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ENERGY DIVISION STAFF PROPOSAL

ED Staff Proposal on SGIP

Staff Proposal to Modify the

Self-Generation Incentive Program

Pursuant to SB 861 and the Commission's Own Motion

November 23, 2015

Prepared by:

California Public Utilities Commission

Energy Division

Customer Generation Programs

ED Staff Proposal on SGIP

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Acronyms

AB:	Assembly Bill
ACR:	Assigned Commissioner's Ruling
ALJ:	Administrative Law Judge
CE Study:	2015 SGIP Cost Effectiveness Study, by Itron
CESA:	California Energy Storage Alliance
CHP:	Combined heat and power
CPUC or Commission:	California Public Utilities Commission
CSE:	Center for Sustainable Energy
CSI:	California Solar Initiative
D.:	Decision *(of the Commission)*
DER:	Distributed energy resource (i.e. distributed generation and storage)
DBG:	Directed biogas
GHG:	Greenhouse gas
GRC:	General rate case
ICE:	Internal combustion engine
IOU:	Investor-Owned Utility (*here* PG&E, SCE, SDG&E)
M&E:	Measurement & Evaluation
MIRR:	Modified internal rate of return
MOEWS:	Minimum Operating Efficiency Worksheet
MT Study:	2015 SGIP Market Transformation Study, by Itron (expected October 2015)
NO_X:	Nitrogen oxide
NRTL:	Nationally recognized testing laboratory (e.g. UL)
OSBG:	On-site biogas

PAC test: Program administrator cost test

PBI: Performance-based incentive

PCT: Participant Cost Test

PG&E: Pacific Gas and Electric

PM_{10}: Particulate matter with diameter no greater than 10 micrometers

PRT: Pressure reduction turbine

PV: Photovoltaic solar cells

SB: Senate Bill

SCE: Southern California Edison

SCG: Southern California Gas Company

SDG&E: San Diego Gas & Electric Company

SGIP: Self-Generation Incentive Program

SO_2: Sulphur dioxide

Staff Proposal: Staff Proposal to Modify the Self-Generation Incentive Program

STRC test: Societal TRC test

TRC test: Total Resource Cost test

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I. Background and Introduction

This Staff Proposal to Modify the Self-Generation Incentive Program (Staff Proposal) represents Energy Division's proposal to implement Senate Bill (SB) 861 (2014 Committee on Budget and Fiscal Review) and Assembly Bill (AB) 1478 (2014 Committee on Budget)[1] and to improve the Self-Generation Incentive Program's (SGIP's) ability to achieve the program's goals. It follows directly from the April 29, 2015 Assigned Commissioner's Ruling (ACR). The ACR sought comments from parties regarding requirements to conform to new statutory provisions required by SB 861 and AB 1478, excluding greenhouse gas (GHG) factor updates.[2] In addition, the ruling asked parties to comment on other possible program revisions that may improve the SGIP that are not required by SB 861 or AB 1478. On May 22 and June 6, 2015 parties filed comments and replies, respectively, to the ACR.

In addition to the ACR and parties' comments, this Staff Proposal is informed by the decision (voted on November 19, 2015) on GHG factor updates and by recent SGIP studies. The decision updates the greenhouse gas emission factor that determines eligibility to participate in SGIP by:

- Setting 350 kg/MWh (down from 379 kg/MWh, the current standard) as the maximum level of CO2 emissions allowed for technologies participating in program year 2016.
- Reflecting increasing renewables targets imposed by SB 350 (2015, DeLeon), with a resulting GHG threshold that decreases with each program year, ending at 337 kg/MWh in 2020.
- Establishing 66.5% (up from 63.5%) as the minimum round trip efficiency (RTE) for storage technologies.
- Maintaining ten years as the period over which new SGIP projects' averaged emissions should be compared to the grid's emission, with the assumption of 1% annual degradation in SGIP project performance.

Energy Division and the SGIP program administrators commissioned Itron to perform three studies on SGIP to be released in 2015. The first study, the 2013 SGIP Impact Evaluation, was completed in April 2015 and reviews how SGIP has reduced the grid's energy requirements, peak demand, and pollutant emissions. The second study, the 2015 SGIP Cost Effectiveness Study (CE Study), was released on November 23, 2015.[3] The report performs cost effectiveness analyses of SGIP technologies and uses the results to make recommendations for continued participation in the program. Itron is currently drafting the third study, a market transformation study evaluating the potential for different SGIP

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[1] After the passage of SB 861, AB 1478 made minor modifications to Public Utilities Code Sections 379.6(e)(1) and 379.6(l)(4) to address impacts on customer peak demand. All code references are to the Public Utilities Code unless otherwise indicated.

[2] A Proposed Decision addressing updates to the SGIP GHG factors, as required by PU Code 379.6(b)(2), mailed on July 7, 2015 and a revised version was approved by the Commission on November 19, 2015

[3] These Itron SGIP studies are available at http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm.

technologies to be self-sustaining, as well as the extent to which they have already done so. That study is expected to be released to the public by the end of this year.

This Staff Proposal reviews the issues raised by the ACR and addressed in parties' comments, discusses possible policy directions, and provides recommendations.

II. Program goals and requirements

The April 29, 2015 ACR posed a number of questions related to SGIP goals and requirements, as well as how program success should be measured. Parties' responses to these questions provided a range of perspectives and have informed the following proposed framework.

A. SGIP goals

We propose that SGIP goals be grouped into three categories – environmental, grid support, and market transformation. Some of the goals listed below are specified in the statute, while others are proposed because they represent good public policy. The proposed goals are outlined as follows:

1. Environmental:
   a. Reduce GHGs.[4] This can be accomplished in two ways:
      i. Operationally emit fewer GHGs than the eligibility threshold, representing the grid's carbon intensity
      ii. Facilitate integration of renewables (this is especially applicable to storage)
   b. Reduce criteria air pollutants (namely, SO_2, NO_X, and PM_{10})[5]
   c. Limit other environmental impacts
      i. Water use[6]
2. Grid support:
   a. Reduce or shift peak demand.[7]
   b. Improve efficiency (e.g. fewer line losses) and reliability of the distribution and transmission system.[8]
   c. Lower grid infrastructure costs.[9]
   d. Provide ancillary services.[10]

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[4] 379.6(a)(1).
[5] While the statute does not explicitly state this is as a program goal, 379.6(e)(4) does require that participating SGIP technologies reduce criteria air pollutants.
[6] The statute does not include this as a goal for SGIP. Bloom recommended this goal in their comments; NFCRC and Doosan supported this goal in their replies. Staff agrees that limiting water use is important, both because of the long-term structural and environmental strains on water sources that California faces, and because of the current drought which exacerbates these long-term constraints.
[7] 379.6(a)(1).
[8] 379.6(a)(1).
[9] 379.6(a)(1).
[10] Ancillary services are not listed in the statute, but they are an important form of grid support.

e. Ensure customer reliability of DER.[11]

3. Market transformation: SGIP should support technologies that have the potential to thrive in future years without rebates.[12]

B. Requirements for program design

In addition to program goals, the statute requires that the program:

1. Maximize the value to ratepayers from SGIP incentives.[13] We propose to accomplish this by:
   a. Lowering rebates for those qualifying technologies which meet too few of the program goals. (See below for more detail)
   b. Lowering rebates for those technologies that are already cost effective from the participant's perspective. (See below for more detail)
2. Provide for an equitable distribution of the costs and benefits of the program:[14]
   a. Costs are currently allocated across all customer classes, with residential customers absorbing roughly half the cost of the program even though just one percent[15] of rebates go to projects with residential host customers. Staff proposes that future general rate cases (GRCs) adjust this allocation, so that costs are borne by customer classes more in proportion to their level of program participation. The utilities should include reallocation proposals in their next GRC Phase II applications.
   b. Environmental and grid benefits accrue to all ratepayers.

III. Eligible technologies

In this section we propose certain requirements for participating SGIP technologies, review parties' comments as well as the findings of two recent Itron studies, note the determination regarding the recently updated GHG factor, and recommend certain technologies for inclusion in the program going forward.

A. List of requirements for technology eligibility

The statute requires that each SGIP technology, either directly or indirectly:

1. Lower GHG emissions,[16] and

[11] System reliability is presented as an SGIP goal in 379.6(a)(1) and required to be used as a criterion in allocating funding across technologies in 379.6(h)(2), while customer reliability is required to be measured in gauging program success in 379.6(l). Staff proposes that the customer reliability criterion be assumed to have been met, a priori, because customers would not choose technologies which rendered their provision of electric service less reliable.

[12] In D.11-09-015 the Commission included market transformation as a program goal. By transforming the market for certain technologies, SGIP can ensure that the program's benefits endure after the program ends.

[13] Concern for SGIP's impact on ratepayers is registered in several places in the statute, namely, 379.6(a)(1), 379.6(a)(2), 379.6(h)(1), and 379.6(i).

[14] 379.6(a)(1).

[15] An October 6, 2015 download of the SGIP projects database reveals that, of the $479 million of SGIP rebates for active (i.e. not cancelled or waitlisted) projects from the 2012 to 2015 program years, just $5 million went to projects with residential host customers.

[16] 379.6(b).

2. Lower or shift peak load to off-peak[17], <u>and</u>
3. Be safe and commercially available[18], <u>and</u>
4. Reduce criteria air pollutants.[19]

To this list we add two more criteria (these are preferences, or "soft" requirements; in other words, they are desirable qualities, but not required). The technology should achieve:

5. Cost-effectiveness. Technologies should provide a net benefit to society, as measured by the Societal Total Resource Cost (STRC) test, or have the potential to do so.

6. Market transformation. Technologies should demonstrate the possibility of becoming self-sufficient, or attaining market transformation.

The STRC incorporates information about market prices for capital investments, fuel, labor, as well as federal tax rules. It also incorporates some environmental factors. However, because of the uncertainty inherent in this type of analysis, we will treat this criterion like a preference rather than a requirement.

The ACR asked parties whether the potential for self-sufficiency should be a criterion for program participation. Except for CESA and SolarCity, nearly all parties argued that the potential for self-sufficiency should not be required of program technologies, citing the unknowability of the future. Staff agrees that future technological and market developments cannot be known with certainty, and so instead of making this a requirement, we propose to give preference to programs which display promise for future self-sufficiency. Because the Itron market transformation study (MT Study) has yet to be released, this Staff Proposal does not contain results from that report's published findings. Energy Division expects the report will be available later this year to inform the Commission's decision-making.

Staff also considered adding another requirement, namely, that only those technologies which *need* incentives in order to be cost effective from the participant's perspective (see Section III.B.1.b above) should be eligible. In their comments to the ACR's question on this topic, parties generally expressed their agreement in theory, but noted how difficult it is to gauge cost effectiveness in practice. For this reason, we propose to exclude this criterion from the list of eligibility requirements. But the program design requirement to maximize ratepayer value mandates that we avoid paying out generous rebates where they are not needed. Staff therefore proposes to comply with that requirement by lowering incentives for technologies which are not deemed to need as much support from SGIP incentives (see below for staff's proposed rebate levels).

