversify the ratepayer portfolio of DER and reduce over-exposure to any one product or developer. It will also facilitate a more equitable distribution of SGIP funds.

Although most parties support the general concept of limiting the availability of the SGIP budget for a single technology or installation contractor in order to make limited program funds available to more technologies and participants, they differ on whether the limit should be a fixed dollar amount or a percentage of the budget. They also have different proposals regarding what the limit should be.

SDG&E and SoCalGas contend that a 50% limit is too high to ensure a diversified portfolio. SoCalGas recommends we lower the cap to 25%, and SDG&E recommends a $15 million statewide cap for each technology. CESA also recommends a $25 million cap. CESA contends any form of percentage-based cap will be too difficult to administer. CCSE counters CESA's argument and states that SGIP database could simply be modified to track total incentives in a calendar year to a single technology supplier and/or installation contractor.

Discussion:

We adopt a 40% manufacturer concentration limit, but not the proposal that a similar cap apply to project developers. Parties have stressed the importance of having a mechanism that will indicate if there is an imbalance in the supplier concentration. A supplier limit will serve as a program safety measure and provide checks and balances necessary to ensure that one supplier does not receive a disproportionate share of the SGIP funds. For this purpose, there is little, if any, difference in adopting a percentage-based versus a fixed amount cap. Either approach would function similarly in informing us if a high concentration of one supplier exists. We believe a percentage-based cap is an appropriate mechanism to ensure diversity of the portfolio and will equitably distribute SGIP funds. In comments on the proposed decision, CESA, CCDC, and Primus Power advocate a 25% limit to ensure greater diversity. We believe that a 25% manufacturer cap may be overly restrictive and limit customer choice. Therefore, we adopt a 40% cap that we believe will strike a better balance between ensuring that a diversity of technologies and manufacturers are able to benefit from the SGIP and allowing the program to incentivize the products that prove to be most successful in the marketplace.

To ease implementation, the 40% cap shall apply statewide. PAs 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 at the beginning of the year, including any carry-over funds from previous years. Because SGIP will begin to accept new reservations with only two or three months left in 2011, the initial 40% limit will cover the period from the launch of the new program through 2012 and will be calculated based on the total funding available at the start of the program plus any additional funds collected in 2012, if applicable.

CCDC recommends a $4 million incentive cap per project, in addition to the per manufacturer cap. CCDC notes that as proposed in the proposed decision, a 3 MW or larger natural gas-fired CHP system could receive as much as $875,000, and up to $2.2 million in incentives if using biogas. Similarly, a biogas fuel cell could receive up to $7.4 million in incentives. If a biogas fuel cell includes AES, then the incentive payment could exceed $10 million.

We agree it is important to ensure program funds are used to create a diverse portfolio of projects. A maximum per project incentive payment is a reasonable method to preserve program funds and avoid allocating a disproportionate share of SGIP funds to only a few projects. However, we believe the $4 million cap may be too low to allow a broad range of project participation, and we adopt a $5 million maximum incentive amount per project instead of the $4 million proposed by CCDC.

4.3.6. SGIP Incentive Limit as Share of Project Cost

Staff recommends that the SGIP not pay incentives that represent more than 30% of upfront project costs because many SGIP projects are eligible for an additional investment tax credit of up to 30%. Moreover, Staff believes that SGIP participants should pay a larger share of the project cost than either the ratepayers' share or the federal taxpayers' share. Therefore, Staff recommends that SGIP participants pay at least 40% of the project costs after properly accounting for project costs and tax benefits.

Several parties are opposed to the adoption of a project limit. SCE contends the requirements to cap upfront incentives would necessitate establishing and tracking both a project cost cap and threshold, which in SCE's view could not be implemented without significant time and administrative cost to the PAs. PG&E, CCSE and SoCal Gas also believe a project cost cap could become administratively burdensome. SCE maintains that the requirement to have participants pay 40% of the project cost is also problematic because it requires the PAs to obtain tax information from participants. PG&E and other parties note that many customers (government and non-profit) cannot take advantage of the tax relief that was considered when setting the 30% cap.

Discussion:

We adopt the Staff proposal to limit SGIP incentives as a share of project costs. The cap would ensure that SGIP recipients are financially committed to projects' success. We are not convinced by SCE's claim that these requirements would be overly burdensome or require a significant administrative cost. The relatively small size of the SGIP program limits the time or investments needed to implement these requirements for SGIP applications. Moreover, as TURN points out, since the SGIP currently requires that incentives not exceed project costs, the PAs could apply the same process and documentation to measure and enforce the limit on incentives as a portion of project costs.

While we generally adopt Staff's proposal, we decline to adopt the 30% cap for projects that are ineligible for a federal tax credit, either because the technology is an emerging technology that is not eligible or because the applicant is a non-taxable entity such as a state or local government agency that will own the DER system. Rather than adopting Staff's proposal, we direct the PAs to determine the per project limitation using the following formula:

SGIP share of project costs <= 1 – applicable ITC – 0.4

This approach will ensure that applicants generally pay a minimum of 40% of project costs.

In addition, we recognize that there is a potential for gaming, such as creating different ownership structures to allow participants to achieve more funding than the capped amount. In response to comments from CCDC, we also clarify that the biogas adder does not apply to the applicable limit for projects using DBG. Instead, the adder should be 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. Therefore, we direct the PAs to file an advice letter within 30 days of the effective date of this decision proposing guidelines on how to implement these requirements.

