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ADMINISTRATIVE LAW JUDGE'S RULING FINALIZING GREENHOUSE GAS EMISSIONS ACCOUNTING METHODS, LOAD FORECASTS, AND GREENHOUSE GAS BENCHMARKS FOR INDIVIDUAL INTEGRATED RESOURCE PLAN FILINGS

Table of Contents

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Summary

This ruling finalizes a methodology for accounting for the greenhouse gas emissions of individual load-serving entity (LSE) electric resource portfolios and adopts updated greenhouse gas (GHG) benchmarks, to use for purposes of planning, in the integrated resource plan (IRP) filings due August 1, 2018, as required in Decision (D.) 18-02-018.

1. Greenhouse Gas Accounting Methodology

An administrative law judge (ALJ) ruling issued April 3, 2018 in this proceeding included a staff proposal for stakeholder feedback on the appropriate GHG accounting methodology for use in the upcoming individual IRP filings. The staff proposal contained a proposed approach which is a modified version of a methodology originally proposed by Pacific Gas and Electric Company (PG&E) in the context of the California Energy Commission's (CEC's) Assembly Bill (AB) 1110 rulemaking, which is designed to address power content labeling for historical electricity deliveries. The approach discussed here, termed the clean net short (CNS) methodology, apportions GHG emissions to each LSE based on its projected hourly electricity demand. The method is demand- or load-based, in contrast to many GHG accounting frameworks that are source-based accounting for emissions directly from power plants, regardless of the load they serve. It is also unique in that it is an hourly methodology, whereas many others are based on annual averaging.

Commission staff recommended the CNS methodology to ensure that the GHG emissions reported by an LSE more closely match the system emissions generated to serve that LSE's actual load, as well as to be more comparable to the Reference System Plan analyzed in the RESOLVE model and adopted by the Commission in D.18-02-018. A spreadsheet tool now being called the "CNS Calculator" was also provided and commented on by parties.

1.1. Comments from Parties

Sixteen sets of parties filed formal comments in response to the April 3, 2018 ALJ ruling on GHG accounting, including the following: Alliance for Retail Energy Markets (AReM); California Community Choice Association (CalCCA); Calpine; California Wind Energy Association (CalWEA); Center for Energy Efficiency and Renewable Technologies (CEERT); California Environmental Justice Alliance (CEJA) and Sierra Club (jointly); California Energy Storage Alliance (CESA); Clean Coalition; California Municipal Utilities Association (CMUA); Green Power Institute (GPI); PG&E, San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE), jointly (collectively: the investor-owned utilities (IOUs)); Natural Resources Defense Council (NRDC); Office of Ratepayer Advocates (ORA); Protect our Communities Foundation (POC); Powerex Corporation; and The Utility Reform Network (TURN).

Reply comments in response to the April 3, 2018 ALJ ruling were filed by the following 15 parties: AReM; American Wind Energy Association California Caucus (AWEA); CalCCA; Calpine; CalWEA; CEJA and Sierra Club, jointly; Clean Coalition; CMUA; GPI; IOUs, jointly; ORA; Powerex; SCE; TURN; and the Regents of the University of California (UC Regents).

The rest of this section summarizes the comments and replies from parties on a topical/thematic basis.

The following parties generally support the CNS methodology proposed by staff, primarily because it rewards LSEs for planning for GHG-free resources that best fit their customers' collective load shape: CalWEA, CEERT, CESA, GPI, NRDC, the IOUs, and TURN.

POC, on the other hand, argues that the entire methodology is flawed and inaccurate, beginning with first step in the approach where owned or contracted non-dispatchable GHG-emitting resources are subtracted out and then, POC contends, never added back in. They also make a distinction between wholesale and retail energy sales, which POC believes leads to inaccurate load forecasts at the root of the methodology.

Numerous parties raised more specific concerns with the methodology. The first topic raised by several parties, including AReM, GPI, IOUs, and the UC Regents, was related to the concern that not all LSE load shapes (aggregated, based on their particular customers) would necessarily be similar to the overall California Independent System Operator (CAISO) system average load shape which was pre-loaded into the CNS calculator developed by Commission staff and consultants.

Another issue raised by Calpine, among other parties, relates to credit for an LSE's purchase of GHG-free energy in excess of the energy required to serve its load in any given time period. A number of parties advocate for at least some crediting for excess purchases that displace energy from GHG-emitting resources, even when not serving the LSE's native load.

Numerous parties, including AReM, CEJA, CMUA, Sierra Club, and POC, argue that the methodology used by the Commission for IRP purposes should be consistent with that used by the California Air Resources Board (CARB) in its reporting and compliance programs, since IRP is the planning process designed to achieve eventual GHG regulatory compliance at CARB. Those parties, plus AWEA, are also concerned about consistency with the CEC's AB 1110 efforts, arguing that the IRP purpose is similar to that of power content labeling.

Of particular concern to many parties, including AReM, CalCCA, and POC, among others, is consistency with the rules of the renewables portfolio standard (RPS) program, particularly the treatment of portfolio content category (PCC) 2 and 3 renewable energy credits (RECs), procured under the RPS program. CARB allows for an "RPS adjustment" for PCC 2 renewables in its Cap-and-Trade program for the purposes of calculating a compliance obligation, and many parties argue the Commission should do the same type of recognition of PCC 2 renewables here. Essentially, this change would allow the PCC 2 resources to count as GHG-free, even though they may be firmed and shaped by non-zero-emission resources.

CalCCA also argues that the environmental attributes of PCC 3 RECs should be counted in the GHG accounting methodology, since they are compliant with the RPS and there has been no previous requirement that RPS deliveries match load profiles on an hourly basis.

CalCCA goes on to argue that the CNS methodology is inconsistent with the RPS, and also unfairly penalizes leading LSEs, particularly in the areas of rooftop solar and the green tariff, among other programs. In addition, CalCCA argues the methodology undermines the ability of LSEs to claim to be 100 percent GHG-free and will result in devaluing of existing RPS-eligible purchases.

These are perhaps the most controversial topics in the methodology. Numerous other parties argue that PCC 2 (and some argue, by extension, PCC 3) RECs should not be counted as GHG-free, including CalWEA, CEERT, CESA, Clean Coalition, and TURN. CEERT states it most simply in its comments:

"While RECs do have a GHG benefit, the GHG reductions from unbundled RECs would be near impossible to calculate."

The IOUs also raise concerns about only counting PCC 1 renewables for a different reason, namely that it limits counting of energy from contracts signed earlier than June 1, 2010, but that is otherwise RPS eligible and GHG-free.

