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 13-12-010 (Filed December 19, 2013)

THE OFFICE OF RATEPAYER ADVOCATES' REPLY COMMENTS ON ASSUMPTIONS AND SCENARIOS FOR THE CPUC's 2014 LONG TERM PROCUREMENT PLAN PROCEEDING AND THE CAISO'S 2014-2015 TRANSMISSION PLANNING PROCESS

DIANA L. LEE
MATT MILEY
Attorneys

Office of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-4342
Email: Diana.Lee@cpuc.ca.gov

NIKA ROGERS
RADU CIUPAGEA
Analysts

Office of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-1529
Email: Nika.Rogers@cpuc.ca.gov

January 15, 2014

85898593

TABLE OF CONTENTS

I. INTRODUCTION

Pursuant to Administrative Law Judge (ALJ) Gamson's email ruling on December 19, 2013, the Office of Ratepayer Advocates (ORA) submits the following reply comments in response to the opening comments of some parties and questions posed in the "Planning Assumptions and Scenarios for use in the California Public Utilities Commission (CPUC) 2014 Long Term Procurement Plan (LTPP) Proceeding and the California Independent System Operator (CAISO) 2014-2015 Transmission Planning Process (TPP)."[1]

II. DISCUSSION

A. The Commission Should Accurately Account for Resources Coming Online in the Planning Horizon including Procurement Authorized in Decision (D.) 13-02-105 as well as any other Commission Decisions Authorizing Procurement.

ORA agrees with the recommendation of both Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E) that the 2014 LTPP standard planning assumptions should account for procurement authorization from Tracks 1 and 4 of the 2012 LTPP. In Decision (D.) 13-02-015, the Commission authorized SCE to procure a minimum of 1,400 megawatts (MW) of resources and no more than 1,800 MW of resources to meet local capacity requirements (LCR). A proposed decision is forthcoming on Track 4 of the 2012 LTPP where it is likely the Commission will authorize additional megawatts of local capacity in both SCE and San Diego Gas & Electric Company's (SDG&E) territory to account for the premature closure of the San Onofre Nuclear Generating Station (SONGS). Thus, the standard planning assumptions should account for, at a very minimum, the 1,400 MW of LCR resources that SCE was authorized to procure. SCE plans to procure "the entire 1,800 MW of new resources to meet LCR needs"[2] so it is equally reasonable to assume a minimum of 1,800 MW. The Track 1 procurement authorization should be either embedded in the planning assumptions or subtracted out of the residual need in each of the selected/finalized scenarios. ORA agrees that failure to conduct modeling without these MW additions "could lead to inaccurate results that may not be

[1] The Planning Assumptions are available at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm under 2014 LTPP, December 26, 2013 documents.

[2] Opening Comments of Southern California Edison Company on Standardized Planning Assumptions, January 8, 2014, (SCE Ccomments), p. 3.

useful for determining additional needs."[3] Additionally, ORA agrees with PG&E that once additional authorization has been determined in Track 4 of the 2012 LTPP, the assumptions should be updated to reflect any incremental procurement authorization amount.[4]

B. The Commission Should Reject PG&E's Recommendation to Reduce the Base Assumptions for Power Imports into California

PG&E recommends reducing the base assumption for power imports into California from 13,396 MW to 10,350 MW. PG&E contends that this reduction is appropriate "given the significant reduction of firm southwest imports of coal into the [California Independent System Operator Corporation] CAISO through the planning horizon."[5] However, ORA understands that the operating flexibility modeling will consider such resources' availability in assessing renewable integration needs, thus addressing this specific concern. The planning assumptions correctly maintain the 2012 LTPP import assumption based on the CAISO Maximum Imports minus Existing Transmission Contracts outside the CAISO's control area. ORA supports the use of this metric based on the assumption that reasonable amounts of imports in the future will enable cost-effective out of state resources to participate in meeting future system needs. The Commission should reject PG&E's recommendation to reduce the base assumptions for power imports into California and should instead use 13,396 MW for power imports.

C. The Commission Should Model Higher Levels of Demand Response in Select Scenarios

A number of parties[6] recommend modeling a higher level of demand response (DR) in the finalized scenarios. ORA agrees that greater levels of both dispatchable and non-dispatchable DR should be modeled in the exercise to better comply with California's Loading Order, which requires cost-effective preferred resources like DR to be procured first by the

---

[3] SCE Comments, p. 3.