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[17] 379.6(e)(1).
[18] 379.6(e)(2,3).
[19] 379.6(e)(4).

B. Review of technologies with respect to the requirements

In this section we review each of the six proposed technology requirements to see how they will affect the list of eligible technologies.

1. *Lower GHG emissions:*

Pursuant to SB 861, the Commission has updated the factor (i.e. 350 kg/MWh, descending to 337 kg/MWh) for avoided GHGs in the proposed decision on GHG factor updates, as well as the minimum RTE (66.5%) required for energy storage technologies.[20] The GHG threshold applies to SGIP technologies that consume natural gas, namely, fuel cells and the "conventional" combustion technologies.[21] Currently, fuel cells in SGIP may be either "pure electric" or combined heat and power (CHP), whereas the conventional technologies (ICE, gas turbine, and microturbine) must be CHP.

The 2013 SGIP Impact Evaluation summarized the GHG impact of each natural gas-consuming technology. All of these technologies except for microturbines were found, on average, to avoid GHG emissions.[22]

The most recent decision which significantly revised SGIP was D.11-09-015. In that decision, the Commission ruled that CHP systems' GHG emissions contain enough variability to require that each system should independently document to the SGIP PAs its compliance with the GHG emissions requirement. If CHP fuel cells and CHP conventional technologies are allowed to continue to participate in the program, then it is reasonable that the program should continue this individual review for natural gas-consuming CHP systems for GHG emission compliance.[23]

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[20] Because the RTE for currently participating SGIP storage technologies is well above the 66.5% threshold, continued participation of energy storage is note in question; energy storage applicants for SGIP rebates will simply need to provide the SGIP program administrators (PAs) with documentation that their systems will operate above this level for the ten year comparison period.

[21] These conventional combustion technologies are internal combustion engines (ICEs), gas turbines, and microturbines (i.e. gas turbines which are smaller than 1 MW). Fuel consuming technologies in SGIP can consume either natural gas or biogas, but because the use of biogas results in no GHG emissions on a life-cycle basis, the GHG limits discussed here apply only to the natural gas consuming systems.

[22] Table C.4 of the IE Study shows the results of the study and Section C.3 describes the methodology, which involves an hour-by-hour production cost model. The method used in the Impact Evaluation differs from the approach taken in the Decision updating the GHG factor in that the Impact Evaluation assumes that only gas plant operation is avoided by SGIP systems; the Impact Evaluation does not account for the "build margin" incorporated in the Proposed Decision's approach.

[23] For the review, the SGIP applicants provide information to the PAs in a form called a Minimum Operating Efficiency Worksheet (MOEWS).

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Having addressed conventional and fuel cell CHP technologies, we next address pure electric fuel cells. In response to an August 7, 2015 data request, the SGIP PAs have provided to Energy Division the claimed ten-year average of GHG emissions for each pure electric fuel cell in SGIP.[24] The claimed fuel cell emissions rate in virtually every case was 351 kg/MWh. In addition to emission rates claimed by applicants, Energy Division analyzed actual performance based incentive (PBI) performance data, which has revealed that pure electric fuel cells on average emit 351 kg/MWh. By a small margin, then, it appears that the current generation of fuel cell technology fails to meet the GHG requirements of the decision on GHG factor updates.

2. *Lower or shift peak load to off-peak:*

Chapter 6 of the 2013 SGIP Impact Evaluation examines the impact of SGIP projects on the grid during peak times. Figure 6-5 summarizes these impacts. While some technologies provide more benefits than others, all SGIP technologies inject power into the grid at peak times, or at least some portion of peak times. Therefore, we consider that this requirement is being met by all SGIP technologies now in the program.

3. *Be safe and commercially available:*

SGIP currently requires that technologies be commercially available, and allows certification by a nationally recognized testing laboratory (NRTL) to demonstrate compliance with this requirement. Staff recommends that NRTL certification be confirmed as a means of demonstrating commercial availability. Staff further recommends that NRTL certification be deemed sufficient to demonstrate compliance with the requirement that the technology is safe. Because this certification may require some time, we recommend allowing a one-year grace period (after the date of the decision addressing this Staff Proposal) before this requirement is enforced. Following the grace period, this new standard should be enforced on all applications, including current and past participants.

4. *Reduce criteria air pollutants:*

Senate Bill 861 introduced the requirement that SGIP technologies must improve air quality by reducing criteria air pollutants.[25] Criteria air pollutants are a concern only for SGIP technologies that consume methane (i.e. either natural gas or biogas). And, as shown in the 2013 SGIP Impact Evaluation, these pollutants are not a problem for fuel cells, which emit them in extremely small quantities.

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[24] The SGIP applicants provide this information to the PAs through the MOEWS form. This form is intended to demonstrate whether the system will emit fewer GHGs than the allowed threshold (currently, 379 kg/MWh) when averaged over a ten year period, assuming one percent annual performance degradation.

[25] 379.6(e)(4).

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What, then, about conventional natural gas-burning or biogas-burning technologies? Table 7-3 of the 2013 SGIP Impact Evaluation shows decreases for all three types of criteria air pollutants: NO_X, SO_2, and PM_{10}. However, a deeper look into the calculations behind these findings reveals a complex picture. Appendix D of that report confirms that the criteria air pollutant emissions from fuel cells are indeed miniscule, but that the emissions from conventional SGIP technologies either match or exceed the emissions of the grid's baseload units. The reason that the conventional technologies are seen as reducing emissions vis-à-vis the grid is because the addition of CHP makes the systems more efficient, and because the grid to which they are being compared includes not only the baseload combined cycle units but also the less efficient peakers. We should note that in the 2013 SGIP Impact Evaluation, Itron's methodology for estimating emissions (be they GHGs or criteria air pollutants) from grid energy looks only at energy avoided by operational decisions as opposed to a GHG factor methodology that includes a combination of energy avoided by both operational and investment decisions. If Itron's analysis had included avoided emissions due to investment decisions (the "build margin" from the proposed decision on GHG factors), the grid portfolio used for the criteria air pollutant calculations would have included some proportion of renewable energy and thus would have been cleaner than the grid emissions used in the study.

From the foregoing, we can conclude that although the conventional SGIP CHP technologies do emit fewer criteria emissions than the grid in Itron's analysis, it is likely that changing some modeling assumptions would diminish (and might possibly erase) the criteria air pollution benefits from SGIP conventional fossil and biogas units.

5. *Provide benefit to society, as measured by the Societal Total Resource Cost (STRC) test, or have the potential to do so:*

On November 23, Energy Division and the SGIP PAs released the 2015 SGIP Cost Effectiveness Study (the CE Study).[26] The CE Study, conducted by Itron, recommends that decisions regarding the continuation of SGIP funding should be informed by the degree to which the technologies are expected to deliver societal benefits in the future.[27] The CE Study applies a filter to technologies based on how

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[26] The CE Study can be found at http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm

[27] In order to address these criteria, the CE Study performs cost effectiveness (CE) analyses using the California Standard Practice Manual framework, while focusing on the Participant Cost Test (PCT) and the Societal Total Resource Cost (STRC) perspectives, but also providing results of the Program Administrator Cost (PAC) test. In this study, the STRC is exactly the same as the TRC except that it uses a lower discount rate. The Standard Practice Manual can be found at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Cost-effectiveness.htm.

they are expected to perform on the STRC in the year 2020.[28] This future perspective is intended to reflect the technology's potential to provide societal benefits. While a strict application of the STRC test would filter out technologies with an STRC benefit-to-cost ratio below 1.0, Itron argues that uncertainty about future costs and market trends makes it prudent to lower the threshold to 0.8. Staff agrees that it is reasonable to make such an allowance for uncertainty.

Table 2: Technologies' 2020 STRC and PAC[29] test ratios from the CE Study.[30] (STRC ratios below 0.8 are gray-shaded.)

Technology	Capacity (kW)	2020 STRC	2020 PAC
Wind turbine	1500	1.04	7.47
Fuel cell – electric only – natural gas	500	0.62	6.35
Fuel cell – electric only – onsite biogas	500	0.65	3.43
Fuel cell – electric only – directed[31] biogas	500	0.73	3.43
Fuel cell – CHP – natural gas	1,200	0.69	6.29
Fuel cell – CHP – onsite biogas	1,200	0.94	3.40
Fuel cell – CHP – directed biogas	1,200	0.75	3.40
Gas turbine – natural gas	2,500	0.94	27.37
Gas turbine – onsite biogas	2,500	1.45	9.51
Gas turbine – directed biogas	2,500	0.93	9.51

[28] The Societal Total Resource Cost (STRC) test looks at the overall cost effectiveness of SGIP technologies to society at large. The societal test is similar to the TRC except it uses the societal discount rate (a lower discount rate than the utility discount rate used in the Total Resource Cost (TRC). If the ratio of the STRC benefits-to-costs exceeds 1.0, the benefits to society exceed the costs in implementing the SGIP technology.

[29] The Program Administrator Cost (PAC) test examines the cost effectiveness of SGIP technologies from the utility perspective (noting that these costs and benefits are passed onto ratepayers)

[30] CE Study Table 6-1, where statewide average is weighted by electric sales. For reasons of brevity, this table contains only commercial, and no residential, systems. For the analysis, Itron chose system sizes that it considered to be characteristic for that technology.

[31] DBG is gas that is taken from the natural gas grid in equal measure to biogas which is injected into the gas grid at another location. Thus, while the gas consumed by the SGIP system contains very little actual biogas, paper accounting ensures that an environmental benefit has occurred.

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Technology	Capacity (kW)	2020 STRC	2020 PAC
Gas turbine – natural gas	7,000	0.97	47.68
Gas turbine – onsite biogas	7,000	2.16	18.11
Gas turbine – directed biogas	7,000	0.96	18.11
Microturbine – natural gas	200	0.67	18.34
Microturbine – onsite biogas	200	1.21	6.06
Microturbine – directed biogas	200	0.63	6.06
ICE – natural gas	500	0.86	23.12
ICE – onsite biogas	500	1.21	7.71
ICE – directed biogas	500	0.83	7.61
ICE – natural gas	1,500	0.91	24.26
ICE – onsite biogas	1,500	1.52	8.15
ICE – directed biogas	1,500	0.88	8.05
Organic Rankine Cycle	500	2.21	8.44
Energy storage – commercial scale	30	0.83	0.71
Energy storage – industrial scale	5,000	0.77	1.10
Pressure reduction turbine	400	1.85	9.21

Based on these findings, Itron recommends that the seven lowest of the eight technologies with STRC ratios below 0.8 be considered for removal from SGIP. Citing uncertainty as well as its closeness to the 0.8 threshold, Itron recommends that the 5,000 kW energy storage technology be allowed to remain in SGIP. The seven technologies that Itron recommends be considered for removal from the program are: fuel cell – electric-only – natural gas, onsite biogas, and directed biogas; fuel cell – CHP – natural gas and directed biogas; microturbine – natural gas and directed biogas. Staff agrees with Itron's assessment that 5,000 kW energy storage should be allowed to remain in SGIP due to uncertainty and its closeness to the 0.8 threshold.[32]

6. *Demonstrate the ability to become self-sufficient, or attain market transformation:*

This Staff Proposal does not address this criterion, because the Itron MT Study has not yet been published. The findings of that study may inform parties' comments to this Staff Proposal as well as the ensuing proposed decision.