In comments on the proposed decision, UTC requests that we provide a definition of total project costs to ensure that all projects are treated equally. UTC also requests that we include the cost of a ten year warranty in the calculation of total project costs.

We agree that in order to calculate the 30% cap, the PAs would need to determine cost components that are eligible to be included in a project total cost. The SGIP Working Group should consider whether additional clarifications on the definition of project costs as defined in the SGIP Program Handbook are necessary.

4.4. Budget Allocation

When the SGIP was fist established, there were three incentive levels for eligible technology categories (Level 1, Level 2, and Level 3). D.01-03-073 allocated a percentage of the SGIP budget to each category and established rules for transferring funds between the three categories. Later, when Level 1 technologies were removed from the SGIP because solar PV was moved to the CSI program, the list of eligible technologies was limited to Level 2 and Level 3. Currently, Level 2 includes wind, and fuel cells using renewable fuels and Level 3 applies to fuel cells using natural gas. PAs are authorized to move funds from the non-renewable category to the renewable category as needed. However, in order to move funds from the renewable category to the non-renewable category, PAs must file an advice letters seeking authorization from the Commission.

Staff recommends keeping this practice, but suggests eliminating the "Level 2" and "Level 3" designations and using "renewable" and "non-renewable" categories instead. In addition, Staff suggests AES coupled with a renewable DG technology on-site, such as solar, wind, or biogas, be funded out of the renewable budget allocation, and all other energy storage technologies be funded out of the nonrenewable budget allocation.

Discussion:

We agree with Staff that the Level 2 and 3 designations are outdated and should be changed. To maintain consistency with the incentive rate categories described in Section 4.3.3.1, we use similar categories (renewable/waste heat to power, emerging, and non-renewable) for describing the allocation of the budget. However, in order to avoid creating an allocation that is overly restrictive and may quickly result in a need for one or more PAs to shift funds among categories, we will combine the renewable and emerging technology categories. The budget allocation categories depart slightly from the incentive categories in that funding for projects using conventional CHP technologies will be drawn from the renewable funding "bucket" for projects using on-site biogas or directed biogas under a contract that meets the SGIP eligibility criteria. Stand-alone AES and AES paired with a renewable or emerging generating technology will be funded from the renewable and emerging budget. AES paired with conventional CHP will be funded from the non-renewable budget. Similar to the current hierarchy, we will allow PAs to shift funds from the non-renewable category to the renewable and emerging technologies category as needed, but we require the PAs to file advice letters to shift funds from the renewable and emerging technologies category to the non-renewable category.

The funds collected each year will be allocated with 75% dedicated to the renewable and emerging technology bucket and 25% dedicated to the non-renewable bucket. Due to the reconfiguration of the budget categories, any carry-over funds remaining from the previous program in the PAs' SGIP budget shall also be distributed 75% to the renewable and emerging technologies category and 25% to the conventional CHP category.

4.5. Other SGIP Program Modifications

4.5.1. Measurement and Evaluation (M&E)

The SGIP Staff Proposal, Part I identifies several reports and activities that have been in place since the inception of the SGIP and are currently part of the SGIP M&E process. Staff recommends additional M&E guidance to streamline the M&E process after implementing SGIP program changes pursuant to SB 412. Most significantly, Staff recommends a specific budget for the SGIP M&E program.

Ice Energy, though supportive of Staff's recommendation to obtain accurate measurement and monitoring of the performance of SGIP facilities, contends that thermal energy storage for air conditioning has unique characteristics that need to be taken into account with regard to measurement and metering. For these types of AES, Ice Energy alleges that the discharge energy is not the most important factor in measuring their performance on the grid. Rather, it is the electrical energy that they displace – the kW and kWh of electric demand that is avoided during peak hours as a result of the discharge of the stored thermal energy – that is the appropriate quantity to measure and monitor. According to Ice Energy, this is well suited to the Staff Proposal's approach to robust metering, measurement, monitoring and reporting.

Discussion:

Obtaining accurate and current performance data is critical in establishing historical performance of SGIP funded projects, particularly when a PBI mechanism is used to pay incentives. It also enables the Commission to make informed decisions regarding design and administration of SGIP program rules in the future. We adopt Staff's proposal.

4.5.2. Metering Requirements

Staff proposes that we expand the metering and reporting requirements adopted in D.10-02-017 to all SGIP applications and require metering and monitoring equipment to be installed on SGIP facilities as a condition of receiving incentives. Specifically Staff recommends the following:

- Install metering equipment capable of measuring and recording 15-minute interval data on generation output, and (where applicable) fuel input, heat output (for CHP), and storage system charging and discharging.
- Provide data by the system owner or its designee to the PA, directly to Energy Division Staff and/or to relevant M&E contractors on a quarterly basis for the first five years of operation.

- The PAs in consultation with the Energy Division Staff shall hold a public workshop to establish specific protocols to govern the metering and data reporting requirements for SGIP systems. The PAs shall submit metering and monitoring protocols through a Tier 2 advice letter that modifies the SGIP Program Handbook within 30 days of the adoption of a final decision.
- For M&E purposes, the investor-owned utilities shall be required to provide interval data on total energy consumption for project sites (which is different than the system production data described above that must be provided by the system owner) to the PAs, Energy Division Staff, and relevant M&E contractors. This should be done for a period of five years.

