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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues.	Rulemaking 12-11-005 (Filed November 8, 2012)

ASSIGNED COMMISSIONER'S RULING REQUESTING COMMENTS ON SENATE BILL 861 COMPLIANCE AND REVIEW OF SELF-GENERATION INCENTIVE PROGRAM

This ruling seeks comments from parties regarding requirements to conform the Self-Generation Incentive Program (SGIP) to new statutory provisions required by Senate Bill (SB) 861 (2014 Committee on Budget and Fiscal Review) and Assembly Bill (AB) 1478 (2014 Committee on Budget),[1] excluding greenhouse gas (GHG) factor updates.[2] Additionally, this ruling asks parties to comment on other possible program revisions that may improve the SGIP that are not required by SB 861 or AB 1478.

[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] The GHG factors, as relevant to the SGIP and SB 861, are being evaluated pursuant to an Assigned Commission's Ruling issued on March 27, 2015.

1. Background

Section 379.6 authorizes the SGIP and establishes the basic program rules. In 2014, the legislature enacted SB 861 and AB 1478, which revised § 379.6 in several respects. These two bills:

1. Authorize collections for SGIP through 2019 (§ 379.6(a)(2)).
2. Authorize administration of SGIP through 2020 (§ 379.6(a)(2)).
3. Require the Commission to update the factor for avoided GHG emissions on or before July 1, 2015 (§ 379.6(b)(2)).
4. Restrict SGIP eligibility to distributed energy resource (DER) technologies that:
    a. Reduce demand from the grid by offsetting customer onsite energy load (§ 379.6(e)(1));
    b. Are commercially available (§ 379.6(e)(2));
    c. Safely utilize the grid (§ 379.6(e)(3)); and
    d. Improve air quality by reducing criteria air pollutants (§ 379.6(e)(4)).
5. Subject incentive recipients to audits and inspections (§ 379.6(f)).
6. Require the Commission to determine a capacity factor for each DER technology (§ 379.6(g)).
7. Require the Commission to consider the relative amount and the cost of GHG emission reductions, peak demand reductions, system reliability benefits, and other measurable factors when allocating program funds between eligible technologies (§ 379.6(h)(2)).
8. Simplify the requirements needed to qualify for an additional incentive as a California manufacturer (§ 379.6(j)(2)).
9. Require the Commission to measure the program's overall success based on:
    a. GHG emissions (§ 379.6(l)(1));

b. Criteria air pollutant air emission reductions and credits secured (§ 379.6(l)(2));

c. Energy reductions as measured in energy value (§ 379.6(l)(3));

d. Reductions of customer peak demand (§ 379.6(l)(4));

e. Capacity factor (§ 379.6(l)(5));

f. Avoided costs for grid upgrades and replacements (§ 379.6(l)(6)); and

g. Improved onsite electric reliability (§ 379.6(l)(7)).

All of the revisions to § 379.6 enacted in 2014, with the exception of Number 2, above, require some action by the Commission.[3]

In response to § 379.6(a)(2), President Peevey, who was the Commissioner assigned to Rulemaking (R.) 12-11-005 at the time, issued an Assigned Commissioner Ruling (ACR) on September 23, 2014, addressing the amount of funding to collect in rates for SGIP through 2019 (SGIP Funding ACR). Parties filed opening comments on October 15, 2014 and reply comments on October 20, 2014. After review of these comments, President Peevey issued a proposed decision authorizing the full $83 million in annual collections for the SGIP through 2019, which the Commission approved on December 18, 2014.[4]

On March 27, 2015, I issued an ACR addressing the maximum GHG emissions rate for technologies to be eligible for SGIP incentives in response to the direction in § 379.6(b)(2). Parties are now filing comments and reply comments in response to this ruling and I intend to issue a proposed decision on this matter in the near future.

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[3] A copy of Section 379.6, as amended, is attached as Appendix A.

[4] Decision (D.) 14-12-033, Ordering Paragraph 1.