C. <u>Staff recommendations for eligible technologies</u>

The preceding discussion reveals particular issues with natural gas- and biogas-consuming technologies, summarized as follows:

- In terms of GHGs, natural gas-consuming pure electric fuel cells fail, by a small margin, to be cleaner than the grid, while both fuel cell CHP and conventional CHP have wider variability. Among the conventional technologies, natural gas-fired microturbines perform least well, due to their low operating efficiencies.
- In terms of criteria air pollutants, fuel cells are clean, while conventional combustion technologies provide few benefits, with microturbines (both biogas- and natural gas-fired) again performing the least well. Itron's Impact Evaluation did, however, find that all SGIP technologies had lower criteria pollutant emissions than grid power (on a short-term avoided cost, or "operating margin," basis).
- Finally, it is expected that in 2020 the total societal costs of fuel cells and natural gas- and directed biogas-fired microturbines[33] will greatly exceeded their benefits – fuel cells because of high capital costs, and microturbines because of low operating efficiencies.

Based on these observations, staff recommends that SGIP funding no longer be provided for natural gas-fueled pure electric fuel cells[34] or for natural gas-fired microturbines. For all other natural gas-fired CHP technologies, both fuel cell and conventional, the applicant should provide documentation to the program administrator to demonstrate compliance with the GHG factor requirement that over the ten year comparison period, the system will on average emit fewer GHGs than allowed for that

[32] In addition, Itron provides the Program Administrator Cost (PAC) test results (see Table 2). Using the PAC test, all technologies pass the 1.0 net benefits threshold, except for 30 kW energy storage.
[33] Similar to ICEs and gas turbines, microturbines which burn onsite biogas are much more cost effective in the Itron study. This result must be understood in the context of two important facts. First, the fuel costs are zero, since the biogas supply (e.g., a dairies, water treatment plant, or landfill) is understood to be owned and controlled by the owner of the microturbine. Second, the capital cost of the biogas digester is not included in the cost equation, since this generally already required by local air quality laws.
[34] Pure electric fuel cells are almost exclusively natural gas-fueled. Of the 232 pure electric fuel cells which have signed up since 2012, 226 are fueled by natural gas.

program year's threshold, with the assumption that, for all technologies (including CHP) there is 1% annual performance degradation.

IV. Biogas

SGIP now offers those generators whose plants are fueled by biogas, whether onsite or directed, a "biogas adder."[35] This biogas feature of SGIP represents a complex ensemble of promise and problems. The promise of biogas is that it provides GHG-free, renewable energy that makes productive use of waste and can be stored more easily than electricity. At the same time, however, biogas has problems with market adoption, and it presents difficulties for program administration.

A. Market adoption challenges with biogas

Onsite biogas projects benefit from having an inexpensive feedstock, but can be hindered by local zoning ordinances and air quality rules, as well as by mandatory gas collection infrastructure that is capital- and maintenance-intensive. Conversely, directed biogas suffers from high market prices.[36] We expect that this theme will be further developed in the upcoming SGIP MT Study.

B. Administrative challenges with biogas

From a program administration perspective, the challenge is to ensure that SGIP biogas participants are meeting the program's requirement that at least 75% of the gas consumed by the SGIP generator is in fact biogas. To document the level of compliance, the SGIP program administrators issue to the Energy Division regular[37] Renewable Fuel Use Reports (RFURs)[38]. The program's accounting system[39] is important in order to prevent fraud and to ensure that the environmental benefits paid for by ratepayers are actually occurring.[40] Biogas has been a feature of SGIP since the program's beginning,

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[35] For Program Year 2015, the biogas adder was $1.46/W. This is incremental to the rest of the incentive of the generator, which could be conventional ($0.44/W) or fuel cell ($1.46/W)

[36] In their comments, Fuel Cell Energy stated that in-state DBG sources cost from $10.50 to $14.00 per mmBtu. This compares to current California natural gas wholesale prices below $3.00 per mmBtu.

[37] Until 2014 this report was issued semi-annually. Pursuant to an ALJ ruling on December 30, 2015, it is now issued annually.

[38] The 2014 report, RFUR #24, issued August 2015, as well as previous RFURs, can be found at http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm

[39] The SGIP accounting system publishes the RFURs, which track biogas consumption by onsite- as well as directed-biogas plants. To inform the RFUR, for each plant consuming directed biogas, the contractor (presently, Itron) conducts an audit annually.

[40] From 2009 through 2015, SGIP paid $214,841 for the directed biogas audits and $166,281 for the RFUR reports (from data request to PG&E, with response received September 8, 2015).

and so has the accounting procedure. Currently, directed biogas participants are required to provide to the program administrators evidence of a ten-year biogas supply contract. In addition, SGIP biogas participants are required to meet, and demonstrate that they are meeting, the biogas requirements for the duration of their "warranty" period. The length of the warranty period can be three, five, or ten years, depending on the year in which it signed up for the program.

The 2014 RFUR #24 reveals problems with biogas documentation for both onsite biogas plants[41] as well as directed biogas plants. Of the 73 plants still in their warranty period, 51 (70%) were found to be in compliance, thirteen directed biogas plants did not provide enough information to confirm compliance, one project had been out of operation for over a year, and three onsite biogas (OSBG) plants were found to be out of compliance.

When D.11-09-015 instituted the hybrid PBI payment system, one of the problems it aimed to address was the lack of compliance with the biogas requirement. Unfortunately, the delivery of the annual PBI payments and the (now) annual RFUR are ill-timed, with the PBI payments being made prior to the RFUR's compliance determination. Furthermore, even for PBI projects there is no convenient enforcement mechanism in place to ensure that SGIP biogas participants comply with the 75% requirement after five years, when their PBI payments[42] are completed, aside from the ten-year contract noted above. The rebate structure of SGIP, which delivers all incentive payments within the first five years, is an inherently awkward method of incentivizing fuel choices to be made for longer than five years.

Regarding the current rules which award 100% of the biogas rebate when at least 75% of the fuel consumed is biogas, and 0% of the award when less than 75% of the fuel consumed is biogas, most commenters to the ACR indicated their preference for a scheme which would prorate payments based on the percentage of biogas in the blend, or the "biogas blend ratio." As noted by SoCal Gas/SDG&E in their comments, the current approach can force sub-optimal system designs. For example, in a situation where there is not enough supply to meet the 75% minimum, applicants are motivated by the SGIP rules to build two systems, which will be less efficient from a project perspective but will enable one of the systems to receive an SGIP biogas adder.

[41] Biogas plants can be set up to consume either 100% biogas or a blend of biogas and natural gas. SGIP biogas plants whose fuel is provided exclusively from onsite source(s) are subjected to an initial physical inspection by a third party and thereafter assumed to meet the biogas requirement (i.e. they are not subject to this ongoing audit procedure).

[42] PBI payments are made annually over a five year period.

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C. Biogas policy options

To address these various administrative problems, the following program changes (of which some, but not all, are mutually exclusive) are possible:

1. Eliminate the biogas incentives in SGIP.
   - Pros: this would cut administrative costs and remove the possibility of fraud related to biogas.
   - Cons: this would eliminate an important potential source of future GHG emission reductions.
2. Eliminate the directed biogas incentives and retain the onsite biogas incentives.
   - Pros: directed biogas is more difficult (and expensive) to audit than onsite biogas[43]; directed biogas participants have an on-going incentive to buy much cheaper natural gas; as shown in the CE Study, directed biogas projects deliver much fewer societal net benefits than do OSBG projects.
   - Cons: the directed biogas feature has more built-in flexibility and potential for market growth than the onsite biogas feature, so losing this component would be significant.
3. Convert the 75% minimum requirement (which results in an all-or-nothing payment) to a prorated payment scheme.
   - Pros: this avoids encouraging sub-optimal designs; prorating incentivizes participants to choose biogas along the full range of the biogas blend ratio (i.e., from 0% to 100%), not just with respect to clearing the 75% threshold.
   - Cons: because the range of biogas blend ratios over which incentives are present is increased (i.e., not just at the 75% threshold), the RFUR audits may engender more contention between participants and the program administrators.
4. Require that the RFUR be completed before any PBI payments are made.
   - Pros: this largely eliminates payments for non-compliance and ensures promised environmental benefits, at least during the five-year PBI period.
   - Cons: PBI payments for biogas participants would be delayed several months; this remedy does not address what happens in years six through ten, and beyond.
5. Convert SGIP's up-front biogas feature (noted above) into a renewable fuel rebate program, with rebates based on renewable energy (either $/mmBtu or $/kWh) instead of for generating capacity installed ($/kW). This would most appropriately apply to directed biogas, given directed biogas participants' on-going financial incentive to consume cheaper natural gas.
   - Pros: this design feature matches the payment to the action.
   - Cons: given the likelihood that directed biogas prices will not drop quickly over the next five years, this design feature suggests the need for an on-going program, going past 2020 (the last year of SGIP incentives).

D. Biogas policy recommendations

The CE Study shows that onsite biogas projects in general have high STRC scores (see Table 2). Furthermore, because they are renewable, their deployment results in substantial GHG emission

[43] Although onsite biogas is more difficult to measure directly than is natural gas, work-arounds exist which can approximate consumption.

reductions. Therefore, staff recommends that onsite biogas be allowed to continue with the program. Directed biogas, on the other hand, performs relatively poorly from the STRC perspective, so in spite of its contribution to substantial GHG emission reductions, staff has seriously considered recommending that it be eliminated from the program.

Arguing for continuing inclusion, however, is the fact that the state of California has placed a very high priority on renewable fuels. For example, Assembly Bill 1900 (2012, Gatto) required the Commission to develop standards for constituents in biomethane to protect human health and pipeline integrity and safety. Accordingly, the Commission issued Decision (D.) 14-01-034 in January of 2014 identifying seventeen constituents of concern in biomethane and establishing the concentration standards that must be met for each of them before the gas is allowed to be injected into the utilities' pipelines, where it mixes with natural gas. The decision established monitoring, testing, reporting, and recordkeeping protocols. In June of 2015, in D.15-06-029, the Commission addressed the cost issues associated with the actions adopted in the earlier decision. While ruling that the costs of complying with the standards and protocols adopted by D.14-01-034 should be borne by the biomethane producers, the decision provides ratepayer subsidies of 50% of the any biomethane project's interconnection costs, up to $1.5 million per project, with a statewide program funding cap of $40 million.