AReM also recommends crediting benefitting customers of ESPs and CCAs for the GHG emissions (or reductions) associated with resources procured under the cost allocation mechanism (CAM) or other charges such as for public purpose programs, where ESP or CCA customers pay either the full revenue requirement or at least the net capacity costs for these resources. The argument is that customers who pay the costs should also receive any benefits. CESA also raises concerns along these lines.

Calpine is also concerned that the CNS methodology does not adequately incentivize purchases of GHG-emitting energy from resources with lower heat rates or offsetting system power purchases with lower-GHG-emitting (but not zero-emitting) resources.

CEJA and Sierra Club criticize the methodology for not accounting for local air pollutant emissions, particularly associated with cycling, partial load operation, and starts for conventional generation. The IOUs also suggested that future iterations of the tool at least address the GHG emissions associated with GHG-emitting resources that need to run at specified minimum levels to be available for ramping, and utilize a simple allocation across load or ramping needs to individual LSEs.

CEJA and Sierra Club also recommend that the methodology take into account lifecycle emissions. Finally, CEJA, Sierra Club, CMUA, and CEERT suggest that the results of the CNS methodology undergo "groundtruthing" by comparing against actual emissions to ensure a reasonable degree of accuracy.

ORA recommends a different manner of benchmarking the results, utilizing both the CNS and the source-based methodology associated with the Energy Resource Recovery Accounts (ERRA), to ensure comparable results.

CMUA also raises concerns about the potential for unintended consequences of modification of procurement decisions solely to respond to this GHG accounting methodology.

CEERT disagrees with leaving out behind-the-meter (BTM) combined heat and power (CHP) in the methodology and having staff deal with it later, arguing that this would be inconsistent with how CARB treats these emissions.

Powerex would prefer that the Commission create a class of imports that is distinct from system power, which is assigned a default emissions factor, for those suppliers who provide GHG-free energy from known hydro or other GHG-free resource bases outside of California. TURN, on the other hand, is concerned about the potential for resource-shuffling of contracts for existing GHG-free resources, where no new output is produced, but instead is simply sold to California, resulting in no actual GHG reductions beyond historical levels.

The Clean Coalition is also concerned about the potential for devaluing of BTM resources, including energy efficiency and demand response, in this methodology, especially at levels going beyond the CEC's Integrated Energy Policy Report (IEPR) assumptions. They also make a distinction between these BTM resources and those at the transmission level, accounting for line loss factors. Clean Coalition also raises concerns about the potential for double-counting of emissions.

CESA is concerned about how BTM storage is accounted for, and also the accuracy of treatment of resources needed for ramping and ancillary services. ORA also raises concerns about GHG emissions associated with stand-alone storage, as compared to storage co-located with a generation resource, either GHG-free or GHG-emitting.

The Joint IOUs also point out that pumped storage dispatch is not reflected in the spreadsheet tool, though it is modeled, dispatched, and reported separately in RESOLVE, the model used to develop the Reference System Plan in D.18-02-018. They suggest inclusion of a heat map for pumped storage dispatch, similar to the treatment of battery storage and large hydroelectric resources.

Finally, GPI is concerned about increases in GHG emissions after the closure of the Diablo Canyon nuclear plant, and seeks constraints in the model to ensure no emissions increase. In addition, GPI seeks additional functionality to allow biomass and biogas power systems to show net positive or negative emissions of biogenic GHGs related to their fuel sources and the alternative disposal methods for the materials.

1.2. Disposition

The purpose of the GHG accounting methodology addressed in this ruling is primarily to provide a basis for understanding whether Commission-regulated LSEs are on track to help the state achieve GHG emissions reductions consistent with California's 2030 climate goals. While actual progress toward and compliance with the climate goals is tracked in CARB's emissions inventory, our purpose here is to guide planning and procurement behavior toward achieving those goals. The emphasis here, as with the entire IRP process, is on planning. The GHG accounting methodology is not intended as a compliance obligation. Rather, it provides a way for the Commission to understand, in a planning context, whether the portfolios proposed by LSEs in their individual IRPs out to 2030 are likely to result in the portion of the electricity sector overseen by the Commission reaching its share of the 2030 GHG target.

Within that broad purpose, there are two critical needs that need to be met: 1) ensuring the Commission's ability to compare and aggregate the GHG emissions expectations associated with individual LSE resource portfolios, and 2) allowing comparison and benchmarking against the Reference System Plan.

The variation of the CNS methodology adopted in this ruling is designed to achieve those broad planning purposes. It is very likely that improvements can be made to the methodology described herein. In fact, desirable updates and enhancements are described at the end of this section. For now, however, the Commission needs a common methodology to be used for purposes of filing and evaluating the individual LSE IRPs to be considered in 2018.

These purposes are distinct, as described in D.18-02-018, from the CEC's Power Source Disclosure program, as modified by AB 1110, which addresses the reporting and disclosure of the emissions intensity associated with the electricity delivered to retail customers during the previous calendar year. The GHG emissions reporting and compliance programs of CARB also may have some common elements, but are focused on the annual reporting and accounting of emissions by source for reporting, tracking, and compliance purposes. The Commission is focused, instead, on guiding LSE planning and procurement behavior in the future.

The modified CNS approach we adopt here is a demand- or load-based GHG accounting framework, where GHG emissions are attributed to each LSE based on the energy it uses to serve its load. The method provides insights into the GHG emissions associated with the resources necessary to match an LSE's load profile.

These GHG emissions estimates are heavily dependent on the time variable in the calculation. While GHG emissions can be calculated on an annualized (or net annual) basis in a simple and straightforward manner, an annualized approach can serve to obscure the actual value of those resources to the electricity system on an hourly basis.

This annual averaging, as proposed by some parties including CalCCA, can allow LSEs to claim credit for producing GHG-free energy at times of the day when it is not needed, and avoid being attributed GHG emissions associated with resources that are necessary to support the LSE's actual load at times when GHG-free energy is unavailable. An annual averaging approach could encourage LSEs to procure resources that generate more zero-emission electricity necessary to serve their own load, and then credit that extra supply against the system power that they plan to purchase at a different time of day, appearing to cause fewer GHG emissions than are actually occurring.

The problem associated with such an approach is not that LSEs will over-procure renewable resources, leading to an oversupply of zero-GHG power at some hours of the day. Indeed, the RESOLVE model and the Reference System Plan show that curtailment can be a viable and cost-effective renewable integration strategy. However, calculating the GHG emissions on an annualized (or net annual) basis is likely to result in systematic undercounting of GHG emissions across the entire electric system.