This ruling addresses the remaining issues (numbers 4 through 8) from the above list. Additionally, with the five-year program extension in SB 861, the Commission has the opportunity to review the program in light of past experience and determine whether any other changes should be made to the program rules to better achieve the goals of SGIP. To inform the Commission's evaluation of the need to modify the program rules, I request parties to provide comments on matters specifically identified in SB 861 and other topics described herein.

The questions set forth below are organized under six broad topics: (1) program goals; (2) program evaluation; (3) eligibility criteria and eligible technologies; (4) program design (technology categories, or "buckets," and rebates); (5) advanced energy storage (AES); and (6) miscellaneous.

2. Program Goals

Section 379.6 provides a number of program goals. Section 379.6(a)(1) states that SGIP was created to deploy DERs in order to improve grid efficiency and reliability, and to reduce GHGs, peak demand, and ratepayer costs. It also states that the program's costs and benefits must be apportioned equitably. Section 379.6(e) suggests that eligible technologies: reduce grid demand (and especially peak grid demand) be commercially available; integrate safely into the grid; and reduce criteria air pollutants. Finally, § 379.6(l), as amended, requires the Commission to evaluate the program according to seven "performance measures," some of which restate certain goals set forth earlier in the code:

1. Reduction of GHGs;[5]

[5] It should be noted that because GHG emissions from the electricity sector are covered by the state's cap and trade program, SGIP-funded projects do not truly reduce GHGs overall.

Footnote continued on next page

2. Reduction of criteria air pollutants;
3. Energy reduction "measured in energy value";
4. Reduction of customer peak demand;
5. Project capacity factors;
6. Avoided transmission and distribution costs; and
7. Improvement in onsite electricity reliability.

Finally, the Commission previously adopted market transformation for DER technologies as a core goal, even though it is not mentioned in the statute.[6] Based on language in §§ 379.6(a)(1), 379.6(e) and 379.6(l), as well as D.11-09-015, I propose that the SGIP have the following goals:

1. Reduce GHGs;
2. Reduce criteria air pollutants;
3. Reduce customer peak demand;
4. Improve efficiency and reliability of the distribution and transmission system;
5. Promote market transformation of emerging technologies that have the potential to provide valuable grid services cost-effectively; and
6. Maximize the value to ratepayers from SGIP incentives, and provide for an equitable distribution of the costs and benefits of the program.

Q.1: Do you agree or disagree with the proposed program goals, and why? In addition to the goals enumerated above, should SGIP include any other goals? If so, describe the

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however, requiring that SGIP projects' GHG emissions do not exceed the displaced emissions from grid-delivered electricity ensures that the SGIP does not impede the achievement of the GHG reduction targets under the cap and trade program.

[6] D.11-09-015 at 7, 9. http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/143459.PDF..

additional goals and explain why they should be included. How should the reduction of customer peak demand weigh reductions of coincident peak demand at the system and local levels? Should the Commission give some goals greater or lesser weight? If so, describe how the goals should be ranked and discuss your rationale for the ranking you propose.

3. Program Evaluation

As described above and in reference to § 379.6(l), SB 861 enacted seven metrics that the Commission should consider when measuring and evaluating the program's success.[7] Currently the SGIP measurement and evaluation (M&E) program is guided by a July 23, 2014 Administrative Law Judge (ALJ) ruling.[8] Now and in the past, the Commission has conducted Impact Evaluations.[9] As this ACR is being released, the Commission is in the process of publishing three SGIP studies: (1) a 2013 impact evaluation; (2) a cost effectiveness study; and (3) a market transformation study. It is expected that these studies will evaluate most of the metrics identified in § 379.6, as amended by SB 861.

1. <u>Reduction of GHGs</u>: The 2012 impact evaluation tracked GHGs reduced by SGIP projects, measured in metric tons of carbon dioxide (CO2). The avoided GHGs were compared to displaced central station generation and, for combined heat and power projects, boiler fuel. The 2013 impact evaluation, which is now near release, will also track GHG impacts.
2. <u>Reduction of criteria air pollutants</u>: The 2012 impact evaluation did not track criteria air pollutants; however, the 2013 impact evaluation, which is near release, will track

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[7] § 379.6(l)(7) pre-existed SB 861 and concerns onsite customer reliability.

