FILED
6-06-16
04:59 PM

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)

THE OFFICE OF RATEPAYER ADVOCATES' OPENING COMMENTS ON PROPOSED DECISION REVISING THE SELF-GENERATION INCENTIVE PROGRAM PURSUANT TO SENATE BILL 861, ASSEMBLY BILL 1478, AND IMPLEMENTING OTHER CHANGES

DIANA L. LEE
Attorney for the Office of Ratepayer Advocates

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-4342
E-mail: diana.lee@cpuc.ca.gov

TIM DREW
HELENA OH
Analysts for the Office of Ratepayer Advocates

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-5618
E-mail: tim.drew @cpuc.ca.gov

June 6, 2016

SUBJECT INDEX

Page

TABLE OF AUTHORITIES

Page

CPUC Decisions

Public Utilities Code

I. INTRODUCTION

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, the Office of Ratepayer Advocates (ORA) submits these opening comments on the May 16, 2016 "*Proposed Decision Revising the Self-Generation Incentive Program Pursuant to Senate Bill 861, Assembly Bill 1478, and Implementing Other Changes*" (PD). The PD 1) adopts new incentive levels for the Self-Generation Incentive Program (SGIP), 2) allows SGIP to be administered on a continuous basis with incentive levels declining based on the capacity installed through the program, 3) divides the incentive budget between storage and generation technologies, 4) establishes minimum biogas usage levels for eligible combustion technologies, 5) establishes a lottery system to manage the incentive application process, 6) caps the amount of incentives a project developer can reserve, and 7) establishes requirements for sourcing technologies from within the State of California.

ORA supports many aspects of the PD, but as explained in Section III below, the Commission should revise the PD to state explicitly that natural gas generation technologies must meet the greenhouse gas (GHG) emissions factor adopted in Decision (D.) 15-11-027, *Decision Revising the Greenhouse Gas Emission Factor to Determine Eligibility to Participate in the Self-Generation Incentive Program Pursuant to Public Utilities Code Section 379.6(b)(2) as Amended By Senate Bill 861* without regard to their use of biogas fuels. The Commission should also revise the PD to clarify the Commission's goal in adopting Bloom Energy, Inc.'s (Bloom) proposal to incorporate the California Energy Commission's directed biogas Renewable Portfolio Standard (RPS) into the SGIP. It appears that the PD intends to remove the requirement that directed biogas must be produced by facilities located within California, but as written, the PD is not clear on this point. Finally, the PD should explicitly state that SGIP participants that also participate in demand response programs should not receive multiple payments (i.e., SGIP incentives and DR incentives) for a single action.

II. BACKGROUND

In 2014 Senate Bill (SB) 861 and Assembly Bill (AB) 1478 revised Public Utilities Code Section 379.6. The revisions to Public Utilities Code Section 379.6 authorize the extension of SGIP and require several significant modifications to the SGIP, including updating the program eligibility factor for GHG emissions. Decision 15-11-027 revised the GHG emissions factor on November 19, 2015. On November 23, 2015, the assigned Commissioner issued a ruling asking parties to comment on an attached Energy Division *Staff Proposal to Modify the Self-Generation Incentive Program pursuant to SB 861 and the Commission's Own Motion* (Staff Proposal).[1] The Staff Proposal recommended additional modifications to SGIP required by SB 861 and AB 1478. Parties filed opening and reply comments on the Staff Proposal in January 2016. On February 25, 2016, the assigned Commissioner issued a ruling (ACR) seeking parties' comments on a proposal to require natural-gas fueled technologies to use a percentage of biogas as a condition of eligibility. Parties filed opening and reply comments on the ACR in March 2016.

III. DISCUSSION

A. The Proposed Decision should explicitly state that gas-fired projects must meet the emissions factor adopted in D.15-11-027 without consideration of the use of biogas.