Senate Bill (SB) 1122 (2012) mandated that the Commission order the utilities it regulates to procure up to 250 MW of bioenergy capacity.[44] Accordingly, the Commission issued Decision (D.) 14-12-081 in December of 2014 establishing a starting price of $127.72/MWh for electricity which is obtained from various types of bioenergy (with the exclusion of landfill gas). The fact that the state is willing to commit roughly $3 billion to the development of this industry speaks to its policy importance.[45] Therefore, staff recommends that directed biogas be allowed to stay in the program.

Staff also considered carefully the option of converting the adder for directed biogas capacity to an energy-based incentive program. While this approach has advantages, it also entails potential problems, primarily for program administration. One issue is the length of time that the program would

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[44] The allocations set forth in Section 399.20(f)(2)(A) are:

- 110 MW for biogas from wastewater treatment, municipal organic waste diversion, food processing, and co-digestion;
- 90 MW for dairy and other agricultural bioenergy; and
- 50 MW for bioenergy using byproducts of sustainable forest management.

[45] 250 MW at 80% capacity factor for twenty years works out to 35 million MWh. Over the past 12 months, the average hourly price at the CAISO has been $32/MWh. If the premium for this SB 1122 energy is $95/MWh ($127 – $32/MWh), then the program will cost about $3.3 billion.

be needed to properly support this industry. If SGIP were to provide rebates on a pure energy basis, and do so for the life of the generator, then the five year PBI commitment should be extended for at least another five years – a significant administrative burden. In addition, a long-lived energy-based approach would bring up issues of budgeting: with uncertain capacity factors, the program administrators would have difficulty knowing how much money to put aside in order to avoid over-committing funding, when their SGIP budget cap is codified in the statute. For these reasons, staff recommends against paying for directed biogas on an energy basis.

Having rejected biogas policy options 1, 2, and 5, staff endorses options 3 and 4, which inform the following recommendations:

1. For 100% onsite biogas projects, where the program administrators can confidently determine at project commencement that no natural gas will be consumed, the program should pay the project at the full onsite biogas rate, through five years of normal PBI monitoring and payments.
2. For blended (natural gas and biogas) projects – where the biogas is either onsite or directed – the program should prorate the rebate payment to the percentage of fuel that is actually consumed, based on audits which are conducted throughout the five-year PBI period. The payments should not be made until the annual audit is conducted and the RFUR reports on the amount of biogas consumed.

V. Budget categories and rebate design

A. Design principles

In reviewing the program architecture, staff was guided by the following principles (not all of which harmonize with the others):

1. Support program goals (See Section II.A).
2. Simplify program design.
3. Minimize change from current program design.
4. Minimize uncertainty (e.g. re availability of funds, rebate levels) going forward.
5. Minimize program interruptions going forward.
6. Avoid opening day "stampede."[46]
7. Avoid excessive domination by one or two large players – diversify the portfolio of awardees and of technologies participating in the program.[47]

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[46] When the annual SGIP round opened in January of 2015, the refunds in PG&E's program were exhausted in a matter of days. In the other utility territories, the funds lasted only a few weeks.

[47] In the 2014 program year as well as the 2015 program year, both Bloom and Tesla reached the 40% individual manufacturer cap, and together the projects associated with them garnered 80% of SGIP rebate dollars.

B. Basis for rebate declines

The ACR asked for parties' input regarding the structure of rebate step declines. The majority favored leaving the structure as it is, with annual rounds of equal total dollars and declining rebate levels year-on-year. A large minority favored capacity-based declines (a' la CSI), while SDG&E favored rebate step-downs based on program popularity (or subscription rates). These proposals plus one more are discussed below.

1. Calendar-based rebate declines. This is the current approach, with annual program rounds. Some parties have recommended accelerating this to semi-annual rounds.
   - Pros: familiarity means there are no unknown problems; provides natural breathing room between cycles for program adjustments, in the event that annual funding runs out before the end of the calendar year.
   - Cons: this entails program funding interruptions and possible opening day stampedes every year.
2. MW-based rebate declines. This approach has been used in the very successful California Solar Initiative (CSI).
   - Pros: the incentives are continuously available to participants, with no program interruptions.
   - Cons: many parties have criticized this as too complicated, given the different rebate levels for different technologies.
3. Subscription-driven rebate changes. Here, "undersubscription" would trigger a rebate increase in the following period, while "oversubscription" would trigger a rebate decrease in the following period. Parties provided limited details on this approach, and to understand it better, staff has developed a hypothetical subscription-driven rebate model. This is shown in Appendix A. It is worth noting that in Decision (D.) 12-05-035 the Commission adopted a similar system for the Renewable Market Adjusting Tariff (ReMAT) of rebates which adjust themselves based on market participation levels.
   - Pros: enables price discovery.
   - Cons: it is a more complex scheme.
4. Dollar-based rebate declines. (This was not an option that was contemplated in the ACR.) Instead of lowering rebates once a pre-set number of MWs is achieved, it would lower the rebates once a pre-set amount of dollars is committed. This approach substantially follows the design of the current program's annual rounds, except that it eliminates any down-time between steps, it avoids opening day stampedes, and it allows for the different technology category/utility territory buckets to step down independently of each other.
   - Pros: this option has no program interruptions, unlike the current calendar-based scheme (#1); it avoids all opening day stampedes, except the first one; it eliminates all waitlists; because the SGIP is a budget-constrained program and does not have statutory capacity goals (such as CSI), designing the steps around dollar amounts is far simpler than designing the steps around MW amounts (#2).
   - Cons: the program may run out of funds well before the end of its authorized five year life.

Option 3, which lowers rebates based on subscription levels, is admirable in that it incorporates a price-finding mechanism; furthermore, it has the advantage of having been adopted already by the

Commission in the ReMAT; but downside of that mechanism is a higher level of program complexity and rebate instability.[48] Staff instead recommends Option 4, wherein rebate levels decrease as dollar pools are exhausted. This option promises to avoid program interruptions (as compared to the current program design (Option 1 above), and avoids much of the complexity of Option 2.

C. Technology budget categories

The ACR asked parties whether the current categories[49] should be altered, and if so how and why. Parties responded with a wide range of opinions, from leaving things as they are to abolishing all categories, with many variations in between. To avoid ambiguity, we note that the technology buckets being discussed in this section concern budget allocations, and not rebate steps, which are discussed later. Before making a recommendation, we recall that the benefit of having technology budget buckets is that they offer some measure of protection, or assurance, that a certain pool of funds will be reserved for a certain group of technologies. On the other hand, the cost of having categories is that they add rigidity and complexity to the program.

SGIP currently has two budget buckets, although the program administrators have leeway to shift funds from one bucket to the other. While it is tempting to eliminate all categories, and keep only one pool of funds, we find that there is value in providing a measure of protection for the universe of distributed generation technologies, as well as the universe of storage technologies. Staff therefore recommends having two budget buckets, but changing them to the following – (1) energy generation and (2) energy storage technologies. Staff suggests that the Commission encourage both.

The next question is – what should the relative size of these buckets be? The main criteria here are – what is the market potential; and what is the funding need? Because the MT Study is not yet available, we seek insight from SGIP participation trends. As shown in Appendix B, for SGIP program years 2013-2015, advanced energy storage (AES) technologies were awarded roughly 45% of the program rebates (and MW capacity). In 2015 AES was awarded 55% of the program rebates (and MW capacity). Thus the trend toward storage is increasing, and a 60% program allocation going forward would seem reasonable. However, given staff's recommendation to remove natural gas-based pure

[48] This subscription-based approach also uses a lottery in order to avoid an opening day stampede, but the delay this entails in notifying participants of their award is a serious drawback.

[49] The Handbook notes three categories: Renewable and Waste Energy Recovery; Non-Renewable Conventional CHP; and Emerging Technologies. For budgeting purposes, however, there are effectively only two categories, with Renewable and Waste Energy Recovery lumped together with Emerging Technologies in one budget category, and Non-Renewable Conventional CHP in another budget category.

electric fuel cells (which have drawn roughly 40% of program funds each program year from 2012 through 2015) from the program, a figure closer to 75% seems more reasonable, with 25% for generation technologies. Therefore, staff recommends a 75% storage / 25% generation split.

D. Initial rebate levels

We propose that rebates be based on the degree to which the technologies support the program goals and the degree to which they require support in order to be cost effective from the participant's perspective. For this analysis, we assign different weighting values to each program goal and to the need for support:

- GHGs: 3
- Criteria air pollutants: 1
- Grid support: 2
- Market transformation: 3
- Need for SGIP support: 3

We then assign a value (1, 2, or 3) to each technology for each of the five criteria and, using the weighting factors, arrive at composite scores for each technology.[50] We then group the composite scores into high, middle, and low scoring groups. The analysis is shown in Appendix C.

Keeping in mind our design principle of simplicity, we propose that the technologies with lower composite scores receive 60 cents per watt as their initial rebate, those with medium composite scores receive 90 cents per watt as their initial rebate, while those with the highest scores receive 120 cents per watt as their initial rebate.[51]

The "stampede" which occurred at the beginning of 2015, in which the leading energy storage manufacturer Tesla reached its 40% manufacturer cap within weeks, was a sign that the rebate of $1.46/W for the 2015 program year was too rich.[52] We see $1.20/W for storage as striking a reasonable balance: it will support customer acquisition of this key component of the renewable future while extending limited ratepayer dollars.

[50] CSE (response to Question 11) and Etagen (response to Question 12) recommended that rebates be based on "stackable" environmental and grid attributes. The approach described here embodies the spirit of that approach by stacking the various technologies' attributes to arrive at technology-specific scores.

[51] An alternative pricing scheme for rebates could assign to each technology the exact score or, rather, an amount exactly proportional to the score, from Appendix C. This is a reasonable approach, but was not chosen here so as to maintain design simplicity.

[52] Online, Tesla posts that its price for the 7 kWh version of the 2 kW (continuous power) PowerWall is $3,000. Adding to this the cost of the inverter and installation (100% gross-up estimate), we estimate a total cost of $6,000, or $3.00/W. Thus a rebate of $1.20/W would cover roughly 40% of the initial cost.

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Currently SGIP pays for storage capacity based on two hours of discharge at the rated capacity. While shifting two hours of demand from the peak to the off-peak will help with grid support (in particular mitigating renewables' over-generation and the resulting late-afternoon ramping needs, as indicated by CAISO projections), more hours of peak shifting capability would be more effective in removing generated energy from the grid at peak supply times and injecting it into the grid at peak demand times. Several parties noted the limitations of the incentivized two-hour storage in their comments. To get more hours of storage shifting capacity onto the grid, we propose to introduce higher rebates for more hours of storage. For an incremental two hours we propose to offer an additional 67% of the original rebate (or a total of $2.00/W for four hours of storage), and for four incremental hours we propose an additional 100% of the original rebate (or a total of $2.40/W for six hours of storage).[53]

At the other end of the rebate spectrum, the current rebate levels ($0.44/W for 2015) for "non-renewable conventional CHP" have not been sufficient to draw significant participation in recent years (see Appendix B). Providing a modest boost to the rebates for these resources, to $0.60/W, will give them a real chance to increase program participation, especially in the early steps.

