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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)

OPENING COMMENTS OF BLOOM ENERGY, INC. ON THE PROPOSED 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

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July 30, 2015

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Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, Bloom Energy, Inc. (Bloom) respectfully submits these Opening Comments on the *Proposed 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.*

I. Summary

Bloom applauds the Commission for the thorough and concise direction of the Proposed Decision. Overall, Bloom finds that the proposed methodology is the right approach, but needs nuanced and specific adjustments to ensure that this precedent-setting emissions factor is without reproach.

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) used in the Self Generation Incentive Program (SGIP) and Bloom supports the CPUC's efforts to ensure that the purpose and intent of the statute is fully implemented. However, Bloom cannot support the proposed update to the emissions factor as it is based on data that are not supported by the record.

As noted by the PD and as evidenced by the wide variance of parties' comments on the Assigned Commissioner's Ruling (ACR) there is no clear consensus about how SGIP technologies may interact with the grid in the long term. In June, the California Energy Commission (CEC) released its *Proposed Near-Term Method for Estimating Generation Fuel Displaced by Avoided Use of Grid Electricity* and limited their analysis to five years, explaining that uncertainty around future grid conditions make estimates beyond five years extremely difficult. The CEC cited six examples of how rapid developments in the market may alter the operation of the grid in such a way that the basic assumptions being made today may change in the long term. Specific examples of note:

- "New disruptive technologies are likely to change the operational profile of key resources. Technologies such as electricity storage may drastically alter the operational landscape of the grid, rendering the assumptions this approach is based on obsolete."[1]
- "The future construction of renewables beyond the next five years may no longer be driven by legislative mandate, but rather by cost competition. In this environment, generation procurement and the mix of grid resources will change dramatically, altering the process of estimating grid displacement."[2]

What *is* clear is that many SGIP technologies are reducing significant emissions today and will continue to do so for the foreseeable future. The SGIP program reduced 162,434 MTCO2e in 2013. All-electric fuel cells alone reduced 71,926 MTCO2e under the program in 2013.[3] It would be irresponsible to set an emissions factor that in effect would exclude projects that reduce GHG emissions today based upon uncertain assumptions of how SGIP technologies *may* impact the grid in ten or fifteen years.

Thus, Bloom Energy urges the CPUC to be cautious and diligent in the assumptions used regarding future grid operations. Throughout these comments we have addressed the assumptions and data used in the proposed ten-year emissions factor in order to improve the estimate using the best facts and data available and to avoid reliance on speculation or assumptions.

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 and as such urges the CPUC to readjust the emissions factor and to do so based on data and facts rather than speculative assumptions. Without such adjustment, the Program will use an

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[1] California Energy Commission. *Proposed Near-Term Method for Estimating Generation Fuel Displaced by Avoided Use of Grid Electricity*. http://www.energy.ca.gov/2015publications/CEC-200-2015-002/CEC-200-2015-002.pdf Page 8

[2] California Energy Commission. *Proposed Near-Term Method for Estimating Generation Fuel Displaced by Avoided Use of Grid Electricity*. http://www.energy.ca.gov/2015publications/CEC-200-2015-002/CEC-200-2015-002.pdf Page 8

[3] Itron. 2013 SGIP Impact Evaluation Submitted to PG&E and the SGIP Working Group. http://www.cpuc.ca.gov/NR/rdonlyres/AC8308C0-7905-4ED8-933E-387991841F87/0/2013_SelfGen_Impact_Rpt_201504.pdf Page 7-2

erroneous GHG calculation that reduces the program to a limited set of technologies and miss opportunities to deliver additional immediate GHG reductions so desperately needed in California.

