BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CAL

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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)

OPENING COMMENTS OF BLOOM ENERGY, INC. TO THE ASSIGNED COMMISSIONER'S RULING REQUESTING COMMENT ON UPDATING GREENHOUSE GAS EMISSION FACTOR FOR SELF-GENERATION INCENTIVE PROGRAM ELIGIBILITY

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Pursuant to the *Assigned Commissioner's Ruling Requesting Comment On Updating Greenhouse Gas Emission Factor For Self-Generation Incentive Program Eligibility,* Bloom Energy, Inc. (Bloom) respectfully submits these Opening Comments in response to the questions posed in the Assigned Commissioner's Ruling (ACR).

I. Introduction

Bloom supported Senate Bill 861, the legislation that requires the California Public Utilities Commission (CPUC) to update the factor for avoided greenhouse gas emissions (GHGs) and Bloom supports the CPUC's efforts to ensure that the purpose and intent of the statute is fully implemented.

Bloom has installed many projects with customers that use the Self-Generation Incentive Program (SGIP), helping to meet the program goals of GHG reduction. Bloom's technology has either met, or has come close to meeting, the limit on the number of projects any one manufacturer can do under SGIP since the program was revised in 2011. This is a signal of customer interest in choosing Bloom's fuel cell technology as their clean energy resource. In the six years Bloom has had a commercial product, SGIP remains the only California program or policy that enables customers to choose a reliable, 24x7x365 low carbon, all-electric fuel cell. Importantly, not only do all electric fuel cells reduce GHGs by displacing centralized gas generation, they also virtually eliminate the smog forming pollution that traditionally comes from combustion plants and enhance the reliability and power quality of the electrical grid by providing firm 24x7 output.

According to the most recent SGIP Impact Evaluation report, SGIP reduced emissions overall and Bloom's all-electric fuel cell is responsible for over half the GHG reductions in the program. The Report stated:

> *In 2012, the SGIP was responsible for a net reduction in GHG emissions of more than 128 thousand metric tons of CO_2 — equivalent to removing the GHG emissions from over 25,000 passenger vehicles per year in California. All-electric fuel cells and IC engines achieved the greatest GHG emission reductions.*[1]

Bloom Energy looks forward to continuing to provide a clean energy solution that enables California customers to make investments that help the state meet its GHG reduction goals.

II. Using Consistent Methodology

It is critical that the update take into consideration the best and most accurate available information, experience and understanding regarding GHG displacement by distributed energy resources. It is broadly accepted that distributed generation, including those technologies supported by SGIP, displaces generation from marginal power plants rather than displacing the construction of new renewable capacity. Examples of established guidance include:

- As sited in the ACR, this was the approach taken by the State Air Resources Board (ARB) in the *2008 Scoping Plan*, in which electricity reduction "measures are assumed to replace in-state natural gas electricity generation.[2]" ARB's approach was appropriate in 2008 and is still appropriate in 2015.

[1] 2012 SGIP Impact Evaluation and Program Outlook, page 1-9
[2] ARB 2008 AB32 Scoping Plan, page I-23.
http://www.arb.ca.gov/cc/scopingplan/document/appendices_volume2.pdf

- The California Energy Commission (CEC) has released a draft report entitled *Estimating Fuel Displacement for California Electricity Reductions* which provides a method for calculating emissions reductions based upon "the amount of generation fuel displaced from avoided use of grid electricity."[3]
- The US EPA publishes a Fossil Fuel Output Emissions Rate in its *Emissions & Generation Resource Integrated Database* (eGRID), and "recommends the use of the fossil fuel output emission rates for displaced grid supplied electricity from a CHP application because CHP units tend to operate on a continuous basis[4]." US EPA's recommendation for CHP would hold true for other forms of baseload distributed generation such as all-electric fuel cells.

As the Commission updates the emission factor it is important to get the policy right, both on the technical and policy merits. This is critical not only to ensure that the program continues to enable new GHG reducing technologies but to also ensure that, as a complement to California's renewable energy policies, the state is doing everything to reduce emissions from current and future non-renewable energy sources. As our responses below will show, SGIP projects – and distributed energy resources in general – do not displace the deployment of new renewable capacity. Instead, these advanced clean technologies that are on the customer's side of the meter allow California's energy consumers to play a necessary part in meeting the state's carbon reduction goals by displacing generation from less efficient, centralized combustion generation.

