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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007

ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON GREENHOUSE GAS EMISSIONS ACCOUNTING METHODS AND ADDRESSING UPDATED GREENHOUSE GAS BENCHMARKS

Summary

This ruling invites comments from parties on a method proposed by Commission staff and included as Attachment A, for comparing greenhouse gas (GHG) emissions from electricity resource portfolios submitted as part of individual integrated resource plan (IRP) filings. Those IRP filings are required by August 1, 2018, as directed in Decision (D.) 18-02-018.

This ruling also provides updated GHG Benchmarks for individual load-serving entities (LSEs) as a result of the final publication of the California Energy Commission's (CEC's) 2017 Integrated Energy Policy Report (IEPR), and includes clarification of certain IRP filing requirements related to the IEPR assumptions, as required in D.18-02-018. Community choice aggregators (CCAs) that are newly registered and not included in the 2017 IEPR are required to file load forecasts out to 2030 in response to this ruling; other parties may comment on these forecasts.

Interested parties may file comments on this ruling and Attachment A, and new CCAs must file 2030 load forecasts, by no later than April 20, 2018. Reply

comments on GHG accounting and comments on new CCA load forecasts are permitted no later than April 30, 2018.

As provided for in D.18-02-018, a common GHG accounting methodology for all LSEs to use in their individual IRP filings, as well as 2030 GHG benchmarks for new CCAs, will be finalized by an Administrative Law Judge (ALJ) ruling to follow this round of comments by parties.

1. Greenhouse Gas Accounting Methodology

D.18-02-018 set requirements for LSEs to file IRPs and delegated to the assigned ALJ to develop and publish a common methodology and set of assumptions for LSEs to use in accounting for the GHG emissions in their proposed IRP portfolios.

The purpose of this methodology is distinct from the purposes of either the California Air Resources Board in accounting for GHG emissions for its GHG emissions compliance programs or the California Energy Commission in accounting for GHG emissions as part of the Power Source Disclosure program.

While a reasonable degree of accuracy is important to the Commission's methodology, the primary purpose here is to create a best-available approach that aligns with the production cost modeling that Commission staff will conduct in 2018 and allows a comparison across multiple LSEs on a consistent basis.

1.1 Staff Proposal for GHG Accounting in IRPs

Commission staff has developed a proposal for GHG accounting purposes to be used by LSEs in developing and submitting their individual IRPs. The proposal was discussed informally at a March 1, 2018 Modeling Advisory Group webinar. A modified version of this proposal is attached to this ruling as Attachment A and will be entered into the record of this proceeding by way of this ruling.

In addition, staff has also provided an Excel workbook calculator to assist LSEs in preparing their individual GHG emissions estimates. A modified version of that calculator is available at the following link: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/GHG%20Calculator%20for%20IRP%20v1.3.xlsx

1.2 Questions for Parties on GHG Accounting Method

This ruling seeks formal comments from interested parties on Attachment A. Parties are requested to respond to the following questions:

1. Are the basic steps of the accounting methodology described in Attachment A and the associated GHG calculator tool internally consistent and technically sound? Why or why not? Identify any flaws in the method that are likely to have a material impact on long-term planning and explain how these deficiencies should be addressed.
2. What impacts might using the method described in Attachment A and the associated calculator tool have on an individual LSE's long-term resource investment decisions? Provide any suggestions for how the method could be modified to reduce or eliminate any negative impacts identified.
3. Does the method in Attachment A hinder or improve the state's ability to achieve its long-term GHG emissions reduction goals? Explain your answer.
4. Do you agree or disagree with the characterization of renewable energy credits related to compliance with the renewables portfolio standard program and their relationship to IRP's GHG emissions goals in the proposed methodology in Attachment A? Explain why or why not.
5. Provide any suggestions for improving the GHG calculator tool.

6. Comment on any specific aspects of the methodology in Attachment A with which you disagree and explain your proposed alternative approach.
7. Describe any alternative GHG accounting methodology that the Commission should consider adopting for IRP purposes and explain why the alternative is preferable to the method described in Attachment A.
8. Comment on any other aspect of the methodology in Attachment A that was not already covered in the previous questions, explaining your rationale and suggested modifications.

