BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

THE DIVISION OF RATEPAYER ADVOCATES' REPLY COMMENTS TO THE ASSIGNED COMMISSIONER'S RULING SETTING FORTH STANDARDIZED PLANNING SCENARIOS FOR COMMENT

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I. INTRODUCTION

Pursuant to the September 20, 2012, Assigned Commissioner's Ruling Setting Forth Standardized Planning Scenarios for Comment (ACR), the Division of Ratepayer Advocates (DRA) submits these reply comments in response to parties' opening comments on the Standardized Planning Scenarios for Track II of the long-term procurement planning (LTPP) proceeding. DRA's reply comments recommend revisions to the four proposed scenarios that are designed to improve the accuracy of the modeling efforts and to ensure that resources in the loading order are properly accounted for in this modeling exercise.

II. RECOMMENDATIONS

Based on DRA's own analysis and parties' opening comments on the various planning assumptions, the Commission should revise the planning assumptions as follows:

1. Energy Efficiency (EE) should continue to be modeled as demand-side resource that reduces the load forecast.
2. Event-Based Demand Response (DR) is modeled as a supply-side resource. Operating characteristics of DR programs should be defined to identify DR resources which can be used for renewable integration. DR resources which do not meet these operating characteristics should either be integrated in the demand forecast to reduce system load or modified in the DR Rulemaking.
3. The 1-in-5 peak load forecast should be removed or adjusted to 1-in-2 peak load forecast.
4. The import expectation should not be modeled downward and should remain at the California Independent System Operators' (CAISO) maximum import capability.
5. The scenarios should match a realistic dispatch of resources in 2022 so that infrequent curtailment of must-take resources is integrated into the modeling for operating flexibility.
6. The scenarios should assume that all resources used for renewable portfolio standard (RPS) compliance will be repowered.
7. The scenarios should take into account factors other than the age of the plant that impact retirement.
8. The planning exercise should account for the costs associated with the four scenarios.
9. The amount of renewable resources in each scenario should vary to account for changes in EE, DR, and combined heat and power (CHP) assumptions.

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III. DISCUSSION

A. The CAISO's recommendations regarding how to account for EE and DR fail to capture the value of those resources in meeting system need.

The CAISO argues that incremental "energy efficiency programs should be considered like a supply-side solution to any identified need, rather than a reduction to the load forecast."[1] Currently, the Commission-adopted planning assumptions account for incremental energy efficiency as a demand side resource reducing the system load forecast.[2] DRA respectfully disagrees with the CAISO's recommendation and maintains that incremental energy efficiency should continue to be accounted for as a demand side resource that reduces load forecast. While energy efficiency provides capacity by reducing the need for incremental new capacity, energy efficiency programs are designed to maximize reduced energy use and lower energy bills. Furthermore, given California's strong commitment to the loading order and the requirement of Public Utilities Code Section 454.5(b)(9)(C), it is reasonable to assume that incremental energy efficiency programs will materialize. Therefore, it is appropriate to rely on incremental energy efficiency programs to reduce the load forecast when determining potential need.

Similarly, the CAISO proposes that "demand response should be considered a supply-side solution to any identified need, rather than a reduction in the load forecast."[3] DRA notes that in the Commission adopted planning assumptions,[4] Event-Based Demand Response (DR) is already modeled as a supply-side resource. DRA recognizes the value in defining the operating characteristics of DR programs, in order to accurately assess their operating flexibility effectiveness. However, to the extent there are DR resources that do not meet the operating characteristics necessary to provide renewable integration, they should not be excluded from the modeling analysis. These DR resources should either be integrated in the demand forecast to reduce system load or modified in the DR Rulemaking[5] such that they are capable to provide operating flexibility.

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[1] Comments of the Californian Independent System Operator Corporation on Standardized Planning Assumptions and Study Case, October 5, 2012 (CAISO Opening Comments), p. 4.

[2] Assigned Commissioner's Ruling on Standardized Planning Assumptions, June 27, 2012, p. 16.

[3] CAISO Opening Comments, p. 4.

[4] Assigned Commissioner's Ruling on Standardized Planning Assumptions, June 27, 2012, p. 21.

[5] R.07-01-041 or subsequent Demand Response Rulemaking.