CESA and CCSE argue that the Commission should consider waiving metering requirements for small projects (e.g., < 10kW) due to the increased transaction and overhead cost associated with the metering requirements. However, for small projects, CESA recommends we require sampling and audits to ensure compliance with performance as predicted.

Bloom supports monitoring system performance to ensure SGIP projects that receive incentives perform as required, but has several concerns regarding privacy of the data and metering costs. Bloom suggests if we mandate additional metering requirements on SGIP customers, we continue the existing practice of requiring the PAs to pay the cost of any additional metering that is not normally required by the utilities, but is required as a condition of receiving incentives. Bloom also cautions us about competitive sensitivity of data for SGIP facilities. Bloom recommends we consider what data needs to be collected, who the data will be released to and what purpose the data will fulfill. Bloom also argues requiring quarterly reporting will increase costs and administrative burdens and recommends we delay requiring such reporting until additional funding is available.

Discussion:

Currently, metering and monitoring equipment for M&E purposes are installed only on a sample of SGIP systems. Additionally, the cost of this monitoring is paid from the SGIP administration budget of the PAs.

We find that accurate metering and monitoring data will be necessary to calculate and verify performance for purposes of PBI payments. Furthermore, quarterly reporting will provide important information and feedback on program performance and will contribute to improving the M&E studies of the program as a whole. We see no reason to delay this requirement. Therefore, we adopt Staff's proposal. We do note, however, that additional information will be needed to implement the metering and reporting requirements. Furthermore, while some level of consistency among projects may be desirable, smaller projects may not require the same level of metering and reporting as larger projects. CESA's and CCSE's recommendation to waive the metering requirement for smaller projects should be further discussed. Staff shall hold a workshop at which parties discuss the specific protocols to govern the metering and data reporting for all SGIP projects, including the appropriateness of any size-differentiated metering requirements and who should pay for the additional metering expenses.

4.5.3. Marketing and Outreach (M&O)

Staff suggests we adopt a specific budget for M&O activities, focused on informing and educating customers about DER opportunities and addressing market barriers to DER adoption. Staff recommends that we allocate 3% of the program administration budget for M&O purposes.

Staff also recommends activities to make statewide outreach efforts more uniform and to better coordinate M&O activities with the CEC and industry groups. In particular, Staff proposes the SGIP Working Group create a committee dedicated to M&O activities.

Discussion:

Currently, 10% of the SGIP budget for each PA is set aside for administration, which includes general administration, M&E, and M&O. The proposed decision recommended that 3% of the budget for program administration be allocated to M&O activities. Several parties oppose this allocation. They recommend instead that the M&O funds be allocated to the incentive budget. UTC believes there is sufficient awareness of the value and benefits of the SGIP and recommends the M&O budget be used to cover the PAs additional administrative costs, including the cost of metering equipment. CCSE agrees that 3% allocation may be too high but believes that the PAs should maintain discretion to use a portion of their program administration budgets for M&O purposes to implement SB 412 and related modifications to the SGIP.

Staff reports that past program participation shows no correlation between M&O funding and increased SGIP activity. We agree with parties that at this point, significant M&O activities may not be necessary. With the introduction of the PBI, the PAs now face a longer administrative commitment, and it may be premature to transfer administrative funds to the incentive budget. The PAs, in consultation with the Energy Division, should continue to have flexibility to determine the best use of their administrative budgets. Accordingly, we reject Staff's proposal to allocate 3% of the budget for program administration for M&O purposes. Accordingly, the administration budget for PAs shall be reduced to 7%.

4.5.4. Export to the Grid

Staff recommends SGIP projects that qualify for the AB 1613 FiT should be allowed to sell up to 25% of their self-generated electricity to the interconnected utility. Staff believes allowing SGIP projects a limited amount of export is consistent with the SGIP intent and would complement the export tariff program.

Parties generally support allowing some export, but differ on the export limitation amount. FCE asserts the 25% limit imposes new and unnecessary restrictions on projects that are currently eligible under AB 1613 to export to the grid. According to FCE, the AB 1613 program is only available to projects that are sized to meet onsite thermal load.

Foundation supports giving customers some ability to export power to the grid and believes the current project sizing rule has been effective in excluding projects that are net energy exporters. As long as the current limit on the SGIP self-generation project sizing (200% of a customers' peak 12-month demand is maintained, Foundation believes there is no need to apply a specific cap on the amount of exported power.

Sustainable Conservation is also against the 25% limit. They allege that the amount of fuel a generator may be able to produce in the case of biogas digesters at farms and food processing facilities, generally exceeds the 25% limit. Thus, Sustainable Conservation contends a 25% limit may result in unused fuel for electricity. Debenham supports the 25% limit on the amount of export to the grid.

Sustainable Conservation argues that projects should be sized to meet available fuel source, not limited to on-site load. SCE opposes the adoption of this proposal. SCE contends SGIP eligibility should be limited to DG technologies on the customer's side of the utility meter that provide electricity for a portion or all of that customer's electric load. CLECA states that allowing unlimited (aka limited only to fuel availability) access to SGIP funding for a project that will sell power to the utility under the FiT requires a more thorough analysis than can be undertaken here.