As illustrated in the example provided by CalCCA in its opening comments, if an LSE develops a supply portfolio relying strictly on wind resources, it will also need to rely on system power when the wind is not blowing. A net annual calculation would apply the overproduction of GHG-free wind energy, relative to the LSE's load, against the GHG-emitting system power it relies on during other hours of the day. If the surplus GHG-free energy exceeds the system energy on which the LSE relies, the LSE could incorrectly claim to be 100 percent GHG-free over the course of the year, regardless of whether its surplus GHG-free energy has caused GHG-emitting resources on the system to back down or run less. This would create not only an accounting problem, but also an equity problem among LSEs, penalizing LSEs whose generation portfolios happen to more closely match their loads. Responsibility must be fairly attributed to LSEs to ensure they are planning for GHG reductions on a level playing field.

On the physical system, GHG emissions cannot be offset by surplus GHG-free energy, unless that surplus energy offsets GHG-emitting generation that would have otherwise been relied upon. A net annual calculation cannot capture this subtlety, but an hourly calculation of GHG emissions, such as the CNS methodology, can.

In some cases, zero-GHG generation in excess of an LSE's hourly load may be sold into the system and cause another LSE to reduce its gas-fired generation production or the CAISO to dispatch fewer gas-fired resources, thus reducing overall emissions. This effect was observed in RESOLVE modeling, which showed solar resources contributing to reduced natural gas usage in some hours of the day, especially in earlier years of the analysis (2018 and 2022).

To avoid penalizing the procurement of resources that offset GHG-emitting generation, the CNS methodology adopted in this ruling has been modified from Commission staff's initial proposal to give LSEs credit for excess GHG-free energy provided to the grid in excess of its load, in hours in which the

GHG-free energy displaces energy from GHG-emitting resources. "Oversupply" is now quantified in the spreadsheet tool (instead of curtailment), because it allows LSEs to oversupply relative to their hourly load and receive credit for GHG-free energy that displaces GHG-emitting resources in given hours.

To address the concerns of CalCCA and AReM, among others, about the inconsistency of the CNS methodology with the requirements of the RPS program, it is important to understand that the goals of the RPS program are numerous, with GHG reductions being only one. Other RPS purposes include in-state economic development, renewable resource development, and a host of other goals and aspirations. Not all RPS-eligible resources are GHG-free, which is, in part, acknowledged by the existence of the PCC categories themselves.

Certain resources may be RPS-eligible but actually GHG-emitting, whereas other GHG-free resources may not be RPS-eligible at all. The CNS methodology seeks to account for these differences between RPS eligibility and GHG attributes. It is worth restating that the RPS program rules are not entirely consistent with the Cap-and-Trade program rules, as those two programs are designed to achieve different goals using different compliance rules and mechanisms.

The IRP process is yet a third mechanism, albeit with a planning purpose and not a compliance one. Whereas the RPS program is designed to increase the procurement of eligible renewable energy resources, the overarching goal of the IRP process is planning and then procuring to reach the state's 2030 GHG emissions goals. Compliance with the RPS requirements may indeed not be enough to assure achievement of the 2030 GHG goals without additional targeted procurement.

The advantage of the CNS method is that it takes into account the average hourly resource mix and allows LSEs and their customers to benefit from the collective efforts of all entities investing in low- and zero-GHG emitting resources, regardless of whether those resources are RPS-eligible.

This represents acknowledgement of the complaint of CalCCA that the CNS methodology may serve to undermine LSEs who wish to claim to be GHG-free. While LSEs may be fully compliant with the RPS program and purchasing enough GHG-free energy to serve its load on an average annual basis, unless an LSE is purchasing GHG-free energy to perfectly match its own load profile, it is almost certain that the physical reality of grid operations is that such an LSE is actually causing some GHG emissions. The purpose of the CNS method is to fairly and equitably account for those effects for all LSEs, and not advantage the GHG attribute claims of some LSEs to the detriment of others.

With respect to the specific arguments put forth by the largest number of parties about counting of PCC 2 RPS-eligible resources as GHG-free, both CalCCA and AReM argued that the CNS method penalizes an LSE's new renewable resource investments and devalues existing investments independent of any assessment of whether those investments are needed or economic for the grid as a whole.

However, the CNS method adopted by this ruling does not count PCC 2 resources as GHG-free. PCC 2 resources, which represent "firmed and shaped" products, delink the hourly profile for imported energy from the hourly production profile of the underlying renewables. Thus, PCC 2 energy can be substituted with GHG-emitting generation under the RPS rules, as pointed out by CalWEA, CEERT, CEJA and Sierra Club, Clean Coalition, GPI, ORA, TURN, and the IOUs. Under existing RPS rules, LSEs could claim existing out-of-state

GHG-free energy production on paper while emissions on the western grid do not change.

Without some type of regional carbon pricing and compliance regime, not counting PCC 2 RECs as GHG-free appears to be the most equitable and accurate way to address the uncertainty around projecting the GHG emissions that will likely be experienced by the atmosphere as a result of serving California electricity load, while providing the correct directional incentive for the investment in new GHG-free resources necessary to achieve the state’s 2030 GHG targets.

It is also noteworthy, in response to numerous party comments about consistency among California agencies including the Commission, CEC, and CARB, that the CEC’s proposal for Power Content labeling under AB 1110 does not count PCC 2 RECs as GHG-free either. Instead, CEC staff are proposing assigning PCC 2 RECs the GHG emissions intensity of the substitute power, and if the substitute power is unknown, assigning the default GHG emissions intensity for unspecified electricity. The CEC’s approach also differs between “power content” reporting and “GHG intensity” reporting, utilizing PCC 2 resources for the former but actual imported substitute power for the latter.

In the case of CARB regulation, the Cap-and-Trade Program has an optional RPS adjustment that may be claimed for purposes of calculating the compliance obligation in cases where an LSE can show that renewable energy was not directly delivered to California but was purchased by the LSE, which in turn owned and retired the REC. These requirements are not met by all PCC 2 resources.