Rebates for waste heat-to-power and pressure reduction turbines, which currently are incentivized at the rate of $1.07/W, are proposed to be reduced to $0.60/W. This reduction is no reflection on their value in supporting SGIP goals, but rather on the fact that they are already very cost effective from the participant's perspective.[54] By reducing these rebates, we comply with the program design requirement, noted above, of maximizing the program's value to ratepayers.

The score for wind technologies falls in the middle, and so this proposal assigns it a rebate of $0.90/W.

In the current program, biogas project payments are comprised of a base payment, related to the underlying generation technology, plus a biogas "adder." In the current program the biogas adder is $1.46/W, nearly equal to the highest rebate in the program[55]. Table 3 shows the level of participation (in terms of incentives) for onsite biogas and directed biogas projects for Program Years 2011-2015

[53] Given that for most battery technologies it is the energy capacity and not the power capacity that drives the cost, it is likely that most storage participants will continue to choose to be paid based on the two-hour price, but there may be technologies (e.g. flow batteries) where longer duration deployments (and incentive payments) make more sense because they are less able to quickly discharge the energy they have stored.
[54] See the CE Study, Table 6-6.
[55] In their comments to the ACR, CSE explaineds that the current biogas adder ($1.46/W) amounts to a GHG price of $84/metric ton, whereas the market price for carbon is now $12/metric ton.

(2015 has no biogas projects), with onsite biogas obtaining roughly four times as many rebate dollars as directed biogas. This outcome is not surprising, given the finding in the CE report that onsite biogas is much more cost effective than directed biogas.

Table 3: Rebates for biogas projects: 2011-2015 (source: SGIP Public Export 2015-10-27)

Row Labels	2011	2012	2013	2014	2015
Directed	**2,500,000**	**2,467,500**	**4,325,580**	**5,000,000**	
Fuel Cell Electric	2,500,000	2,467,500	4,325,580	5,000,000	
Onsite	**11,420,000**	**23,848,717**	**2,079,300**	**22,630,484**	
Fuel Cell CHP				4,142,000	
Gas Turbine				3,812,000	
Internal Combustion	11,420,000	21,635,717		12,213,436	
Microturbine		2,213,000	1,900,800	2,463,048	
Waste Heat to Power			178,500		
Grand Total	**13,920,000**	**26,316,217**	**6,404,880**	**27,630,484**	

In this Staff Proposal, we propose to continue the biogas adder approach, and thus will deviate from the scheme laid out in Appendix C. To reflect the observation that onsite biogas projects in general do not need as much outside support as directed biogas, staff recommends two tiers for biogas adders: a directed biogas adder corresponding to the highest basic rebate level, or $1.20/W; and an onsite biogas adder corresponding to the middle rebate tier, or $0.90/W. While still a high price to pay for GHG reductions, it is lower than the current level, and it faithfully represents California policy priorities.

Table 4: Summary of the proposed initial capacity rebate levels ($/W)

Technology	Current Rebate (2015)	Proposed Initial Rebate
Wind	$1.07	$0.90
Waste heat to power	$1.07	$0.60
Pressure reduction turbine	$1.07	$0.60
ICE CHP natural gas	$0.44	$0.60
ICE CHP onsite biogas	$1.90	$1.50
ICE CHP directed biogas	$1.90	$1.80
Microturbine CHP onsite biogas	$1.90	$1.50
Microturbine CHP directed biogas	$1.90	$1.80
Gas turbine CHP natural gas	$0.44	$0.60

Gas turbine CHP onsite biogas	\$1.90	\$1.50
Gas turbine CHP directed biogas	\$1.90	\$1.80
Fuel cell CHP natural gas	\$1.65	\$0.60
Fuel cell CHP onsite biogas	\$3.11	\$1.50
Fuel cell CHP directed biogas	\$3.11	\$1.80
Energy storage – 2 hour	\$1.46	\$1.20
Energy storage – 4 hour	--	\$2.00
Energy storage – 6 hour	--	\$2.40

E. Rebate step declines

To mimic the current program design which, left unchanged, would feature five separate rebate steps over the next five years because of annual rebate declines, we recommend a different (dollar-based) five-step arrangement for the remaining SGIP rebate funds, as discussed below.

First, we tackle the question of how much to lower rebates between each step. Rebate step-downs reflect the expectation that over time, emerging technologies with market potential will achieve production efficiencies which result in lower manufacturing costs, in turn requiring smaller rebates to attract investors. Knowing that program support will decrease over time also exerts pressure on manufacturers and installers to lower costs.

At present, SGIP rebates are programmed to decrease 5% (for renewable, waste energy recovery, or conventional CHP) or 10% (for emerging technologies) per year. We agree that this rate of decrease should be tailored to a reasonable expected rate of cost decline for each respective technology. Energy storage is a field experiencing dramatic changes, including steep price drops. We will therefore propose to lower rebates at the accelerated rate of one-sixth of the initial rebate level per step. Since energy storage is set for an initial rebate of \$1.20/W, the incremental drop will be \$0.20/W per step, ending at \$0.40/W for Step 5. The technologies in the generating category, on the other hand, are more mature, with less expectation of rapid decline in manufacturing costs. Here, we set the incremental rebate decrease at one twelfth of the initial rebate. Thus, where the initial rebate is \$1.20/W the incremental drop is \$0.10/W (ending at \$0.80/W); where the initial rebate is \$0.90/W the incremental drop is \$0.075/W (ending at \$0.60/W); and where the initial rebate is \$0.60/W the incremental drop is \$0.05/W (ending at \$0.40/W).

Finally, staff recommends that once a technology budget category reaches the end of its available funding in its Step 5, it be allowed to draw funds from the other category's bucket, at the Step 5 rebate rate of the drawing technology. Allowing cross category drawing like this to occur will allow the program to avoid interruption while funding lasts; and it will force the drawing party to pay at its own lowest (Step 5) rate will slow the rate at which funds are drawn down from the slower-moving category.[56] In Tables 5 and 6, we provide an example of the proposed rebate levels and step declines as they could apply to PG&E's territory.

Table 5: Example of derivation of proposed PG&E category buckets

PG&E's total rebate allocation over 5 years	$167,400,000
PG&E's rebate allocation for energy storage (75%)	$125,550,000
PG&E's rebate allocation for generation (25%)	$41,850,000
PG&E's rebate allocation for each step of energy storage	$25,110,000
PG&E's rebate allocation for each step of generation	$8,370,000

Table 6: Example of proposed PG&E buckets and rebates through five steps

PG&E		Step 1	Step 2	Step 3	Step 4	Step 5	Total
Energy storage bucket		**$25,110,000**	**$25,110,000**	**$25,110,000**	**$25,110,000**	**$25,110,000**	**$125,550,000**
	2-hour	$1.20/W	$1.00/W	$0.80/W	$0.60/W	$0.40/W	
	4-hour	$2.00/W	$1.67/W	$1.33/W	$1.00/W	$0.67/W	
	6-hour	$2.40/W	$2.00/W	$1.60/W	$1.20/W	$0.80/W	
Generation bucket		**$8,370,000**	**$8,370,000**	**$8,370,000**	**$8,370,000**	**$8,370,000**	**$41,850,000**
	FC CHP DBG, GT DBG ICE DBG, MT DBG	$1.80/W	$1.65/W	$1.50/W	$1.35/W	$1.20/W	
	FC CHP OSBG, GT OSBG ICE OSBG, GT OSBG	$1.50/W	$1.375/W	$1.25/W	$1.125	$1.00/W	
	Wind	$0.90/W	$0.825/W	$0.75/W	$0.675/W	$0.60/W	
	WHP, PRT, ICE NG, GT NG, FC CHP NG	$0.60/W	$0.55/W	$0.50/W	$0.45/W	$0.40/W	

[56] Another possible variation on this approach would require the drawing technology to incrementally drop its rebate one level beyond Level 5.

CA Supplier Adder[57]	20%	20%	20%	20%	20%	

VI. Additional topics

A. Performance-based incentives

The ACR asked for parties' input regarding the PBI payment structure. In large measure, parties expressed approval of the current arrangement, with two requests for change. Etagen suggested that reducing the payout period from five years to three years would save administrative costs, while adequately demonstrating the functioning of the incentivized technology. To better ensure system benefits, staff recommends keeping the five-year payout period.

Several parties, citing the need for greater administrative efficiency, advocated raising the threshold (currently 30 kW) beyond which PBI would be the required method of payment. CSE advocated instead for requiring PBI for all projects, citing its efficacy in promoting beneficial behavior and in providing great data. Staff finds CSE's arguments compelling but, to avoid imposing unnecessary reporting costs on participants, we recommend that the current threshold be kept.

At present, projects with PBI incentives for natural gas consuming technologies are required to abide by annual measurements of GHG emissions.[58] The program allows projects to exceed, by five percent, the GHG threshold; it penalizes PBI projects for any year in which emissions are between five and ten percent higher than the threshold; and it pays no PBI payments in years in which the emissions exceed the threshold by more than ten percent. This use of each year's emissions for determining that year's PBI payments contrasts with the program eligibility determination, which estimates the average GHG emissions over the entire span of the project's first ten years. Staff recommends that this approach to PBI payments be continued, with the understanding that the performance standard for any given project becomes more stringent over time, reflecting the annually-changing GHG factor adopted by the Commission. Because PBI projects will continue to be paid after 2020, the performance benchmark in 2021 and in the years following should remain at 337 kg/MWh, which is the threshold for 2020 adopted by the Commission. For PBI projects which signed up in 2015 and earlier, they should remain subject to the standard in place when they signed up, 379 kg/MWh.

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[57] Because the step downs in this proposal occur based on incentive dollars committed instead of MWs, the inclusion of California supplier bonus payments into the scheme will not create any implementation difficulties with respect to budgeting; the California supplier bonuses will simply make the steps complete faster.
[58] See D.11-09-15, Attachment A, page 3.

