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Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (Filed March 22, 2012)

REPLY COMMENTS OF THE DIVISION OF RATEPAYER ADVOCATES ON THE 2012 LTPP PLANNING STANDARDS

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Pursuant to the *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* (Scoping Memo) filed on May 17, 2012, the Division of Ratepayer Advocates (DRA) submits these reply comments on Track II of the Long Term Procurement Plan (LTPP) Standard Planning Assumptions (Assumptions) presented in the *2012 Energy Division Straw Proposal on LTPP Planning Standards* (Straw Proposal) issued on May 10, 2012.

I. INTRODUCTION

DRA used Energy Division's template and numbering system in preparing these comments, omitting those sections on which it has no reply comments. DRA's recommendations for changes or clarifications to the Straw Proposal are the following:

- Planning for years 11-20 should be eliminated;
- There should be further opportunity for comment on the Assumptions once final forecasts are released;
- Guiding principles should consider the impact of demand-side resources;
- The Commission should include savings for incremental energy efficiency (EE) in the "low" and "mid" scenarios, not just the "high" case scenarios;
- In order to properly account for Non-Event Based demand response (DR), the Assumptions should include Time-of-Use rate forecasts for Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric Company (SDG&E)[1] and SCE's Real Time Pricing, as well as Permanent Load Shifting amounts adopted for 2014 and further adjusted for potential increases through 2022;
- Assumptions should account for anticipated Commission decisions and Legislative measures that will increase the amount of behind-the-meter distributed generation;
- Until the Commission conclusively decides how best to treat energy storage resources, storage should be treated on the demand-side of the equation as a reduction in need;

[1] DRA's reply comments refer collectively to PG&E, SCE and SDG&E as Utilities.

- Event-Based DR should include DRA's recommended PG&E's peak-time rebate amounts, and the "high" scenario should be 20% higher than the "mid" scenario;
- The definition of deliverability should be broadened to encompass more renewable projects;
- The Commission should use a 10-year planning horizon and 33% RPS in the 2012 LTPP;
- The Commission should adopt two planning scenarios, the base case and High DG case;
- The once-through cooling (OTC) assumptions are overly conservative and should be adjusted to account for known and reasonably likely replacements;
- DRA supports the proposed EE allocation methodology as a reasonable first step that should be further refined;
- DRA recommends the Commission defer adoption of any DR allocation methodology until these important issues are properly analyzed and addressed, preferably in a workshop setting;
- DRA supports the proposed methodology for calculating greenhouse gas (GHG) prices with the opportunity for parties to review the reasonableness of those GHG prices as more robust market data becomes available; and
- GHG implications of long-term resource procurement decisions must be a primary consideration in LTPP.

II. DISCUSSION

A. General -- Further Comments are Necessary Once Final Forecasts are Released

DRA noted that planning Assumptions developed before final forecasts and data on which the Assumptions rely are available will be less robust and reliable than Assumptions informed by complete information.[2] Other parties voiced similar concerns. For example, PG&E states "it is premature to debate and adopt planning assumptions before considering

[2] Comments of the Division Of Ratepayer Advocates on The 2012 LTPP Planning Standards, May 31, 2012 (DRA Comments), p. 1.

renewable integration issues" and recommends adopting Assumptions after stakeholder input and "after understanding the analysis that will be used to estimate need for flexible capacity."[3] NRDC/Vote Solar note that the California Energy Commission's (CEC's) incremental energy efficiency (EE) forecast is not yet released, and urges "the Commission to provide stakeholders an opportunity to meaningfully comment on efficiency assumptions at the 'scenario stage' of this proceeding."[4] The EE forecast should be released in late June, and parties should have an opportunity to comment two weeks after that release.

In order to develop the most dependable and accurate Assumptions the Commission should allow parties the opportunity to further comment on refining the Assumptions once final forecasts and data are available.

1. Guiding Principles

a) Guiding Principles Should Consider the Importance of Demand-Side Resources

NRDC/Vote Solar urge the Commission to consider the "priority of energy efficiency and demand-side resources in this Commission's Energy Action Plan and the loading order."[5] California Environmental Justice Alliance (CEJA) agrees, pointing to the Commission's recent demand response decision and the latest clarification of the loading order, stating that:

> "The planning standards must take into account what impacts these types of [Commission] actions will have on demand response and energy efficiency programs. It is likely that both of these resources will increase due to these actions. Failure to consider these recent developments would result in undercounting these resources."[6]

[3] Comments of Pacific Gas and Electric Company on the May 10, 2012, Energy Division Standardized Planning Assumptions Proposal, May 31, 2012 (PG&E Comments), pp. 1-2.