In addition, this adjustment to an entity’s compliance obligation in the Cap-and-Trade Program does not change how emissions from firmed and shaped contracts are counted under CARB's mandatory reporting regulation (MRR). When CARB assesses progress toward the 2030 GHG emissions reduction goals through the emissions inventory, one of the bases is MRR. This assessment is done based on total reported emissions, not an individual entity's or even an individual sector's compliance obligations. However, as part of the IRP, CARB will be assigning individual LSE GHG targets, and under the method of assigning individual GHG targets currently under consideration, both load forecast and projected resources for 2030 will play a part in assignment of GHG targets.[1]

Finally, the Commission has spoken about the relationship between RECs and GHG attributes in the past in relationship to the definition of a REC, in D.08-08-028, which states: "[a]lthough the avoided GHG emissions attribution is included in the definition of the REC, under a cap, the avoided GHG emissions attribute should…have zero value."[2] Accordingly, the REC may not be used for GHG emissions reductions purposes.

In sum, CEC, CARB, and the Commission, as part of this IRP process, have different purposes and different programs to address different goals and compliance obligations associated with RPS and GHG emissions goals. Thus, the CNS addresses our IRP requirements, separate and apart from RPS goals and Cap-and-Trade compliance obligations. In addition, the CNS approach is consistent with other GHG reporting methodologies that have a comparable

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[1] *See* CARB's draft staff report on this topic available at: https://www.arb.ca.gov/cc/sb350/draftstaffreport_sb350_irp.pdf

[2] D.08-08-028 at 23.

purpose, which are the CARB's MRR and the CEC's proposed GHG intensity reporting requirements.

Another criticism of the CNS method, brought up by CalCCA, was that it is inconsistent with the methodology used in RESOLVE modeling, which dispatches units without any constraint that each LSE's generation match its load. This type of dispatch protocol aims to minimize GHG emissions in dispatch regardless of resource ownership. CalCCA argued that if RESOLVE had been run with an ownership constraint, the resulting resource buildout and costs would have been significantly different, and likely higher. These points are correct, but somewhat miss the point. The purpose of the CNS is not to apportion emissions consistent with the RESOLVE methodology, nor to artificially inflate the actual emissions, but rather to give LSEs an estimate of the emissions associated with their actual resource portfolios as part of the sectoral total, on an equitable basis. The Commission will then evaluate the aggregate emissions from the LSEs' IRP filings by using production cost modeling to further analyze the emissions from the planned portfolios submitted.

Some additional changes have been made to the CNS methodology, in response to comments from parties summarized in the section above, beyond the crediting of some GHG-free excess purchases that result in GHG benefits, as already described.

First, the definition of GHG-free energy was revised to include RPS "Bucket 0" resources that were purchased prior to the PCC 1 cutoff date for contract execution, but that otherwise exhibit the same operational characteristics as PCC 1 resources.

In addition, the CNS calculator tool has been modified to give LSEs more control over how to enter their specific load profiles, in order to support development of Alternative Portfolios. For Conforming Portfolios, LSEs are still required to use their individual assigned load forecast for IRP, as well as the default load profile from RESOLVE, which is pre-loaded in the CNS calculator, in order to ensure comparability across LSE filings. The default load profile from RESOLVE is associated with the CAISO's underlying transmission area.

The CNS calculator tool has also been modified to allow LSEs to input custom production shapes for GHG-free resources that have a production profile that is significantly different from any of the RESOLVE resources.

Finally, heat maps have been provided in the tool for pumped storage dispatch.

Due to the impending August 1, 2018 filing deadline for the individual LSE IRPs, there were inherent limitations on the modifications that Commission staff could make to the GHG accounting method and associated spreadsheet tool in this round of IRP. Below is a list of modifications that Commission staff will consider addressing for future IRP cycles, with the benefit of additional time to conduct the analysis to recommend whether these changes are feasible and warranted:

- Using an emissions factor to determine the criteria pollutant emissions from the relevant generation facilities with those types of emissions, as requested by CEJA and Sierra Club.
- Accounting for the GHG benefits of resources procured by IOUs on behalf of all customers and recovered through non-bypassable charges, as requested by AReM and CalCCA.
- Counting of low-carbon, hydro-dominated Asset-Controlling Supplier (ACS) systems as GHG-free, or using the ACS-specific GHG emissions factors from CARB, as requested by Powerex.
- Accounting for emissions from generation operating at minimum load, as well as cycling and startup emissions, as requested by CEJA, Sierra Club, and the IOUs.

- Collecting and considering information from contractual agreements related to unit dispatch (for fossil-fueled generation) and import profile data (for zero-GHG imports), in part to identify instances of resource shuffling, as requested by several parties including TURN.
- Comparing the GHG impact of stand-alone storage, co-locating storage, with renewables, and co-locating storage with fossil-fueled generation to test the assumption that all storage facilities should be assigned the system-level GHG emissions rate, as requested by ORA.
- Performing a "ground truthing" of the GHG accounting method against CARB and CAISO findings for system-wide GHG emissions, in an effort to benchmark and ensure accuracy, as requested by numerous parties.
- Distinguishing between distribution-connected or BTM resources from transmission-connected resources, when accounting for GHG attributes, as requested by the Clean Coalition.

For the current CNS method, as modified as described above in response to party comments, and required for use in the individual LSE IRPs due August 1, 2018, the steps of the methodology are described in Attachment A. In addition, Commission staff has also provided a modified version of the Excel workbook CNS calculator to assist LSEs in preparing their individual GHG emissions estimates. The new version of the calculator is available at the following link: http://www.cpuc.ca.gov/General.aspx?id=6442451195.

2. Final Individual LSE Load Forecasts and GHG Benchmarks

The April 3, 2018 ALJ ruling adopted GHG benchmarks for LSEs that were different than those included in D.18-02-018, Table 7, due to updates adopted in the interim by the CEC in their 2017 IEPR. D.18-02-018 also delegated to the ALJ updating of those GHG benchmarks.

The April 3, 2018 ALJ Ruling also noted that six new community choice aggregators (CCAs) had been recently certified to begin serving load in California. Those new CCAs were asked to submit load forecasts with projections out to 2030, in response to the ALJ ruling. Other parties were invited to respond to those new load forecasts, if desired.

2.1. New CCA Load Forecasts

The six CCAs whose load forecasts were not reflected in Table 1 of the April 3, 2018 ALJ ruling are: Desert Community Energy; King City; Rancho Mirage; Riverside County; San Jacinto; and Solana Beach. Five entities filed responses to the ruling, five of which attached load forecasts, with Riverside County CCA indicating that it has notified the Commission of its intent not to proceed with registering a CCA or serving load at this time.