The PD requires that beginning in 2017 all natural gas-fueled generation technologies must blend biogas with natural gas as a condition of receiving SGIP incentives.[2] Gas-fired generators must use at least 10% biogas in 2017, increasing to a requirement of using 100% biogas in 2020. Decision 15-11-027 requires that gas-fired technologies must meet the adopted emission factor of 350 kilograms carbon dioxide per megawatt hour ($kgCO_2/MWh$) to be eligible for SGIP incentives.[3] The PD does not purport to change the GHG emission factor adopted in D.15-11-027. The PD recognizes that "adopting a zero emission fuel requirement is another important step towards supporting SGIP's GHG reduction and market transformation goals."[4] The most effective way to meet the goals of both D.15-11-027 and the PD is to require natural gas-fired generators to meet the GHG emissions factor adopted in D.15-11-027 without the help of biogas blending. In other words, SGIP projects should meet the GHG emissions factor even without factoring in the GHG emissions reductions associated with biogas blending.

Gas-fired generators that use a blend of natural gas and biogas and do not meet the GHG emission factor without biogas cannot be guaranteed to be in compliance with D.15-11-027 and

---

[1] http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=155978793.

[2] PD, p. 20.

[3] D.15-11-027, pp. 26-27 "we find that, pursuant to § 379.6(b)(2), to be eligible for SGIP incentives, gas-fired technologies must emit GHGs at a rate lower than this emission factor averaged over the first ten years of operation, and the calculation of a project's emissions must take into account the assumed 1% annual degradation in electrical efficiency for technologies subject to this assumption. This results in a maximum first-year emission rate of 334 kgCO2/MWh."

[4] PD, p. 20.

Public Utilities Code Section 379.6(b)(1). Decision 15-11-027[5] and Public Utilities Code Section 379.6(b)(1)[6] limit emissions from generation technologies without articulating any specific exceptions for technologies that use on-site renewable fuel or directed biogas. Directed biogas projects pose additional challenges in light of the compliance and verification problems highlighted in ORA's March 10, 2016 opening comments.[7] By explicitly requiring that natural gas-fired generators meet the GHG emissions factor adopted in D.15-11-027 without the inclusion of biogas, the Commission can be reasonably assured that all participating projects reduce emissions even if the SGIP program administrators encounters obstacles enforcing and verifying compliance with the fuel-blending requirements of the PD.

B. The Commission should clarify the PD's adoption of Bloom Energy, Inc.'s (Bloom) proposal to incorporate the California Energy Commission's directed biogas eligibility requirements under the RPS into the SGIP.

The PD adopts Bloom's recommendation that the SGIP's eligibility requirements for directed biogas project should align with those of the California Energy Commission's (CEC) for the Renewable Portfolio Standard (RPS)."[8] The PD describes Bloom's proposal as requiring that directed biogas projects 'must meet the currently applicable RPS eligibility requirements for biogas injected into a natural gas pipeline.'"[9] The PD states that D.11-09-015 adopted the directed biogas eligibility requirements prior to the CEC's finalization of revised RPS eligibility requirements.

However, the requirement that a directed biogas project "must meet the currently applicable Renewable Portfolio Standard eligibility requirements for biogas injected into a

[5] D.15-11-027, p. 2; p. 26; p. 40-41.

[6] P.U. Code Section 379.6(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).

[7] *The Office of Ratepayer Advocates' Comments in Response to the Assigned Commissioner's Ruling Seeking Additional Information Regarding the Potential Eligibility requirements for the Self-Generation Incentive Program*, p. 3, March 10, 2016.

[8] PD, p. 18.