II. Response to Proposed Decision

1. SGIP Project Performance Degradation

Bloom concurs with the PD's proposal to keep the current degradation assumption of 1%. This degradation assumption is applied to the initial test efficiency of a particular technology to determine if it meets the eligibility factor. It is not included as part of the eligibility factor calculation and also is not relevant to the measurement of the GHG impact of a particular project over time, which should be measured using actual data. As noted in the 2010 Staff Proposal:

> *"All technologies decline in performance over time. In this analysis, kWh production decreases proportionally to performance degradation. It is assumed that any given technology will generate 100% of expected energy in the first year, and that this figure will begin to decline in year two. In the case of technologies which use an external fuel source, fuel consumption is held constant and energy generation is assumed to decline. Staff assumed 1% annual performance degradation for all technologies."*[4]

2. Length of GHG Emission Comparison Period

Bloom continues to support the current 10 year requirement for all technologies because this timeframe aligns with the SGIP minimum contract and warranty period and is the de facto SGIP project lifetime.

3. Operating Margin or Build Margin Methodology

a. Generation Technology

Bloom Energy generally agrees with the concept that SGIP technologies will impact the operating margin in the near-term and could theoretically have some impact on the need for new capacity in the long-term. However, we find the PD's methodology for determining the appropriate weight to assign to the operating margin and the build margin to be lacking in precision. The PD states that "determining the timing of the avoidance of new capacity would necessitate analysis of factors specific to the locations and generation profiles of each project"[5] but then assigns an equal weight to the operating margin and build margin without justification.

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[4] Self Generation Incentive Program (SGIP) Staff Proposal, September 2010, Page 66

[5] Proposed Decision, Page 11

Bloom finds the use of a 50/50 weight to be arbitrary. We therefore propose the following methodology to arrive at a more reasonable weight based upon available data.

As cited in our comments on the ACR, the *GHG Protocol Guidelines for Grid Connected Electricity Projects* notes that "[i]f the grid has more than enough capacity to meet foreseeable power demands, then the project activity may not actually displace any new capacity because no new builds are otherwise occurring."[6] A review of the CAISO 2015 Summer Assessment shows significant Operating and Planning Reserve Margins, in all cases in excess of the CPUC's 15% resource adequacy requirement for planning reserve margin.[7] Thus, SGIP projects cannot be assumed to impact the build margin in the near term.

Table 1
Planning Reserve Margins

Summer 2015 Supply & Demand Outlook (Planning Reserve Margins)			
Resource Adequacy Planning Conventions	ISO	SP26	NP26
Existing Generation[5]	54,044	26,660	27,384
Retirement	0	0	0
High Probability Addition[6]	278	117	161
Net Interchange (Moderate)[7]	9,500	8,700	2,000
Total Net Supply (MW)[8]	63,822	35,477	29,545
DR & Interruptible Programs[9]	1,840	1,297	543
Demand (1-in-2 Summer Temperature)[10]	47,188	27,183	20,832
Planning Reserve Margin[11]	**39.1%**	**35.3%**	**44.4%**

Table 2
Normal Scenario Operating Reserve Margins

Summer 2015 Outlook - Normal Scenario 1-in-2 Demand, 1-in-2 Generation Outage and Moderate Imports			
Resource Adequacy Conventions	ISO	SP26	NP26
Existing Generation	54,044	26,660	27,384
Retirement	0	0	0
High Probability Additions	278	117	161
Hydro Derate	(1,511)	(634)	(878)
Outages (1-in-2 Generation)[12]	(5,028)	(2,163)	(2,882)
Net Interchange (Moderate)	9,500	8,700	2,000
Total Net Supply (MW)[13]	57,283	32,680	25,785
DR & Interruptible Programs	1,840	1,297	543
Demand (1-in-2 Summer Temperature)	47,188	27,183	20,832
Operating Reserve Margin[14]	**25.3%**	**25.0%**	**26.4%**

The *GHG Protocol* also notes that "any capacity provided by the project activity could still avoid the need for new capacity in the future, once demand grows and market conditions change."[8] Consistent with the *GHG Protocol* guidance, the CPUC should "assume [SGIP technologies] will displace only the [operating margin] for the first time period" and then "determine a separate weight [between the operating margin and build margin]…for the second time period."[9] This raises two questions: a) what is the appropriate length of each time period?