III. Response to ACR Questions

1. Should the updated SGIP GHG eligibility factor(s) use a short run methodology, a long run methodology, or a combination of the two? Why?

The updated SGIP eligibility factor should use a short run methodology because projects receiving an incentive via SGIP will generally impact the operating margin as opposed to the build margin.

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[3] CEC. 2014. *Estimating Fuel Displacement for California Electricity Reductions*: Summary of Staff's Proposed Method. Pg 1 http://www.energy.ca.gov/chp/documents/2014-07-14_workshop/Estimating_Fuel_Displacement_Summary.pdf

[4] EPA. 2012. *How to use eGRID for Carbon Footprinting Electricity Purchases in Greenhouse Gas Emission Inventories.* Page 10

The ACR appropriately distinguished that estimates of the emissions avoided by SGIP technologies may vary depending on whether it is assumed to displace output from existing sources of generation (the short run or "operating margin" effect) or to displace the deployment of new sources of capacity that would have been added but for the generation in question (the long run or "build margin" effect), or from some combination of the two. SGIP projects offset the operating margin.

The California utilities do not consider individual SGIP projects in their capacity planning processes. As explained by the Greenhouse Gas (GHG) Protocol's *Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects*[5], since the projects are "not implemented in response to demand for new capacity" but rather built to "avoid the need for grid-based power at a particular site…if grid operators give no consideration to the project activity in determining their capacity requirements, then the project activity may <u>not displace new capacity</u>." SGIP projects are by definition deployed to provide electricity directly to the host facility and not to provide capacity to the grid, and therefore cannot be assumed to offset the build margin. This can be illustrated by a number of key examples:

a. **Standby Tariff:** Investor-owned utilities require customers with on-site generation not exempt under the utilities' Net Energy Metering programs to pay monthly "reservation capacity" standby charges for the right to use power from the utility grid when necessary. Such a policy implies that utilities are assuming they will need to build the capacity to serve these customers, and that these customers' self-generation projects are not accounted for in build margins.
b. **Utility Planning**: The output of SGIP projects are not accounted for as part of the Long Term Planning Process (LTPP) undertaken by the investor-owned utilities either on the supply or demand side[6] and are largely a minor or partial load reduction or modification and hence are not part of the scenarios used by utilities to plan for new resource procurement. Thus, by definition they do not impact the build margin.

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[5] http://ghgprotocol.org/files/ghgp/electricity_final.pdf
[6] Assigned Commissioner's Ruling (ACR) on Updates to Planning Assumptions and Scenarios for 2014 LTPP and CAISO's 2015-16 Transmission Planning Process - http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M147/K780/147780118.PDF

It is also important to note that SGIP projects are extremely small in comparison to the scale at which the utilities consider capacity requirements. As noted by the GHG Protocol, "many individual end-user project activities are small in scale, and are often implemented for reasons wholly unrelated to grid capacity requirements. These types of project activities will have little or no effect on the BM [build margin]." As of the most recent SGIP impact report in 2012[7], there were 294MW of rebated capacity under SGIP across the state. In comparison to the 78,133MW[8] of total capacity in CA, the SGIP program as a whole represents 0.38% of California's installed capacity. The impact of any given project under SGIP is even smaller – the average size of SGIP projects installed since 2007 is 219kW and only 5% of projects have been larger than 1MW. The CEC *Quarterly Fuel and Energy Report* does not even include projects under 1MW, further illustrating that such small projects are not considered in capacity planning when the scale of utility procurement is at the scale such as the recently approved 500MW Carlsbad facility. In fact, the vast majority of projects used for compliance with the California Renewables Portfolio Standard (RPS) in the CPUC's RPS project status table are 20MW or greater (with slightly more than 50% of Renewable Auction Mechanism (RAM) projects being 18-20MW). Given this differential between the size of RPS procurement, the size of recent procurements, and the overall State capacity compared to the size of SGIP projects and the overall installed SGIP capacity, it is unreasonable to consider that the utilities are procuring less or smaller plants as a result of any given SGIP project.