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B. Scenarios with a 1-in-5 peak load forecast should be removed or adjusted to a 1-in-2 peak load forecast.

Numerous parties raised concerns regarding the two scenarios that use 1-in-5 peak load forecasts. DRA's opening comments, as well as the comments of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), Sierra Club and the Union of Concerned Scientists (UCS), the CAISO, the City and County of San Francisco (CCSF), and The Utility Reform Network (TURN) all emphasize the necessity of using a 1-in-2 peak load forecast.[6] TURN points out that this type of a forecast can have an unintended impact on the operating flexibility modeling effort, noting that "it is not clear how these "1-in-5" peak loads can – or even should - be combined with Base scenario energy for the detailed hourly modeling CAISO needs."[7]

DRA recommends that the Commission remove the Replicating Transmission Planning Process (TPP) scenario from the list of scenarios, and replace it with a peak load scenario that uses the California Energy Commission (CEC) high load forecast of 58,412 MW.[8] All other assumptions from the base case should remain the same, as they reflect an already conservative view of future progress in EE, DR, and distributed generation (DG).

C. Import capacity should remain at CAISO's maximum import capability (MIC).

While CAISO's maximum import capability (MIC) minus Existing Transmission Contracts (ETC) outside of their control area is currently estimated to be 13,308 MW,[9] both PG&E and the CAISO seek to lower this amount, and SCE seeks to use a new tool to adjust this amount. PG&E seeks to use the net interchange estimate of 10,350 MW from the CEC's

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[6] Southern California Edison Company's Comments on Track II Standardized Planning Assumptions, October 5, 2012 (SCE Opening Comments) pp. 3-4; Comments of Sierra Club California and Union of Concerned Scientists on the Revised Scenarios for Use in Rulemaking 12-03-014, October 5, 2012 (Sierra Club/UCS Opening Comments), pp. 8-9; CAISO Opening Comments, pp. 3-4; Comments of the City and County of San Francisco on the Standardized Planning Scenarios Attached to the September 25, 2012 Assigned Commissioner's Ruling, October 5, 2012, (CCSF Opening Comments), p. 12; Comments of The Utility Reform Network In Response to the Assigned Commissioner Ruling Setting Forth Standardized Planning Scenarios, October 5, 2012 (TURN Opening Comments), pp. 2-3.

[7] TURN Opening Comments, pp. 2-3.

[8] ACR, p. 11.

[9] ACR, p. 14.

Summer 2012 Electricity Supply and Demand Outlook report[10] for import capacity.[11] The CAISO seeks to use the maximum historical actual simultaneous observed imports of 12,400 MW.[12] These metrics are used to calculate the actual results of the current grid, and do not take into account its maximum capability. It is likely that by planning for lower amounts of imports in the future, the opportunity for cost effective out of state resources to participate in meeting future needs will be limited.

In addition, the maximum import capability of transmission into the CAISO is used for the resource adequacy (RA) proceeding.[13] Planning assumptions for RA and LTPP planning assumptions should be harmonized whenever possible. DRA therefore supports the use of the MIC as the proper import assumption for planning purposes.

SCE seeks to use the CAISO's import capability tool for calculating import capacity to prevent underestimating need for resources. The CAISO's import capability tool has not yet been fully vetted for use in this proceeding. Ideally, the CAISO import capability tool would be examined in the 2014 LTPP proceeding, with adequate advance notice to parties. If the Commission intends to use the CAISO's tool for import capacity in this LTPP proceeding, the entire output of the tool should be available to parties,[14] including the level of need for inertia which SCE references,[15] so that parties can suggest non-generation solutions to this need as well as a need to supply peak load. However, DRA is concerned that this tool will not be transparent to stakeholders and that it is a short-term tool that has not been designed for long-term planning.

D. The scenarios should reflect a realistic dispatch of resources in 2022.

The Center for Energy Efficiency and Renewable Technologies (CEERT) recommends that its proposed "Do the best you can with what you have" scenario should:

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[10] California Energy Commission Staff Report, May 2012, available at http://www.energy.ca.gov/serp.html?q=summer+outlook+2012&cx=001779225245372747843%3Actr4z8fr3aa&cof=FORID%3A10&ie=UTF-8&submit.x=8&submit.y=3

[11] Comments of Pacific Gas and Electric Company on the Energy Division Draft Scenarios, October 5, 2012 (PG&E Opening Comments), pp. 2-3.