Discussion:

We adopt the Staff proposal to allow customers to export 25% of their output to the grid on an annual basis. Allowing SGIP facilities to export to the grid will facilitate optimal and efficient sizing of SGIP systems and as TURN states, will allow customers some flexibility "to account for resource variability in the case of wind projects and to account for demand fluctuations due to business downturn." [39] However, we agree with DRA and TURN that there should be a limit on the amount of export. As DRA states, the intent of SGIP is to facilitate self-generation. Allowing customers to export to the grid without any caps would not benefit ratepayers.[40] TURN does not support a blanket 25% provision for all SGIP customers and argues that such an allowance for five years is excessive. TURN's proposal is to limit the exports to a maximum of 25% in

---

[39] TURN Comments on Staff Proposal Regarding Modifications to the SGIP, November 15, 2010 at 7.

[40] DRA Comments on Staff Proposal Regarding Modifications to the SGIP, November 15, 2010 at 4.

any given year but no more than 10% on average during the first five years of operation.[41] DRA does not oppose the proposed 25% export allowance.

While allowing export to the grid would provide flexibility in the program and motivate customers to invest in SGIP systems, we do not want to provide SGIP incentives for projects that are designed to export a substantial portion of their output to the grid. A 25% cap provides a reasonable export limit. Accordingly, we adopt a 25% export allowance. We believe that the 10% limit proposed by TURN is overly restrictive and would be counter to the optimal system sizing principle that we want to promote through this provision.

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

> At an 80% assumed capacity factor, the CHP facility designed to meet heat demand would generate 9.1 GWh/year (1.3 MW * 80% * 8760). In the previous year, the facility only consumed 7 GWh, or ~3/4 of the expected output. Because the facility's electricity demand 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 1MW (~3/4 * 1.3MW). The total incentive would be $500,000 (1MW * $.50/W), with $250,000 paid up-front. The remaining $250,000 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 ($250,000 / 5 years / 7 GWh).
>
> Now assume that the actual capacity factor is 90% instead of 80%, total generation is 10.3 GWh while on-site consumption remains constant at 7 GWh. The 90% capacity factor is partially attributed to on-site load as follows: (90% * 1MW * 8760) = 7.9 GWh. This increased generated would benefit from the higher capacity factor,

---

41 TURN Comments on Staff Proposal Regarding Modifications to the SGIP, November 15, 2010 at 7.

and would receive a PBI payment of $56,252 (0.7 cents * 7.9 GHw * 8760), even though 0.9 GWh of this amount attributed to "on-site" capacity was exported. In this example, a total of 3.3 GWh would be exported, with 0.9 GWh of this total being compensated under both the PBI and FIT tariffs. Without this arrangement, DER projects which export larger quantities of electricity to the grid due to higher capacity factors would never be able to receive accelerated PBI payments.

4.5.5. Energy Efficiency Requirements

Staff recommends that similar to the CSI, customers receiving SGIP incentives should be required to obtain energy efficiency audits prior to receiving SGIP incentives. Staff recommends that after an energy audit is performed, SGIP customers submit a summary of the completed audit recommendations. The summary would also specify which, if any, energy efficiency or demand response measures identified in the audit will be undertaken, and describe how the audit recommendations influence sizing of the project.

Parties generally support the proposed energy efficiency requirements. However, to the extent that any new audit tools need to be developed to support the proposed requirement, some argue the Commission should authorize funding for this purpose.

Discussion:

Energy efficiency is the top priority in the State's loading order. Any opportunity to educate customers about energy efficiency measures that could potentially reduce their demand and thereby reduce the size of SGIP project and corresponding incentives should be encouraged. An audit will also help the customer consider related energy efficiency measures that could be deployed at the time of project installation, thereby potentially lowering the total cost to the customer. While it is possible that some SGIP applicants might consider energy efficiency measures when sizing their projects on their own initiative, we cannot be certain that such a practice is universal.

We agree that, as CCSE notes, "the appropriate energy efficiency measures will vary not only from technology to technology, but likely from project to project."[42] We adopt Staff's recommendation that customers be required to submit a summary of the completed audit, identifying which, if any, energy efficiency measures will be taken and how these measures affect sizing of the project. As a general rule, we will require that any measures with a payback period of two years or less be implemented prior to receipt of the upfront incentive payment. Exceptions may be granted by the PA if documentation is submitted by the applicant explaining why implementation of the measure(s) was not feasible. In order to avoid duplication of effort, the audit requirement will be waived if a comprehensive audit has been performed within five years of the date of submission of the SGIP reservation request. Applicants should submit documentation that verifies the audit was performed and a description of the measures identified in the audit that were undertaken.

4.5.6. Application Fee and Maximum Reservation Hold Time

Staff recommends an application fee for all SGIP projects and solicits comments on whether the fee should be a fixed amount or a percentage of project cost. According to Staff, the PAs have experienced additional work and increased administrative costs due to SGIP projects re-submitting the same application right after their project was cancelled because the project did not

[42] CCSE November 15, 2010 comments at 16.

meet the required project milestones. Staff argues re-submitting an application re-sets the timeline at no penalty to the developer and slows the processing time for SGIP applications.

Staff proposes that projects should pay an application fee at the point of initial reservation requests, but the fee should be refundable once projects are complete. Staff also proposes that public entities pay half the application fees that commercial customers pay. The proposed application fees for commercial customers are as follows:

0-25 kW = $0
25-50 kW = $1,000
50-100 kW = $2,500
100-250 kW = $5,000
250-500 kW = $10,000
500-1000 kW = $20,000
1000-3000 kW = $25,000

Staff also proposes that the current reservation hold time of 18 months for a project be limited to a maximum of two extensions, for six months each According to Staff, there is no formalized or consistent process for granting extensions. Staff reports a significant number of SGIP projects have held reservations for longer than 18 months. These projects are holding up SGIP funds that could be used for other projects.