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[6] http://ghgprotocol.org/files/ghgp/electricity_final.pdf Page 14
[7] https://www.caiso.com/Documents/2015SummerAssessment.pdf
[8] http://ghgprotocol.org/files/ghgp/electricity_final.pdf Page 47
[9] http://ghgprotocol.org/files/ghgp/electricity_final.pdf Page 47

and, b) what is the appropriate weight between the operating margin and build margin for the second time period?

Appropriate Length of Each Time Period

The PD notes that SCE and SDG&E will not need new capacity before 2022, and so SGIP technologies cannot impact the build margin until *at least 2022*. This means that SGIP technologies must be assumed to displace only the operating margin through 2022. Since the aim is to develop a ten-year eligibility factor, the weight assigned to the build margin relative to the operating margin should be based upon the total number of years out of the ten year timeframe the project can be expected to impact the build margin. Thus, a project deployed in 2016 will impact only the operating margin from 2016 through 2022 (seven years), and then may impact the build margin from 2023 to 2026 (three years), resulting in a 70% operating margin to 30% build margin weight. Thus, the *maximum* weight that could justifiably be assigned to the operating margin would be 30% accounting for the three years between 2023 and 2026 when SGIP technologies could conceivably impact the build margin.

Weight Between Operating and Build Margin for Second Time Period

As noted by the PD, even within the three years between 2023 and 2026 SGIP technologies may partially displace the operating margin and partially displace the build margin. There are a number of reasons to believe that even within these three years SGIP projects will either not impact the build margin at all or will impact the build margin on a less than 1kW:1kW basis:

- In Bloom's comments on the ACR, Bloom showed that 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. Within the context of utility procurement on the scale of the recently approved 500MW Carlsbad facility, it is unreasonable to assume that any given SGIP project is going to have a 1kW:1kW impact on utility procurement.
- Bloom agrees with the PD that "determining the timing of the avoidance of new capacity would necessitate analysis of factors specific to the locations and generation profiles of

each project."[10] For example, certain clusters of SGIP projects may impact the need for capacity in a specific location, but projects in other areas would be unlikely to actually impact the need for new capacity.

- Investor-owned utilities require customers with on-site generation to pay monthly "reservation capacity" standby charges for the right to use power from the utility grid when necessary, unless exempt under specific Net Energy Metering tariffs. Such a policy implies that utilities are assuming they will need to provide the capacity to serve these customers. SGIP projects are deployed on the customer side of the meter to serve a particular load. Since they are operated based upon the preferences of the customer (i.e. a customer could decide to turn off an SGIP generator for a period of time or permanently), they cannot be assumed to entirely displace grid capacity on a 1kW:1kW basis.

Each of these three factors will independently reduce the extent to which an SGIP project impacts the build margin. Taken together, Bloom finds that it is reasonable to assume that SGIP projects will at least *mostly* impact the operating margin and therefore the weight assigned to the build margin should be less than 50%. While it is impossible to assess the exact impact that a project may have ten years from now, a number well below 50% would be reasonable absent more precise data. As a reasonable assumption, we recommend that the CPUC apply a 25% weight to build margin impacts and 75% weight to operating margin impacts within the three years (30% of ten years) when SGIP projects can reasonably be expected to impact the build margin is reasonable. Thus, the total build margin weight would be 25% of 30%, or 7.5%. As the program progresses and approaches the need for new capacity, the CPUC and the utilities should study the impact of SGIP projects on the need for new capacity in order to enable more precise revisions to the eligibility factor the future.

b. Renewable Capacity Avoided by SGIP Projects

While Bloom Energy agrees with the CPUC's decision to rely on current policy (33% RPS) rather than speculate on future policy (i.e. 40% or 50% RPS), Bloom Energy disagrees with the Proposed Decisions' use of 33% renewables within the build margin. Bloom understands that the utilities' demand forecasts include the SGIP program, and therefore the amount of retail sales against which they are required to procure renewables is reduced.

[10] Proposed Decision, Page 11

However, Bloom does not agree with the Proposed Decision's assumption that this translates directly to reductions of renewable capacity procurement under the RPS.