In addition, on May 11, 2018, Marin Clean Energy filed a motion seeking adoption of a new, higher load forecast out to 2030, with the associated change in its GHG benchmark in 2030.

2.2. Responses to New CCA Load Forecasts

SCE was the only party to respond to the load forecasts of the six new CCA entities. SCE commented that for the three new CCAs that filed load forecasts in its territory, they appeared to be generally consistent with the 2030 load departure projections outlined in the CCAs' implementation plans. However, SCE pointed out that the Riverside County CCA notification of its intent not to move forward with CCA formation represents an extreme example of the uncertainty faced by the utilities in planning, where assumptions about departing load can change rapidly and unexpectedly. SCE also pointed to the changes in forecasts of Los Angeles County's CCA, as having changed fairly dramatically between the 2017 IEPR forecasts and its 2018 implementation plan.

SCE's general concern is that the Commission and the CEC adopt a common process for managing fluctuating CCA load projections for use in the bi-annual IRP process. SCE recommended that the IEPR process be the venue annually for adopting the LSE load forecasts, working collaboratively through the Demand Analysis Working Group. SCE then recommended that the IRP process then utilize the most recent adopted load forecasts, to avoid intra-cycle uncertainty and fluctuations.

2.3. Disposition

The points raised by SCE are reasonable with respect to the need for certainty of load forecast assumptions to inform the development and submission of IRPs for consideration by the Commission, as well as for the broader purposes of ensuring reliability and serving end-use customer load.

The purpose of this ruling is only to determine the load forecast assumptions to be used by LSEs in their August 1, 2018 required individual IRP filings. The Commission and the CEC will work together to craft a more permanent solution for future cycles in the coming months. However, for the current purpose related to assumptions to be used for the August 1, 2018 individual IRP filings, Table 1 below represents the updated load forecast assumptions and GHG benchmarks for 2030.

Consistent with D.18-02-018, an individual LSE may always file a motion to modify these load forecasts and the associated GHG benchmarks, with justification, if it believes that these benchmarks need to be further updated. However, to avoid further uncertainty and to allow time for the IOUs, in particular, to lock down their residual load forecasts in response to CCA load forecasts in advance of August 1, 2018, we will allow one final window for modifying load forecasts and associated GHG benchmarks.

Any LSE that wishes to modify its load forecasts or GHG benchmark beyond the modifications already made in this ruling for purposes of the August 1, 2018 IRP filings must file an updated load forecast by no later than June 4, 2018. Any party desiring to respond to any such filings must do so by June 11, 2018. If necessary, another ALJ ruling will be issued. Such an ALJ ruling with any subsequent adjustments to load forecasts or benchmarks will affect only the LSE(s) seeking the adjustment and the relevant IOU. Otherwise, benchmarks and load forecasts for other entities listed in this ruling will not be further adjusted.

Any motions filed in the proceeding for consideration of new load forecasts that are filed after June 4, 2018 will be considered later and applied only to future IRP filings. The Commission will likely further adjust this process in the future to make it more manageable and predictable.

Table 1. Load Projections and GHG Emissions Benchmarks by LSE, Updated Based on 2017 IEPR, Form 1.1c, Mid Demand Baseline, Mid AAEE and Mid AAPV Savings, and modified to incorporate new CCA load forecasts

Utility	LSE within Utility Territory	Proportion of 2030 Emissions Under Cap and Trade	2030 Load (GWh)	Proportion of 2030 Load within Utility Territory	2030 GHG Emissions Benchmark (MMT)
Bear Valley Electric Service	NA	0.1%	141	NA	0.025
Liberty Utilities	NA	0.3%	610	NA	0.107
PG&E	Bundled	33.8%	37,341	46.7%	6.632
	Direct Access		9,520	11.9%	1.691
	Marin Clean Energy		6,793	8.5%	1.207
	Sonoma Clean Power		2,507	3.1%	0.445
	Clean Power San		574	0.7%	0.102

Utility	LSE within Utility Territory	Proportion of 2030 Emissions Under Cap and Trade	2030 Load (GWh)	Proportion of 2030 Load within Utility Territory	2030 GHG Emissions Benchmark (MMT)
	Francisco				
	Peninsula Clean Energy		3,579	4.5%	0.636
	Silicon Valley Clean Energy		3,492	4.4%	0.620
	Redwood Coast Energy		623	0.8%	0.111
	Pioneer Community Energy		1,075	1.3%	0.191
	Monterey Bay Community Power		3,331	4.2%	0.592
	East Bay Community Energy		6,136	7.7%	1.090
	Valley Clean Energy Alliance		726	0.9%	0.129
	San Jose City		4,280	5.3%	0.760
	King City Power		40	0.1%	0.007
PacifiCorp	NA	0.7%	809	NA	0.313
SCE	Bundled	33.2%	62,888	79.0%	11.013
	Direct Access		11,618	14.6%	2.035
	Lancaster Choice Energy		581	0.7%	0.102
	Apple Valley Choice Energy		200	0.3%	0.035
	Pico Rivera Innovative Municipal Energy		70	0.1%	0.012
	Los Angeles Community Choice		2,151	2.7%	0.377
	Desert Community Energy		1,531	1.9%	0.268
	Rancho Mirage Energy Authority		326	0.4%	0.057

Utility	LSE within Utility Territory	Proportion of 2030 Emissions Under Cap and Trade	2030 Load (GWh)	Proportion of 2030 Load within Utility Territory	2030 GHG Emissions Benchmark (MMT)
	San Jacinto Power		191	0.2%	0.033
SDG&E	Bundled	8.8%	14,244	79.7%	2.959
	Direct Access		3,562	19.9%	0.740
	Solana Beach CCA		75	0.4%	0.016

In addition to the issues addressed above with respect to new CCAs and their load forecasts and GHG benchmarks, Commission staff has become aware of some issues for smaller electric service providers (ESPs). Specifically, small ESPs with annual peak loads under 200 megawatts (MW) are not required to file IEPR load forecasts.

However, smaller ESPs are required to file load forecasts with the Commission for purposes of resource adequacy year-ahead requirements. For ESPs that are in this situation, they are requested to utilize their most recent load forecast submission for resource adequacy purposes and extend that annual energy requirement (in GWh) out to 2030. Those ESPs should then follow the same instructions for other ESPs given in D.18-02-018[3] for calculating their individual GHG benchmarks.

IT IS RULED that:

1. The Clean Net Short Methodology described herein, summarized in Attachment A to this ruling, and reflected in the Excel spreadsheet tool Clean

[3] *See* D.18-02-018 at 124 and in Attachment A of that decision.