[9] PD, p. 18.

natural gas pipeline (pipeline biomethane)" is in the 2016 SGIP Handbook,[10] and has been a requirement in SGIP Handbooks since at least 2013.[11] It is therefore unclear what "adopting" an existing requirement would mean in practice. Bloom's May 22, 2015 comments appear to state what Bloom really seeks:

> "The CPUC should remove the unnecessary requirement that the 'renewable fuel supplier facility must be located within California' as it is inconsistent with state policy. The current requirement that the 'project must meet the currently applicable Renewables Portfolio Standard (RPS) eligibility requirements for biogas injected into a natural gas pipeline (pipeline biomethane)' is more than sufficient."[12]

If the PD intends to remove the requirement that the renewable fuel supplier facility must be located in California," the final decision should clearly state that, and explain the rationale for its removal. When D.11-09-015 *Decision Modifying the Self-Generation Incentive Program and Implementing Senate Bill 412* adopted the requirement that directed biogas be from a facility located within California, the Commission explained that:

> "incentivizing the capture of fugitive methane in California provides local air quality benefits and ensures that directed biogas used for the program meets the environmental standards that biogas produced in California must meet, in addition to alleviating concerns about tracking and verifying directed biogas."[13]

The CEC's requirement that biogas must meet the RPS standard for biogas injected into a natural gas pipeline (pipeline biomethane) "ensures that directed biogas used for the program meets the environmental standards that biogas produced in California must meet," but does not address the other concerns that the Commission identified in D.11-09-015. The final decision should explain the elimination of the requirement that the renewable fuel supplier facility must be located in California in light of those concerns.

---

[10] *2016 Self-Generation Incentive Program Handbook*, p. 54.

[11] *2015 Self-Generation Incentive Program Handbook*, p. 52; *2014 Self-Generation Incentive Program Handbook,* p. 49; *2013 Self-Generation Incentive Program Handbook*, p. 48; *2012 Self-Generation Incentive Program Handbook*, p. 58 (but not including the parenthetical "(pipeline biomethane) shown in the later handbooks.

[12] *Opening Comments of Bloom Energy, Inc. to the AssignedCommissioner's Ruling Requesting Comments* on *Senate Bill 861Compliance and Review of Self-Generation Incentive Program,* May 22, 2015, p. 15.

[13] D.11-09-015, pp. 23-24.

C. The PD should explicitly state that SGIP participants that also participate in demand response programs should not receive multiple payments for a single action.

The PD notes that the "majority of parties commenting on the April 2015 Assigned Commissioner's Ruling supported continuing to allow dual participation in SGIP and demand response programs"[14] and therefore finds "no compelling reason to prohibit projects receiving SGIP funds from providing demand response services. ORA agrees that dual participation in SGIP and demand response programs has the potential to achieve load reduction and other ratepayer benefits, but the PD should explicitly state that dual participation must comply with the requirements of Section 4.4.7 of the SGIP handbook, which prohibits multiple payments for the same action (e.g. discharge).[15]

IV. CONCLUSION

The Commission should revise the PD to state explicitly that natural gas fueled generation projects must meet the GHG emissions factor adopted in D.15-11-027, without regard to their use of biogas fuels. The Commission should also revise the PD to clarify the Commission's goal in adopting Bloom's proposal to incorporate the CEC's directed biogas requirements under the RPS into the SGIP. Finally, the PD should explicitly state that SGIP participants that also participate in demand response programs should not receive multiple payments for a single action.

///

///

///

---

[14] PD, p. 31. The PD notes that this would not apply to projects otherwise excluded from participating demand response programs. PD, p. 32.

[15] *2016 Self-Generation Incentive Program Handbook*, p. 57.

Respectfully submitted,

/s/ DIANA L. LEE

Diana L. Lee

Attorney for the Office of
Ratepayer Advocates

California Public Utilities Commission
505 Van Ness Ave.
San Francisco, CA 94102
Phone: (415) 703-4342
E-mail: dil@cpuc.ca.gov

June 6, 2016

APPENDIX A

ORA's PROPOSED CHANGES TO FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDERING PARAGRAPHS OF THE PROPOSED DECISION

Yellow highlight indicates Findings of Fact and Conclusions of Law that appear better-suited for Ordering Paragraphs to prevent confusion about the requirements of this decision. Recommended changes are in red.

Findings of Fact

4. The Staff Proposal's recommendation for the ~~addressed the statutory requirement of~~ equitable distribution of ~~the~~ program costs and benefits ~~of the program~~ and the suggested criteria for a design requirement pertaining to this statutory requirement, including, 1) Maximize Rate Payer Value, and 2) Provide Equitable Distribution among Customer Classes, are reasonable.