[4] Comments of the Natural Resources Defense Council (NRDC) and the Vote Solar Initiative (Vote Solar) on the 2012 Energy Division Straw Proposal on LTPP Planning Standards, May 31, 2012 (NRDC/Vote Solar Comments) p. 6.

[5] NRDC/Vote Solar Comments, p. 4.

[6] California Environmental Justice Alliance's Comments on the Energy Division Straw Proposal, May 31, 2012 (CEJA Comments), pp. 4-5. *See also* Comments Of EnerNoc, Inc., on Energy Division's LTPP Standard Planning Assumptions Straw Proposal, May 31, 2012 (EnerNOC Comments), p. 9; Comments of Sierra Club California on the 2012 Energy Division Straw Proposal on LTPP Planning Standards, May 31, 2012 (Sierra Club Comments), pp. 1-2.

NRDC/Vote Solar recommend revising the first two proposed "problem statements"[7] in the Straw Proposal as follows:

Problem Statement 1: "What new resources ~~infrastructure~~ needs~~s~~ to be authorized ~~constructed~~ to ensure that customers' receive reliable and cost-effective energy services that meet the State's environmental goals ~~adequate reliability, both for local areas and the system generally,~~ during the planning horizon."

Problem Statement 2: "What mix of resources ~~infrastructure~~ minimizes cost, risk, and environmental impacts to customers over the planning horizon?"[8]

DRA agrees with these proposed revisions. The Commission should first look to new or anticipated demand-side resources to ensure adequate reliability, rather than assuming that new infrastructure is necessary. Such an approach is consistent with California's loading order, and would allow ratepayers to reap the benefits of their investments in demand side programs designed to reduce load.

Only by planning to incorporate the benefits of demand-side programs will the benefits be realized. DRA recommends that the Commission adopt the recommendations of NRDC/Vote Solar to revise the two problem statements. This would encourage collaboration between the Commission and the California Independent System Operator (CAISO) on how to direct demand-side programs most effectively so that they will yield savings that are reliable for planning and load reduction purposes.

2. Planning Area and Planning Period

PG&E expresses doubts about the value of a 20-year planning period. PG&E instead supports a ten-year planning period, pointing out that the "[e]stimates that could be provided for the second ten years would be of limited value given that uncertainty grows with time with respect to supply assumptions and the transmission expansion options" and that "it is time consuming to extend the analysis beyond ten years even with generic assumptions."[9] DRA recommends the Commission limit the planning period to ten years.

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[7] The Energy Division Straw Proposal states that "[s]cenarios should be developed to answer the following questions," and defines those questions as problem statements. Straw Proposal, p. vi.

[8] NRDC/Vote Solar Comments, p. 5.

[9] PG&E Comments, Appendix A, p. 2.

SCE points out that the planning period should be 2014-2023, because "2013 is the year that the analysis will be conducted and, therefore, should not be the first year of the study" and that 2023 should be part of the planning period, since it is the first full year after the licenses for San Onofre Nuclear Generating Station ends as well as the year when most of the once-through cooling (OTC) plants must be in compliance.[10] DRA agrees that SCE's suggested revisions to the planning period are more likely to produce dependable Assumptions.

B. Demand-Side Assumptions

5. Incremental Energy Efficiency

NRDC/Vote Solar state that "the methodology outlined in the ED Proposal already undervalues future efficiency and should be revised to include all reasonably-likely-to-occur and cost-effective energy efficiency in the 'Mid Case.'"[11] DRA agrees, and made a similar recommendation in its opening comments.[12] The Commission should ensure that currently excluded savings should be accounted for in the "low" and "mid" case scenarios, not just the "high" case scenarios.

6. Non Event-Based Demand Response

DRA has identified certain inconsistencies in the 2011 Demand Response Load Impact reports filed by PG&E, Southern California Edison Company (SCE) and SDG&E on June 1, 2012, as well as a failure to reflect recent Commission guidance on Permanent Load Shifting. The proposed standard planning assumptions in the Energy Division's Straw Proposal would use the Load Impact reports for Event-Based Demand Response and the California Energy Demand (CED) forecast for Non-Event Based DR. PG&E's Load Impact reports count Permanent Load Shifting and Time-of-Use (TOU) rates as Non-Event based DR. SCE's Load Impact reports do not provide Permanent Load Shifting forecasts, but count Real Time Pricing as Non-Event Based DR. SDG&E's Load Impact Reports provide Permanent Load Shifting forecasts but do not provide TOU rates forecasts.

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[10] Opening Comments of Southern California Edison Company on the Standardized Planning Assumptions, May 31, 2012 (SCE Comments), p. 4.

[11] NRDC/Vote Solar Comments, p. 7.

[12] DRA Comments, pp. 6-7.