A number of parties agree with requiring an application fee. They differ on the structure of the fee or whether the fee should apply to all technologies.

Debenham agrees with re-instituting application fees, and proposes the following tiered fee schedule based on project size.

- $4,000 for first MW
- $2,000 for second MW
- $1,000 for third MW

Debenham also proposes that we waive the application fee for projects that usually invest in obtaining measurement or preliminary engineering work that are needed for securing a permit prior to submitting an SGIP application. In Debenham's view, these types of expenses could be considered as proof that the applicant intends to complete the project, thus no additional application fee should be required.

CESA also supports of an SGIP application fee but proposes the following structure

1) Residential applications (systems < 10kW) should be either free or capped at $100;
2) Project application fees should be a flat 1% of the proposed incentive amount; and
3) All Application fees should be forfeited if a project is either withdrawn, expired, or cancelled. Forfeited fees should be used to offset program administration costs or be returned to fund projects. If a project is successfully completed and a claim is filed and paid the fee should be refunded at the time of claim payment.

CESA also recommends requiring application fees from all SGIP applicants that are currently on the PAs' waitlist to secure their spots. CESA argues that without an application fee, there is almost no downside to simply applying for an SGIP reservation.

With respect to project hold time, several parties support establishing and enforcing project development timelines. Some parties advocate an 18 month deadline with no extensions. FCE suggests extensions be limited in duration and granted only if circumstances arise that are beyond the developer's control. In addition, FCE advocates that extensions should not be granted to projects that have not made satisfactory progress toward completion in compliance with established milestones and requirements.

Discussion:

We adopt an application fee equal to 1% of the amount of requested incentive as for SGIP projects. Previously, an application fee was required of all SGIP applications, but it was eliminated to encourage more participation in SGIP. We agree that an application fee serves to support PAs and create a disincentive for a perpetual application process. Moreover, we agree with CCSE that scaling the fee appropriately to the project size will help deter applicants who are not fully committed to completing their projects. Accordingly, we re-institute the application fee as recommended by CCSE and other parties.

In addition, we require that all projects be limited to a maximum of two, extensions of six month each, after which the reservation expires automatically. We do so to clarify how the PAs should handle requests for extensions. A lack of clarity has resulted in inconsistent treatment of extension requests among the PAs and a general concern over the number of extensions granted. We agree with CESA that given the recent increased demand for SGIP funds, there is a need to ensure that the PAs manage the SGIP budget in such a way that only high quality applications with a high likelihood of completion remain in the queue. Moreover, it is important that the deadlines for completing projects are enforced to ensure unduly delayed projects do not hold up funds that could be used for other projects. At the same time, we agree that there may be circumstances beyond the developer's control that warrant an extension. To that end, extensions should be limited in duration and granted only for special circumstances. In addition, extensions should not be granted to projects that have not made satisfactory progress toward completion in compliance with established milestones and requirements.

Currently, PAs do not collect any information on the number of projects that request extensions or the number of projects that do not meet the extension deadlines. This information would be useful in determining the appropriate number of extensions and the appropriate length of an extension. We will require the PAs to collect this information and submit a report annually to Energy Division. In the propsoed decision we allowed two six-month extension and directed the PAs to cancel projects that do not meet the required deadline. In comments on the proposed decision, PG&E and UTC recommend we require projects justify the need for second extension. We agree the second extension should not be automatic. Instead, the request for a second extension should be made to the SGIP Working Group. The SGIP Working Group should consider whether progress has been made that suggests an ability to meet an extended deadline before granting a second extension.

4.5.7. Warranty Requirement

Staff recommends all technologies except wind turbines have a ten-year service warranty. For wind turbines, Staff recommends a 20-year warranty.

Currently, SGIP only requires projects to have a five-year warranty on parts. There is no requirement for a service warranty. We agree with Staff that requiring only a parts warranty is insufficient to protect ratepayers' investment. A service warranty for a reasonable expected useful life of a project ensures proper maintenance and continued project performance. We find that requiring a service warranty is reasonable. At the same time, we agree with UTC that further stakeholder input on specific warranty requirements is needed. Therefore, we will direct the Energy Division Staff to hold a workshop on the subject of the warranty.

5. Comments on Proposed Decision

The proposed decision in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on August 8, 2011, and reply comments were filed on August 15, 2011 by parties. We have considered parties' comments. Revisions to the proposed decision in response to the comments are reflected in this decision.

6. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Maryam Ebke is the assigned ALJ to this portion of the proceeding.

Findings of Fact

1. The intent of SGIP is to encourage deployment of DG to reduce peak demand, give preference to new renewable energy capacity, and ensure deployment of clean DG technologies.
2. Pub. Util. Code § 379.6 requires the Commission, in consultation with the California Air Resources Board, to determine what technologies should be eligible for SGIP based on GHG emissions reductions.
3. Pub. Util. Code § 379.6 does not require the Commission consider cost-effectiveness or the need for incentives as screens in assessing technology eligibility for the SGIP.
4. The requirement that a technology pass the cost-effectiveness test and the need for incentives can be complex and administratively difficult to implement.
5. Some technologies may be able to provide additional information to demonstrate that they are GHG reducing.
6. Stand-alone AES may reduce peak demand and GHGs.
7. The CSI program has a declining incentive structure.