[4] Comments of Pacific Gas And Electric Company (U 39 E) On The Energy Division's December 18, 2013, Workshop Materials, January 8, 2014 (PG&E Comments), p. 12.

[5] PG&E Comments, p. 2.

[6] PG&E Comments, p. 13, Comments Of Enernoc, Inc. on December 18, 2013 Workshop Materials, January 14, 2014 (EnerNoc Comments) p. 3; Comments of the California Large Energy Consumers Association on the Planning Assumptions and Scenarios for Use in the CPUC 2014 LTPP Proceeding and the CAISO 2014-15 Transmission Planning Process, January 14, 2014(CLECA Comments) p. 2; Clean Coalition's Comments in response to Questions on the December 12, 2013 LTPP Scenarios Workshop, January 8, 2014 (Clean Coalition Comments), pp. 2 – 3, 4 – 5.

investor-owned utilities (IOUs). EnerNOC correctly notes in its opening comments that assuming the current level of DR across the entire 10-year planning horizon is overly conservative.[7] ORA agrees with EnerNOC's recommendation:

> "that the Commission require that the LTPP Team adjust their assumptions to provide a range of potential DR scenarios, including a high, mid-range, and low forecast, as was done in the 2012 LTPP. The mid-range would assume a 20% increase over current levels, the low forecast would assume existing DR capacity through 2024, and the high forecast would assume a 30% increase over current DR levels."[8]

ORA also supports the recommendation that the "CAISO should also be required to disclose the amount of DR assumed in the Trajectory Scenario 1.a. for local capacity purposes."[9]

D. The Planning Assumptions Should Include Scenarios that Reflect a Post-2018 Transition to Residential Default Time of Use (TOU) Rates.

ORA agrees with the Environmental Defense Fund (EDF) that clean energy resources are not adequately represented in the LTPP modeling scenarios[10] and with EDF's observation that "[n]o scenario yet considers a significant increase in voluntary price-responsive load shifting through time-of-use (TOU) rates."[11] ORA agrees that the LTPP should include scenarios reflecting a post 2018 transition to residential default TOU rates.[12] EDF has estimated that "if half of all ratepayers adopted TOU rates, thirty three 100-megawatt (MW) fossil fuel power plants would be avoided."[13] While this estimate, which is based on a peak demand reduction of about 0.6 kilowatt (kW) per participant, is optimistic, it would be valuable for the Commission to examine scenarios that extrapolate TOU results from California and Arizona utilities. The "Low" case below extrapolates PG&E's summer 2012 TOU 13% (0.20 kW per participant) peak load impacts for non-net energy meeting (NEM) customers, while the "Medium" case extrapolates Arizona's Salt River Project and Sacramento Municipal Utility District's (SMUD's)

---

[7] EnerNOC Comments, p. 5.

[8] EnerNOC Comments, p. 5.

[9] EnerNOC Comments, p. 7.

[10] Comments of Environmental Defense Fund on the Long-Term Procurement Planning Docket Workshop Held on December 18, 2013, January 8, 2014 (EDF Comments), p .4

[11] EDF Comments, p. 6.

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

[13] EDF Comments, p. 7.

results of a 25% peak demand reduction (roughly 0.4 kW per participant). The following are some potential TOU peak demand impacts (that could be included as three "Managed Demand" forecasts).

TOU RATE PEAK LOAD REDUCTION SCENARIOS (Coincident Peak MW) (Based on 10 million residential IOU customers statewide) Residential TOU Penetration %			
	10%	**30%**	**50%**
Low Scenario (13%)[a]	200	600	1000
Medium Scenario (25%)[b]	400	1200	2000
High Scenario (EDF)[c]	630	1900	3300

(a) Extrapolated from PG&E summer 2012 ex post TOU results (0.20 kW per custom34.) for non-NEM customers on combination TOU/inclining block rates[14] (E-6 and E-7). "See 2012 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-based Pricing Programs", report prepared by Freeman Sullivan & Co. issued April 1, 2013, p. 6, Table 1-4

(b) Scaled up from case (a), based on a 25% peak demand reduction for TOU rates observed by SMUD and by Salt River Project. See "Effects of Three-Hour On-Peak Time-of-Use Plan on Residential Demand during Hot Phoenix Summers", by Loren Kirkeide of Salt River Project, in Public Utilities Fortnightly, Volume 25, Issue 4, May 2012

(c) EDF estimated 630 MW based on 20% TOU penetration in SCE's service territory.