B. Operating requirements for energy storage

The ACR asked about incentives for storage so that owners of this technology would dispatch it to optimize the grid. Several parties argued that the number of minimum required annual equivalent hours (now set at 10% of 5,200 hours per year) is too high.[59] They argue that storage provides benefits to the grid (e.g., peak shifting, enabling more rapid electric vehicle charging) that are not dependent on high levels of dispatch. They argue further that forcing storage to dispatch excessively will actually lead to more GHG emissions (given the fact that storage typically has an RTE of under 100%). Another question asked specifically about residential storage applications. In general parties stated that the current rules, as established in Resolution E-4717, were a good start.[60]

For peak shifting purposes, it would appear that storage is currently most useful during the times of the year when capacity is constrained. If we assume that this tends to occur during the six warmer months of the year, and that the grid is more strained on weekdays than weekends, then this means that storage could provide its main benefit by being dispatched once per day for the week days of twenty six weeks, or 260 hours (= 2 x 5 x 26). Therefore, we propose that the minimum equivalent hours of dispatch for storage should be reduced from 520 to 260 hours.

Under current rules residential storage owners receiving SGIP rebates must dispatch fifty two times per year at an average two hours per discharge. This amounts to 104 hours of dispatch per year. Meanwhile, non-residential storage must dispatch 520 hours per year, which for a two-hour system means 260 cycles. There appears to be no clear reason why different rules should apply to residential and to non-residential applications. Therefore, staff proposes that the requirements for new residential storage rebate recipients be increased from 104 to 260 hours.

C. Dual Participation in Demand Response Programs

The ACR asked whether dual enrollment in demand response and SGIP should continue to be allowed, and if so, what SGIP size limitations should apply to avoid double collection. Most parties affirmed the current rules. Guided by the principle that one action should garner an incentive from no more than one program, they point out that SGIP incentivizes investments while demand response incentivizes operational decisions. We note that the introduction of the PBI mechanism has blurred these formerly neat distinctions.

[59] Some also suggested that there should be a rebate for more than two hours of storage. We have addressed separately the question of adding more storage rebate options.
[60] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K610/152610903.PDF

Staff recommends that the rules governing rebates for customers who also participate in demand response programs be left unchanged, for the following reasons. On July 23, 2015 the Commission issued Resolution E-4728,[61] disallowing natural gas consuming equipment from participating in its Demand Response Auction Mechanism (DRAM) program. More recently, on September 29, 2015 Energy Division published a proposal to disallow any fossil-powered generation source (whether CHP or not) from participating in demand response programs, beginning in 2017. If the Commission adopts this recommendation, the issue of coordination of SGIP and demand response becomes limited to storage technologies. Because storage is a relatively new technology, and we do not wish to encumber it with unnecessary operational constraints, we recommend continuation of the current policy.

D. Individual manufacturer and installer caps

Current program rules bar individual manufacturers' projects from receiving more than 40% of any given year's rebate budget. In response to the ACR parties offered an array of opinions on whether to modify this rule. Most parties argue that the current limits are too lax and allow for too much domination by large players. Bloom, on the other hand, argues that the current cap is working well, while CESA reminds us that caps can hurt customers who are barred from purchasing equipment which has reached its cap. SolarCity cites the project flow headaches that caps create for customers, and notes that its research of U.S. incentive programs turned up some participant caps but no manufacturer caps.

On balance, staff believes that the current rules, which are set at 40% of the total program, should be adjusted so that no individual manufacturer's or installer's projects total for a given utility territory[62] can obtain more than 40% of that technology category's (i.e. either energy storage or generation) total, for that territory, for that step.[63] This program rule change will have a much larger effect on generation technologies, whose budget in this proposal is only 25% of the program total. But even for storage, whose share of the total available incentives is set at 75%, the proposed rule

[61] See the Administrative Law Judge's Ruling issued on September 29, 2015 in R.13-09-011. response capacity, referred to as the demand response
auction mechanism. Resolution E-4728 also required the Utilities to exclude fossil-fueled back-up generators from participating in the auction mechanism bidding.
[62] CSE recommended this utility territory-specific cap.
[63] In implementing the individual participant cap, the program administrators have sometimes had difficulty communicating timely with each other regarding project sign-ups, to know when the 40% program-wide cap had been reached. With utility-specific caps, this operational challenge will be removed.

represents much less market share potential for individual participants, since it caps market share for each utility territory, as opposed to the current rules, which cap it program-wide and allow manufacturers in individual utility territories to exceed the 40% cap.

A related topic concerns limitations on installer/developers as opposed to manufacturers.[64] Staff believes there are good reasons to avoid excessive domination of the program by both manufacturers and installer/developers and therefore recommends extending the current rules to apply to both. For purposes of the individual cap, the program administrators should identify just one installer/developer and just one manufacturer, where the designated manufacturer is the entity supplying the largest portion of value of capital equipment.[65] Encouraging diversity in the supply chain, whether it is for manufacturers or for installers/developers, promotes market transformation and competition, with accompanying price reductions in the long run.

In their comments SolarCity raised the scenario where a cap could inadvertently lead to program stagnation. SolarCity suggested that a solution to this scenario could be to allow the cap to rise if, after a certain period of time has passed, there are inadequate sign-ups. We appreciate the flexibility of this approach, and recommend that through the advice letter process, a Program Administrator may request that four months after the beginning of any step the cap be raised from 40% to 70%, and after two more months to 100%. This will protect the smaller players from being swamped at the beginning of any step, while providing the flexibility to allow the program to continue in the event competition fails to show up. Staff is aware of the downside in this arrangement. For example, it may require that the program administrators establish waitlist rules, a complexity which the continuous program design proposed here sought to avoid.

Staff also notes the proposed manufacturer cap would apply equally to projects where the same entity builds and installs as to projects where an entity only manufactures. While an imperfect rule, we decline to propose even more complex rules which might treat the cases differently. Finally, staff

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[64] The program administrators have informally requested guidance from Energy Division (and the Commission) regarding what constitutes a "manufacturer," and specifically whether software which optimizes the operation of equipment can be considered a "manufactured" product. The individual manufacturer cap is concerned with fairness and with market development while the California manufacturer adder is concerned with boosting the California economy, and in all these respects, whether a product is hardware made in factory or software made on a computer is immaterial. Therefore, Staff believes that SGIP should consider software the same as hardware for purposes of implementing the manufacturer cap and the California manufacturer portion of the rules.

[65] Section 3.3.3 of the 2015 SGIP Handbook lists 18 types of "eligible project costs." Only manufacturers of capital equipment of type 4 (equipment capital costs), 5 (primary heat recovery equipment), 14 (electricity storage devices), and 18 (incremental boiler and turbine capacity for steam turbine CHP projects) should be considered with respect to the individual manufacturer cap.

recognizes that caps which are set too high allow market domination by individual parties. Caps which are set too low can deprive customers of the installers and the products they would freely choose to hire and/or purchase, and can cause program stagnation. Therefore staff recommends that the program administrators and/or Energy Division be authorized to change, via advice letter and/or resolution, the rules associated with manufacturer and installer caps, based on their experience with the caps under the new rules. The rules which may be altered in this way include: who is subject to the cap (installers/developers, manufactures); the level of the cap or caps; the step back mechanism (i.e. 40% to 70% to 100%). The reason for this provision is to allow for a relatively quick program adjustment, should it be deemed necessary.

E. California supplier 20% adder

SGIP provides a 20% adder for projects in which the equipment is manufactured in California. SB 861 simplified certain “California supplier” requirements.[66] However, the adder remains. SGIP program administrators have been challenged to comply with this requirement. We propose that equipment be deemed to be manufactured in California if 50% or more of its value[67] is determined to have been added in a manufacturing process (or processes) located in California. Making this determination is well outside the expertise of the SGIP program administrators. They should either contract with a third party who can make this certification, or they should take advantage of the new “Made in California” program which was noted in the comments of the California Clean DG Coalition.[68] [69]

Beginning twelve months after the date of the decision that will follow this Staff Proposal, the program administrators should deny requests for the “California supplier” adder for suppliers that have not received this new certification, even suppliers which are currently approved as California suppliers. Until that time, currently grandfathered California supplier participants may continue to qualify, and new suppliers may apply for the California supplier status to the program administrators under the

[66] SB 861 removed “California supplier” code requirements related to the business definition, the domicile of the owners, the location of the company headquarters, the length of time manufacturing, etc.

[67] Just as with the individual manufacturer cap (see footnote 63), for purposes of determining eligibility for the California manufacturer adder for a given project, the program administrators should consider only the equipment of types 4, 5, 14, and 18 (see the 2015 SGIP Handbook Section 3.3.3). The entity supplying the largest amount of value of this capital equipment is the one whose California credentials will be considered in each project. If at least 50% of the value of that entity’s capital equipment in that project is deemed to have been added in a California process, then that project should receive the 20% California manufacturer bonus.

[68] Senate Bill 12 (Corbett, 2013) establishes a program within the Governor’s Office to certify products as “Made in California.”

[69] If the entity seeking “California supplier” status is a software developer (see footnote 62) then the eligibility evaluation should include such factors as domicile of their staff, and whether they pay income tax in California.

current criteria. To ensure that the vendor or the agency performing the certification has adequate time to perform its work before the beginning of the new requirement, the program administrators should ensure that the vendor's or agency's window for receiving applications from would-be California SGIP suppliers opens no later than six months after the date of the decision which will follow this Staff Proposal. We recommend allowing for the program administrators to file a Tier 2 advice letter to modify the timing of this roll-out in the event they believe this is needed.

F. Megawatt-based project size rebate tiers

The ACR asked for input on the declining payment structure.[70] Most parties advocated no changes. SolarCity argued that a limit of 1 MW should be considered in order to allow more projects to be funded, while Fuel Cell Energy and the National Fuel Cell Research Center advocated richer rebates going up to 5 MW. SCG/SDG&E would extend the current 25% level, now applicable to the 2-3 MW range, up to 5 MW, arguing that some technologies naturally scale. Staff agrees that beneficial large technologies can and should be encouraged, with relatively little impact on the overall program budget, and thus agrees with the SCG/SDG&E proposal.

In their comments and reply, respectively, CSE and CESA noted that the program currently penalizes applicants from investing in more than one system on their premises, by allowing the rebate step-down to apply to the aggregated capacity of the various projects. Staff agrees that SGIP should encourage more than one installation on a single premises, in cases where the additional installations have inherent economic merit. However, the program administrators should disallow funding in those cases where it appears that the systems are being downsized simply in order to take advantage of the higher rebates (100%) of the zero-to-one megawatt tier.

G. Load-based rebate caps for storage

The Handbook currently states, "Advanced Energy Storage Projects may be sized up to the Host Customer's previous 12-month annual peak demand or for Advanced Energy Storage Projects coupled with generation technologies, the CEC-AC rated capacity of the PV system or SGIP eligible technology at the proposed Site." This language is problematic because it leaves some ambiguity with respect to whether paired storage is limited by the lower of or the greater of the customer's load or the paired

[70] Currently, the program provides 100% of the given rebate for the first megawatt of capacity, 50% of the given rebate for the second megawatt of capacity, and 25% of the given rebate for the third megawatt of capacity.

generator's capacity. It is also problematic because it appears to contradict the directive in D.11-09-15, which states, "No minimum or maximum size restrictions given that project meets onsite load."[71]

Staff recommends that the policy as expressed in the Handbook be clarified to clearly indicate that whether or not a storage system is paired with an SGIP-eligible or a photovoltaic generator, the size of the SGIP storage system shall only be limited by the customer's load.