In the case of the few outliers in the SGIP program that are larger than 1MW, it is possible that some small portion of the project could impact the build margin. This population is likely also limited to ramping and intermittent SGIP technologies as opposed to baseload SGIP technologies, as the majority of new procurement by California utilities is limited to ramping and intermittent technologies. However, given that the number of projects that will affect the build margin is relatively small, and the extent to which they may impact the build margin will be relatively small if not zero, introducing this level of complexity is overly burdensome when considering the scope of impact and the underlying policy direction supporting the deployment of SGIP projects. Further, determining the appropriate weighting to apply to the build margin as

[7] http://www.cpuc.ca.gov/NR/rdonlyres/25A04DD8-56B0-40BB-8891-A3E29B790551/0/SGIP2012ImpactReport_20140206.pdf
[8] http://www.energyalmanac.ca.gov/electricity/electric_generation_capacity.html

opposed to the operating margin would require an analysis of the size, location, and capacity factor of each project. Again, this level of complexity for a very small number of projects outweighs the potential programmatic benefits.

For the reasons stated above, the updated SGIP GHG eligibility factor should remain consistent with the assumptions made in D.11-09-015 and use short run methodology.

2. **Section 379.6(b)(2) directs the Commission to update the factor "based on the most recent data available to the State Air Resources Board for GHG emissions from electricity sales in the self-generation incentive program administrators' service areas…" Based on your response to Question 1, exactly what data sources from ARB should be used and how should they be applied to derive the short run and/or long run-based factors?**

In the 2008 *AB32 Scoping Plan Appendix II*, the State Air Resources Board (ARB) established that measures to reduce electricity consumption from the grid should be assumed to replace in-state natural gas electricity generation (i.e. operating margin). Using a weighted average of in-state natural gas generation, ARB established an emissions factor of 437 kg CO2e/MWh, to which a 7.8% line loss adjustment is applied when appropriate, to arrive at an emissions rate of 473.9 kg CO2e/MWh. This is a reasonable approach because natural gas plants are generally the marginal generators whose output is reduced in response to demand reductions caused by distributed resources. The CPUC Staff Proposal explained the reliance on the ARB approach by stating "Although there are many different kinds of electricity generating resources in California, including nuclear and renewables, gas-fired generators are those most likely to be turned on or turned off on the margin. Therefore, when considering an appropriate emissions factor for emissions avoided by an alternative resource, the emissions profile of gas-fired generators is most appropriate".[9]

When updating the SGIP emissions rate, the CPUC should apply an approach similar to that conducted by ARB in 2008 using the most recent data available on the heat rate of California natural gas generation. The ARB 2008 emissions rate was based upon the average heat rate of all in-state natural gas generation. One improvement to this approach is to exclude cogeneration, which is not used to balance supply and demand and thus is not typically part of

[9] http://docs.cpuc.ca.gov/efile/RULINGS/124214.pdf, page 56-57.

the operating margin, as well as aging plants, which are generally run for reliability purposes and therefore are typically not part of the operating margin.

Taking into account these considerations, the most appropriate data and methodology for determining the operating margin emissions rate is:

a. **Determine Heat Rates of Marginal Resources:** The most recently data available is the CEC's *Thermal Efficiency of Gas-Fired Generation in California: 2014 Update,*[10] which provides historical heat rates for California gas-fired generation. After excluding aging plants and cogeneration as discussed above, the CPUC should consider only combined-cycle plants and peaker plants. The CEC published heat rate for combined-cycle plants is 7,205 BTU/kWh and for peaker plants is 10,268 BTU/kWh in 2013, which is the most recent year for which data is available.
b. **Determine Weighted Average Heat Rate:** In order to convert these figures to an emissions rate, the CPUC should apply a methodology similar to that proposed by the CEC in the 2014 *Estimating Fuel Displacement for California Electricity Reductions: Summary of Staff's Proposed Method*[11]. This methodology proposes applying a weighting to peaker plants and to combined cycles based upon the percentage of energy they generate. As outlined in Bloom Energy's reply comments to the Staff's Proposed Method[12], a more appropriate weighting to apply to peaker plants is equivalent to the percentage of time that the peaking plants are on the margin. Considering that peaker plants are generally on the margin whenever they are operating, the capacity factor of the peaker fleet provides a reasonable estimate of the percentage of time they are on the margin. The CEC estimates the capacity factor of the peaker fleet to be 5% in 2013[13]. Applying a 5% weighting to the peaker fleet heat rate of 10,268 BTU/kWh and a 95% weighting to the combined-cycle heat rate of 7,205 BTU/kWh results in a heat rate of 7,358.15 BTU/kWh[14].