2. Use of 2017 IEPR Updates, including Individual LSE GHG Benchmarks

Since D.18-02-018 was adopted by the Commission, the CEC has finalized the 2017 IEPR, including the electricity load forecast through 2030. There are also numerous associated underlying assumptions that were updated or modified, and may be different from the assumptions utilized by the Commission staff in modeling that informed the Reference System Portfolio adopted in D.18-02-018. Those include, but are not limited to, electric vehicle load, other electrification, additional achievable energy efficiency (AAEE), additional achievable behind-the-meter photovoltaics (AAPV), other on-site generation or storage, time-of-use rate impacts, and load-modifying demand response.

Commission staff have been asked numerous clarifying questions informally by LSE representatives and others since the IEPR was adopted. Attachment A of D.18-02-018 specified the use of 2017 IEPR inputs to create a "Conforming Portfolio."[1] In general, LSEs are required to use input assumptions consistent with those used to develop the Reference System Portfolio, with

[1] *See* D.18-02-018, Attachment A, at 3-4.

exceptions based on updated information available. That updated information includes the 2017 IEPR demand forecast, as well as its load modifiers, such as those listed above, included in the "mid Baseline mid AAEE mid AAPV" case.

This also means that those assumptions should be used if an LSE needs to make assumptions about the rest of the electric system (outside of its own resources). In general, if the 2017 IEPR contains an updated assumption, it should be used, with the Reference System Portfolio assumptions used if no updated 2017 IEPR assumption exists.

In addition, the 2017 IEPR contained updated individual LSE load forecasts out to 2030. These load forecast updates affect the adopted individual GHG Benchmarks in D.18-02-018, Table 7, which were also delegated to the ALJ to update, as necessary.

Based on the 2017 IEPR demand forecast, contained in Form 1.1c, the "Mid Demand Baseline Case, Mid AAEE, Mid AAPV," Table 1 below contains the updated GHG Benchmarks by individual LSE. LSEs should note that the individual benchmarks have been developed based on an electric sector planning target of 42 million metric tons (MMT) and do not assume that LSEs report emissions from behind-the-meter combined heat and power (CHP), which is a change from the benchmarks included in D.18-02-018. LSEs are now expected to exclude load met by such facilities in preparing their portfolios and GHG emissions estimates.

In addition, six new CCAs have been registered that were not included in the 2017 IEPR, and will need to have benchmarks established based on their 2030 load forecasts, in advance of their filing of IRPs August 1, 2018. Those CCAs are:

- San Jacinto Power
- City of Rancho Mirage
- City of Solana Beach
- King City CCA
- Desert Community Energy
- Rivo CCA.

To facilitate our establishing GHG benchmarks for these CCAs in advance of the 2018 individual IRP filing deadline, these CCAs are requested to file annual load forecasts projected out to 2030 in response to this ruling, on April 20, 2018. Other parties may comment on these load forecasts on the due date for reply comments to this ruling, April 30, 2018. A subsequent ruling will be issued to establish their individual GHG benchmarks for 2030.

Consistent with D.18-02-018, an individual LSE may also file a motion to modify these benchmarks, with justification, if it believes that these benchmarks need to be further updated.

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

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%	39,320	49.1%	6.984
	Direct Access		9,520	11.9%	1.691

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)
	Marin Clean Energy		4,854	6.1%	0.862
	Sonoma Clean Power		2,507	3.1%	0.445
	Clean Power San Francisco		574	0.7%	0.102
	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
	Monterrey 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
PacifiCorp	NA	0.7%	809	NA	0.313
SCE	Bundled	33.2%	64,936	81.6%	11.371
SCE	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
SDG&E	Bundled	8.8%	14,318	80.1%	2.974
	Direct Access		3,562	19.9%	0.740

IT IS RULED that:

1. Attachment A to this ruling titled "GHG Accounting Methodology for LSE Portfolio Development in the IRP 2017-2018 Cycle" is hereby entered into the record of Rulemaking 16-02-007.
2. Interested parties may file and serve comments on Attachment A and respond to the questions included in Section 1.2 of this ruling by no later than April 20, 2018.
3. Interested parties may file and serve reply comments to this ruling by no later than April 30, 2018.
4. Load serving entities required by Decision 18-02-018 to file individual integrated resource plans shall use updated assumptions contained in the California Energy Commission's 2017 Integrated Energy Policy Report demand forecast and associated load modifiers contained in the "mid demand baseline mid additional achievable energy efficiency mid additional achievable photovoltaics" case in their conforming portfolios.
5. 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.
6. The following community choice aggregators shall file load forecasts projected out to 2030 in comments in response to this ruling, by no later than April 20, 2018:
    a. San Jacinto Power
    b. City of Rancho Mirage
    c. City of Solana Beach
    d. King City CCA
    e. Desert Community Energy

f. Rivo CCA.