The Proposed Decision justifies the 33% weight by stating that "the utilities would forecast their loads, taking into account SGIP and other demand side measures, and submit compliance plans demonstrating sufficient procurement of renewable capacity to meet the higher standard set by the Commission." The PD also states that "until either the legislature codifies a higher RPS or we act on the authority granted by AB 327 and explicitly adopt a higher standard than the RPS minimum, we will not assume a higher avoided renewable capacity than 33%."[11] However, the Proposed Decision fails to take into account that SDG&E has *already* contracted for renewables beyond the 33% mandate, and PG&E has nearly 33% RPS procurement already under contract for 2020.[12]

Percentage of RPS Procurement Currently Under Contract for 2020

PG&E- 31.3%

SCE – 23.5%

SDG&E - 38.8%

The same concept from the *GHG Protocol* cited above with respect to the build margin – "[i]f the grid has more than enough capacity to meet foreseeable power demands, then the project activity may not actually displace any new capacity"[13] – can be applied here. If the grid has enough eligible renewable resources contracted to meet RPS mandates then the project cannot displace new RPS capacity. Considering that SDG&E has *already* contracted for more renewables than the mandate, SDG&E does not need to contract for more renewables to meet its mandate. Therefore, SGIP technologies cannot be assumed to displace any renewable procurement driven by the mandate. In the case of PG&E, more up to date data are likely to show that PG&E has contracted for at least 33% of its retail sales.

In the case of SCE, which has 23.5% renewables under contract, and also for the purposes of developing a methodology that can be applied if the RPS is raised in the future, it is useful to review the CEC's *Proposed Near-Term Method for Estimating Generation Fuel Displaced by Avoided Use of Grid Electricity*, which points out that:

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[11] Proposed Decision, Page 13

[12] http://www.cpuc.ca.gov/PUC/energy/Renewables/

[13] http://ghgprotocol.org/files/ghgp/electricity_final.pdf Page 14

> *"…[R]eductions in demand, specifically from energy efficiency and onsite generation, do not automatically correlate with reductions in the amount of electricity generated by renewable resources…the translation from projected demand reductions to reduced capacity procurement to reduced electricity generation from renewables is tenuous at best, given the frequently repeated viewpoint that the 33 percent Renewables Portfolio Standard goal is a floor to procurement rather than a ceiling*.[14]

The Proposed Decision's assumption that each kWh of reduced retail demand results in 0.33 kWh less renewables (before line losses) rests on the assumption that the utilities will procure renewable capacity only and precisely based upon the legislative mandate of AB 327. It is important to consider other factors, such as the fact that the cost of renewables is dropping rapidly and, as the CEC points out, "future construction of renewables beyond the next five years may no longer be driven by legislative mandate, but rather by cost competition."[15] For example, the CEC's *Estimated Cost of New Renewable and Fossil Generation and California* projects in the 'mid-case' that new Solar PV on par with new CCGT on an LCOE basis and in the 'low case' is significantly cheaper.[16] It is important to note that even if a small number of individual renewable projects are cheaper than CCGTs, then utilities will make procurement decisions based upon least cost rather than RPS mandate, and therefore SGIP technologies cannot be assumed to displace renewable procurement.

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[14] California Energy Commission. *Proposed Near-Term Method for Estimating Generation Fuel Displaced by Avoided Use of Grid Electricity*. http://www.energy.ca.gov/2015publications/CEC-200-2015-002/CEC-200-2015-002.pdf Page 42

[15] California Energy Commission. *Proposed Near-Term Method for Estimating Generation Fuel Displaced by Avoided Use of Grid Electricity*. http://www.energy.ca.gov/2015publications/CEC-200-2015-002/CEC-200-2015-002.pdf Page 8

[16] California Energy Commission. *Estimated Cost of New Renewable and Fossil Generation in California. http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf*