[12] CAISO Opening Comments, p. 9.

[13] Assigned Commissioner's Ruling on Standardized Planning Assumptions, June 27, 2012, p. 15.

[14] Possible ways to distribute the information include posting it on the Commission's web site or sending it to the service list.

[15] SCE Opening Comments, pp. 4-5.

> "also assume rare curtailment of currently 'must take' resources to handle the tails of the distribution curve, but should *not* require or assume the building of expensive conventional generation capacity to deal with events that are perfectly predictable (extreme ramps are caused by extreme weather) and are relatively rare."[16]

DRA supports CEERT's recommendation to assume rare curtailment of "must take' resources and recommends the consideration and integration of realistic operating conditions into the operating flexibility modeling effort to include the possible options dispatchers will have available to resolve stressed operating conditions. Rare curtailment of renewables is an essential option that dispatchers can use and, in certain instances, should use. While this curtailment should be modeled, over-use of this provision could impact the ability for LSEs to reach their RPS compliance and could trigger further renewable procurement, which could lead to an additional need for flexible resources. A model that reflects the optimal amount of curtailment is required to correctly identify the instances when a flexibility need determination must lead to the procurement of new flexible resources. This could include cost-effective modification of existing generation, as the California Environmental Justice Alliance (CEJA) references in its comments.[17]

Before the utilities procure resources based on determination of system flexibility need, the Commission should attempt to determine the impact of the CAISO's flexible ramping product and other market mechanisms on addressing flexibility constraints. If market mechanisms can be used to incent generators to modify resources to be more flexible, the need for new resources to provide flexibility need will diminish. Additional changes to Net Qualifying Capacity to incorporate flexible operating characteristics, which will be discussed in the RA proceeding, could have a similar impact and must be accounted for in the operational flexibility model.

E. All scenarios should assume that resources used for RPS compliance will be repowered and should reflect realistic assumptions about plant retirements.

PG&E suggests that geothermal and biomass resources should be modeled as RPS resources for retirement calculations.[18] As PG&E mentions, the renewable net short would need to be recalculated in the event that renewable resources retire before 2022. DRA's technical

[16] CEERT Opening Comments, p. 5.

[17] California Environmental Justice Alliance's Policy Comments on the Revised Scenarios, October 5, 2012 (CEJA Opening Comments), p. 15.

[18] PG&E Opening Comments, p. 4.

comments indicated that there are several reasons geothermal and biomass should be assumed to be repowered at the end of life.[19] Upon further investigation, DRA has determined that 463 MW net qualifying capacity of geothermal resources is expected to retire in Energy Division's scenario tool. These resources include numerous units of Calpine's Geysers Complex as well as the "Control QFS" units in SCE's territory.[20] This amount of lost renewable energy could have a drastic effect on IOU's RPS compliance obligations, and to DRA's knowledge, there are no planned retirements for these resources. DRA recommends that the scenarios assume that all renewable resources that qualify for RPS compliance will be repowered at the end of life.

Sierra Club/UCS point out the importance of realistic retirement assumptions for resources in general.[21] DRA agrees that assuming resources will retire when they are needed for local capacity requirements (LCR) is overestimating the overall level of expected retirements. Units that will retire for economic reasons should be included in the assumption of expected retirements. However, there are a number of reasons why generation is kept online beyond the individual economics of the generator. The CAISO may not allow some generating units to retire due to their locational characteristics. Retirement decisions take into account the costs and feasibility of comparable solutions, such as transmission upgrades or the costs to repower the resource. Because retirement decisions are based factors other beyond the age of a plant, the assumptions behind this long term planning effort should also take into account these factors.

For example, there are 749.6 MW of non-once-through cooling (OTC) capacity located in the Los Angeles Basin area and reflected in the scenario tool that is assumed to be retired. However, the CAISO considers this capacity as needed for LCR according to the most recent addendum to the LCR 2013 study.[22] DRA recommends that the Commission assume resources that have been designated as needed for local capacity requirements (LCR) will be on-line through the planning period or assume these resources will be repowered outside of the Track 2 LTPP proceeding.

