Comments by EtaGen on the GHG Emissions Reduction Standard for the Fuel Cell NEM Program

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I. Introduction

Driven by its mission to bring affordable, reliable, and clean power to the world, EtaGen has developed advanced power generation technology that unlocks the full potential of distributed generation. EtaGen's "linear generator" uses a low-temperature reaction of air and fuel to drive magnets through coils to efficiently produce electricity -- providing customers an unmatched combination of economic value, resiliency, and GHG savings.

California consistently leads the nation in establishing progressive clean energy policies which serve as an example for many other states to follow. As such, it is of the utmost importance that accurate data and comprehensive methodologies are employed in order to determine the GHG Emissions Reduction Standard (the "GHG Standard") that will govern eligibility in the Fuel Cell NEM program ("FC NEM"). While EtaGen's linear generator technology differs from fuel cells in the manner by which fuel is converted into electricity, both technologies efficiently and cleanly produce electricity at the distributed scale. EtaGen's linear generator technology is not currently eligible under the existing FC NEM, however, as noted by California Air Resources Board ("CARB") Staff during the workshop held on May 30, 2017, Assembly Bill 36 is currently moving through the legislature and would convert FC NEM into a technology neutral program while retaining the GHG Standard set by CARB at the conclusion of this process. Because this standard would therefore apply to a broader group of clean, EtaGen has a direct interest in this proceeding and appreciates the opportunity to provide comments

II. Comments

Interpretation of AB 1637

As modified by Assembly Bill 1637,[1] Section 2827.10 of the Utility Code provides the following guidance for establishment of the GHG Standard:

[1] EtaGen was one of two major stakeholders engaged with legislative staff in negotiations on the GHG emissions standard included in AB 1637.

> *2827.10(b)(2) "The greenhouse gas emissions reduction standards shall ensure that each fuel cell electrical generation resource, for purposes of clause (iii) of subparagraph (A) of paragraph (3) of subdivision (a), reduces greenhouse gas emissions compared to the electrical grid resources, including renewable resources, that the fuel cell electrical generation resource displaces, accounting for both procurement and operation of the electrical grid."*

Two elements are critical to understanding the intent of the above provision. The first element pertains to the language, "reduces greenhouse gas emissions compared to the electrical grid resources, including renewable resources, that the fuel cell electrical generation resource displaces." This language was meant to ensure that the GHG standard is based on all grid resources that are displaced (i.e., no longer needed to supply electricity to the grid) by the reduction in demand on the grid from the behind-the-meter (BTM) fuel cell generation. Accordingly the GHG Standard should be based on the displaced marginal grid resources. The phrase, "including renewable resources", was meant to ensure that renewable resources are accounted for in the GHG Standard if they are marginal grid resources and also displaced.

The second element relates to the language, "accounting for both procurement and operation of the electrical grid." This language was meant to ensure that the GHG Standard accounts for all grid-related aspects associated with the electricity displaced by BTM fuel cell generation. Since BTM generation displaces electricity that would otherwise have been purchased from the electrical grid, and this electricity inherently has associated transmission and distribution losses ("T&D losses" or "line losses"), this language is meant to ensure that line losses are included in the GHG Standard.

Accordingly, when determining the GHG Standard, it is incumbent on CARB to account for line losses and to limit its analysis to displaced marginal grid resources.

Renewable Procurement & Curtailment

The potential impact of BTM generation could potentially have on renewable generation is dictated by two factors, renewables procurement and renewables curtailment, each of which is addressed separately below.

Renewable Procurement

An often debated question that arises when determining displaced emissions factors in California is whether and to what extent BTM fuel-based generation reduces the amount of renewable energy that is procured by Investor Owned Utilities ("IOUs") as part of the state's Renewable Portfolio Standard ("RPS"). A common response is that, since BTM generation reduces demand on the grid, the IOUs can purchase less renewable energy in order to meet their RPS targets. This logic is inherently flawed for two reasons. First, pursuant to California Public Utilities Commission ("CPUC") rulemaking, BTM generation is not considered in IOU capacity planning processes and, therefore, could not impact renewable procurement.[2] Second, in 2013, passage of Assembly Bill 327 changed the law such that the RPS percentage is now a floor, not a cap, thereby giving utilities the authority to contract/purchase an amount of renewable energy greater than the mandated RPS percentage (in the event that there is lower demand).[3]

Just as reductions in demand from energy efficiency improvements do not impact renewable energy procurement, reductions in demand from BTM fuel-based generation also do not impact renewable energy procurement. For these reasons, it would be improper and inaccurate to include any adjustments to the GHG Standard based on the RPS or any other perceived potential impacts on renewables procurement.