[8] July 23, 2014 ALJ DeAngelis Ruling (R.12-11-005) is available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M098/K755/98755196.PDF.

[9] http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm.

nitrogen oxides (NOx), sulfur dioxide (SO2), and particulate matter whose diameter is smaller than ten micrometers (PM10). These impacts are measured in pounds.

3. Energy reduction "measured in energy value": The 2012 impact evaluation and the soon-to-be-released 2013 impact evaluation track the amount of grid energy avoided by SGIP-funded DERs. These impacts are measured in megawatt-hours.

4. Reduction of customer peak demand: The 2012 impact evaluation and the 2013 impact evaluation track the impact that SGIP-financed DERs have on the California Independent System Operator system peak demand, measured in megawatts. In addition, the 2013 impact evaluation examines the impact which SGIP DERs have on the peak demand for a sampling of distribution feeder lines.

5. Project capacity factors: The 2012 impact evaluation and the 2013 impact evaluation track the capacity factors[10] for SGIP-funded DERs by technology and fuel type.

6. Avoided transmission and distribution costs: The 2012 impact evaluation tracked the utility costs which the SGIP program helped each utility avoid. These avoided utility costs included several components, including transmission and distribution. The soon-to-be-released cost effectiveness study will include avoided cost data related to transmission and distribution.

7. Improvement in onsite electricity reliability: Until now, the SGIP's measurement and evaluation program has not tracked changes in customer's onsite electricity reliability.

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[10] Capacity factor is a measure of the amount of energy actually supplied by a DER as a percentage of the maximum possible amount of energy supplied. Put another way, it is the average output divided by the nameplate capacity and expressed as a percentage.

The Commission, thus, has been tracking, at least in part, all of the above criteria except for onsite electricity reliability.

> Q.2: For those criteria which the Commission has been measuring, should any changes be made in how this is done? For those criteria which the Commission has not been tracking (namely, onsite reliability) how should the Commission measure success? Are there other measures of success, not listed in the statute, that should be examined in future impact evaluations?

4. SB 861 Eligibility Criteria and Eligible Technologies

Section 379.6(b)(1) requires that DER technologies, to be eligible for incentives under SGIP, must lower GHGs. Section 379.6(e) requires that SGIP DER technologies reduce grid demand (including but not limited to peak grid demand), be commercially available, integrate safely into the grid, and reduce criteria air pollutants.

> Q.3: The GHG reduction criterion will be addressed in a forthcoming decision as discussed above. For each of the other eligibility criteria (i.e., demand reduction, commercial availability, safety, and reduction of criteria air pollutants) how should the criterion be defined and how should a technology's compliance with each criterion be verified?

In the past, the Commission has considered adopting other eligibility criteria in addition to those mandated by statute. For example, in D.11-09-015 the Commission considered, but then rejected, using as an eligibility criteria that SGIP incentives be provided only to those technologies that needed them to earn a reasonable return on investment. Staff proposed this criterion to avoid spending ratepayer dollars on projects that did not need program incentives.

This test was rejected, in part because of complexities foreseen in calculating project profitability.[11]

> Q.4: Should the Commission now restrict SGIP to those technologies that require an incentive in order for them to be profitable for the system owner? Why or why not? If so, how should the profitability threshold be measured?

In that same decision, the Commission considered and rejected the guiding principle that the SGIP should only support DER technologies that are cost effective, or represent the potential to achieve cost-effectiveness in the near future. The Commission reasoned that cost data were highly uncertain, that cost effectiveness screens might yield unreliable results, and that premature disqualification of DERs based on cost effectiveness could impede the program goal of market transformation.[12]

> Q.5: Should the requirement of present or near future cost effectiveness now be adopted? Why or why not? If so, how should it be measured? Should the Commission require that SGIP technologies have the potential to become self-sustaining DER industries? Why or why not? If so, how should this potential be measured?