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[19] The Division of Ratepayer Advocates Comments in response to Technical Questions on Proposed Scenarios, September 7, 2012, p. 3.

[20] Geysers Units 5,6,7,8,11,12,13,14,17 and Control QFS.

[21] Sierra Club/UCS Opening Comments, p. 5.

[22] *See* 2013 Local Capacity Technical Analysis Addendum To the Final Report and Study Results: Absence of San Onofre Nuclear Generating Station (SONGS), August 20, 2012. Available at http://www.caiso.com/Documents/Addendum-Fin … alCapacityTechnicalStudyReportAug20_2012.pdf. DRA calculated 749.6 MW by adding up the NQC figures of the Glen Arm Units 1&2, Etiwanda Units 3&4, and Broadway Unit 3 Power Plants, shown at pages 7 and 8 of the August 20, 2012 Addendum.

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F. The planning exercise fails to identify the costs associated with the four scenarios.

Section VI of the ACR, *Building Scenarios*, states that one of the critical questions of the 2012 LTPP is determining what mix of resources minimizes cost to customers over the planning horizon.[23] DRA agrees that the four proposed planning scenarios do not adequately address how each scenario minimizes costs, nor do the scenarios adequately reveal cost information.[24] This is a major flaw of the modeling exercise. If the Commission plans to remove the cost constrained scenario from the shortlist of scenarios to be modeled, it should, at the very minimum, include the costs associated with each scenario that will be modeled. Without this information it is impossible for stakeholders to determine which scenario represents the most favorable outcome for customers and how changes to planning assumptions can help to reduce costs over the 10-year planning period.

In particular, one of the ACR questions asks if increased distribution-level generation reduces overall costs. However, distributed generation (DG) resources are only accounted for in the High DG Scenario. This scenario includes a range of assumptions that are unique to the High DG/High demand side management (DSM) scenario, including high incremental EE, CHP, and supply-side DR. Because the high DG, incremental EE, CHP and supply-side DR are only presented in the High DG/High DSM Scenario, it would be difficult to isolate whether DG alone reduces overall costs or if potential cost reductions are the result of other factors like increased CHP or incremental EE.

Thus, DRA echoes the recommendation that the planning scenarios and modeling exercise should identify the costs of each scenario going forward and identify which scenarios and mix of assumptions will be optimal for reducing costs for ratepayers.

G. The amount of renewable resources in each scenario should vary.

DRA agrees with SCE that the renewable resource mix should vary by scenario, dependent upon the load forecast used and amount of EE, DR, and CHP assumed.[25] It is inaccurate to assume that the renewable net short will remain constant throughout the four planning scenarios when different assumptions are assumed in each scenario. For example, the

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[23] Assigned Commissioner's Ruling on Standardized Planning Assumptions, June 27, 2012, p. 9.

[24] *See e.g.* CCSF Opening Comments, pp. 3-5 ; CAISO Opening Comments, pp. 6-7; Comments of the Large-Scale Solar Association ("LSA") in Response to the Assigned Commissioner's Ruling Setting Forth Standardized Planning Scenarios for Comment, October 5. 2012, pp. 4-5.

[25] SCE Opening Comments, p. 8.

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Replicating TPP scenario assumes a 1-in-5 peak weather condition as well as a low level of DR and no additional incremental EE or solar PV. In this case RPS resource needs would be higher since policies related to preferred resources would be terminated. However, the High DG/DSM Scenario assumes high levels of incremental EE, PV, and CHP without assuming a 1-in-5 peak weather condition. The variables are drastically different, so the renewable resources needed to make up the net short would fluctuate upward or downward as well.

The renewable energy needed in each planning scenario should be differentiated so that stakeholders can accurately assess how the need for capacity and flexibility requirements and costs change between scenarios. DRA recommends that the Commission revise the planning scenarios to incorporate changes to the renewable net short in each proposed scenario so that stakeholders can ascertain how the amount of flexible resources and capacity needs will differ.

IV. CONCLUSION

DRA appreciates the opportunity to comment on the proposed scenarios and requests that the Commission adopt DRA's recommendations reflected in DRA's opening and reply comments.

Respectfully submitted,

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