The CED forecast is not finalized and it its unclear whether it will include Permanent Load Shifting, Real Time Pricing, and TOU rates. The Commission in D.12-04-045 authorized a total of 53 MW for Permanent Load Shifting through 2014 for the three Utilities.[13] DRA's estimate for Non-Event Based DR includes only Permanent Load Shifting and does not account for TOU rates and Real Time Pricing.[14] PG&E forecasts 175 MW for TOU and 3 MW for Permanent Load Shifting in 2022.[15] For 2021, SDG&E does not provide TOU rates forecasts and provides 5 MW for Permanent Load Shifting.[16] For 2022, SCE forecasts 10 MW for Real Time Pricing and does not provide a forecast for Permanent Load Shifting.[17] It appears that the three Utilities' Load Impact forecasts for Permanent Loading Shifting do not reflect the funding authorized in D.12-04-045 for Permanent Load Shifting, which calls for 53 MW load impact for all three IOUs' Permanent Load Shifting programs in 2014.[18]

In order to properly account for Non-Event Based DR, DRA recommends that the Assumptions include TOU rates forecasts for the three IOUs and SCE's Real Time Pricing in addition to the 53 MW for Permanent Load Shifting in 2014, authorized in D.12-04-045, and further adjusted for potential increases through 2022.

[13] D.12-04-045, pp. 243-244 (mimeo).

[14] DRA Comments, p. 8.

[15] Executive Summary: 2010-2022 Demand Response Portfolio of Pacific Gas and Electric Company, p. 22.

[16] San Diego Gas & Electric Company's (U 902 M) Executive Summary and Summary Tables Pursuant to Decision 10-04-006, p. 56 (mimeo).

[17] Southern California Edison's 2011 Demand Response Load Impact Evaluations Portfolio Summary, p. 45.

[18] D.12-04-045, p. 243.

Table 1: Summary of Non-Event Based DR including Permanent Load Shifting, TOU rates and SCE's Real Time Pricing

IOU	Permanent Load Shifting in 2014 (to be adjusted for potential increases through 2022)	TOU rates in 2022	Real Time Pricing in 2012
PG&E	29 MW	175 MW	N/A
SCE	19 MW	TBD	10 MW
SDG&E	5 MW	TBD	N/A
Total	53 MW	175 MW + TBD	10 MW

7. Incremental Small Photovoltaics

DRA reiterates that the Assumptions should account for anticipated Commission decisions and Legislative measures that will increase the amount of behind-the-meter distributed generation beyond what is reflected in the CEC's load forecast. Similarly, Sierra Club and NRDC/Vote Solar[19] both refer to the Solar Energy Industry Association's report showing estimates that distributed solar generation capacity will reach 5,300 MW by 2016. NRDC rightly points out that the California Solar Initiative (CSI) program is not the sole driver of growth in demand-side PV. According to the most recent CSI progress report,[20] approximately 59% of the customers receiving service on a net energy metering tariff received CSI incentives, which suggests that the remainder found solar PV a worthy investment without CSI rebates. This is a strong indication that small PV installations will persist in the absence of CSI incentives, and should be accounted for in estimating incremental small PV for the Assumptions. DRA recommends the Commission increase the amount of assumed customer-side solar PV by 1400-5250 MW as proposed in DRA's opening comments.[21]

11. Other Comments on Demand-Side Assumptions

The Interstate Renewable Energy Council (IREC) notes that "[s]ince there is currently no counting methodology to establish and NQC [net qualifying capacity] for storage resources, storage capacity will be ignored in this proceeding unless it is treated as a demand-side

[19] Sierra Club Comments, pp. 8-9. NRDC/VoteSolar Comments, pp. 7-8.

[20] California Solar Initiative Progress Report, 2011 Annual Data Annex, Table 4, p. 24.

[21] DRA Comments, p. 9.

resource."[22] IREC proposes inclusion of the following language in the demand-side assumptions:

> "Staff recognizes that the development of a robust fleet of energy storage facilities is one of the Commission's resource policy goals. However, the lack of an anticipated procurement level for such resources makes it difficult to determine a realistic assumption of the number of MWs of storage that will be developed over the planning period. The absence of estimated energy storage procurement numbers from these Planning Standards should not be interpreted as a statement regarding the future make-up of California's resource fleet. Further, as a default, energy storage will be considered a demand side resource in this proceeding because the Commission has not yet developed a methodology to determine the NQC for storage facilities. However, to the extent the LTPP identifies a given renewable resource, which will be coupled with storage so as to provide firm load-following capacity over a period of hours during the day, that resource will be treated as a supply-side resource with an NQC commensurate with its ability to provide firm, load-following energy."[23]

DRA agrees with IREC's suggestions, but does not support establishing specific storage targets at this time. Energy storage is an important consideration in considering need and planning for procurement, and should not be ignored. Until the Commission conclusively decides how best to treat energy storage resources, storage should be treated on the demand-side of the equation as a reduction in need. DRA recommends the Commission adopt the language above as expressing intent about planning for storage, and consider estimating forecasts for storage in the next LTPP.