Supporting grid reliability and the efficient use of grid resources are among the SGIP goals included in § 379.6(a)(1). Improving on-site customer reliability is also a program goal (§ 379.6(l)(7)).

> Q.6: Should the criteria of grid reliability, efficient use of grid resources, and on-site customer reliability be explicitly required of SGIP technologies? Why or why not? If so, how would these criteria be measured?

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11 D.11-09-015 at 12.

12 D.11-09-015 at 13.

One of the technologies supported through the Electric Program Investment Charge (EPIC) is a "DC micro-grid." DC micro-grids can be described as buildings or campuses operating primarily on direct current (DC) as opposed to alternating current (AC). The industry has suggested that DC micro-grids hold the potential to lower grid loads because, when coupled with on-site DERs that generate power in DC mode (such as photovoltaics or fuel cells), they can avoid the losses associated with DC to AC inverters; they also can lower capital expenses associated with inverters, among other claimed benefits.

> Q.7: Assuming that any given project would not receive ratepayer support from both EPIC and SGIP, should DC micro-grids as a category be eligible for SGIP incentives? Is this a specific technology or is it a package of technologies, and does it matter? Might this technology more appropriately be categorized as energy efficiency? Is this a technology or package of technologies that has been available long enough to be considered commercially available (required per § 379.6(e)(2))?

Currently the SGIP incentivizes the following technologies: combined heat and power (CHP) fuel cells; electric-only fuel cells; waste heat to power; CHP combustion technologies (gas turbines, micro-turbines, internal combustion engines (ICE)); pressure reduction turbines; wind; and advanced energy storage (AES).

> Q.8: Should any of the currently eligible technologies be eliminated from SGIP eligibility? If so, which ones? Why or why not, and based on what criteria? Are there any additional technologies that should be added to the program, and if so, what are they and why should they be included?

5. Program Design (Buckets and Rebates)

Currently, the SGIP divides eligible technologies into three incentive level categories: renewable and waste heat capture (wind, waste heat to power, pressure reduction turbines); non-renewable conventional CHP (gas turbines and ICEs); and emerging technologies (fuel cells and AES). As of 2015, renewable and waste heat capture technologies are eligible for $1.07 per Watt, conventional CHP technologies are eligible for $0.44 per Watt, and emerging technologies are eligible for $1.46 per Watt (AES) and $1.65 per Watt (fuel cells).

> Q.9: Should the current categories of "Renewable and Waste Heat Recovery," "Non-Renewable Conventional CHP," and "Emerging Technologies" be maintained? Why or why not? Should any technology be moved from its current category to another? Why or why not?

In a November 13, 2009 ruling,[13] the assigned ALJ asked parties to consider whether the SGIP incentives should decline as more capacity is installed, along the lines of the California Solar Initiative. The rationale for declining incentives is that as technologies advance they become more cost effective and therefore need fewer incentives. Furthermore, reducing incentives is meant to spur the move toward self-sufficiency and market transformation.

In the subsequent Staff Proposal that was published in September 2010 (September 2010 Staff Proposal), the Staff discussed but did not recommend the idea that incentive reductions should be explicitly linked to capacity (MW) additions. Several parties had noted that applying such a structure for SGIP would be unworkable, stating: "The number of different technologies and the relatively small number of projects of each technology that can be funded through the SGIP makes it difficult to establish MW triggers for declining

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[13] November 13, 2009 ruling by ALJ Duda in R.08-03-008 at 4. http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULINGS/109738.PDF.

incentives."[14] Staff did however recognize the importance of declining incentives in spurring DER technologies toward self-sufficiency. Therefore, Staff instead recommended that incentives decline on an annual basis. D.11-09-015 ordered annual incentive reductions of 10 percent for emerging technologies and 5 percent for all other technologies.[15]

One of the benefits of the current design, with rebates declining annually, is the certainty provided to businesses that plan investments over a several year period. However, a drawback might be that the current incentive design does not adjust to market changes and might provide excessive incentives for certain technologies. For example, all of the incentives allocated for renewable and emerging technologies in PG&E's territory were exhausted within the first several weeks of 2015. It is possible that a program design that lowered incentives in response to capacity reservations might have been more responsive to market signals, lowered incentives earlier, and stretched incentive dollars over more capacity. On the other hand, perhaps the issue of "over-generous" incentives could be rectified simply by lowering the incentive levels.