H. DC micro-grids

As part of Question 7, the ACR asked several questions about DC micro-grids, including whether the technology should be eligible for SGIP incentives or should more appropriately be reckoned as energy efficiency. Most parties responded that it should not be allowed into SGIP, arguing that it is a suite of technologies, some of which (e.g. fuel cells, gas turbines, micro-turbines, storage) are already eligible for SGIP. They argue that the generation components should be evaluated based on their own merits.

In addition, parties raised other arguments:

1. Bloom and CESA request that if the micro-grids are allowed into SGIP, then no distinction should be made with respect to whether the micro-grid is AC or DC.
2. CESA argued that DC micro-grids should be disallowed because they do not operate in parallel.
3. Etagen argues that, because DC micro-grids are already more efficient, they pay for themselves and thus should not require subsidies.
4. CCDC argues that DC micro-grids should be disallowed because the components are not yet commercially available.
5. In their comments, Bosch asks that SGIP rules be revised so that inverters sizes are not capped by the size of the generator.
6. SCG/SDG&E clarified that under current rules the components of a DC micro-grid project could be eligible for both EPIC and SGIP funding.
7. In their reply, Bosch responds to these arguments, and also proposes a specific incentive of 7% of the project cost, which would represent the estimated operational savings from efficiency gains.

Staff believes that the commenters arguing that DC micro-grids are already eligible for SGIP via their components have not appreciated the fundamental advantage of DC micro-grids, which is: to lower capital costs by avoiding, partially or entirely, the need for inverters to convert DC power (from a DC source like photovoltaic or fuel cell) to AC power, as well as the need for lighting ballasts which convert AC power to DC; and to avoid power losses which these inverters and ballasts entail. However, in spite of our recognition of the merits of DC micro-grids as an innovative approach to lowering capital costs

[71] D.11-09-015 Attachment A, page 2.

and energy consumption, and our belief that the generation and the storage components which are part of a given DC micro-grid may continue to apply for SGIP rebates, staff believes that the wiring and the controls portion of the DC system should not be eligible for SGIP rebates. This is based on the simple reason that the wiring and controls are neither generation nor storage.

Several of the other opinions noted above – Bloom's and CESA argument that no distinction should be made between AC and DC micro-grids, Etagen's argument that DC micro-grids provide savings and so do not require subsidies, CCDC's argument that DC micro-grid technologies are not yet commercially available, and Bosch's request for a 7% incentive – are all mooted by our recommendation that rebates for DC micro-grids *per se* not be paid by SGIP. Staff disagrees with CESA's claim that DC micro-grid technologies do not operate in parallel with the grid; rather, they do operate in parallel, even if on the DC side of the inverter. Staff understands that SCG/SDG&E's comments were in reference to the 2015 SGIP Handbook Section 3.3.8, which allows for funding by more than one source, provided that an adjustment is made to the SGIP award depending on the amount and the source of the other award(s); we do not here recommend that this rule be changed. Finally, we note that our recommendation in the area of "Load-based rebate caps for storage" (Section VII.G. above) addresses Bosch's concern about inverter cap limits.

I. <u>Locational adder</u>

The ACR asked whether locational benefits (or costs) should be reflected in SGIP payments, and if so, how. Most parties agreed that there would be value in adding a locational adder to the SGIP payment, and noted that this is also being handled in the Distribution Resources Plan (DRP)[72] filings. SCE noted that a decision on the DRP filings was expected by March 2016, with DRP projects beginning one year after that. SCG/SDG&E recommended waiting until more is known about DRPs. On the other side, PG&E argued against a locational adder, saying that it would overlap with DRP efforts. Bloom argued that locational adders are too complicated and should be avoided.

Staff believes that locational adders could substantially improve the program's ability to meet its grid support goal. Staff agrees with most respondents to the ACR, and believes that the results of the DRP proceeding will best inform this effort. Therefore, staff recommends that the Commission consider including such a program component when the results of the DRP proceeding provide confidence that the locational information will be relevant and useful for the SGIP.

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[72] AB 327 mandated annual DRP filings by the utilities to identify opportunities for distributed energy resources can cost effectively manage grid investment and operational challenges.

J. Rules for adding new technologies and for handbook changes

The ACR did not include a question about the procedure for adding new technologies to the program. At present there is an official procedure for introducing new technologies or modifying program rules, known as a "Program Modification Request."[73] The most recent version of this procedure was adopted in D.08-11-044.[74] No party has called for an overhaul of this procedure, however staff notes that two problems with the procedure.

First, the protocol does not account for the possibility of advice letter filings as vehicles for program changes. Rather, it envisions changes occurring either (in the case of minor and non-substantive changes) directly by Working Group alterations to the Handbook, or (for significant changes) by the filing of a petition to modify, resulting in a Commission decision. Advice letter filings should be considered as a vehicle for program changes of an intermediate nature. Second, the protocol in one place sets Energy Division up as the gate keeper for program modification requests, but does not spell out what, if any, recourse an applicant has if Energy Division rules against a request. Staff declines to offer a specific proposal for clarifying or improving the process in this document, but recommends that Program Modification Request be improved to address the issues note above.

At present, the SGIP program administrators do not use advice letter filings to modify the program handbook to reflect routine or non-controversial program changes, and file advice letters for handbook changes only when those changes are potentially controversial.[75] Staff believes that the current practice is appropriate, provides flexibility from which all benefit, and avoids excessive regulatory friction, even though it requires the program administrators to discern between routine/non-routine and between controversial/non-controversial. This practice in no way gives the program administrators carte blanche to make program changes: we note that a recent program change, addressing the SGIP eligibility for residential storage, was deemed to be substantive and non-routine, and resulted in an advice letter filing by the program administrators and an Energy Division resolution.[76]

[73] The Self-Generation Incentive Program Modification Guideline (PMG) can be found in Section 4.5 of the Handbook.

[74] Within the past two years, two technologies have been introduced to the program via advice letter (e.g. thermal energy storage in AL CSE 56; conventional topping cycle steam turbines in AL CSE 47-A (et al)). In both instances these technologies were allowed into SGIP via letter of disposition and without recourse to a decision, because the Commission understood that these specific technologies belonged to broader categories of technologies which had previously been granted eligibility to SGIP.

[75] This is a different operating procedure from the California Solar Initiative (CSI) which requires an advice letter filing for all handbook changes.

[76] E-4717. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K610/152610903.PDF

K. Energy efficiency audit requirements

In D.11-09-015 the Commission established the requirement that prior to receiving SGIP incentives, customers must obtain an energy audit and submit the audit report to the program administrators, with certain exemptions allowed. The decision required, further, that the applicant perform all measures from the audit report with paybacks under two years, with exemptions granted for cases where the applicant could explain and document why the measure(s) was not feasible.

In response to the ACR, CESA raised the issue of energy efficiency audits. CESA is concerned that there are no guidelines to prevent requiring an audit which will be prohibitively expensive. CESA provides the example of a 30 kW proposed electric vehicle charger for which the SGIP program administrator required the applicant to perform a campus-wide audit, where the total campus load was in excess of 9 MW.

Staff believes that the audit requirement (as well as the requirement to implement highly cost effective measures) supports a fundamental aspect of California energy policy and should remain as a required part of the program. The example provided by CESA points out the need, however, for a reasonable limit on costly audits. Staff therefore suggests establishing a cap on the cost of the audit (not counting any measures required as a result of the audit) at a level which is 5% of the requested SGIP incentive payment.

L. Sampling for inspection of systems

At present, the SGPI administrators inspect every SGIP installation prior to awarding any incentives. Conducting these inspections is expensive for both the program administrator and the applicant who must have a representative be at the site during the inspection. In their comments (response to Question 25) CESA suggests that a sampling of systems which are sized under 10 kW would be appropriate and lower costs. We appreciate this suggestion, but also recall the importance that Resolution E-4717 placed on inspections in ensuring that systems are deployed in a way that provides advantages to the grid. To more fully inform this discussion, staff recommends that the program administrators hold a work shop on the topic of sampling for system inspections, and publish a report including recommendations within six months of the date of the decision disposing of this Staff Proposal. The program administrators should be allowed to file an advice letter proposing changes to the inspections/sampling regime, following the publication of this workshop report, if they believe it will benefit the program.

M. Cap O&M project costs

The claimed total project costs are important because they help to determine the cap on incentives (participants must put in at least 40% of the total project costs). Section 3.3.3 of the 2015 SGIP Handbook includes "Warranty and/or maintenance contract costs…" in the list the items which can be included. In their comments to the ACR (Question 25), CESA suggests limiting this component to 10% of the claimed project costs. CESA explains that such a limit is in line with Federal Investment Tax Credit (FITC) rules and would increase transparency and simplicity. Staff agrees that such a constraint would be useful, primarily because it limits the artificial inflation which applicants can claim.

N. Measurement, evaluation, and public reporting

The ACR asked parties what metrics should be used to measure program success, and parties' responses have helped to form the following Staff Proposal recommendation on this topic. Staff recommends that future measurement and evaluation studies focus explicitly on the stated SGIP goals (see Section III.A. above) and on the items listed in PU Code Section 379.6 (l)[77] to the extent that these items are not explicitly included in the SGIP goals affirmed by the Commission. Staff believes it is reasonable for some of the "program success metrics" listed in Section 379.6(l) to be related to the stated program goals and yet not be included among the core objectives which the Commission embraces as "goals."

In addition to studies intended to evaluate the program's success in meeting SGIP goals, staff believes that measurement and evaluation funds should also be used to ensure that the program is performing well both administratively and fiscally. Therefore, staff recommends that Energy Division contract for an annual review of the administrative performance of each program administrator, and a

[77] 379.6(l): "The commission shall evaluate the overall success and impact of the self-generation incentive program based on the following performance measures:
(1) The amount of reductions of emissions of greenhouse gases.
(2) The amount of reductions of emissions of criteria air pollutants measured in terms of avoided emissions and reductions of criteria air pollutants represented by emissions credits secured for project approval.
(3) The amount of energy reductions measured in energy value.
(4) The amount of reductions of customer peak demand.
(5) The ratio of the electricity generated by distributed energy resource generation projects receiving incentives from the program to the electricity capable of being produced by those projects, commonly known as a capacity factor.
(6) The value to the electrical transmission and distribution system measured in avoided costs of transmission and distribution upgrades and replacement.
(7) The ability to improve onsite electricity reliability as compared to onsite electricity reliability before the self-generation incentive program technology was placed in service."

biennial review, or audit, of the program finances. The annual administrative review should include, but not be limited to, a survey of program participants regarding the program administrators' clarity and timeliness of oral and written communications, their accessibility, their helpfulness to applicants submitting and processing applications, and the clarity and helpfulness of their websites. The biennial fiscal audit would ensure that program funds are accounted for, are being spent appropriately, and that safeguards are in place to ensure this. Energy Division should work to ensure that the first rounds of these two report series are completed within twelve months of the decision disposing of this Staff Proposal.