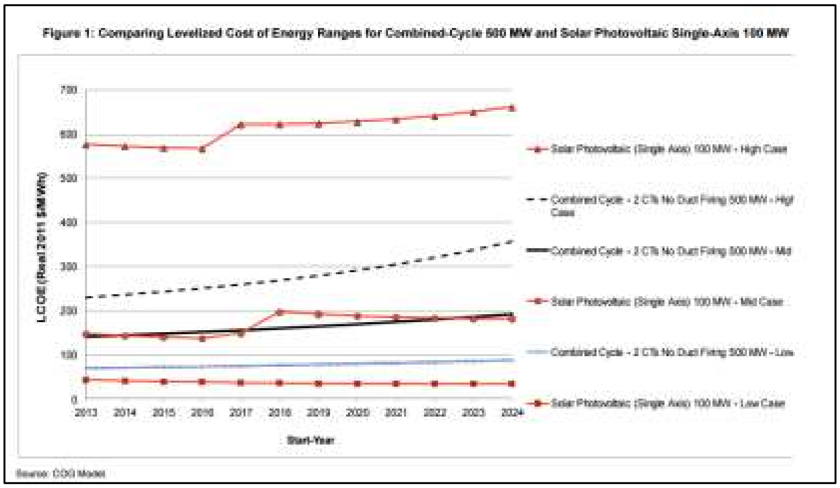

Figure 1: Comparing Levelized Cost of Energy Ranges for Combined-Cycle 500 MW and Solar Photovoltaic Single-Axis 100 MW

Considering that AB 327 sets a floor and not a cap on renewables procurement, and also considering that it allows for the inclusion of generation that may be exported out of California, it is reasonable to believe that the utilities will procure renewables in excess of the legislative floor. Therefore, the weight assigned to renewables under the build margin should be 0%.

4. Data Source – Emission Rates for Gas-Fired Generation Facilities

a. Operating Margin Effect – Emission Rates

Bloom Energy concurs with the Proposed Decision's proposal to use emissions rates of 382 kgCO2/MWh and 544 kgCO2/MWh for load following and peaking plants in the operating margin, respectively. However, the CPUC should note that the emissions rates of peaking plants may be impacted in the future due to the projected increase in renewable generation. The CEC notes that "[a]*s 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."*[17]

b. Build Margin

Bloom Energy agrees that the Proposed Decision's emissions rates of 368 kgCO2/MWh and 524 kgCO2/MWh for CCGTs and CTs in the build margin, respectively, are reasonable starting points. Bloom agrees with the PD that the heat rate may need to be adjusted 5-10% to

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

take into account the impact of dry cooling. Bloom Energy finds it confusing that the Proposed Decision includes in its Findings of Fact that "efficiency improvements of gas-fired technologies may be partially offset if only dry cooled combined cycle plants, which are 5-10% less efficient that wet-cooled units, are permitted in the future" but did not choose to incorporate this fact into the eligibility factor calculation. Bloom suggests that the Commission include this finding of fact in the calculation.

5. Weighting Load-Following and Peaker Plants in the Final Emission Rate

In our comments on the ACR, Bloom Energy noted that "a more appropriate weighting to apply to peaker plants is equivalent to the percentage of time that the peaking plants are on the margin," and the PD agreed that "[t]his approach to weighting peaker and load-following plants is more consistent with the methodology described in the World Resources Institute's GHG Guidelines."[18] Bloom Energy continues to believe that the appropriate weight to assign to peaker plants is based upon the number of hours that peaker plants operate on the margin, but we don't believe the approach proposed in the PD accurately estimates this value.

In order to precisely assess the appropriate weighting to peaker plants, the CPUC would need to conduct an analysis of the hourly generation of peaker plants, defined by the PD as those with a heat rate of at least 10,268 BTU/kWh. However, in the absence of publicly available data, Bloom Energy finds that the PD's use of capacity factor data to try to back into the number of hours per year that peaker plants operate to be reasonable.

The PD used 8% based upon the capacity factor of a new combustion turbine from the 2013 CAISO *Annual Report on Market Issues and Performance*. Bloom would first like to note that the more recent 2014 CAISO *Annual Report on Market Issues and Performance* lists a capacity factor of 10% for a new combustion turbine[19]. Thus, the starting point should be 10%, not 8%.