7. Interested parties may comment on the load forecasts of the community choice aggregators listed in Ordering Paragraph 6 above by no later than April 30, 2018.

Dated April 3, 2018, at San Francisco, California.

/s/ JULIE A. FITCH
Julie A. Fitch
Administrative Law Judge

Attachment A: GHG Accounting Methodology for LSE Portfolio Development in the IRP 2017-18 Cycle

A CPUC Staff Proposal

Introduction

On February 8, 2018, pursuant to Senate Bill (SB) 350, the California Public Utilities Commission (CPUC) voted to set requirements for load serving entities (LSEs) to file integrated resource plans (IRP). Among other things, the decision concludes that the Commission should adopt 42 million metric tons (MMT) by 2030 as the greenhouse gas emissions (GHG) target for the electric sector in IRP. The decision also delegates to Commission staff and the assigned administrative law judge (ALJ) to develop and publish a common methodology and set of assumptions for LSEs to use in accounting for GHG emissions in their IRP portfolios.

As the decision explains, the GHG accounting methods used in IRP will serve a very different purpose from those developed for the California Energy Commission's (CEC's) Power Source Disclosure (PSD) program as modified by AB 1110.[1] Whereas the CEC's AB 1110 process addresses the reporting and disclosure of actual emissions during the previous calendar year, the CPUC's IRP process is designed to estimate GHG emissions out to 2030 and to guide LSE planning and procurement behavior in the future. Similarly, the GHG accounting methods used in IRP may differ from those used in the California Air Resources Board's (CARB's) GHG emissions reporting and compliance programs, such as the Mandatory Reporting Regulation, which are focused on accounting in previous years for compliance purposes. It is not the intent of the IRP process to recommend a particular outcome in the AB 1110 process or to contradict the emissions reporting in CARB's compliance programs. IRP will use its own GHG accounting methods to meet a separate and distinct objective: to ensure that CPUC-regulated entities are on track to achieve GHG reductions consistent with the state's long-term climate goals.

The purpose of this document is to propose a GHG accounting method and seek party comments in order to develop the best-available methodology for this cycle of IRP (2017-18). The goal is not to create a perfect methodology, but rather to develop a reasonable method for emissions approximation that aligns with the production cost modeling that staff plans to conduct in 2018, so that individual IRPs may be compared across LSEs and with the Reference System Plan adopted for IRP 2017-18.

[1] To implement the changes introduced by AB 1110, the Energy Commission must adopt guidelines for the reporting and disclosure of unbundled RECs and the GHG emissions intensity associated with retail sales, and also adopt a method in consultation with California Air Resources Board (CARB) for calculating GHG emissions intensity factors for each purchase of electricity by a retail supplier to serve its customers.

Policy Context for GHG Accounting

Generally speaking, GHG accounting frameworks can range from source-based to demand-based, or contain some combination of the two. Under a source-based accounting framework, such as with the method used in the CPUC's Energy Resource Recovery Account (ERRA) applications,[2] all emissions from an LSE's owned and contracted GHG-emitting resources are attributed to that LSE, regardless of whether those resources are used to serve that LSE's load. This method provides insights into the GHG emissions-related costs that are associated with an LSE's resource portfolio. Under a demand-based accounting framework, GHG emissions are attributed to each LSE based on the energy it uses to serve its load. This method provides insights into the GHG emissions associated with the resources necessary to match an LSE's load profile.

An important and related point is that GHG emissions estimates depend on the time variable used in the calculation. GHG emissions are often calculated on a "net annual basis," for example, by multiplying total energy (MWh) in a given year by an emissions factor (tons of carbon/MWh) to estimate tons of carbon associated with that energy for that year. An advantage of this approach is that the calculation is simple and straightforward, which is important for LSEs making long-term resource investment decisions when there is uncertainty about the magnitude and shape of its future load. On the other hand, this method may obscure the actual value of those resources to the system on an hourly basis, potentially allowing LSEs to claim "credit" for producing GHG-free energy during times of day when it is not needed. Similarly, it could allow LSEs to avoid being "charged" for GHG emissions associated with resources that are dispatched to support that LSE's load at times when the GHG-free energy is unavailable.