C. Supply-Side Assumptions

16. Deliverability

DRA disagrees with the Straw Proposal's definition of deliverability, which is overly conservative for renewable resources. The Straw Proposal defines deliverable resources as those that "fit on existing or CPUC approved transmission" or "are baseload or flexible resources."[24]

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[22] Comments of the Interstate Renewable Energy Council, Inc. on 2012 Energy Division Straw Proposal on LTPP Planning Standards, May 31, 2012 (IREC Comments), p. 11.

[23] IREC Comments, pp. 11-12.

[24] Straw Proposal, p. xvi.

Multiple parties[25] oppose this definition. DRA agrees that renewable resources should be assumed to be fully deliverable to prevent undercounting of the capacity these resources contribute to the Utilities' Resource Adequacy (RA) requirements. Most renewable projects seek full deliverability capability, and the CAISO has initiated a process to account for the deliverability of smaller peaking distributed generation projects, so the Commission should not underestimate the capacity these projects can provide. The Commission should thus modify the Straw Proposal's definition of deliverability to account for those renewable resources that are pending and will provide future capacity.

18. Event-Based Demand Response

As DRA stated in its opening comments, the Straw Proposal specifically indicates that savings from PG&E's Peak Time Rebate program should be included in Event-Based demand response (DR).[26] However, PG&E argues that because it does not currently have a Peak Time Rebate program, since it is currently being litigated in PG&E's Application (A.) 10-02-028,[27] the LTPP should recognize the risk of assuming any savings associated with the program.[28] PG&E proposes using the Peak Time Rebate assumptions adopted in the SmartMeter Upgrade Decision (D.09-03-026), to evaluate the "high" scenario in the Straw Proposal.[29] For the "mid" scenario in the Straw Proposal, PG&E proposes to use the Peak Time Rebate values included as Exhibit PGE-18 (PGE-18) during the Commission proceeding in A.10-020-028.[30] For the "low" scenario in the Straw Proposal, PG&E proposes the assumption that the Commission will not implement any Peak Time Rebate.[31]

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[25] Comments of Pathfinder Renewable Wind Energy LLC and Zephyr Power Transmission LLC on 2012 Energy Division Straw Proposal on Planning Standards, May 31, 2012 (Pathfinder Renewable Wind Energy/Zephyr Power Transmission Comments), p. 8; Comments of PG&E, p. 8; Sierra Club Comments, p.13; Comments of the Large-Scale Solar Association ("LSA") on the Energy Division Straw Proposal on Standardized Planning Standards, May 31, 2012, p. 7; Comments of San Diego Gas & Electric Company Regarding Energy Division Straw Proposal on 2012 LTPP Planning Standards May 31, 2012 (SDG&E Comments), p. 9.

[26] DRA Comments, p. 10.

[27] PG&E's 2010 Rate Design Window Proceeding.

[28] PG&E Comments, p. 9.

[29] PG&E's Comments, pp. 9-10.

[30] PG&E's Comments, p. 10.

[31] PG&E's Comments, p. 10

PG&E's arguments are unreasonable, since PG&E justified the expenditures it requested in its SmartMeter Upgrade application based, in large part, on the expected annual Peak Time Rebate savings of approximately 260 MW per year through 2030.[32] This amount was determined after much deliberation in a lengthy and exhaustive proceeding.

PG&E now recommends a much lower estimate of Peak Time Rebate savings based on the new data on Peak Time Rebate performance it included as PG&E-18 in the A.10-02-028 PG&E's 2010 Rate Design Window proceeding. DRA notes that PG&E introduced PG&E-18 at the very end of hearings in that proceeding, and the exhibit was not in testimony or subject to discovery and cross examination. Further, PG&E admitted that the Peak Time Rebate estimates included in PG&E-18 are fraught with uncertainty.[33] PG&E argues for using lower Peak Time Rebate savings based on some recent pilot studies by SDG&E in 2011.[34] However, the Peak Time Rebate savings assumed in the SmartMeter Upgrade are envisioned to be achieved over the long horizon of LTPP.

The Commission should assume that PG&E will achieve these Peak Time Rebate savings the Commission accepted when approving the Smart Meter Upgrade application, because those benefits provided the basis for approving ratepayer funding. If the savings are not included in LTPP planning, ratepayers may need to pay for both the funding approved in PG&E's SmartMeter Upgrade application as well as the costs of additional unnecessary procurement. Moreover, the Energy Action Plan II, places DR near the top of the loading order for procurement of resources.[35] The Commission should therefore include the full amount of Peak Time Rebate savings assumed in justifying PG&E's SmartMeter Upgrade request, in <u>all</u> of its scenarios in the Straw Proposal and not just in the "high" scenario as PG&E recommends.