Renewable Curtailment

Renewable resources bid into the CAISO market at or close to $0 per MWh and, therefore, are almost always below the clearing price. There are, however, rare

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[2] *See* Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider LongTerm Procurement Plans, R. 13-12-010 (Dec. 19, 2013), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M147/K780/147780118.PDF

[3] *See* Assembly Bill 327, at page 5 of 32, http://www.leginfo.ca.gov/pub/13-14/bill/asm/ab_0301-0350/ab_327_bill_20131007_chaptered.pdf

occasions in which renewables are curtailed. Aside from self-scheduled outages, renewable curtailment occurs due to: (1) insufficient system-wide demand after the clearing of must-take resources such as nuclear and qualified facilities (referred to herein as "system-demand curtailment events"), and (2) local congestion constraints that limit the flow of power from typically remote renewable plants to a given load center (referred to herein as "congestion curtailment events"). Since BTM generation reduces demand on the grid, the frequency of both types of curtailment events could increase.

Publicly available CAISO data can be used to quantify the potential impact of BTM generation on the amount of system-demand curtailment events. CAISO's daily "Wind and Solar Curtailment Report"[4] provides the daily and year-to-date ("YTD") amount of curtailed renewable generation while CAISO's "Daily Renewables Watch"[5]breaks down the daily cleared generation resources by type and amount, which can be aggregated to provide a YTD breakdown. Table 1 (see below) summarizes the YTD generation and renewables curtailment information available in the aforementioned reports. The YTD (as of 6/8/2017) amount of renewables curtailed due to both types of events was 282,767 MWh, which amounts to only 0.305% of CAISO total generation.[6] It should be noted that, according to CAISO, the majority of renewable curtailment events occur in March, April, and May, so extrapolating this number for the entire year would most likely overestimate the annual amount of renewables curtailed.[7] To investigate the potential impact that BTM fuel cell generation could have on renewables curtailment, we will use the hypothetical scenario in which FC NEM is fully subscribed over this same time period (158 days, from 1/1/17-6/8/17). The maximum amount of electricity that could have been generated YTD by 500 MW of BTM fuel cells is 1,896,000 MWh (500 MW x 100% capacity factor x 158 days / 365 days x 8760 hours/year). With this reduction in

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[4] *See* http://www.caiso.com/Documents/Wind_SolarReal-TimeDispatchCurtailmentReportJun08_2017.pdf, at Page 3.
[5] *See* http://www.caiso.com/market/Pages/ReportsBulletins/DailyRenewablesWatch.aspx
[6] Referred to as "Economic - System" events in the reports, which are described as "market dispatch of generators with economic bids to mitigate system wide oversupply."
[7] *See* Integrating High Penetration Renewable Energy into the CAISO Market (April 19, 2016), at Page 4, https://energy.gov/sites/prod/files/2016/08/f33/Shucheng%20Liu.pdf.

total CAISO generation, the amount of renewables curtailment would have increased to 0.312% (282,767 / (92,624,732 - 1,896,000)).

Table 1. CAISO generation and curtailment summary, 1/1/17-6/8/17.

CAISO YTD, 6/8/2017	Generation (MWh)	% of Total
Generation		
Renewables	23,306,488	25.2%
Nuclear	7,238,809	7.8%
Thermal	21,508,575	23.2%
Imports	25,703,343	27.7%
Large Hydro	14,867,517	16.1%
Total	**92,624,732**	**100.0%**
Renewables Curtailed	**282,767**	**0.305%**

Given this small difference (only 0.006 percentage points) and the fact that the program is not yet fully subscribed, EtaGen recommends assuming zero impact on curtailment of renewable generation for purposes of calculating the GHG Standard.