> Q.10: Should the Commission retain the existing SGIP program design, with incentives declining over time, or does another design, such as one which lowers incentives in response to capacity reservations, better support program participation and market transformation? Explain why one approach is better than the others.
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> Q.11: If a capacity-based approach is adopted, provide the details of the new approach, identifying the technologies and

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[14] September 2010, Staff Proposal at 44. http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULINGS/124214.PDF.

[15] D.11-09-015 at 41.

> the amount of money that would belong in each bucket, as well as the number, size (MW and dollar), and rebate levels for the steps in that bucket.
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> Q.12: If the annual reduction approach is retained, should the program rebates be reduced (or increased) overall or only for certain technologies? Why or why not? And if they are reduced (or increased), then by how much and why? Should the annual rate of reduction be increased for one or more technology categories, and if so, to what rate and why?

While the current program limits the amount of SGIP financial awards per project ($5 million), and limits the amount of capacity that is awarded incentives (3 MW),[16] there are currently no limits on project size. Rebates are currently structured so that the first megawatt of a project is incentivized at the full rate, the second megawatt is incentivized at half of the full rate, while the third megawatt is incentivized at only a quarter of the full rate.[17]

> Q.13: Should the SGIP continue to fund projects of any size? Should the declining payment structure for each project be continued or altered? Why or why not? And if so, what should the size limits be? What should the new structure be?

SGIP rules allow systems to be sized up to current or forecasted on-site load (with systems 5 kW and less exempt from this restriction). For stand-alone AES, projects may be sized up to the host customer's previous twelve-month peak, while paired AES may be sized up to the capacity of the PV or other SGIP system (except when paired with wind, when it is capped at the twelve-month peak demand).

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[16] SGIP Handbook at 37.

[17] *Id*. at 35.

> Q.14: Should the load-based size restrictions currently in place be continued or altered? How and why?

Currently the program gives projects an adder for using biogas. The adder, which is $1.46 per watt in Program Year 2015, is the same amount as is paid for AES projects and can be added to the incentive for any project that consumes fuel, whether fuel cell or conventional gas-based generation.

> Q.15: Should the biogas adder be continued as it is currently applied? Why? If it is changed, how should it be changed and why?

The program currently mandates that projects which are larger than 30 kW be paid on a "performance based incentive" (PBI) basis, with half of the incentive awarded in an up-front lump sum payment, and half of the payment awarded over the following five years, based on metered and reported performance.

> Q.16: Should the PBI structure be maintained or modified? Why? If modified, then how should it be modified and why?

Pursuant to AB 327, the Commission issued Rulemaking 14-08-013. As part of that rulemaking, the electric utilities are ordered to file a Distribution Resources Plan (DRP) each year, starting in 2015. In the DRP, each utility submits an analysis of its distribution grid, noting which resources are subject to congestion and quantifying the costs and benefits of network infrastructure improvements.

> Q.17: Should SGIP payments reflect locational benefits (or costs) they provide (or impose)? If so, how (from a timing and methodogical perspective) should this be accomplished? Because some customers are in locations where their contributions might be especially valuable to the grid, does the introduction of a locational component raise concerns about equity?

SGIP is a program that provides upfront rebates, as well as PBI payments which increase (up to a maximum amount) with higher capacity factors. The current incentive structure does not compensate SGIP projects for providing any particular grid services, for generating at peak times of the day, or days which the utilities designate as "critical peak days."[18] Additionally, the SGIP incentives are not structured to incentivize AES charging during over-generation events or discharging during peak events.