SDG&E supports the use of Load Impacts from the June 1, 2012 reports to estimate savings from event-based DR. SDG&E, however, argues that the "high" DR scenario should be higher than the "mid" scenario by 20% rather than the 10% assumed in the Straw Proposal. Similarly, SDG&E argues that the "low" DR scenario should be lower than the "mid" scenario

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[32] PG&E's Comments, p. 11, footnote 11.

[33] PG&E 2010 RDW, A.10-02-028, Exh. PG&E-18, p. 2.

[34] PG&E Comments, p. 10.

[35] Energy Action Plan II, p. 2. *See* http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF

by 20% rather than the 10% assumed in the Straw Proposal. SDG&E proposes this change because it contends that the 10% does not reflect the uncertainty in long-term DR forecasting and policy changes in the DR area.

DRA agrees that much uncertainty remains with long-term DR forecasting, but disagrees with SDG&E's recommendations to decrease savings in the "low" scenario by 20% rather than the 10% assumed in the Straw Proposal. Much of the long-term DR forecasting uncertainty has resulted in underestimating DR in the Energy Division's Straw Proposal. As noted in DRA's opening comments savings, from AMI-enabled DR such as Peak Time Rebate, Home Area Network (HAN) based Automated Demand Response (ADR), and potential DR through the expected market penetration of readily available HAN-related devices remain unaccounted for in the Straw Proposal.[36] In addition, as EnerNOC points out in its comments, the Straw Proposal ignores increased DR as a result of Smart Grid Investments, Renewable Integration needs, and integration of DR in the CAISO's wholesale markets.[37]

Additionally, CEJA correctly observes that the Commission had been concerned that the Utilities were filling their net short positions with conventional resources, rather than preferred resources and has directed the Utilities to procure additional EE and DR.[38] Therefore, DRA agrees with SDG&E that the "high" demand response scenario should be higher than the "mid" scenario in the Straw Proposal by 20%. However, DRA does not agree with SDG&E that the "low" demand response scenario should be lower than the "mid" scenario by 20% compared to the 10% assumed in the Straw Proposal.

20. Renewable Resources

a) High DG Portfolio

In its opening comments, SCE states that it does not support the inclusion of multiple renewable portfolios to examine how the need for flexible resources fluctuates across a variety of future scenarios.[39] Instead, SCE argues that only a base case portfolio for renewables should be

[36] DRA Comments, p. 11.

[37] EnerNOC Comments, pp. 5-6. Also, see Appendix A, p. 7.

[38] CEJA Comments, pp. 4-5.

[39] SCE Comments, pp. 2-3.

considered, "with the possible exception of a High Distributed Generation (DG) Portfolio."[40] DRA agrees that multiple renewable portfolios are probably not necessary and neither is the environmental sensitivity.

DRA supports including within the Straw Proposal a High DG Portfolio for the renewable net short to accommodate the Base Case Portfolio. The High DG Portfolio is useful for two reasons. First, this scenario is completely plausible given the expansion of customer and utility side distributed generation programs and the State's momentum towards a 12,000 MW by 2020 DG goal. Stakeholders, including DRA, have been involved in mapping out a path to attain the Governor's 12,000 MW of DG goal in a cost-effective manner. Secondly, the downward photovoltaics (PV) cost projections make distributed generation a cost-effective path towards filing the renewable net short for a 33% RPS.

b) Long-Term target

DRA reiterates that the Commission should stick to modeling only two 10-year planning portfolios for the 2012 LTPP; the Base Case and High DG Portfolios proposed. In the May 10, 2012 *Energy Division Straw Proposal on LTPP Planning Standards*, ED staff proposed to model two 10-year portfolios at a 33% Renewables Portfolio Standard (RPS) target and an additional 20-year forward study with a linear progression to a 40% RPS by 2030.[41] Due to time-constraints and resource uncertainties, planning beyond a 10-year time frame should only be done under limited circumstances, such as an examination of once-through cooling (OTC) plant retirement or transmission planning. With that, the Commission should disregard proposals to consider an RPS target of 55% or higher as suggested by Sierra Club and supported NRDC/Vote Solar in their opening comments.[42] Sierra Club claims that a 40% RPS is "far too low" and thus the Commission should, at a minimum, examine a 55% RPS target for 2030.[43] This is an extreme and unrealistic assumption to be modeling for in the 2012 LTPP and should be rejected. As DRA stated in opening comments, a linear progression to a 40% RPS by 2030

[40] SCE Comments, p. 3.

[41] Straw Proposal, p. 20.