Line Loss Factor

As previously discussed, the intent of the the relevant emissions standard language in AB 1637 was to include all operational aspects associated with the electricity displaced from the grid by BTM fuel cell generation. Since BTM generation displaces electricity that would have otherwise been purchased from the electrical grid, and this electricity inherently has associated line losses, it is essential that they are included in the GHG Standard. Additionally, inclusion of line losses in the GHG Standard is consistent with other state-supported distributed generation programs (e.g., the Self Generation Incentive Program) and the World Resources Institute's GHG Guidelines report.[8]

There have been several methodologies used to quantify line losses across the various state programs. EtaGen recommends that CARB use the methodology adopted by the CPUC in its SGIP Decision, in which the CPUC calculated a statewide line loss factor of

[8] http://www.wri.org/sites/default/files/pdf/ghgprotocol-electricity.pdf

8.4%, inclusive of losses from the transmission, sub-transmission, and distribution levels as well as congestion.[9] Given the soundness of the methodology and the wide-ranging support it received from numerous distributed generation stakeholders, EtaGen recommends that CARB adopt the same methodology and standard as adopted in the SGIP Decision.

Displaced Marginal Heat Rates

Natural gas plants comprise nearly all marginal energy resources in California; a fact acknowledged by the CPUC in their SGIP Decision which, as a basis for their avoided GHG emissions factor, adopted heat rates from the CEC's "Thermal Efficiency of Gas-Fired Generation in California: 2014 Update".[10] EtaGen agrees with the CPUC's decision to utilize this CEC report, but disagrees with the CPUC's down-selection of data. Table 2 shows the gas-fired power plant performance data from the CEC report that was used in the SGIP Decision. The SGIP Decision adopted the use of *combined-cycle* heat rates for "load-following plants" and *peaker* heat rates for "peaker plants", which were then weighted to give an avoided GHG emissions factor (weighting is discussed in the next section).[11] The CPUC correctly noted that cogeneration facilities are not displaced by BTM generation because they are qualified facilities but the CPUC improperly ignored the displaced generation from *aging* and *other* facilities. As shown in Table 2, both *aging* and *other* facilities had higher capacity factors than *peaker* facilities, so it is unclear why these two types of plants were ignored. EtaGen recommends that CARB utilize the most recent update of the CEC's thermal efficiency report and incorporate all displaced natural gas facilities (i.e., *combined cycle*, *peaker*, *aging*, and *other* facilities) per the methodology described in detail below.[12]

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[9] *See* Decision Revising the Greenhouse Gas Emission Factor to Determine Eligibility to Participate in the Self-Generation Incentive Program, D.15-11-027 (Nov. 19, 2015), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M156/K044/156044151.PDF ("SGIP Decision").

[10] *Available at* http://www.energy.ca.gov/2014publications/CEC-200-2014-005/CEC-200-2014-005.pdf.

[11] Quotes are used to refer to terminology specific to the SGIP Decision and italic is used to refer to terminology specific to CEC Thermal Efficiency reports.

[12] *Available at* http://www.energy.ca.gov/2016publications/CEC-200-2016-002/CEC-200-2016-002.pdf

Table 2. CA natural gas-fired power plants summary statistics for 2013 (from CEC report)

	Capacity (MW)	Share of Capacity	GWh	Share of GWh	Capacity Factor	Heat Rate (Btu/KWh)
Total Natural Gas	50,779	100.0%	129,766	100.0%	29.2%	8,537
Combined-Cycle	19,676	38.7%	87,361	67.3%	50.7%	7,205
Aging	15,851	31.2%	7,589	5.5%	5.5%	11,413
Cogeneration	6,117	12.0%	29,859	23.0%	55.7%	11,459*
Peaker	7,418	14.6%	3,310	2.6%	5.1%	10,268
Other	1,717	3.4%	1,647	1.3%	11.0%	9,504

Table 3 shows the gas-fired power plant performance data from the most-recent CEC Thermal Efficiency (2015 Update) report, which is based on 2014 generation data. Consistent with the SGIP Decision, EtaGen recommends using the *combined cycle* heat rate of 7,329 Btu/kWh for “load-following plants.” However, EtaGen recommends using a load-weighted average heat rate of *peaker*, *aging*, and *other* facilities for “peaker plants.” The load-weighted average heat rate for “peaker plants” is 10,951 Btu/kWh, as shown in Table 4 (note that heat rates shown in Tables 2 and 3 are not adjusted for line losses).