5. The four primary criteria from the Staff Proposal for participating SGIP technologies are consistent with the statute and reasonable. These include: (1) Lower GHG emissions; (2) Lower or shift peak load to off-peak; (3) Be safe and commercially available; and (4) Reduce criteria air pollutants. Additionally, regarding the safe and commercially available requirement, within one year of adoption, all eligible technologies must be certified for safety by an NRTL. The SGIP Program Administrators may allow a developer to apply for incentives for a device that has not yet received certification from an NRTL if the certification process is underway but funds shall not be disbursed until certification is complete.

8b. By requiring that combustion generators meet the GHG emissions factor adopted in D.15-11-027 without the inclusion of biogas, the Commission can be reasonably assured that all participating projects reduce emissions even if the SGIP program administrators encounter obstacles enforcing and verifying compliance with the adopted fuel-blending requirements.

12. While Staff Proposal's recommendation to keep electric-only fuel cells out of the Program is not adopted, it is reasonable to ~~significantly weigh of incentives in~~ weight the incentive budget towards energy storage is justified in light of the program's goals of reducing GHGs, providing grid support and enabling market transformation.

15. All natural gas fueled technologies must utilize a minimum quantity of zero emission fuel, with any fuel usage above this minimum subject to a pro-rated incentive adder.

16. The static biogas adder is eliminated from the program and incorporates an incentive design that sets a minimum rebate and allows projects that utilize more biogas to increase the incentive up to the maximum rebate level.

17. The program will discontinuing awarding incentives based on the kW size for energy storage projects and, instead, will now will rely on the quantity of kWh associated with a given energy storage project to determine the incentive that projects receive.

29. The existing PBI structure is retained because, as suggested in the Staff Proposal, the existing structure rewards projects that continue to meet program goals over time.

35. "California supplier" is modified per the Staff Proposal.

<u>Conclusions of Law</u>

1. The Staff Proposals environmental goals, the reduction of GHGs, the reduction of criteria air pollutants and the limitation of other environmental impacts (such as water usage), are adopted going forward.

2. The Staff Proposal's suggested grid support goals are adopted.

3. The Staff Proposal's goal and related language pertaining to Market Transformation is adopted.

4. The Staff's Proposal suggested criteria for design requirements pertaining to the statutory requirement of equitable distribution of the costs and benefits of the program, including, 1) Maximize Rate Payer Value and 2) Provide Equitable Distribution among Customer Classes, are adopted.

5. The utilities should file Tier 3 advice letters within 60 days of the effective date of this decision with proposals to reallocate the collection of revenues to fund SGIP among customer classes to effectuate the statutory requirement to equitably distribute the costs of SGIP among customer classes.

6. The four criteria from the Staff Proposal and as reflected in statute for participating SGIP technologies are adopted.

7. The additional criteria suggested in the Staff Proposal for participating SGIP technologies, societal benefit and market transformation, are adopted as so-called "soft" criteria.

The Staff Proposal requirements for biogas and Bloom's proposal to adopt the California Energy Commission's biogas eligibility, which states, that SGIP's biogas eligibility requirements should be modified to match the eligibility requirements of the California Energy Commission's RPS guidelines is adopted.

9. The following requirements are adopted for natural gas fueled generation technologies, based on Bloom's proposal, to blend zero emission fuels with one significant change, which is to set a minimum fuel blending requirement starting in 2017.

Table 9: Schedule for adopting a fuel blending requirement:

Program Application Year	% Biogas Requirement
2016	0%
2017	10%
2018	25%
2019	50%
2020	100%

9b. It is reasonable to require that all combustion generation projects, unless 100% of the fuel is supplied from on-site biogas, meet the GHG emissions factor adopted in D.15-11-027 without the inclusion of biogas in the calculation of emissions.

10. Regarding the incentive budget, the Staff Proposal's 75%/25% incentive budget split is adopted.

11. A 15% carve-out from the energy storage budget category for energy storage projects that are 10 kW and smaller is adopted; a 10% carve-out set for renewables in the Generation technology category is adopted.