[42] Sierra Club Comments, p. 15; NRDC/Vote Solar Comments, p. 9; Pathfinder Renewable Wind Energy LLC and Zephyr Power Transmission LLC also support the consideration of a RPS target above 40% but do not include a percentage target amount. Pathfinder and Zephyr Opening Comments, p. 11.

[43] Sierra Club Comments, p. 15.

appears reasonable if the Commission elects to move forward with the proposed 20-year LTPP outlook. However, DRA does not consider this scenario to be critical for planning purposes in the 2012 LTPP and does not recommend that the Commission include a scenario for an RPS that is above 40% in the next 20 years. Instead, the Commission should be more concerned with the operational impacts of renewables on the grid, the results of the renewable integration modeling exercise, and the rate impact of a 20% and 33% RPS before contemplating an increase to the RPS target.

21. Retirements -- Once-Through Cooled Power Plant Assumptions Are Overly Conservative

Similar to DRA, CEJA expressed concerns about overly conservative OTC retirement assumptions, stating that the Commission should avoid overestimating the amount of OTC retirement which needs to be replaced.[44] However, PG&E, Independent Energy Producers Association (IEP), SDG&E, and GenOn appear to equate the uncertainty associated with Track 2 compliance with zero successfully retrofitted capacity. They all propose a mid-retirement scenario similar to the high retirement scenario, which assumes OTC plants in Track 2 compliance will retire by the compliance date, or otherwise more conservative mid and/or high retirement scenarios.[45] DRA disagrees with the conclusions of PG&E, IEP, and GenOn. While there is uncertainty associated with Track 2 compliance, a scenario in which all OTC is retired is more appropriate for a high level of retirement, not a moderate level of retirement. Given the likelihood that some of the OTC plants will successfully retrofit capacity, making both "high" and "mid" scenarios identical for OTC reduces the value of having different scenarios

Even at a high level of OTC retirement, it is unreasonable to assume a zero rate of success. As discussed in opening comments, one can safely assume that the generation owners who have filed for Track 2 compliance are best able to determine the financial viability and likelihood of successful Track 2 compliance, and would not have attempted Track 2 compliance

[44] CEJA Comments, pp. 6-8.

[45] PG&E Comments, p. 12; Comments of the Independent Energy Producers Association on the Planning Standards Straw Proposal, May 31, 2012 (IEP Comments), p. 3; SDG&E Comments, pp. 14-15; Comments of GenOn Energy, Inc. on Energy Division's Planning Standards Straw Proposal, May 31, 2012 (GenOn Comments), pp. 2-3.

without a reasonable level of both.[46] In the high retirement scenario, the factors (study progress, technology chosen, permitting, construction, etc.) affecting the probability of success should be weighted and calculated, similar to what the Utilities do in their RPS procurement plan,[47] providing probability-weighed amount of MW for each plant. Although the amount of replacement capacity required may not be significantly reduced with a low probability of success for Track 2 compliance, DRA believes such a calculation would more accurately reflect a high retirement- as opposed to total retirement- OTC scenario.

Further, in adopting Assumptions, the Commission should consider that even if OTC plants are retired, the same MW of generating capacity may not be needed to replace them. DRA recommends that the Commission consider non-generation resources- such as transmission upgrades, renewable energy, peak demand programs, and energy efficiency- particularly if those resources can replace peak OTC generation at a lower cost. For example, the CEC estimates a new 600 MW gas fired plant as costing $720-900 million, compared to "as little as $135 million in in-state transmission upgrades."[48]

Finally, SDG&E claimed that "the Commission adopted rules that discourage the IOUs from relying on units subject to the OTC regulation for the final two years prior to their compliance dates."[49] SDG&E was presumably referring to section of D.12-04-046 which states if a "power purchase agreement terminates one year [or] less prior to the applicable SWRCB [State Water Resources Control Board] compliance deadline, that agreement must be submitted to the Commission for approval via a Tier 3 advice letter."[50] However, the procurement rules referenced do not mean that the Utilities *cannot* rely on units subject to OTC regulation; they merely establish the required regulatory filings for seeking necessary Commission approval. The previously adopted procurement rules certainly do not indicate that *all* OTC plants should be considered retired for planning purposes. In fact, SDG&E states that "for OTC units in load

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[46] DRA Comments, p. 15.

[47] Such as http://docs.cpuc.ca.gov/efile/RESP/167812.pdf, p. 1

[48] CEJA Comments, p. 7, citing California Ocean Protection Council & State Water Resources Control Board, *Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California* (ICF Jones & Stokes, April 2008).

[49] SDG&E Comments, pp. 14-15.