[10] http://www.energy.ca.gov/2014publications/CEC-200-2014-005/CEC-200-2014-005.pdf
[11] CEC. 2014. *Estimating Fuel Displacement for California Electricity Reductions*: Summary of Staff's Proposed Method. http://www.energy.ca.gov/chp/documents/2014-07-14_workshop/Estimating_Fuel_Displacement_Summary.pdf
[12] http://www.energy.ca.gov/chp/documents/2014-07-14_workshop/comments/Bloom_Energy_Comments_re_Draft_Proposal_Estimating_Fuel_Displacement_for_California_Electricity_Reductions_08-26-14_TN-73714.pdf
[13] http://www.energy.ca.gov/2014publications/CEC-200-2014-005/CEC-200-2014-005.pdf
[14] 7,205 * 5% = 6,844.75; 10,268 * 95% = 513.4; 6,844.75 + 513.4 = 7,358.15

c. **Apply Line Loss Factor:** As outlined in response to Question 7, the appropriate line loss factor is 7.3%. Applying this to the heat rate of 7,358.15 BTU/kWh results in an operating margin heat rate of 7,937.59 BTU/kWh[15].

d. **Convert to Emissions Rate:** A 7,937.59 BTU/kWh heat rate is equivalent to an emissions rate of 420.8 kg CO2/MWh[16].

The existing SGIP eligibility factor of 379 kg CO2/MWh is approximately 10% lower than this operating margin emissions factor of 420.8 kg CO2/MWh, ensuring that all SGIP technologies result in emissions reductions. The 2015 revision should not lower the bar for participation in the program. Therefore, the CPUC should maintain the existing 379 kg CO2/MWh eligibility requirement, enabling the program to continue to achieve meaningful emissions reductions in comparison to the operating margin.

3. **The emission factor adopted in D.11-09-015 assumes that SGIP technologies will avoid the need for new renewable generation in proportion to the 20% RPS goal in effect during the time the staff developed its proposals. Section 379.6(b)(2) also directs the Commission to include "consideration of the effects of the California Renewables Portfolio Standard." How should this be accomplished?**

In D.11-09-015, the CPUC adjusted the ARB emissions factor downwards by 20% to account for the renewable resources required under the RPS. As noted in our response to Question 1, SGIP technologies should not be assumed to avoid the deployment of new renewable capacity, and therefore this 20% reduction, although intending to encourage clean technologies, was not required. If the SGIP GHG emissions factor is adjusted based on the RPS, it will have the perverse effect of 1) inhibiting the deployment of technologies that in actuality are reducing GHGs in real time, and 2) actually increasing emissions from centralized combustion plants because these cleaner technologies, which displace generation from those plants, will not be deployed.

In the context of California's 33% by 2020 RPS, the CPUC should consider that SGIP technologies will continue to offset the generation from centralized natural gas generation. As noted in Question 3, this emissions rate can be calculated based upon the average heat rate of California gas fired generation excluding cogeneration and aging plants. According to the

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[15] 7,358.15 / (1-7.3%) = 7,937.59

[16] 7,937.59 Btu/kWh / 1,000,000 MMBtu/Btu * 1,000 kWh/MWh * 53.02 kg CO2/MMBtu = 420.85 kg CO2/MWh

CPUC's RPS project database, the contract terms for projects approved and online, approved and in development, pending approval, and incorporated in the Renewable Auction Mechanism have average contract terms of approximately 20 years. Therefore, the RPS resources expected to be operating in 2020 will likely operate for terms of 20 years or more, making it improbable that DG resources will displace these resources. Instead, DG reduces the need for centralized natural gas generation.

Furthermore, D.11-09-015 assumed that "…because the ARB AB 32 Scoping Plan emission factor value is based on the emission rate of gas-fired power plants from 2002 to 2004, it does not reflect the lower emission rate of newer gas-fired units that SGIP projects may avoid going forward"[17]. According to the CEC's *Thermal Efficiency of Gas-Fired Generation in California: 2014 Update*[18], the majority of reductions in the state average resulted from retiring aging plants which, as discussed in response to Question 2, should be excluded from the methodology since the remaining aging plants that have not been fully retired are primarily run "for local reliability that may include voltage control, frequency response, and other ancillary services." In fact, as shown in Figure 1, there is almost no historical change in the heat rates of the combined cycle and peaker fleets.