12. The adopted incentive levels **(capacity rebate levels ($/W) or $/Wh)** are as follows:

Table 10: SGIP Adopted Incentive Levels

Technology	Current Rebate (2015)	Proposed Initial Rebate	Proposed Max Rebate w/ bio gas adder
Generation Technologies			
Wind	$1.07	$0.90	n/a
Waste heat to power	$1.07	$0.60	n/a
Pressure reduction turbine	$1.07	$0.60	$1.20
ICE CHP	$0.44	$0.60	$1.20
Microturbine CHP		$0.60	$1.20
Gas turbine CHP		$0.60	$1.20
Fuel cell CHP		$0.60	$1.20
Fuel cell electric only		$0.60	$1.20
Energy Storage			
Large Scale - >10 kW			
Energy storage	$1.46 --	$0.50/Wh	n/a n/a
Small Scale - <=10 kW			
Energy storage	n/a n/a	$0.60/Wh	n/a n/a

13. The Staff Proposal's regarding step-down design for incentive steps and budget allocations per incentive step is adopted.

14. For generation technologies, fewer than five incentive steps are reasonable due to the reduced budget allocation to this category. We adopt three incentive steps for generation technologies.

15. For energy storage five incentive steps is adopted.

16. Rather than relying on the Staff's Proposal regarding rebate step declines, a different initial incentive is adopted that uses a static dollar amount to reduce incentives between incentive steps instead of the percentage approach that has been used by SGIP in the past.
17. An equal split of incentive across each incentive step within each incentive category is adopted.

18. The following incentive rebate step downs ($/W) for Generation Technologies are adopted:

Table 11: Summary of rebate step downs ($/W) for Generation Technologies

	Step 1		Step 2		Step 3	
		Proposed Max Rebate w/biogas adder		Proposed Max Rebate w/biogas adder		Proposed Max Rebate w/biogas adder
Wind[16]	$0.90	n/a	$0.80	n/a	$0.70	n/a
Waste heat to power	$0.60	n/a	$0.50	n/a	$0.40	n/a
Pressure reduction turbine	$0.60	$1.20	$0.50	$1.10	$0.40	$1
ICE CHP	$0.60	$1.20	$0.50	$1.10	$0.40	$1
Microturbine CHP	$0.60	$1.20	$0.50	$1.10	$0.40	$1
Gas turbine CHP	$0.60	$1.20	$0.50	$1.10	$0.40	$1
Fuel cell CHP	$0.60	$1.20	$0.50	$1.10	$0.40	$1
Fuel cell electric only	$0.60	$1.20	$0.50	$1.10	$0.40	$1

19. The following incentive rebate step downs ($/W) for Energy Storage Technologies are adopted:

Table 12: Summary of rebate step downs ($/W) for Energy Storage Technologies

Large Scale - >10 kW	Step 1	Step 2	Step 3	Step 4	Step 5
Energy storage	$0.50/Wh	$0.45/Wh	$0.40/Wh	$0.35/Wh	$0.30/Wh
Small Scale - <=10 kW[17]	$0.60/Wh	$0.55/Wh	$0.50/Wh	$0.45/Wh	$0.40/Wh

16 Note that 10% of the incentives in each step shall be reserved for renewable generation technologies, meaning that natural gas fueled technologies may see their incentives decrease to a lower step while renewable technologies may remain at a higher step if they have not met their 10% carve out.

17 Note that 15% of the incentives in each step shall be reserved for small scale energy storage, meaning that large scale energy storage may see their incentives decrease to a lower step while small scale energy storage may remain at a higher step if they have not met their 15% carve out.

20. The following project size caps and rebate level, which are consistent with those currently in place, are adopted:

<u>Table 13: SGIP Project Size Caps and Rebate Levels</u>

Project size	<1 MW	1-2 MW	2-3 MW
Generation Technologies	100%	50%	25%
Energy Storage Technologies	100%	50%	25%

21. Staff Proposal's recommendation is adopted that the SGIP handbook be amended to explicitly state that the system sizing requirements for energy storage paired with generation should be based solely on the customer's previous 12-month annual peak demand, not the paired capacity.