Indeed, evaluating LSE progress toward achieving GHG targets by calculating GHG emissions on an annual basis may incentivize an LSE to procure resources that generate more zero-emission electricity than it needs to serve its load, and then to credit any extra supply against the system power it plans to purchase at a different time of day. For example, if an LSE sells its oversupply of solar generation into the CAISO system during midday hours, but relies on market power during evening hours when there are more GHG emitting resources serving the system, the LSE may be able to report zero or near-zero GHG emissions for its portfolio on a net annual basis, despite the fact that it is consuming GHG-intensive power during some or many hours of the year.

The Clean Net Short Methodology

Staff recommends using a GHG accounting methodology in IRP that apportions GHG emissions to each LSE based on its projected hourly electricity demand. Staff believes that such a method would help ensure that the GHG emissions reported by an LSE more closely match the system emissions generated

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[2] As described in the ALJ ruling on the Proposed Reference System Plan issued September 19, 2017, staff proposed that LSEs use the ERRA accounting method to calculate the emissions of their IRP portfolios. The ERRA accounting method relies on simplifying assumptions about the emissions embedded in wholesale CAISO market purchases.

to serve that LSE's load, and that the emissions of all LSE plans in aggregate would be more comparable to the Reference System Plan adopted by the Commission.

As a starting point, staff proposes using a method called "clean net short" (CNS), which PG&E described in its comments filed on the CEC's AB 1110 Implementation Rulemaking.[3] Staff believes the CNS method is a reasonable starting point for approximating portfolio emissions because it more accurately depicts the emissions profile of the electricity an LSE delivers to its customers. Under the CNS method, each LSE would be assigned emissions associated with the system's dispatchable fossil generation based on how the LSE plans to rely on CAISO system power on an hourly basis in 2030. IRP is uniquely positioned to develop and apply such a method, as the hourly (8760) emissions intensity (tons/MWh) of fossil generation on the CAISO system can be estimated for the Reference System Portfolio developed using RESOLVE modeling.

The conceptual steps of the CNS method, as modified by CPUC staff, are as follows:

1. The LSE will subtract out any owned or contracted non-dispatchable 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 in 2030.
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, 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 "clean net short" (CNS) in each hour.
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 2030.
5. Finally, the emissions from all owned or contracted non-dispatchable GHG-emitting resources used to serve hourly load in step #1 will be computed using plant-specific emissions factors 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.

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[3] Docket Number 16-OIR-05.

Staff has estimated the average emissions intensity (tons/MWh) of fossil generation on the CAISO system associated with the Reference System Portfolio on an hourly basis in each of the RESOLVE study years (2018-2022-2026-2030). Average emissions factors are calculated as the sum of GHG emissions (MMT CO2) divided by the sum of generation (MWh). For the purposes of the CNS method, only dispatchable GHG-emitting resources[4] and unspecified imports are included in the average emissions factor calculation because GHG-free and non-dispatchable GHG-emitting resources are accounted for elsewhere.

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 calculator tool for LSEs to use in estimating the GHG emissions of their portfolios. The instructions for using this calculator are provided in the next section. Staff proposes that all LSEs filing Standard Plans as part of the IRP process be required to demonstrate use of the CNS method and calculator tool in accounting for GHG emissions in their portfolios. LSEs would be 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 GHG Calculator

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

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[4] 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.

1. **<u>Dashboard</u>**: This worksheet contains input tables that the LSE is to fill out (left) as well as the final CNS and emission results (right).
2. **<u>Assumptions</u>**: This worksheet contains information regarding key assumptions made in calculating the CNS, and explains the color-coding used for the worksheets.
3. **<u>Calculations</u>**: This worksheet contains the core hourly calculations for calculating the CNS, emissions, and curtailment.
4. **<u>Curtailment Heat Map</u>**: This worksheet displays month-hour heat maps of the average curtailment in the LSE's territory for each of the modeling years, based on the LSE's input on the Dashboard.
5. **<u>Renewable Profiles</u>**: This worksheet displays hourly renewable capacity factors for all the possible candidate resources that the LSE can choose from on the Dashboard. The capacity factor shapes are for one full year (8760 hours) and are based on 2007 weather. This worksheet is a **read-only input worksheet** that the user should not change.
6. **<u>Load Profiles</u>**: 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. This worksheet is a **read-only input worksheet** that the user should not change.
7. **<u>Emissions Factors</u>**: This worksheet displays the average emissions factors by month-hour and modeling period, as calculated for the Reference System Plan using the RESOLVE model. These emissions factors are used as an input to calculate the LSE's CNS emissions. This worksheet is a **read-only input worksheet** that the user should not change.
8. **<u>Hydro Dispatch</u>**: This worksheet displays the average large hydro dispatch 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. This worksheet is a **read-only input worksheet** that the user should not change.
9. **<u>Storage Dispatch</u>**: This worksheet displays the average storage dispatch (assuming 4-hour batteries) by month-hour and modeling period, as calculated for the Reference System Plan using the RESOLVE model. This storage dispatch pattern is applied to any storage that the LSE specifies on the Dashboard. This worksheet is a **read-only input worksheet** that the user should not change.
10. **<u>IEPR Form 1.1c</u>**: 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 input worksheet** that the user should not change.
11. **<u>IEPR CAISO Load Modifiers</u>**: This worksheet contains data from the 2017 IEPR and is used to calculate detailed demand inputs given an LSE's managed retail sales forecast. This worksheet is a **read-only input worksheet** that the user should not change.