Net Short Calculator posted on the Commission's web site, shall be used by all load-serving entities required by the terms of Decision 18-02-018 to file an individual integrated resource plan (IRP), for purposes of the IRP due on August 1, 2018.

2. Load serving entities required by Decision 18-02-018 to file individual integrated resource plans shall use the individual greenhouse gas benchmarks contained in Table 1 of this ruling for developing their Conforming Portfolios for their filings due August 1, 2018.

3. Community choice aggregators serving the following communities shall use the annual load forecasts contained in their responses to the April 3, 2018 administrative law judge ruling in this proceeding to develop their Conforming Portfolios for their integrated resource plans due August 1, 2018: Desert Community Energy, King City, Rancho Mirage, San Jacinto, and Solana Beach.

4. In developing its Conforming Portfolio for purposes of its August 1, 2018 integrated resource plan, San Diego Gas & Electric Company shall utilize its annual load forecasts reflected in the 2017 Integrated Energy Policy Report, subtracting out the load forecasts of the Solana Beach community choice aggregator in its April 20, 2018 filing in this proceeding.

5. In developing its Conforming Portfolio for purposes of its August 1, 2018 integrated resource plan, Southern California Edison Company shall utilize its annual load forecasts reflected in the 2017 Integrated Energy Policy Report, subtracting out the load forecasts of the Desert Community Energy, Rancho Mirage Energy Authority, and San Jacinto Power community choice aggregators in their April 20, 2018 filings in this proceeding.

6. In developing its Conforming Portfolio for purposes of its August 1, 2018 integrated resource plan, Pacific Gas and Electric Company shall utilize its

annual load forecasts reflected in the 2017 Integrated Energy Policy Report (IEPR), subtracting out: 1) the load forecasts of King City community choice aggregator included in its May 9, 2018 response to the April 3, 2018 administrative law judge ruling in this proceeding and 2) the difference between the 2017 IEPR load forecasts of Marin Clean Energy and the load forecasts included in its May 11, 2018 motion in this proceeding.

7. Electric service providers (ESPs) whose annual peak loads are smaller than 200 megawatts and who are not required to submit load forecasts as part of the California Energy Commission's Integrated Energy Policy Report process, shall extend their most recent resource adequacy load forecasts out to 2030 and follow the instructions for other ESPs given in Decision 18-02-018 at page 124 and in its Attachment A, for purposes of the Conforming Portfolios for their integrated resource plan filings due August 1, 2018.

8. Bear Valley Electric Service, Liberty Utilities, Sonoma Clean Power, Clean Power San Francisco, Peninsula Clean Energy, Silicon Valley Clean Energy, Redwood Coast Energy, Pioneer Community Energy, Monterey Bay Community Power, East Bay Community Energy, Valley Clean Energy Alliance, San Jose City, Lancaster Choice Energy, Apple Valley Choice Energy, Pico Rivera Innovative Municipal Energy, Los Angeles Community Choice (Clean Power Alliance), and all electric service providers with peak loads of 200 megawatts or greater, shall utilize their annual load forecasts included in the 2017 Integrated Energy Policy Report to develop their Conforming Portfolios for purposes of their August 1, 2018 integrated resource plan filings.

9. Any load serving entity wishing to update its load forecast and associated greenhouse gas benchmark beyond the figures included in Table 1 of this ruling for purposes of informing its August 1, 2018 integrated resource plan filing

required by Decision 18-02-018 must file its updated annual forecasts out to 2030 by no later than June 4, 2018.

10. If any load serving entity files an updated forecast on June 4, 2018, any interested party may file a response by June 11, 2018.

Dated May 25, 2018, at San Francisco, California.

/s/ JEANNE McKINNEY for
Julie A. Fitch
Administrative Law Judge

Attachment A: Final Greenhouse Gas Accounting Methodology for use in Load-Serving Entity Portfolio Development in the 2017-18 Integrated Resource Planning Cycle

The Clean Net Short (CNS) Methodology

The conceptual steps of the CNS method, as modified by Commission staff in response to comments from parties, are as follows:

1. For each hour of the year, the load serving entity (LSE) will subtract out any owned or contracted non-dispatchable greenhouse gas (GHG)-emitting resources (such as non-dispatchable combined heat and power (CHP) or fossil imports) it plans to use to serve its hourly load from its projected hourly electricity demand.
2. The LSE will subtract its owned or contracted (either current or planned) GHG-free generation from the projected hourly electricity demand, less the amount subtracted in the previous step.
    a. "GHG-free" generating resources: RPS Bucket 1, hydroelectric, and nuclear generation, and any other RPS-eligible resources that meet the criteria to qualify as RPS Bucket 1 except for the contract execution date of the resource. Resources can count as GHG-free only if delivered to a California balancing authority area.
    b. "GHG-emitting" generating resources: any resources other than those deemed GHG-free above.
3. The LSE will subtract the discharging pattern (and add the charging pattern) of any storage resources owned by or contracted to the LSE from the hourly profile derived in step #2. The result is the CNS in each hour. The CNS may be negative or positive. Positive CNS values indicate that the LSE is relying on system power to serve part of its demand. Negative CNS values indicate that the LSE is supplying GHG-free power to the system.
4. The CNS will then be multiplied by the system GHG emissions intensity on an hourly basis, yielding total emissions associated with using unspecified system power for that LSE for every hour of the year. When an LSE has an oversupply of GHG-free power (a negative CNS), it may receive credit for avoiding unspecified system power at the system GHG emissions intensity during that hour.[1] Note that the system GHG emissions intensity can be zero during hours of system-wide oversupply. In these hours the LSE would receive no credit for oversupply because it is not possible to displace system dispatchable fossil generation.

[1] The credit applies only at the hourly level, as emissions are calculated for each hour independently of the others.

5. Finally, the emissions from all owned or contracted non-dispatchable GHG-emitting resources used to serve hourly load in step #1 will be calculated using a weighted-average emissions factor and added to the emissions from unspecified system power calculated in step #4.

For example, an LSE may anticipate 100 MW of demand in a given hour in 2030. If the LSE's owned and contracted resources produce 75 MW of GHG-free power and 5 MW of non-dispatchable CHP in that hour, then the LSE's CNS is 20 MW for that hour. Assuming that the average emissions intensity of fossil generation on the CAISO system is estimated to be 0.5 tons/MWh for that hour, the LSE would multiply its CNS (20 MW) by the emissions intensity (0.5 tons/MWh) to yield 10 tons of CO2e for that hour of unspecified CAISO system power. The LSE would then add the emissions associated with the 5 MW of non-dispatchable CHP to its total.