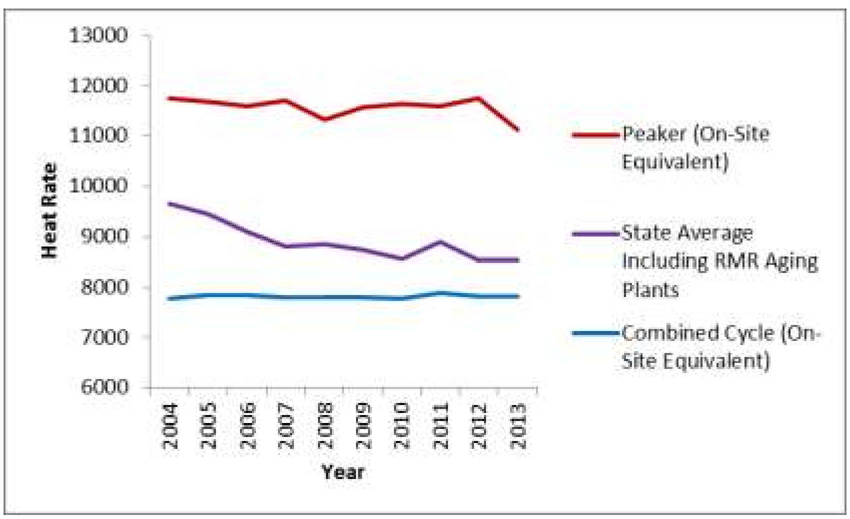

Figure 1. CEC Historical Heat Rates of California Natural Gas Generation, Adjusted for 7.8% Line Losses

[17] D. 11-09-015, page 15.

[18] http://www.energy.ca.gov/2014publications/CEC-200-2014-005/CEC-200-2014-005.pdf

Looking forward, it is likely that the relatively flat trend in heat rates will continue. In fact, the introduction of more intermittent renewable sources to the grid in the coming years is likely to result in more cycling and reduction in the number of hours that plants operate at their maximum efficiencies. In addition, peaker plants may generate a higher percentage of total energy than they currently do. The CEC discusses the potential that increased renewables penetration will increase heat rates:

> *As intermittent renewable generation projects are added to the resource mix, the gas plant fleet is increasingly going to be tasked with ramping generation up and down over a wider range of conditions, as well as cycling on and off daily, to compensate for the fluctuations the variable wind and solar resources create. Adding this functionality to new gas-fired generation comes at the cost of efficiency*[19].

4. **For factors based on long run effects, what combination of technologies, and in what proportions, should SGIP projects be assumed to displace?**

As discussed in Question 1, SGIP technologies should not be assumed to displace long run effects. Even if the CPUC were to assume that SGIP technologies did impact the build margin, a precise analysis of the impacted build margin would require significant modeling and analysis. This would include the potential that the utilities' plans to procure intermittent renewables may also result in a need to procure more gas plants with ramping capabilities. Additionally, as mentioned in response to Question 3, the CPUC would also need to consider the fact that procuring more intermittent renewables may result in changes to the heat rate of the operating margin, as existing gas plants will be required to operate differently. Although the CPUC has the expertise to execute such an analysis, it is unwarranted. Utilities are not deferring or downsizing procurement of renewables based on SGIP. Again, SGIP is proportionally small to the overall load and planning process.

5. **D.11-09-015 states that SGIP-funded technologies should avoid GHG emissions through at least the first ten years of operation, taking into account system degradation.[19] Should that time frame be revised, and if so, why? Should the time frame be the same for all technologies? If not, what time frames should apply to which technologies and why? How does your proposal comply with the requirement in § 379(b)(2) that the methodology account for "estimates of greenhouse gas emissions over the useful life of the distributed energy resource"?**

[19] http://www.energy.ca.gov/2014publications/CEC-200-2014-005/CEC-200-2014-005.pdf

The ten year time frame for the avoidance of GHG emissions should not be revised as this time frame aligns with the SGIP minimum contract and warranty period and is the de facto SGIP project lifetime. The time frame should be consistent across all the technologies as this aligns with the SGIP program objective to ensure that GHG emissions are reduced regardless of the technology platform. Bloom's proposal maintains the existing SGIP program structure of determining GHG emissions based on actual performance data, not estimates, and ensuring that the cumulative reductions are in compliance with the updated GHG avoidance factor on average across the first ten years of operation. This emissions reduction should be measured on a per kWh basis which would ensure compliance regardless of any degradation.