Table 3. CA natural gas-fired power plants summary statistics for 2014 (from CEC report)

	Capacity (MW)	Share of Capacity	GWh	Share of GWh	Capacity Factor	Heat Rate (Btu/KWh)
All Categories of Natural Gas	48,067	100.0%	129,498	100.0%	30.8%	8,513
Cogeneration	5,850	12.2%	28,013	21.6%	54.7%	11,244
Noncogeneration Natural Gas Totals	42,217	87.8%	101,485	78.4%	27.4%	7,760
Combined-Cycle	19,675	40.9%	89,411	69.1%	51.9%	7,329
Aging	13,315	27.7%	6,226	4.8%	5.3%	11,776
Peaker	8,337	17.3%	4,288	3.3%	5.9%	10,415
Other	890	1.9%	1,560	1.2%	20.0%	9,131

Table 4. Load-weighted average capacity factors and heat rates for “peaker plants”.

	GWh	Share of GWh	Capacity Factor	Heat Rate (btu/kWh)
Aging	6,226	52%	5.3%	11,776
Peaker	4,288	36%	5.9%	10,415
Other	1,560	13%	20.0%	9,131
Load-Weighted Average			**7.4%**	**10,951**

Weighting of Marginal Heat Rates

Using the heat rates for "load-following plants" and "peaker plants" provides proxies for the marginal resource resources displaced by reductions in grid demand, but a model is needed to determine the percentage of the hours each type of resource is displaced. EtaGen agrees with the acknowledgement in the SGIP Decision that "the contribution of load-following and peaker plants must be weighted to account for the approximate <u>amount of time spent</u> operating on the margin."[13] However, EtaGen strongly disagrees with the SGIP Decision of 10% weighting for peaker plants. This value was taken from CAISO's "2014 Annual Report on Market Issues and Performance" and is based on the capacity factor of peaker plants, and not the amount of time spent operating on the margin.[14] Peaker plant <u>average</u> capacity factor is not an appropriate model for the fraction of hours per year <u>any</u> "peaker plant" is on the margin because it does not take into account wholesale pricing dynamics or part-load operation.

Table 5 shows the three categories of "peaker plants" from CEC's 2014 QFER data with the highest capacity factors and with greater than 10 MW of capacity. Since these plants had the highest capacity factors, they therefore had the highest number of hours in which they cleared the CAISO market marginal price. Accordingly, this reflects that the *peaker* plant operated <u>at least</u> 30.2% of the hours per year, the *aging* plant operated <u>at least</u> 24.2% of the year, and the *other* plant operated <u>at least</u> 33.5% of the year. The minimum number of operating hours for these plants is more than three times the 7.4% load-weighted average capacity factor for all "peaker plants" shown in Table 4. This example, while simplified, illustrates the fundamental flaw in using average capacity

[13] *See* SGIP Decision at p. 22 (emphasis added).
[14] *See* 2014 Annual Report on Market Issues and Performance (June 2015), *available at* http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

factor to represent the fraction of hours per year that any "peaker plant" is on the margin -- it simply does not capture when *any* "peaker plant" is operational, let alone the marginal resource.

Table 5. Highest capacity factor "peaker plants" with capacity > 10 MW.

Type	CEC Plant ID	Capacity Factor	Heat Rate (Btu/kWh)
Peaker	G0220	30.2%	9,980
Aging	G0274	24.2%	10,563
Other	G0679	33.5%	8,554

Given that average capacity factor is not an appropriate model, and since EtaGen does not have access to historic hourly marginal plant data or advanced forward-looking dispatch models, EtaGen recommends that CARB utilize IOU tariffs for weighting the heat rates of marginal resources because the tariffs are designed to capture real pricing dynamics. Table 6 shows the time periods for energy charge and demand charge pricing across the main commercial tariffs in the major IOUs.[15]

Table 6. IOU tariff pricing time periods.