However, it is important to recognize that, as noted in the PD, 10% represents the annual capacity factor of peakers, but the goal is to estimate the number of hours per year that peakers are operating. A 10% capacity factor would only result in 10% hours per year if peaker plants only have two settings: 'off' and 'operating at 100% full nameplate capacity'. As reflected in

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[18] Proposed Decision, Page 19

[19] 2014 Annual Report on Market Issues and Performance. http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf Page 54

table below, using the calculation of *Output as % of Nameplate x % of Hours Operating = Capacity Factor %,* if a peaker operates at 70% of its nameplate output on average, then a 10% capacity factor would imply that the plant operated 14% of time. In this case the appropriate weight to apply to peakers in the eligibility factor would be 14%.

Table 1. Sensitivity of Capacity Factor to Output and Operating Hours

Ave. Output When Operating (% of Nameplate)	100%	90%	80%	70%	60%	50%
% of Hours Operating	10%	11%	13%	14%	17%	20%
Capacity Factor	10%	10%	10%	10%	10%	10%

It's not reasonable to assume that the peaker plants in California operate at full nameplate capacity. While Bloom is not aware of publicly available data on the hourly operating characteristics of peakers in California, a review of the technical characteristics of peakers makes it clear that they cannot be assumed to be operating at full nameplate capacity. For example:

- General Electric's Gas Turbine Performance Characteristics[20] show that "typically, performance degradation during the first 24,000 hours of operation (the normally recommended interval for a hot gas path inspection) is 2% to 6% from the performance test measurements when corrected to guaranteed conditions." Thus, output should be assumed to be 1% to 6% below nameplate capacity.
- NRDC's *Power Plant Cooling and Associated Impacts* shows that "average annual loss of output for a plant using a dry cooling system is approximately 2 percent."[21]
- General Electric's Gas Turbine Performance Characteristics[22] spec sheet shows that the output of power plants in comparison to their nameplate capacity is dependent on additional factors such as temperature and humidity (see Figure 1 below). Considering that CAISO capacity needs are defined by summer peak, when temperatures are high, the actual operational of these plants is likely to be below their nameplate capacity. Even assuming an average temperature of 70^{o} while plants are operating results in a 5% impact to output. GE's *Performance Monitoring for Gas Turbines* lists additional factors effecting output including inlet temperature and inlet pressure[23].

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[20] http://www.up.farsscript.ir/uploads/13316846411.pdf
[21] http://www.nrdc.org/water/files/power-plant-cooling-ib.pdf
[22] http://www.up.farsscript.ir/uploads/13316846411.pdf
[23] https://www.gemeasurement.com/sites/gemc.dev/files/bently_performance_orbit_article_english.pdf

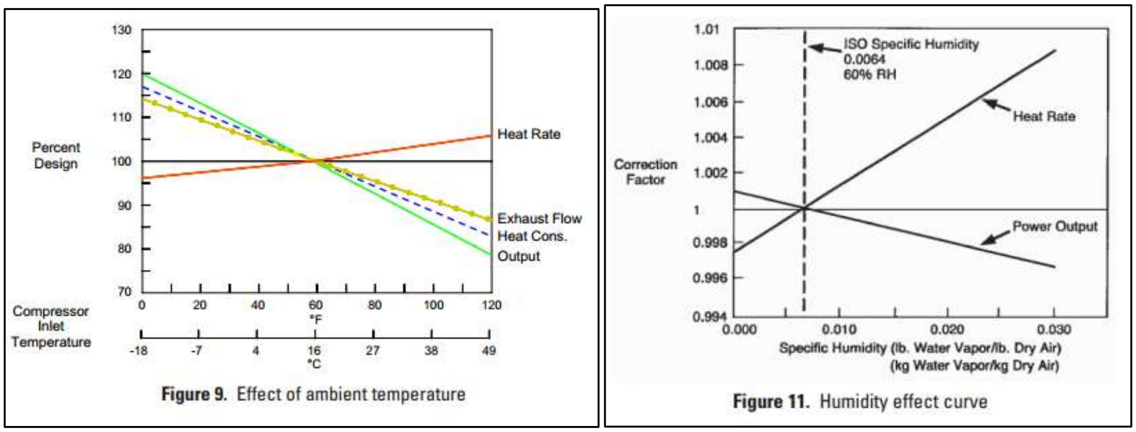

Figure 9. Effect of ambient temperature

Figure 11. Humidity effect curve

Figure 1. GE Gas Turbine Performance Characteristics

Considering the potential impact of all of these factors, the CPUC should recognize that the 10% capacity factor for peakers provided by the CAISO must be less than the number of hours that peakers operate on the margin. Recognizing the PD's point that the capacity factor of any given peaking plant should not be used as the average across the state, 10% should be considered the minimum number of hours per year that the peakers could operate in a given area.