[50] D.12-04-046, p. 25.

pocket, the IOU may be required to rely on such OTC units until replacement units are developed and built."[51] This indicates that, contrary to SDG&E's proposal to retire "all units two years prior to the retirement date" in a high retirement case, the Commission should consider that at least some OTC will remain online.

D. Allocation Methodology

25. Energy Efficiency

DRA continues to support the concept of allocating energy efficiency (EE) savings by busbar locations and further urges the Commission to use the findings of this proceeding with regard to both system and local capacity requirements to direct the allocation of resources from demand side programs like EE.

PG&E opposes application of savings from EE resources in the determination of transmission and distribution (T&D) resources needs, noting the uncertainty in nodal distribution of energy savings.[52] However, in the EE proceeding, R.09-11-014, PG&E supports recent updates to the T&D EE avoided cost calculator "until better locational and time dependent EE related T&D avoided cost estimates can be developed."[53] SCE similarly opposes the use of the Straw Proposal's recommendation to include energy efficiency in the LCR analysis, citing timing issues and that the LCR analysis has already been conducted by the CAISO.[54] However, ratepayer-funded EE savings are offsetting T&D requirements and Utilities are being credited for this offset in their avoided cost methodologies as well as receiving ratepayer-funded bonuses based, at least in part, on these offsets. While these savings are not traditionally considered in the CAISO's T&D planning studies, they alleviate some of the need for the infrastructure. There

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[51] SDG&E Comments, p. 15.

[52] "PG&E… does not see the need to allocate EE and DR impacts for Track 2 analysis given that the purpose of the Track 2 analysis is to determine CAISO system-wide need for resources, and given that the models that are going to be used in the analysis do not represent loads and resource by nodes or constraint areas." And further, "PG&E also has concerns over the allocation of incremental EE and DR load impacts given the somewhat arbitrary methodology used to allocate load impacts, and the uncertainty that this creates on the resources that are likely to be available in a particular node or congestion area." PG&E Comments, p. 14.

[53] PG&E Opening Comments on ALJ Ruling on Updates and Adjustments to Energy Efficiency Avoided Cost Inputs and Methodologies, R.09-11-014, October 27, 2011, p. 3. (available at http://docs.cpuc.ca.gov/efile/CM/146923.pdf.)

[54] SCE Comments, p. 13.

is a gap here that unfairly tips the direction of the benefits to Utilities and needlessly adds costs to ratepayers. EnerNOC correctly points that:

> "It is vitally important that the assumptions used for demand-side resources, and other technologies, are consistent with Commission policies, especially the loading order. To do otherwise would result in planning that is inconsistent with stated Commission policy, thereby undermining those very policies, creating inefficient, duplicative investments, and placing unnecessary burdens on ratepayers."[55]

DRA agrees with SCE that the Allocation Methodology in the Straw Proposal may be inadequate, as "there are varying levels of EE measure adoption at the customer level."[56] Nevertheless, DRA shares the City and County of San Francisco's (CCSF's) concern over the CAISO's complete exclusion of uncommitted EE savings in its transmission study models.[57] The "uncertainty" of the nodal distribution of energy efficiency savings that PG&E and SCE note is not only a problem for determining the adequacy of local capacity resources, but also a problem in adding unnecessary costs to ratepayers. The proposed methodology, while needing refinement, serves as a useful starting point for incorporating incremental EE into the CAISO transmission studies.

DRA recommends that the Commission adopt SCE's suggestion to develop targeted EE programs that address the system and local capacity requirements found in this LTPP proceeding and to require cost effectiveness evaluations that value these savings' ability to meet the identified need (to the extent possible).[58] Further, SCE's suggestion that "the California Energy Agencies in conjunction with the IOUs initiate a long-term approach that will increase forecast accuracy at the busbar"[59] is consistent with DRA's recommendation in opening comments that these agencies *and* the Utilities determine a method to better incorporate incremental EE into the CAISO transmission studies. DRA continues to encourage the Commission to use the scheduled EE June 26th workshop to this end.[60]

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[55] EnerNOC Comments, p. 3.

[56] SCE Comments, p. 15.

[57] Comments of the City and County of San Francisco, May 31, 2012 (CCSF Comments), p. 3.

[58] SCE Comments, pp. 13 and 14.

[59] SCE Comments, p. 14.

[60] DRA Comments, p. 16.

Finally, DRA disagrees with PG&E's concerns that the use of incremental EE impacts in the Straw Proposal "is not consistent with CAISO's planning criteria for transmission studies."[61] The Straw Proposal provides a new process where a process did not exist to acknowledge the contribution of EE in partially fulfilling LCR. The response that this new process is not consistent with CAISO's planning criteria is irrelevant. It is the nature of "new" approaches that they are a departure from the way things were done in the past. That the straw proposal is not consistent with past processes has little bearing on whether it is useful or appropriate for LCR determinations.