> Q.18: Should the SGIP program administrators track and should the SGIP payments reflect the operational benefits that SGIP projects provide to the grid on a day-to-day or hour-to-hour basis, or in response to peak grid usage or over-generation events? If so, then specifically how should this be accomplished?

Currently the program does not allow any portion of the customer's load that is committed to utility interruptible programs or any other "state agency-sponsored demand response (DR) programs" to be considered in sizing an SGIP system.[19] The purpose of this rule is to prevent a customer from receiving multiple incentive payments for taking a single action.[20] However the prohibition is only designed around a specific category of DR programs structured on a Firm Service Level commitment.

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[18] The Commission is now reviewing a joint advice letter filed by the SGIP program administrators (Advice Letter 3552-G et al) regarding SGIP rebates for residential AES applications, where those applications are evaluated for eligibility based on TOU and critical peak day criteria.

[19] *See* Section 4.4.7 of the 2015 SGIP Handbook.

[20] *See* (D.01-03-073 at 38.

Q.19.1: Should dual enrollment in DR and SGIP continue to be allowed? If yes, how should the Commission address dual enrollment in DR and SGIP but adhere to its current policy to not allow multiple incentive payments for taking a single action (e.g., through metering?)

Q.19.2: Should the Commission continue to use the project size limitation rule set forth in Section 4.4.7 of the SGIP Handbook to address how the DR and SGIP programs intersect?

- If yes, how, if at all, should the Commission modify the SGIP rules to address DR programs that do not have a Firm Service Level component (e.g., AC Cycling, Demand Bidding, Capacity Bidding)?
- How should the limitation be applied to customers receiving PBI payments who enroll in SGIP first and DR programs later?
- What, if any, additional rules should be adopted to calculate the limitation that applies to customers with systems sized greater than 100% of their load?
- Currently wind and AES projects need not abide by the project size limitation rule. Should these projects remain exempted?

6. Advanced Energy Storage

AES differs from other SGIP technologies for several reasons. First, AES is not typically a net generator,[21] but rather a technology that moves demand from one time period to another. Second, because AES is deployed much of its time in charging mode, it is available for providing power fewer hours per year than

[21] The Commission is now reviewing an advice letter filed by the Center for Sustainable Energy (Advice Letter 56) to introduce Small Thermal Energy Storage (STES) into SGIP. STES is able operate at a round-trip efficiency that is, at least in theory, greater than 100 percent. It accomplishes this by using cooler night time air to create ice, whose coolness is released during the hotter daytime hours.

other SGIP eligible resources.[22] Third, AES is a relatively recent addition to SGIP, and so the program has less operating experience with completed AES applications than with other technologies.

> Q.20: How should the Commission design AES incentives to encourage investments and other behaviors that maximize benefits to the grid? Should the incentive structure stay the same or be revised? If they should change, what specific revisions do you recommend and why?

The SGIP has prohibited program funding for systems used as back-up generation since its inception in 2001.[23] When located behind the meter of a commercial or industrial customer, AES is able to smooth spikes in demand and reduce the customer's monthly demand charge, providing a financial incentive to use AES systems on a regular basis. The same does not hold for residential customers because residential rates do not include demand charges and the difference between peak and off-peak rates in residential time of use rate schedules is generally not sufficient for the regular use of AES systems to be cost-effective.

> Q.21: How should the SGIP ensure that residential AES applicants operate their systems regularly, instead of being reserved for backup only?[24] If residential AES systems are used only during critical peak events, do these systems provide enough of a ratepayer benefit to justify their inclusion in the SGIP?

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[22] The SGIP Handbook at 37 reflects the fact that AES is not available for discharging while it is charging.

[23] D.01-03-073 introduced this requirement into the program (Attachment 1 at fn. 12). It is stated in the current SGIP Handbook at Section 4.2.5.

[24] Note: this issue is addressed in Draft Resolution E-4717, mailed by Energy Division for comment on April 17, 2015. This Draft Resolution is a proposal by Energy Division and will be voted upon by the Commission at a later date.