Commission staff has estimated the *average* emissions intensity (tons/MWh) of fossil generation on the CAISO system associated with the Reference System Portfolio on a month-hourly basis in each of the RESOLVE study years (2018, 2022, 2026, and 2030). Average emissions factors for system power are calculated as the sum of GHG emissions ($MMTCO_2$) divided by the sum of generation (MWh). For the purposes of the CNS method, only dispatchable GHG-emitting resources[2] and unspecified imports are included in the average emissions factor calculation because GHG-free and non-dispatchable GHG-emitting resources are accounted for elsewhere.[3]

Marginal emissions factors, as opposed to *average*, are calculated by processing the results of an electricity dispatch simulation to determine which resources are on the margin. Marginal emissions factors may be more appropriate when assessing the emissions impact of new investments or incremental demand (e.g., estimating emissions reductions from power plants that would turn down to accommodate additional renewable generation).

The decision to use average rather than marginal emissions factors reflects the underlying goal of the CNS method: to attribute system-wide emissions to multiple LSEs in a consistent manner, so that the aggregation of their portfolio emissions will be comparable to those of the system. One benefit of using average emissions factors is that multiplying an average emissions factor by a given level of demand will sum to the total emissions for that level of demand. In California, where there is a single dominant dispatchable fuel (natural gas), marginal emissions factors will tend to overestimate aggregate emissions because the marginal generator tends to be less efficient than generators further down in the stack of dispatchable resources.

Staff has developed a CNS calculator tool for LSEs to use in estimating the GHG emissions of their portfolios. The calculator is posted at: http://www.cpuc.ca.gov/General.aspx?id=6442451195.

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[2] Under this method, "dispatchable GHG-emitting resources" may exclude some CHP facilities that operate under "as-available" contracts, which make a certain portion of their capacity dispatchable. Emissions from such facilities would not be reflected in the calculation of system power emissions factors.

[3] To maintain consistency with RESOLVE's treatment of hydroelectric imports from the Pacific Northwest, an offset is subtracted from each LSE's GHG emissions. The offset is calculated as the LSE's load-ratio share of CAISO demand multiplied by the CAISO-wide hydroelectric offset value of 2.8 $MMTCO_2$/yr.

The instructions for using this calculator are provided in the next section. All LSEs filing Standard Plans as part of the IRP process are required to demonstrate use of the CNS method and calculator tool in accounting for GHG emissions in their portfolios. LSEs are also free to use other tools to inform or supplement this accounting method. Importantly, the calculator is not intended to be used as an after-the-fact compliance tool, but rather to provide LSEs a simple and uniform way of estimating the emissions associated with their IRP portfolios.

Instructions for Using the LSE Clean Net Short Calculator

The LSE CNS Calculator is an Excel tool created to help LSEs calculate their emissions using the CNS method. It calculates the LSE's CNS and annual emissions for the four modeling years used in the IRP RESOLVE framework (2018, 2022, 2026, and 2030). The Excel spreadsheet consists of the following worksheets:

1. *User Input and Results tabs*
    1.1. **Dashboard**: This worksheet contains input tables that the LSE is to fill out (left) as well as the final CNS and emission results (right).
    1.2. **Custom Profiles**: This worksheet contains *optional* input tables that the LSE may fill out with custom 8760 shapes for GHG-free power or load profiles. To enable a custom profile, users must switch the drop-down "Use Shape?" field in row 10 from "No" to "Yes."
2. *LSE-specific IEPR data tab – Read Only*
    2.1. **IEPR Form 1.1c**: This worksheet contains data from the 2017 IEPR and, as described below, can be used to look up an LSE's managed retail sales forecast. This worksheet is a **read-only worksheet** that the user should not change.
3. *Data Sources tab – Read Only*
    3.1. **Data Sources**: This worksheet contains information regarding key data sources.
4. *Inputs and calculations tabs – Read Only*
    1. **Calculations**: This worksheet contains the core hourly calculations for calculating the CNS and emissions.
    2. **IEPR CAISO Load Modifiers**: This worksheet contains data from the 2017 IEPR and is used to calculate detailed demand inputs given an LSE's managed retail sales forecast.
    3. **Load Profiles**: This worksheet displays the hourly, normalized load shape that will be applied to the LSE's annual load forecast for each of the modeling periods. It also contains shapes for electric vehicle loads (both home charging and work + home charging), electrification loads, and energy efficiency.
    4. **Renewable Profiles**: This worksheet displays hourly renewable capacity factors for all the possible candidate resources from which the LSE can choose on the Dashboard. The capacity factor shapes are for one full year (8760 hours) and are based on 2007 weather.
    5. **Hydro Dispatch**: This worksheet displays the average large hydro dispatch profile by month-hour and modeling period, as calculated for the Reference System Plan using the

RESOLVE model. This hydro dispatch pattern is applied to any Large Hydro capacity that the LSE specifies on the Dashboard.

6. **<u>Battery Dispatch</u>**: This worksheet displays the average battery storage dispatch profile (assumes 4 hours of battery energy capacity) by month-hour and modeling period, as calculated for the Reference System Plan using the RESOLVE model. This battery storage dispatch pattern is applied to any battery storage that the LSE specifies on the Dashboard.
7. **<u>Pumped Storage Dispatch</u>**: This worksheet displays the average pumped storage dispatch profile (assumes at least 12 hours of pumped storage energy capacity) by month-hour and modeling period, as calculated for the Reference System Plan using the RESOLVE model. This pumped storage dispatch pattern is applied to any pumped storage that the LSE specifies on the Dashboard.
8. **<u>Emissions Factors</u>**: This worksheet displays the average emissions factor for dispatchable GHG-emitting resources by month-hour and modeling period, as calculated for the Reference System Plan using the RESOLVE model. These emissions factors are an input to the calculation of CNS emissions. An emissions factor of zero in a given hour indicates that it is not possible to displace dispatchable GHG-emitting resources, likely because no displace dispatchable GHG-emitting resources are running in that hour.