22. A 10% cap on O&M Warranty and/or maintenance contract costs of the claimed project costs is adopted.

24. The existing PBI structure is adopted going forward.

25. Continuing to allow dual participation in SGIP and demand response programs, with certain noted fossil-fuel exceptions, is adopted.

26. The 40% manufacturer cap is removed from the SGIP.

27. A 20% developer cap is adopted, as follow: any single developer/installer (or any combination of affiliated developer/installer under the same majority ownership) is limited 20% of the available funding for a given technology category's total. The SGIP Program Administrators shall not issue conditional reservations to a project using a technology installed by a developer (or combination of affiliated installers/developers under the same majority ownership) that has already received reservations for active projects in a given step such that the total exceeds the percentage allocation for that step. Each reservation application shall include the name and address of the customer; the customer's account number; the name and address of the developer/installer; the name and address of the developer/installer's parent company, defined as an entity with a majority ownership interest in the developer/installer (direct parent and ultimate parent, if applicable); the identity of the owner; and the identity of the host.

28. The current policy of a state-wide cap for developers is most consistent with the policy goals of the program and is retained.

29. The provision of SGIP that provides a 20% incremental adder to the applicable SGIP incentive rate for projects in which the equipment used is manufactured in California is modified consistent with new statutory law.

30. The Staff Proposal modification to the term "California supplier" is adopted.

31. The Staff Proposal's recommendation that the generation and storage components which are part of a given DC micro-grid are eligible for SGIP rebates – albeit with no incremental micro-grid adder, is adopted.

32. The existing rule that requires SGIP customers, prior to receiving SGIP incentives, to invest in energy efficiency measures identified in the required energy audit within a two-year payback is removed from the program.

33. The Staff Proposal's recommendation that the SGIP customer's cost of performing the energy audit be limited to a maximum of 5% of the requested incentive payment is adopted.

34. Regarding energy storage operating requirements, the staff proposal's recommended 260-hour discharge requirement for commercial systems is adopted.

35. The existing requirement for residential energy storage systems to dispatch an average of two hours per week for a total of 104 hours per year is adopted.

36. The SGIP retains the requirement that all technologies receiving incentive support be new.

38. The Staff Proposal's recommendations regarding M&E reports/audits are adopted as follows:

    1. Within six months, a SGIP M&E Plan should be developed by Energy Division staff in consultation with program administrators; this mimics the CSI program where M&E was directed by Energy Division, not ALJ ruling.

    2. M&E funds be used to evaluate administrative performance every year and fiscal performance every other year; with the first rounds of each being completed within twelve months of this Decision.

    3. Publicize the online report covering performance for participants receiving PBI payments, including energy generated (kWh), gross and net GHG emissions, number of charging and discharging events and total amount of energy charged and discharged (for storage), amount and type of fuel consumed, and heat recovered (for CHP).

39. Program administrators will no longer accept Renewable/Emerging Technologies Level 2 applications, effective immediately.

40. The Staff proposal that the program administrators hold a workshop to consider whether an M&O program would have value, to flesh out how it would operate, and publish a workshop is adopted.

42. A 5%application fee, due at the time the application is submitted, is adopted.

44. DWEA's Petition for Modification of D.11-09-015 is denied.

45. RightCycle's Petition for Modification of D.11-09-015 is granted.

46. Powertree's Petition for Modification of D.15-06-002 is granted, in part.

47. Under the adopted extension for PowerTree, Powertree must complete its projects and submit final incentive claim forms by December 30, 2016 or lose its reservations.

48. Maas Energy Works' Petition for Modification of D.15-12-027 is denied.

ORDER

1b. All natural gas generation projects must meet the GHG emissions factor adopted in D.15-11-027 without the inclusion of biogas in the calculation of emissions.