	Terminology	Summer Weekdays (non-holiday)	Winter Weekdays (non-holiday)	Weekends & Holidays	Hours per Year	% Total Hours
PG&E, E-19	Off-Peak	9:30 pm - 8:30 am	9:30 pm - 8:30 am	All hours	5,475	62%
	Partial -Peak	8:30 am - 12 pm, 6 pm - 9:30 pm	8:30 am - 9:30 pm	N/A	2,515	29%
	Peak	12 pm - 6 pm	N/A	N/A	771	9%
SCE, TOU8	Off-Peak	11 pm - 8 am	9 pm - 8 am	All hours	5,218	60%
	Mid-Peak	8 am - 12 pm, 6 pm - 11 pm	8 am - 9 pm	N/A	2,772	32%
	On-Peak	12 pm - 6 pm	N/A	N/A	771	9%
SDG&E, AL TOU	Off-Peak	10 pm - 6 am	10 pm - 6 am	All hours	4,717	54%
	Semi-Peak	6 am - 11 am, 6 pm - 10 pm	6 am - 5 pm, 8 pm - 10 pm	N/A	2,860	33%
	On-Peak	11 am - 6 pm	5 pm - 8 pm	N/A	1,183	14%

Given that the IOU tariffs distinguish between peak, part-peak, and off-peak time periods for pricing (albeit with slightly differing terminology), EtaGen recommends using

[15] PG&E E19: https://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-19.pdf.
SCE TOU8: https://www.sce.com/NR/sc3/tm2/pdf/ce54-12.pdf.
SDG&E AL TOU: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_AL-TOU.pdf.

a load-weighted average number of hours per year for each of these three time periods. Table 7 shows the load-weighted number of hours per year and fraction of hours per year for each of the three time periods based on the IOU loads shown in Table 2 (the same IOU loads that were used in the SGIP Decision for determining the 8.4% line loss factor). It is important to note that the percent of hours per year of the partial-peak time period (30.3%) is nearly equivalent to the individual capacity factors for the highest capacity factor "peaker plants" shown in Table 5.

Table 7. Load-weighted time periods for the major IOUs.

Load-Weighted Avg.	Hours per Year	% Hours
Off-Peak	5,295	60.4%
Partial-Peak	2,656	30.3%
Peak	809	9.2%

Proposed FC NEM Emissions Factor & Methodology

EtaGen respectfully recommends setting the GHG Standard at 474 kg/MWh, based upon the following methodology:

Displaced Marginal Heat Rates before Line Losses

Off-peak:	7,329 Btu/kWh	(SGIP Decision methodology, 2014 CEC QFER data)
Peak:	10,951 Btu/kWh	(2014 CEC QFER data)
Part-peak:	9,140 Btu/kWh	(average of off-peak and peak heat rates)

Line Loss Factor

8.4% (SGIP Decision)

Displaced Marginal Heat Rates after Line Losses

Off-peak:	8,001 Btu/kWh
Peak:	11,955 Btu/kWh
Part-peak:	9,978 Btu/kWh

Weighting of Marginal Heat Rates

Off-peak: 60.4% of the hours

Peak: 9.2% of the hours

Part-peak: 30.3% of the hours

Average Displaced Heat Rate

8,956 Btu/kWh = 8,001 Btu/kWh x 60.4% + 11,955 Btu/kWh x 9.2% + 9,978 Btu/kWh x 30.3%

Natural Gas Emission Factor

53 kg CO_2 per MMBTU of natural gas (SGIP Decision)

Average Displaced Emissions Factor

474.7 kg/MWh = 8,956 Btu/kWh x 53 kg/MMBTU x 1/1,000 units conversion

III. Conclusion

EtaGen appreciates the opportunity to provide comments on the GHG Standard for eligibility in the FC NEM program.

Respectfully submitted,

_________/s/__________

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