To use the tool effectively, a user would generally take the following steps:

1. **<u>Define demand level and profile</u>**: On the Dashboard, input the LSE's load forecast on the Dashboard for each of the modeling years. The "Active Demand Inputs" section in cells E40:H46 represents the final demand values used by the tool. LSEs have multiple options to enter specific components of their demand forecast. Values from rows 21-38 are used to populate the Active Demand Inputs.
   a. Simple annual forecast (required for Conforming Portfolios): The LSE must enter its IRP-assigned annual load forecast in cells E21:H21 of the Dashboard tab. LSEs may refer to the "IEPR Form 1.1c" tab for LSE-specific managed retail sales forecast values from the 2017 IEPR. Even if an LSE plans to enter custom load forecast components (described below), cells E21:H21 must be populated because they are used in downstream calculations.

      Entering the load forecast will automatically populate "Default Demand Inputs" in cells E24:H30 by assuming that the LSE has a sales-weighted share of specific components of the IEPR demand forecast, such as the level of BTM PV, energy efficiency, etc. The "Active Demand Inputs" are populated automatically. If an LSE chooses not to provide customized demand inputs (described below), these Active Demand Inputs will be used for all components of the demand forecast.
   b. Custom annual forecast (optional; for Alternative Portfolios only): Enter user-specified information for specific components of LSE demand in cells E32:H38. This option is appropriate for LSEs that have projections of energy efficiency, behind the meter PV, electrification, etc. for their customers, and who wish to reflect those projections in an Alternative Portfolio. The "Use Custom" toggle in cells C32:C38 must be switched from "no" to "yes" for any user-specified component of the demand forecast. Demand values

in the tool represent demand at the generator (not at the customer meter), so custom demand forecasts should be grossed up for T&D losses, typically ~7% to 8%.

c. Custom hourly forecast (optional; for Alternative Portfolios only): Users can specify custom 8760 demand profiles for each component of the demand forecast on the Custom Profiles tab. This option is appropriate for LSEs that know the hourly shape of their demand components and wish to reflect those projections in an Alternative Portfolio. Custom hourly shapes are applied to the demand forecasts in the Active Demand Inputs section of the Dashboard tab. Custom hourly profiles can be used with either simple annual or custom annual demand inputs (a or b, described above).

LSEs should exclude any load met by behind-the-meter CHP from their demand forecasts.[4] Any load met by CHP that is delivered to the CAISO grid should be added to the line "Owned or contracted non-dispatchable GHG-emitting resources," as described in the next step.

LSEs that have information on the fraction of electric vehicle (EV) owners that can charge at work can enter this information in cells E18:H18, as part of an Alternative Portfolio. Workplace EV charging will receive a different hourly consumption shape than the default home charging shape.

2. **<u>Define GHG-emitting resources</u>**: On the Dashboard, input the LSE's owned or contracted non-dispatchable GHG-emitting resources (e.g. CHP; current and planned), in units of average MW (assumes a 100% capacity factor shape), as well as the weighted average GHG emissions factor for these resources. CHP emissions factors should be reported on a net basis by subtracting out emissions from fuel used to produce useful thermal output.[5] The goal is to capture emissions associated with electricity production (the "power" portion of CHP), but <u>not</u> from heat used outside of electricity production (the "heat" portion).

   To calculate the weighted average emissions factor for two or more non-dispatchable GHG-emitting resources with different emissions factors, the LSE should multiply each resource's emissions factor (tCO2/MWh) by its power output (MW), add the results together, and divide that number by the total power output of those resources. For example, consider an LSE that has two CHP resources with two different emissions factors: 200 MW at 0.4 tCO2/MWH, and 300 MW at 0.3 tCO2/MWh. The weighted average emissions factor for those two CHP resources would be calculated as [(200 x 0.4) + (300 X 0.3)] / 500 = 0.34 tCO2/MWh. The LSE would enter 0.34 tCO2/MWh in cells E17:H17.

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[4] As indicated in the IRP decision (D.18-02-018), there is a 4 MMT difference between RESOLVE modeling and PATHWAYS modeling (used by CARB for the Scoping Plan) due to GHG accounting discrepancies for behind-the-meter CHP. Specifically, a 42 MMT target in RESOLVE is equivalent to a 46 MMT in PATHWAYS. Because LSEs are collectively planning toward an electric sector planning target of 42 MMT, which does not include the 4 MMT system-wide emissions estimated from BTM CHP, each LSE should exclude any load met by BTM CHP from its demand forecasts when using the calculator tool. Commission staff plans to account for the 4 MMT of emissions from BTM CHP after all LSEs have submitted their plans and during the development of the Preferred System Plan.

[5] Refer to page 9 of CARB (2016) "California's 2000-2014 Greenhouse Gas Emission Inventory," available at: www.arb.ca.gov/cc/inventory/doc/methods_00-14/ghg_inventory_00-14_technical_support_document.pdf.

3. **Define storage resources**: In the Capacity Inputs section of the Dashboard, input the LSE's owned or contracted energy battery and pumped storage resources (current and planned). The tool will use this user-specified capacity to scale the RESOLVE month-hour shapes that are provided in the Battery Dispatch and Pumped Storage Dispatch worksheets. Please note that these shapes vary by modeling year.
4. **Define GHG-free resources**: In the Capacity Inputs section of the Dashboard, input the LSE's owned or contracted renewable or GHG-free resources (current and planned) for each of the modeling years in the Capacity Inputs section. Only resources that are defined above as "GHG-free" should be added here.[6] Resources modeled in the RESOLVE model are provided as possible resources from which the user can choose.

   LSEs are also permitted the option of adding an energy production profile from custom GHG-free resources in the Custom Profiles tab. One possible use of the custom GHG-free resource functionality would be to represent a wind resource with a production profile that is significantly different than any of the RESOLVE resources. Another possible use would be in cases when an LSE contracts for bundles of PCC 1 RECs that may include multiple types of resources that are either unknown in advance or that vary in type over time.

   Behind-the-meter PV generation is included in the Demand Inputs section and is input in terms of energy (GWh). Row 77 shows a representative installed MW capacity value for BTM PV derived from the Demand Inputs section values. This representative capacity should not be changed by the user.
5. **Investigate results**: Results are shown on the right side of the Dashboard. Results include values for annual energy, total emissions, average emissions intensity, oversupply, and capacity/peak.
6. **Explore alternative assumptions [optional]**: Adjust inputs in the Dashboard to explore different resource and demand scenarios.

(END OF ATTACHMENT A)

[6] "GHG-free generating resources include RPS Bucket 1, hydroelectric, and nuclear generation, and any other RPS-eligible resources that meet the criteria to qualify as RPS Bucket 1 except for the contract execution date. Resources can count as GHG-free only if delivered to a California Balancing Authority area.