In the absence of precise publicly available data, to estimate the *average* number of hours that peakers operate across the State, Bloom finds EtaGen's recommendation to use the capacity factor for the KRCD Malaga Peaking Plant (the plant with the highest capacity factor) of 20.5%, referenced in the PD, to be most reasonable.[24] Given the analysis above, we know that 20.5% is the *minimum* number of hours per year that this plant operates. Given that capacity factor is ultimately a function of the hours per year that a plant operates and its total output during those hours, it is reasonable to assume that some peaker plants operate more frequently than this plant, and some peaker plants operate less frequently than this plant.

6. Line Losses Avoided by SGIP Projects

Bloom Energy finds the approach in the Proposed Decision to be reasonable and supports the use of an 8.4% line loss factor.

7. The Equation

[24] Proposed Decision, page 19.

Bloom Energy's recommended changes to the emissions factor equation, discussed in the sections above, are summarized below. The highlighted sections are those which have changed in comparison to the Proposed Decision.

GHG EF= $((1-(BM_Y*BM_W))*(ER_{OLF}*(1-WFP)+ER_{OP}*WFP) + (BM_Y * BM_W) * (1-RPS\% * (1-LLF)) * (ER_{BLF}*(1-WFP)+ER_{BP}*WFP))/(1-LLF)$

Where:

GHG EF = greenhouse gas emission factor
BM_Y = percentage of years where build margin is impacted = 30%
BM_W = weight assigned to build margin impact within BM_Y = 25%
ER_{OLF}= operating margin emission rate of load-following plats = 382 $kgCO_2/MWh$
WFP = weighting factor for peaker plants = 20.5%
ER_{OP} = operating margin emission rate of peaking plants = 544 $kgCO_2/MWh$
RPS%= amount that a project will impact renewable procurement = 0%
ER_{BLF}= build margin emission rate of load-following plants = 368 $kgCO_2/MWh$
ER_{BP}= build margin emission rate of peaking plants = 524 kg CO_2/MWh
LLF = line loss factor = 8.4%

This results in the following calculation:

452 kgCO2/MWh = ((1-(30%*25%))*(382*(1-20.5%)+544*20.5%) + (30% * 25%) * (1-0% * (1-8.4%)) * (368*(1-20.5%)+524*20.5%))/(1-8.4%)

As discussed in the ACR, the SGIP eligibility factor established in 2011 was 379 kg CO_2/MWh, which is about 15% below the 452 $kgCO_2/MWh$ eligibility factor calculated here. 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 CO_2/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

As the Commission continues to create programs and standards that are leading the nation, we cannot compromise on the appropriate data or methodology. What the CPUC does here with SGIP is setting the stage for other distributed generation programs and will be looked to as precedent. Therefore Bloom urges the Commission to use available data and continued thoughtful approaches in order to achieve real, meaningful and accurate GHG reductions from customer self-generation projects. To that end and in summary of the above comments, Bloom urges the CPUC to make the following adjustments:

1. Adjust the *build margin* weighting based upon the number of years an SGIP project may actually impact the build margin and the extent to which it may impact the build margin during those years.
2. Adjust the weight assigned to renewables under the build margin taking into account existing utility RPS contracts and future projects around renewable cost competitiveness.
3. Adjust the weighting factor of peaker plants to more closely estimate the percent of time that peaker plants operate.

Bloom appreciates the Commission's efforts and diligence on this particularly complicated emissions accounting methodology.

Dated July 30, 2015

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