Thus, ORA agrees that the Expanded Preferred Resources scenario in the Planning assumptions should

> "assess the impact of pursuing higher levels of preferred resources in order to take an ambitious step toward the California Air Resources Board's (CARB) 2050 greenhouse gas (GHG) emission reduction goals. [California Air Resources Board] CARB, via [Assembly Bill] AB 32, seeks to reduce GHG emissions by 80% beyond 1990 levels by the year 2050."[15]

ORA recommends that in addition to

> "assuming the highest amounts of [Additional Achievable Energy Efficiency] AA-EE, moderate incremental amounts of demand-side small PV beyond what is embedded in the 2013 [Integrated Energy Policy Report California Energy Demand] IEPR CED forecast,

[14] Inclining block rates charge higher prices for each successive block of usage

[15] Planning Assumptions, Section 5.7, p. 22.

> high penetration of new demand and supply-side CHP, and a High DG driven RPS portfolio that targets achieving a 40% standard in 2030,"[16]

that the Expanded Preferred Resource Scenario also assume that the IOUs transition to default residential TOU rates in 2018 using the three alternative TOU rate peak load reduction scenarios shown in the table above. As a second alternative, the Trajectory Scenario could be split into two: Trajectory A (business as usual) and Trajectory B (business as usual, with the TOU scenarios stated above), to reflect the start of the transition of customers to default TOU rates in 2018. Either approach would capture the long-term system benefits of TOU pricing.

In recommending inclusion of the above scenarios, ORA cautions that introduction of default TOU rates must be done gradually and with appropriate ratepayer safeguards. Accordingly, the initial TOU offering may have a lower level of time-of-use rate differentiation than the examples used to develop the three TOU scenarios above. The level of demand response may therefore be lower. In addition, most TOU trials have relied upon volunteers rather than default. In general, defaulting customers tend to respond less to price signals than do volunteers. A degree of caution is thus needed in analyzing these TOU scenarios.

In evaluating TOU scenarios, it is important to assume that the hours included in peak periods would shift over time in response to future changes in grid operations. TOU periods should be based on the value of demand reduction (rather than simply peak end-use customer demand). The definition of the peak period should evolve as necessary to include the evening ramp "duck's neck," and to exclude early afternoon hours of peak solar output.[17] Failure to adjust TOU periods in response to changes in the value of demand reduction would greatly diminish the value of TOU pricing as a demand response resource.

E. The Commission Should Allow Stakeholders to Submit Alternative Model Runs.

ORA agrees[18] that the planning process should allow stakeholders to submit the results of their own alternative scenario and sensitivity modeling as part of the planning scenario exercise. The Commission has limited modeling resources, so it would enhance the LTPP process to allow

---

[16] Planning Assumptions, Section 5.7, p. 22.

[17] In the more distant future, the Commission might need to consider a second, early morning peak period, to mitigate the morning ramp (downward), as solar output begins producing.

[18] SCE Comments, p. 5, PG&E Comments, p. 3.

stakeholders to submit the results of scenario or sensitivity runs using their choice of assumptions and inputs. This is also consistent with the previous operational flexibility modeling exercise in the 2010 and 2012 LTPP where ORA ran parallel scenarios to the CAISO's[19] and also alternative scenarios and sensitivities using different assumptions for preferred resources.

III. CONCLUSION

ORA respectfully requests that the Commission incorporate the recommendation in its opening comments and these reply comments into 2014 resource planning assumptions.

Respectfully submitted,

/s/ DIANA L. LEE

____
DIANA L. LEE

Attorney for the Office of
Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Telephone: (415) 703-4342
Facsimile: (415) 703-2262
Email: Diana.lee@cpuc.ca.gov

January 15, 2014

[19] See ORA Track 2 Testimony, prepared before the Track was cancelled, and submitted in R.12-03-014 as an attachment to an *ex parte* notice served January 8, 2014 in that proceeding.