8. Only some of SGIP systems have metering and monitoring equipment installed.

9. Ten percent of the SGIP budget is set aside for administration, including general administration, monitoring and evaluation, and marketing and outreach.

10. Allowing SGIP projects to export to the grid will provide flexibility in the program.

11. Energy efficiency is the top priority in the State's loading order.

Conclusions of Law

1. Using the GHG emissions reduction test as a screen for SGIP eligibility is consistent with Pub. Util. Code § 379.6.

2. It is reasonable to adjust the CARB's GHG factor by 20% to reflect the fact that DG displaces a mix of resources, including renewable resources as required by the RPS statute.

3. It is reasonable to provide interim support to stand-alone AES while the Commission considers various proposals in other related proceedings.

4. It is reasonable to include PRT as an eligible SGIP technology.

5. It is reasonable to remove the minimum size requirement for SGIP projects.

6. It is reasonable to remove the maximum size limit for SGIP projects.

7. It is reasonable to adopt an incentive structure that reflects the nature of the fuel rather than just the technology.

8. It is reasonable to adopt incentive levels of $1.25/Watt for renewable and waste heat capture technologies and $0.50/Watt for conventional fueled-based CHP technologies.

9. Because fuel cells, biogas and AES are emerging technologies that have to potential to make significant contributions to the State's energy and

environmental goals, it is reasonable to adopt higher incentives for these technologies.

10. The SGIP incentives should contain both an up-front incentive and a performance-based incentive component.

11. It is reasonable to reduce or eliminate PBI payments in years that cumulative GHG reductions do not occur.

12. It is reasonable to adopt a declining incentive structure for the SGIP.

13. SGIP participants should be expected to pay at least 40% of a project's up-front cost.

14. It is reasonable to limit the annual manufacturer concentration to no more than 40% of the SGIP annual statewide budget.

15. It is reasonable to require a maximum incentive amount of $5 million per project to ensure that more customers are able to participate in the SGIP.

16. It is reasonable to require accurate and current performance data to track the performance of SGIP funded projects.

17. Accurate metering and monitoring data is necessary to verify performance for PBI payments of SGIP systems.

18. It is reasonable to allocate 3% of the PAs' program administration budget to fund more projects.

19. In order to encourage optimal sizing of CHP installations to achieve maximum efficiency, SGIP projects should be allowed to export up to 25% of their annual output to the grid.

20. It is reasonable to require SGIP systems to conduct an audit to identify which, if any, energy efficiency measures will be taken.

21. Implementation of measures identified in the energy efficiency audit with payback periods of two years or less should be required as a prerequisite to SGIP

participation unless the applicant provides sufficient justification regarding the infeasibility of implementing the measure(s).

22. It is reasonable to require SGIP projects to pay an application fee that is based on 1% of the amount of incentive requested.

23. Projects under 30 kW should receive the entire incentive upfront.

24. It is reasonable to require a service warranty of SGIP projects.

25. Today's order should be made effective immediately.

26. This proceeding shall remain open to address other issues.

O R D E R

IT IS ORDERED that:

1. The program administrators for the Self-Generation Incentive Program shall implement the changes to the program as summarized in Attachment A.

2. Within 30 days of the effective date of this decision, the program administrators for the Self-Generation Incentive Program shall file Tier 2 advice letters that propose:

- Handbook revisions necessary to implement this decision and as summarized in Attachment A;
- Improvements to the waste heat utilization worksheet, to determine and to qualify the project as green house gas reducing;
- A greenhouse gas emission rate testing protocol for electric-only technologies that consume fossil fuels; and
- Guidelines to protect against entities creating different governance structures to be able to achieve more funding than the capped amount.

3. Within 60 days of the effective date of this decision, the program administrators for the Self-Generation Incentive Program shall file Tier 2 advice letters that propose:

- Implementation of the hybrid-Performance-Based Incentive payment structure; and
- Metering and monitoring protocols.

4. Upon approval of the revisions to the Self-Generation Incentive Program handbook, the current suspension of the Self-Generation Incentive Program is lifted and the program administrators shall resume accepting reservation requests for the Self-Generation Incentive Program.

5. This order is effective today.

Dated September 8, 2011, at San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
Commissioners

We reserve the right to file a concurrence.

/s/ TIMOTHY ALAN SIMON
Commissioner

/s/ MARK J. FERRON
Commissioner

ATTACHMENT A

Modifications to the Self-Generation Incentive Program (SGIP)

Eligibility: Based on greenhouse gas (GHG) reductions, not financial need or cost-effectiveness.

- Non-renewable CHP eligibility determined on project-by-project basis.
- Electric-only technologies using fossil fuels will need certification of performance according to a testing protocol to be filed by advice letter.

GHG baseline: 349 kg CO_2/MWh[1]

[1] This avoided emission factor does not account for avoided transmission and distribution losses. The actual on-site emission rate that projects must beat to be eligible for SGIP participation is 379 kg CO_2/MWh. Eligibility is determined based on a cumulative 10 years performance.