26. Demand-Response

Both PG&E and SCE express a number of concerns about the methodology presented in the Straw Proposal to allocate EE and DR impacts to individual load buses. It is unclear whether allocating DR impacts to specific buses, using the proposed methodology, is more accurate than the current method of distributing DR impacts uniformly across all buses.[62] DRA recommends the Commission defer adoption of any DR allocation methodology until these important issues are properly analyzed and addressed, preferably in a workshop setting.

E. Other

29. Any Other Comments

a) DRA Supports the Proposed Methodology for Calculating GHG Prices with the opportunity for parties to review the reasonableness of those GHG prices as more robust market data becomes available

The Straw Proposal states that the Market Price Referent (MPR) model should be used for calculating greenhouse gas (GHG) prices. SCE expresses concern regarding the 2011 MPR methodology, which calculates an implied price for GHG through 2015 based on forward natural gas and electricity prices (i.e. changes in the implied market heat rate).[63] SCE points out that this methodology has limitations, because in reality the implied market heat rate changes could be

[61] PG&E Comments, p. 14.

[62] DRA Comments, p. 16.

[63] Resolution E-4442, p. 10.

due to factors other than just the presence of GHG regulation.[64] DRA supports the use of the 2011 MPR methodology for calculating GHG prices in the 2012 LTPP, but agrees with SCE that there are limitations to this approach. Therefore, DRA supports SCE's recommendation to allow parties to closely examine and determine the reasonableness of the estimated GHG values applying the 2011 MPR methodology.

DRA also supports allowing parties to develop and propose alternative GHG values, for instance if in the future of this proceeding there is more robust GHG trading data publicly available to base GHG prices on. As noted previously, DRA and other parties have recommended that there be an opportunity to further comment on the Assumptions when final forecasts and data are available. If more robust GHG data is available at that time, parties should have the opportunity to comment further on the reasonableness of using GHG assumptions based on MPR methodology. If not, the use of the 2011 MPR methodology for calculating GHG prices should be re-evaluated in the next LTPP cycle.

DRA disagrees with PG&E's proposal to alter the MPR methodology for the years 2021-2030 by only increasing GHG prices by the rate of inflation rather than inflation plus 5%.[65] The 2011 MPR methodology calculates GHG prices from 2016-2030 by escalating each year's GHG price using a rate of 5% plus inflation.[66] This is consistent with the annual increase of the floor price for allowances under the Air Resources Board's (ARB's) Cap-and-Trade Regulation. DRA does not support a 20- year planning horizon. However, if the Commission adopts such horizon, the 2011 MPR methodology should be used for planning years 2013-2030, with the same provisions described above regarding opportunity for party input.

Additionally, while PG&E acknowledges that it expects there will either be a different cap-and-trade program or a different method for pricing GHG emissions in California past 2020,[67] it does not recognize that California's long-term GHG reduction goals (i.e. an 80 percent reduction of GHG by 2050 per Executive Order S-3-05) are increasingly aggressive, and therefore it is unlikely that GHG prices in California will increase at a lower rate after 2020 than

[64] SCE Comments, p. 18.

[65] PG&E Comments, Appendix A, p. 15.

[66] Resolution E-4442, p. 12.

[67] PG&E Comments, Appendix A, p. 15.

prior to 2020. PG&E provides no basis for its reasoning, and the recommendation should not be adopted.

b) GHG Implications of Long-Term Resource Procurement Decisions Must be a Primary Consideration

DRA supports Sierra Club and CEJA's recommendation that the GHG implications of resource procurement decisions must be a primary consideration of long-term planning.[68] CEJA points out that although GHG considerations are related to reliability and cost considerations, GHG implications need to be separately examined to allow decision-makers to make well-informed resource decisions that move California towards its AB 32 goal.[69] DRA agrees with CEJA that the 2012 LTPP must consider the long-term need to reduce GHG emissions, and encourages the Commission to adopt at least one planning scenario that focuses on cost-effective strategies to reduce GHG emissions. This could include a scenario in which maximum levels of EE and DR are achieved and all future resource additions (including flexibility requirements) are met with zero-emitting resources, including energy storage. DRA also agrees with Sierra Club that if the CPUC decides to use a 20-year planning horizon for the 2012 LTPP, the long-term planning assumptions should include a linear reduction of GHG based on Executive Order S-3-05, which requires an 80% reduction of GHGs by 2050.[70]

III. CONCLUSION

DRA respectfully requests that the Commission revise the planning Assumptions as recommended in DRA's opening and reply comments.

[68] Sierra Club Comments, 2012, p. 6; CEJA Comments, p. 4.

[69] CEJA Comments, p. 4.

[70] Sierra Club Comments, 2012, p. 6.

Respectfully submitted,

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