6. **Should the 1% per year assumption for performance degradation be revised for one or more SGIP-eligible technologies, and if so, using what data sources?**

The 1% per year performance degradation is not relevant for GHG emissions as emissions should be measured and validated on a per kWh basis. From an overall distributed energy resource output standpoint there is no need to revise this assumption.

7. **Should the 7.8% line loss factor adjustment to the GHG factor be revised? Explain why or why not. If so, using what data? Should the factor vary by utility service territory, other geographic delineations, or generation profiles of different SGIP technologies? Explain why or why not.**

The Statewide Mid Demand Case of the CEC's 2014 Demand Forecast projects a 2015-2025 loss factor of 7.3% based on net energy for load.[20] This is the loss factor that the CPUC should adopt because 1) SGIP projects are at the point of electricity consumption and displace the operating margin, which is best represented by energy demand and 2) the CEC's demand forecast represents California's best current projection for future statewide load requirements. The CEC's average statewide line loss factor provides a reasonable representation of system performance across California's electric grid.

8. **For SGIP-eligible CHP projects, should the 80% boiler efficiency factor be updated and if so, using what data? Should it vary based on the capacity of the SGIP project or the size of the thermal load? Since exports from technologies not subject to net energy metering do not reduce the utilities' metered load, and thus do not reduce the utilities' obligation to supply RPS-eligible generation, should estimate exports from**

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[20] Kavalec, Chris, 2015. California Energy Demand Updated Forecast, 2015-2025. California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-200- 2014-009-CMF, Demand Forecast Forms, Mid-Case Final Baseline Demand Forecast, Statewide Form 1.2.

CHP (or other technologies not subject to net energy metering) be subject to a different emission rate based only on other fossil-fired sources of generation? Explain why or why not.

Not applicable to Bloom.

9. **Please answer the following questions related to determining the minimum round-trip efficiency for SGIP-eligible storage technologies. In light of the ongoing transformation in the resources serving California's load, is the assumption that combined cycle plants are marginal during off-peak hours and simple cycle plants are marginal during peak hours still valid? Why or why not? If not, what mix of resources should the emission factor assume are on the margin and what data sources should be used? Be explicit regarding whether the effect is long-run, short run, or a combination of the two. Would production cost modeling results be useful (e.g., testimony submitted in R.12-06-013) for the avoided GHG emission calculations for storage? To the extent your proposed methodology assumes that storage affects natural gas-fired generation, should the emission factor for combined cycle and simple cycle power plants be updated, and if so, using what data? Should the line loss factors of 5.3% for off-peak and 10.3% for on peak adopted in Resolution E-4519 be updated, and if so, using what data?**

Not applicable to Bloom.

10. **Please describe the methodology, assumptions, data sources and resulting emission factors (or round-trip efficiencies) that should be used to determine SGIP eligibility for electric-only, CHP, and storage technologies.**

For the reasons laid out in response to Question 1, all electric-only technologies deployed under SGIP offset the operating margin. As outlined in response to Question 2, the most appropriate methodology for determining the operating margin emissions rate results in an emissions rate of 420.8 kg CO2/MWh.

As discussed in the ACR, the SGIP eligibility factor established in 2011 was 379 kg CO2/MWh, which is about 10% below the California operating margin emissions factor. The SGIP program is an important part of California's emissions reductions strategy – therefore it is appropriate that the eligibility factor ensures that SGIP technologies reduce emissions in comparison the operating margin. The 2015 revision should not lower the bar for participation in the program. Therefore, the CPUC should maintain the existing 379 kg CO2/MWh eligibility requirement, enabling the program to continue to achieve meaningful emissions reductions in comparison to the operating margin. Technologies that demonstrate that they can generate electricity at an emission rate less than 379 kg CO_2/MWh under realistic operating conditions per the ASME PTC 50-2002 protocol, as required by the SGIP Handbook, should be determined to be eligible under SGIP.

IV. Conclusion

In conclusion, it is critical that the Commission gets this policy right on both the technical and policy merits as it updates the emissions factor. Bloom wants to ensure that SGIP continues to enable new GHG reducing technologies to develop and send the signal that the state is doing everything it can to reduce any remaining non-renewable emissions. As our responses above explained, SGIP, and distributed energy resources in general, do not displace deployment of new renewable generation capacity. Rather, these advanced clean technologies on the customer's side of the meter actually displace large gas generation, and we hope that the Commission will adjust the emissions factor methodology accordingly.

Dated April 17, 2015

Respectfully submitted,

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