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

1. On the Dashboard, input the LSE's load forecast on the Dashboard for each of the modeling years. There are two options for entering demand:
    a. Option A (simple): Enter the LSE's managed retail sales forecast on Row 11 of the Dashboard tab. Entering the managed retail sales forecast will automatically populate the detailed demand inputs in cells D19:G24 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. This option is best for LSEs that do not have information

on specific parts of their demand forecast, but know how their sales will change in the future. LSEs can refer to the "IEPR Form 1.1c" tab for LSE-specific managed retail sales forecast values from the 2017 IEPR.

b. Option B (detailed): Enter information on all of the LSE's demand components separately in cells D19:G24. In this case the managed retail sales forecast on Row 11 is not used. This option is best for LSEs that have projections of energy efficiency, behind the meter PV, electrification, etc. in their service territories. As noted in the Excel workbook, if an LSE chooses to input detailed values in the Detailed Demand Inputs section, all parts of the gray box (cells D19:G24) need to be filled in.

LSEs should exclude any load met by behind-the-meter CHP from their demand forecasts.[5] Any load met by CHP that is exported to the CAISO grid should be added to the line "Owned or contracted non-dispatchable GHG-emitting resources," as described in the next step.

2. 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.[6] 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).
3. On the Dashboard, input the LSE's owned or contracted renewable or GHG-free resources (current and planned) for each of the modeling years. Only resources that are delivered to California should be added here. Note that an LSE can input behind-the-meter PV generation in the Detailed Demand Inputs section in terms of energy (GWh), or in the Capacity Inputs section in terms of MW installed. If an LSE inputs the MW installed (row 54), row 24 should be updated to reflect the annual energy produced by that capacity of BTM PV.
4. On the Dashboard, input the LSE's owned or contracted energy storage resources (current and planned). The tool will use this user-specified capacity to scale the RESOLVE month-hour shape that is provided in the Storage Dispatch worksheet. Please note that this shape varies by modeling year.
5. Press F9 to recalculate the spreadsheet (calculations are set to "manual" in this spreadsheet).

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[5] 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. CPUC 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.

[6] 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.

6. On the Dashboard (right side), investigate the results, such as total emissions, average emission factor, and percentage of curtailment.
7. [optional] Investigate the curtailment heat map to gain intuition on overgeneration patterns.
8. [optional] Adjust inputs in the Dashboard to explore different resource and demand scenarios.

The CNS Method in Practice

There are important differences between what is considered "GHG-free" under the CNS methodology and what is considered "renewable" under the state's Renewables Portfolio Standard (RPS) compliance rules. Certain resources may be RPS-eligible but treated as GHG-emitting under CNS, whereas other GHG-free resources may not be RPS-eligible. For example, the Portfolio Content Category (PCC)-1 designation of an RPS resource is based on where and how the energy was generated, not whether it was used to serve load. Furthermore, certain GHG-free resources that are considered non-renewable, such as nuclear and hydroelectric, would be still be considered GHG-free under CNS provided they are delivered to a California balancing authority area. Indeed the RPS rules are not themselves entirely consistent with GHG policy under the state's Cap and Trade Program, as the two programs are designed to achieve different goals using different compliance rules and mechanisms.

The CNS method is intended to leverage the success of the RPS program and orient new investments toward achieving the state's long-term economy-wide GHG reduction goal of 80% below 1990 levels by 2050. The average hourly system power in 2030 reflects a resource mix that is significantly cleaner than today's resource mix, in large part due to the expected procurement of additional renewables to comply with RPS mandates. The CNS method 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.

(END OF ATTACHMENT A)