SGIP Incentive Levels by Category

Technology Type	Incentive ($/W)
Renewable and Waste Heat Capture	
Wind Turbine	$1.25
Bottoming-Cycle CHP	$1.25
Pressure Reduction Turbine	$1.25
Conventional CHP	
Internal Combustion Engine – CHP	$0.50
Microturbine – CHP	$0.50
Gas Turbine – CHP	$0.50
Emerging technologies	
Advanced Energy Storage[2]	$2.00
Biogas[3]	$2.00
Fuel Cell – CHP or Electric Only	$2.25

Storage Eligibility: Stand-alone as well as SGIP/PV paired.

Advanced Energy Storage (AES) must be able to discharge its rated capacity for a minimum of 2 hours

Biogas Eligibility: on-site and in-state directed.

- Directed biogas contracts must be for a minimum of ten years, and provide a minimum of 75% of the total energy input required each year.
- On-site biogas must also provide 75% of the total energy input required each year.

System size: No minimum or maximum size restrictions given that project meets onsite load.

---

2 Stand-alone or paired with solar PV or any otherwise eligible SGIP technology.

3 Biogas incentive is an adder that may be used in conjunction with fuel cells or any conventional CHP technologies.

- Wind & renewable-fueled fuel cell: 30kW minimum, smaller projects may apply to the California Energy Commission's Emerging Renewables Program.

Payment Structure: 50% upfront, 50% PBI based on kWh generation of on-site load.

- Projects under 30 kW will receive the entire incentive upfront.
- Projects will be subject to a 5% band for GHG emission rate.
- No penalty is assessed in any year that cumulative emissions rate does not exceed 398 kg CO2/MWh.
- PBI payments will be reduced by half in years where a project's cumulative emission rate is greater than 398 kg CO2/MWh but less than or equal to 417 kg CO2/MWh.
- Projects that exceed an emission rate of 417 kg CO2/MWh in any given year will receive no PBI payments for the year.

Assumed Capacity Factors: 10% for AES, 25% for wind, and 80% for all other distributed energy resources (DER).

- DER which does not achieve this capacity factor over five years will not be paid full PBI

Tiered Incentive Rates: Unchanged.

0-1 MW = 100 %
1-2 MW = 50 %
2-3 MW = 25 %

Incentive Decline: 10% per year for emerging technologies and 5% per year for all other technologies, beginning 1/1/2013.

Program Administrators (PAs) Advice Letter: Within 30 days of the effective date of the decision, the PAs must submit a Tier 2 advice letter detailing:

- Handbook revisions necessary to implement this decision and as summarized in this Attachment;
- Improvements to the waste heat utilization worksheet necessary to qualify fossil fuel-based combined heat and power projects as greenhouse gas reducing;

- A greenhouse gas emission rate testing protocol for electric-only technologies that consume fossil fuels; and
- Guidelines to protect against entities creating different governance structures to be able to achieve more funding than the capped amount.

Within 60 days of the effective date of this decision, the program administrators for the Self-Generation Incentive Program shall file Tier 2 advice letters that propose:

- Implementation of the hybrid-PBI payment structure; and
- Metering and monitoring protocols.
  - These protocols to be informed by a public workshop to be held by PAs, which will examine size-differentiation in metering requirements, among other issues.

Priority: Will be given to waitlisted projects and those completed between 1/1/2011 and the date of this decision.

Supplier Concentration: 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. The initial 40% limit will cover the period from the launch of the new program through 2012 and will be calculated based on the total funding available when the program is reinstated plus any additional funds collected in 2012, if applicable.

Maximum project incentive: $5 million

Minimum customer investment: Based on the formula: 1-applicable Investment Tax Credit (ITC)-0.4

- The biogas adder does not count toward above limit for projects using DBG. Instead, the adder should be 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.

Budget Allocation: 75% renewable and emerging technologies, 25% non-renewable. PAs may shift funds from the non-renewable category to the renewable and emerging technology category at their discretion if funds in the renewable and emerging technology category are exhausted. PAs must file an advice letter to receive authorization to shift funds from the renewable and emerging technologies category to the non-renewable category.

3% of PAs' budgets for program administration should be allocated to funding projects.

Metering: 15 minute interval data for kWh generation, heat output, fuel input, and AES charging/discharging to be provided to PAs, Energy Division, and or evaluation contractor on a quarterly basis for the first five years.

Export to Grid: 25% maximum on an annual net basis.

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. Any measures with a payback period of two years or less shall be implemented prior to receipt of the upfront incentive payment. Exceptions may be granted by the PAs if documentation is submitted by the applicant explaining why implementation of the measure(s) was not feasible.

Application Fees: 1% of the amount of incentive requested Extensions: All projects must be limited to one, six-month extension. A request for second extension should be made to the SGIP Working Group for approval.

Warranty: ten-year warranty required.

(END OF ATTACHMENT A)

R.10-05-004
D.11-09-015

Concurrence of Mark J. Ferron on Item 40 (D.11-09-015) Decision Modifying the Self-Generation Incentive Program and Implementing Senate Bill 412

Colleagues,

I will be supporting this decision.

First of all I wish to acknowledge the very fruitful discussion that we had on this dais at the last business meeting. This is a very complex and technical subject, but it's clear that the open discussion we had here last time shaped this document in many positive ways. I sincerely hope that this way of working through the details of an issue - - in front of an open audience and without the comfort of a safety net - - will be a model going forward.

As I see it, this decision is about how do we best design an incentive mechanism that best encourages local generation and GHG reduction across an array of technologies - - both established and important emerging technologies - - without creating undesirable long-term distortions in this emerging market.