7. Miscellaneous Topics

In D.11-09-015, the Commission discussed different proposals for limiting program participation by an individual manufacturer and decided to limit participation in any given program year to 40 percent of the budget that is available at the beginning of the year.[25]

> Q.22: Is the 40 percent individual manufacturer cap working acceptably well to allow robust participation by an individual manufacturer without squeezing out other participants? Why or why not? Should the cap be maintained or modified? If modified, how should the cap be modified?

Section 379.6(j) requires the Commission to "… provide an additional incentive of 20 percent from existing program funds for the installation of eligible distributed generation resources manufactured in California." SB 861 removed other qualifications and requirements related to this 20 percent adder (e.g., prior to SB 861, the following additional requirements applied: California residency of owners and/or managing officers and a five year history of operations within California). The statute does not define the term "manufactured in California." Currently, the SGIP provides this adder to any product that has any component manufactured in California, with no minimum requirement on the share of the value of California-manufactured components.[26]

> Q.23: In light of the amendments enacted by SB 861, should the Commission revisit the SGIP programs rules for providing an adder to installations "manufactured in California?" Should the adder continue to be given for a product that contains any component, however small in value,

[25] The denominator includes any funds carried over from the previous year.

[26] SGIP Handbook at 34.

> manufactured in California? Should this adder require that more than fifty percent of the value of the product be manufactured in California? Or, should the Commission consider another interpretation?

SB 861 added Section 379.6(g), which directs the Commission to "…determine a capacity factor for each distributed generation system energy resource technology in the program."

> Q.24: How should the Commission comply with this mandate? What should the capacity factors for each eligible technology be? Should the Commission use the most recent available impact evaluation to determine what an average or reasonable capacity factor for each technology is? If not, what other information should be used to determine the capacity factors? Should those same capacity factors be used in administering the PBI payments?

The questions posed above are intended to cover the main points of complying with SB 861 as well as reviewing the program to improve it, parties may feel that certain important topics have not been included.

> Q.25: Are there other important topics that have not been covered in the previously listed questions? If so, what are they? Are there other ways in which the SGIP can be improved to help it meet its goals?

8. Process

Parties may file comments on or before May 22, 2015 with reply comments due on or before June 2, 2015. Comments may be up to 30 pages. Replies may be up to 15 pages.

IT IS RULED that parties may file opening comments on or before May 22, 2015. Reply comments may be filed on or before June 2, 2015.

Dated April 29, 2015, at San Francisco, California.

/s/ MICHAEL PICKER
Michael Picker
Assigned Commissioner

Appendix A:

Public Utilities Code 379.6 changes from SB 861 (and Cleanup Bill)

379.6.

(a) (1) It is the intent of the Legislature that the self-generation incentive program increase deployment of distributed generation and energy storage systems to facilitate the integration of those resources into the electrical grid, improve efficiency and reliability of the distribution and transmission system, and reduce emissions of greenhouse gases, peak demand, and ratepayer costs. It is the further intent of the Legislature that the commission, in future proceedings, provide for an equitable distribution of the costs and benefits of the program.

(2) The commission, in consultation with the Energy Commission, may authorize the annual collection of not more than the amount authorized for the self-generation incentive program in the 2008 calendar year, through December 31, 2019. The commission shall require the administration of the program for distributed energy resources originally established pursuant to Chapter 329 of the Statutes of 2000 until January 1, 2021. On January 1, 2021, the commission shall provide repayment of all unallocated funds collected pursuant to this section to reduce ratepayer costs.

(3) The commission shall administer solar technologies separately, pursuant to the California Solar Initiative adopted by the commission in Decisions 05-12-044 and 06-01-024, as modified by Article 1 (commencing with Section 2851) of Chapter 9 of Part 2 of Division 1 of this code and Chapter 8.8 (commencing with Section 25780) of Division 15 of the Public Resources Code.

(b) (1) Eligibility for incentives under the self-generation incentive program shall be limited to distributed energy resources that the commission, in consultation with the State Air Resources Board, determines will achieve reductions in emissions of greenhouse gases pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code).