Since the program's beginning, the measurement and evaluation (M&E) activities of SGIP have been established in ALJ rulings.[78] On occasion, this requirement that the M&E plan be adopted via ALJ ruling has imposed a burden on the ALJ division which appears unnecessary, especially in the light of the fact that other programs have no similar procedural requirement.[79] Staff recommends that the SGIP M&E plan, like that of CSI, be developed, and established, by Energy Division in consultation with the program administrators, without the need for an ALJ ruling. Staff recommends that Energy Division (upon consultation with the program administrators) be required to establish a new SGIP M&E plan within six months of the date of the decision disposing of this Staff Proposal. After that point, it may be updated by Energy Division from time to time as necessary.

Recently, Energy Division has gained access to an online report covering the performance of all SGIP applicants on PBI schedules. Depending on the technology being tracked, the monthly PBI data include: energy (kWh) generated; amount and type (natural gas or biogas) of fuel consumed; amount of heat recovered (for CHP projects); gross and net GHG emissions; number of charging and discharging events and total amount of energy charged and discharged (for energy storage). Staff recommends that this online report be made available to the public. These data do not include customer load information, which the Commission has determined are confidential. Rather, they provide useful information regarding equipment performance which, by helping to inform potential adopters, will lower uncertainty and advance the market.

[78] D.01-03-073 Ordering Paragraph 13.

[79] The CSI M&E Plan is developed by the Energy Division, in consultation with the CSI program administrators, and is established in a letter from the Energy Division directed to the CSI program administrators. http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm

O. Marketing and outreach

Market transformation is one of the goals of SGIP. In spite of this, the program has, until now, had no marketing and outreach (M&O) program *per se*. Staff recommends that the program administrators hold a workshop to address the possible need for an M&O program along with a description of what this M&O program would look like, and publish a work shop report within six months of the date of the decision which follows this Staff Proposal.

VII. Appendices

Appendix A -- Hypothetical proposal for dynamically driven rebate levels in SGIP

Appendix B -- Recent participation by technology

Appendix C -- Proposed eligible technologies – scoring for rebates

ED Staff Proposal on SGIP

Appendix A -- Hypothetical proposal for dynamically driven rebate levels in SGIP

This scheme is not being proposed.
Several parties suggested that rebates should be driven by subscription level, but no proposals were fully developed. The following scheme represents one possible approach.

California's RPS and RAM are attractive because they deliver ratepayer value by achieving a set of MW goals without overpaying the providers. Unfortunately, small project rebate programs generally do not have this price finding mechanism, and thus can suffer from either a gold rush (too rich) or the doldrums (too lean). This proposal:

- Introduces a price finding mechanism.
- Guards against the opening day stampede phenomenon witnessed in 2015 in SGIP.

Rules/assumptions:

1. Assume the program works in 6 month periods instead of the current 12 month periods (this is to provide a quicker feedback mechanism).
2. Assume there are one or two or more categories of technologies.
3. For each category assume one starting rebate level and a fixed incremental number of dollars.
4. For each category, assume an equal allocation of funds across all remaining periods (i.e. ten semi-annual periods, from 2016-2020). For any period and any technology, this will be augmented by funds left-over from the previous period.
5. Each application requires an application fee, which is refunded if the application either loses the lottery (see below) or wins the rebate and builds the project.
6. There is an individual manufacturer and installer cap set at 50% for that category. No provisional applications will be accepted which violate that cap for that period.
7. No final reservations are confirmed until 30 days (one month) into the period.
8. At the end of the first 30 days, if the applications for that utility territory total more than 100% for the utility-wide allocation for that period and category, then the PA holds a lottery, and randomly allocates the rebates to those who signed up in the first 30 days. No more reservations are accepted, even on an interim basis, during that 6 month period. Rebate levels will be adjusted in the following period depending on subscription (see table below).
9. During those first 30 days, the PAs continue to log applications until 300% of the allocation is filled.
10. If less than 100% subscription occurred in the first 30 days, then PAs continue accepting applications for the first 5 months of the period, or until they reach 100% of subscription. The last month of every 6 month period is a rest and reset period to allow the market and the PAs to get ready for the next period.
11. Rules about waitlists and dropouts are not addressed here, but would need to be.

Rebate adjustment schedule (based on preceding period subscription levels):

	subscription level (percentage of period allocation for a category)		change in rebate level in the following period.
if	0% – 50% in 5 months	then	up 10%
if	50% - 90% in 5 months	then	no change
if	90% - 100% in 5 months	then	down 5%
if	100% - 200% in 1 month	then	down 10%

if	>200% in 1 month	then	down 20%

Observations:
- Large projects especially have long time lines and may need more stability in project economics.
- Therefore, this might be more appropriate for smaller-scale project (under 10 kW?).
- Overall, this may be too complicated and introduce too much instability.
- The lottery proposal is an interesting approach to avoiding perceived unfairness in opening day stampede situations, but the delay in awarding incentives is a serious drawback.

Appendix B – Recent participation by technology

Percentage showing that technology's portion (of capacity (MW) and rebates ($)) for the period between January of that year and August 2015.

Percentages showing that technology's portion for the period between that year and the present (August 2015)															
Sum of Rated Capacity [kW]															
	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
A.E.S.	16.6%	17.0%	18.3%	20.1%	22.5%	24.6%	29.2%	30.4%	30.4%	31.1%	35.9%	39.2%	45.0%	49.9%	57.6%
Fuel Cell CHP	5.9%	6.0%	6.4%	6.9%	7.4%	7.4%	7.6%	7.8%	7.6%	7.2%	5.9%	6.5%	7.7%	7.6%	11.8%
Fuel Cell Electric	18.1%	18.6%	20.0%	21.9%	24.6%	26.9%	31.9%	33.1%	33.2%	32.5%	26.7%	25.3%	26.1%	21.9%	16.0%
Gas Turbine	8.1%	8.3%	8.8%	9.4%	10.4%	9.6%	8.6%	8.0%	8.0%	8.2%	9.5%	9.3%	6.5%	5.7%	0.0%
Internal Combustion	23.9%	22.7%	19.5%	15.9%	13.8%	11.1%	10.8%	9.1%	9.1%	9.4%	10.9%	10.6%	7.6%	8.2%	8.8%
Microturbine	4.6%	4.4%	4.3%	3.9%	3.5%	3.2%	3.2%	2.8%	2.8%	2.9%	3.4%	3.6%	2.6%	1.5%	0.2%
Photovoltaic	17.6%	17.7%	17.0%	15.8%	11.1%	9.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Pressure Reduction Turbi	0.4%	0.4%	0.4%	0.4%	0.5%	0.5%	0.6%	0.7%	0.7%	0.7%	0.8%	0.9%	0.7%	0.9%	0.7%
Waste Heat to Power	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%	0.5%	0.5%	0.0%	0.0%	0.0%
Wind Turbine	4.5%	4.6%	5.0%	5.3%	6.0%	6.5%	7.7%	7.8%	7.7%	7.6%	6.5%	4.2%	3.9%	4.2%	4.9%
Grand Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Sum of Rebates ($)															
	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
A.E.S.	13.4%	13.6%	14.3%	15.5%	18.2%	19.4%	23.7%	24.1%	24.2%	25.2%	34.7%	38.7%	43.1%	49.5%	55.0%
Fuel Cell CHP	7.3%	7.4%	7.7%	8.0%	8.9%	8.7%	8.3%	8.2%	7.9%	7.3%	4.4%	4.9%	5.5%	4.8%	5.5%
Fuel Cell Electric	29.4%	29.9%	31.5%	34.1%	40.1%	42.8%	52.2%	53.0%	53.2%	52.4%	42.3%	39.8%	39.9%	33.5%	31.0%
Gas Turbine	1.1%	1.1%	1.1%	1.1%	1.3%	1.2%	1.2%	1.1%	1.1%	1.2%	1.6%	1.6%	1.6%	1.6%	0.0%
Internal Combustion	10.1%	9.6%	8.6%	7.6%	7.3%	6.6%	7.2%	6.5%	6.5%	6.9%	9.5%	8.5%	4.6%	5.5%	2.6%
Microturbine	2.3%	2.2%	2.2%	1.9%	1.8%	1.6%	1.7%	1.4%	1.5%	1.5%	2.1%	2.3%	1.8%	1.2%	0.1%
Photovoltaic	33.1%	32.8%	31.2%	28.1%	18.0%	15.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Pressure Reduction Turbi	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.5%	0.6%	0.7%	0.6%	0.7%	0.8%
Waste Heat to Power	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.4%	0.0%	0.0%	0.0%
Wind Turbine	2.9%	2.9%	3.1%	3.3%	3.8%	4.1%	5.0%	4.9%	4.9%	4.8%	4.4%	3.1%	2.9%	3.2%	4.9%
Grand Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

ED Staff Proposal on SGIP

Appendix C – Proposed eligible technologies – scoring for rebates

All cell input values are either 1, 2, or 3

	GHG	Criteria air pollutants	Grid support	Market transformation	Need for SGIP support	**Composite scores**
Weighting factor	3	1	2	3	3	
Wind	3	3	1	2	2	**2.17**
WHP	3	3	1	2	1	**1.92**
PRT	3	3	1	2	1	**1.92**
ICE NG	1	1	1	2	2	**1.50**
ICE OSBG	3	1	1	2	2	2.00
ICE DBG	3	1	1	2	2	2.00
Microturbine OSBG	3	1	1	2	1	1.75
Microturbine DBG	3	1	1	2	3	2.25
Gas turbine NG	1	1	3	2	2	**1.83**
Gas turbine OSBG	3	1	3	2	1	2.08
Gas turbine DBG	3	1	3	2	3	2.58
FC CHP NG	1	3	2	2	2	**1.83**
FC CHP OSBG	3	3	2	2	2	2.33
FC CHP DBG	3	3	2	2	3	2.58
Energy Storage	3	3	3	2	3	**2.75**

Basis for scores:

GHG	Renewables are given "3"; natural gas based technologies are given "1."
Criteria air pollutants	Per Appendix D of Impact Evaluation, conventional CHP given "1", all others "3."
Grid support	All scores except storage are based on Figure 6-5 in Impact Evaluation. Storage rated "3" because of typical demand response dispatch.
Market transformation	Because the MT Study is not yet available, all values are set at 2.
Need for SGIP support	From Figure 1-2 in CE Study: PCT>1.2 gets "1"; 0.8<PCT<1.2 gets "2"; PCT<0.8 gets "3"

Color codes:

Gray for biogas
Orange gets lowest initial rebate
Purple gets medium initial rebate
Green gets highest initial rebate

(END OF ATTACHMENT)