We are making decisions about the level of incentive payments, allocation of the amount of money to be spent across competing technologies and supplier concentration limits, as well as other matters. We are dangling out a not-insignificant amount of money, and yet it is impossible for the Commission to know whether it has calibrated its parameters correctly. Most likely, we won't get these parameters exactly right in the first instance, so we need to be careful - - and flexible - - in our approach. We do not want to give away ratepayer money unnecessarily to companies that are a "winning technology" solely because we were unintentionally overly generous, nor do we want to waste money by paying excessive incentives to companies that are going to "win" anyway.

At the same time, we need to balance this "flexibility" with the need to have stability in our incentives in order to encourage the world of inventors and investors to come to California and help us transform the market for Distributed Generation. We need to be flexible yet we should resist the urge to tinker and hence introduce uncertainty which discourages the innovation and investment that the decision is designed to encourage. I believe this decision is a good balance across all of these factors.

I am very pleased that we have put in some additional language requiring Energy Efficiency audits and implementation of EE measures that have a 2-year payback before the applicant can receive an upfront incentive. This is a wonderful step forward, and I hope that we will consider making additional connections between DG and EE going forward. I see this as part of a more holistic, customer-focused approach to these issues - - rather than a silo'd approach - - and will create a greater benefit to ratepayers. I do not think that the language in the PD is as strong as it could be, but I recognize that this is an important first step and that we should continue to take additional steps in the months and years ahead.

I am pleased to offer my support on this item.

Dated September 8, 2011, at San Francisco, California.

/s/ MARK J. FERRON
Mark J. Ferron
Commissioner

Concurrence of Commissioner Timothy Alan Simon on Item 46 [D.11-09-015] Decision Modifying the Self-Generation Incentive Program and Implementing Senate Bill 412

I concur with this decision as a necessary step that will further incentivize and advance the development of small-scale generators in California while integrating state's goal of reducing greenhouse gas emissions. The decision has identified several proactive steps that demonstrate high priority and promotes small generators. This decision further moves California closer to its goal of reducing green house gas emissions and modify the Self Generation Incentive Program (SGIP) conforming to the Senate Bill 412 (Kehoe).[1] Additionally the decision helps SGIP further to conform to the California Global Warming Solutions Act of 2006 (AB32 Nunez/Pavley).[2]

This decision is a concerted effort of many stakeholders to make the already established SGIP program more accountable, environmentally friendly, energy efficient, emerging technology promoting and provide incentives to small-scale generation in California. What the decision lacks is a rational treatment of out of state directed biogas. It begs the question as to whether this decision picks a winner among small generators. I am sympathetic to this concern and urge my fellow commissioners to grant equal time to the evaluation and recognition of out of state directed biogas.[3] I note the concerns that this decision disallows out of state directed biogas to be considered for SGIP eligibility. As there is California's embargo on instate landfill biogas supply,[4] the decision should have

[1] Stats 2009 ch 182 § 1 (SB 412); Cal Pub Util Code § 379.6.

[2] Stats 2006 ch 488 § 1 (AB 32); Cal Health & Saf Code §§ 38500-38599.

[3] CPUC Decision 11-09-015.

[4] 2009 Progress to Plan: Bioenergy Action Plan for California, CEC-500-2010-007, April 2010, at 15, http://www.energy.ca.gov/2010publications/CEC-500-2010-007/CEC-500-2010-007.PDF; Hayden Act, Stats 1988 ch 932 § 2 (AB 4037); Cal Health & Saf Code §§ 25420-25422 and Cal Pub Util Code § 2775.6.

Note: The Hayden Act precludes using California landfill gas in gas pipelines, although utilities can purchase out-of-state landfill gas without restrictions. If a pipeline operator were to allow the injection of landfill gas into the pipeline then such pipeline operator and gas developer would be exposed to $2500 penalty per day for each violation.

allowed out of state directed biogas to participate in SGIP until there was a sunset clause lifting the ban on instate biogas. The result may have a damaging effect on California's renewable advancement and job growth. I am sympathetic to this concern and urge my fellow commissioners to grant equal time to the evaluation and recognition of the role of directed biogas to reduce California's carbon footprint.[5]

The other concern I have with this decision is about budget allocation[6] where the Program Administrators with advice letter approval can allocate funds from the approved 25 percent non-renewable bucket to already budgeted 75 percent renewable and emerging technology bucket when the renewable bucket funds are exhausted. My concern is that by not strictly following the 75-25 budget allocation rule the decision predetermines the fund allocation in favor of renewable technology.

While I am sensitive to the concerns expressed by Bloom Energy[7] I encourage Bloom Energy to follow course and demonstrate how not allowing out of state directed biogas is contradictory of SGIP incentive program. Otherwise, we will miss an opportunity to promote another renewable resource and technology.

Accordingly, I concur with this decision and will determine if we need to revisit a separate proceeding to address directed biogas.

Dated September 15, 2011, at San Francisco, California.

/s/ TIMOTHY ALAN SIMON
Timothy Alan Simon
Commissioner

---

[5] CPUC Decision 91-07-018 at 12; Decision 93-07-054 at 13.

[6] CPUC Decision 11-09-015 (Attachment A pages 4-5).

[7] Reply Comments by Bloom Energy Corporation to the Proposed Decision Modifying the Self-Generation Incentive Program and Implementing Senate Bill 412, August 15, 2011, at 2.