(2) On or before July 1, 2015, the commission shall update the factor for avoided greenhouse gas emissions based on the most recent data available to the State Air Resources Board for greenhouse gas emissions from electricity sales in the self-generation incentive program administrators' service areas as well as current estimates of greenhouse gas emissions over the useful life of the distributed energy resource, including consideration of the effects of the California Renewables Portfolio Standard.

(c) Eligibility for the funding of any combustion-operated distributed generation projects using fossil fuel is subject to all of the following conditions:

(1) An oxides of nitrogen (NOx) emissions rate standard of 0.07 pounds per megawatthour and a minimum efficiency of 60 percent, or any other NOx emissions rate and minimum efficiency standard adopted by the State Air Resources Board. A minimum efficiency of 60 percent shall be measured as useful energy output divided by fuel input. The efficiency determination shall be based on 100 percent load.

(2) Combined heat and power units that meet the 60-percent efficiency standard may take a credit to meet the applicable NOx emissions standard of 0.07 pounds per megawatthour. Credit shall be at the rate of one megawatthour for each 3,400,000 British thermal units (Btus) of heat recovered.

(3) The customer receiving incentives shall adequately maintain and service the combined heat and power units so that during operation the system continues to meet or exceed the efficiency and emissions standards established pursuant to paragraphs (1) and (2).

(4) Notwithstanding paragraph (1), a project that does not meet the applicable NOx emissions standard is eligible if it meets both of the following requirements:

(A) The project operates solely on waste gas. The commission shall require a customer that applies for an incentive pursuant to this paragraph to provide an affidavit or other form of proof that specifies that the project shall be operated solely on waste gas. Incentives awarded pursuant to this paragraph shall be subject to refund and shall be refunded by the recipient to the extent the project does not operate on waste gas. As used in this paragraph, "waste gas" means natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.

(B) The air quality management district or air pollution control district, in issuing a permit to operate the project, determines that operation of the project will produce an onsite net air emissions benefit compared to permitted onsite emissions if the project does not operate. The commission shall require the customer to secure the permit prior to receiving incentives.

(d) In determining the eligibility for the self-generation incentive program, minimum system efficiency shall be determined either by calculating electrical and process heat efficiency as set forth in Section 216.6, or by calculating overall electrical efficiency.

(e) Eligibility for incentives under the program shall be limited to distributed energy resource technologies that the commission determines meet all of the following requirements:

(1) The distributed energy resource technology shifts onsite energy use to off-peak time periods or reduces demand from the grid by offsetting some or all of the customer's onsite energy load, including, but not limited to, peak electric load.

(2) The distributed energy resource technology is commercially available.

(3) The distributed energy resource technology safely utilizes the existing transmission and distribution system.

(4) The distributed energy resource technology improves air quality by reducing criteria air pollutants.

(f) Recipients of the self-generation incentive program funds shall provide relevant data to the commission and the State Air Resources Board, upon request, and shall be subject to onsite inspection to verify equipment operation and performance, including capacity, thermal output, and usage to verify criteria air pollutant and greenhouse gas emissions performance.

(g) In administering the self-generation incentive program, the commission shall determine a capacity factor for each distributed generation system energy resource technology in the program.

(h) (1) In administering the self-generation incentive program, the commission may adjust the amount of rebates and evaluate other public policy interests, including, but not limited to, ratepayers, energy efficiency, peak load reduction, load management, and environmental interests.

(2) The commission shall consider the relative amount and the cost of greenhouse gas emissions reductions, peak demand reductions, system reliability benefits, and other measurable factors when allocating program funds between eligible technologies.

(i) The commission shall ensure that distributed generation resources are made available in the program for all ratepayers.

(j) In administering the self-generation incentive program, the commission shall provide an additional incentive of 20 percent from existing program funds for the installation of eligible distributed generation resources manufactured in California.

(k) The costs of the program adopted and implemented pursuant to this section shall not be recovered from customers participating in the California Alternate Rates for Energy (CARE) program.

(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.