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)

COMMENTS OF L. JAN REID ON PLANNING ASSUMPTIONS

January 8, 2014

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I. Introduction

Pursuant to the December 19, 2013 email ruling (Ruling) of Administrative Law Judge (ALJ) David Gamson, I submit these comments on the planning assumptions and scenarios proposed at the December 18, 2013 workshop in the Long Term Procurement Plan (LTPP) proceeding. Opening comments are due on Wednesday, January 8, 2014. I will send this pleading to the Docket Office using the Commission's electronic filing system on the due date, intending that it be timely filed.

The Ruling requests that parties comment on the Key Technical Questions provided by Energy Division Staff (Staff) in a separate attachment. I answer these questions in Section V below.

II. Summary and Recommendations

I have relied on state law and past Commission rulings in developing Recommendations concerning the standardized planning assumptions and scenarios. I recommend the following:[1]

1. The Commission should order the Energy Division to perform a Low Load Scenario. (pp. 4-5)
2. The Commission should order the Energy Division to perform an Early Nuclear Retirement Scenario in which the Diablo Canyon facility is assumed to be retired in 2015. (p. 7)
3. Energy storage capacity should be counted in both zonal production cost simulations and in power flow studies. (pp. 7-9)

[1] Citations for these recommendations and proposed findings are given in parentheses at the end of each recommendation and finding.

4. The Energy Division should use the information from the IOUs' first energy storage Request For Offers (RFO) to estimate the location and characteristics of future energy storage projects. (pp. 7-9)

5. The Energy Division should assume a Commercial Operation Date (COD) of 821 days after a project has been approved. (p. 9)

6. The Commission should allow parties to litigate all forecast assumptions during the instant rulemaking. (pp. 11-12)

7. Transmission and distribution energy storage should be modeled as a dispatchable resource, and customer-sited energy storage should be modeled as a fixed profile. (p. 10)

8. Small Photovoltaic (PV) solar generation and small Combined Heat and Power (CHP) generation should be modeled as supply-side resources, so that the true value of different resources can be accurately determined. (pp. 10-11)

9. The Energy Division should use the historical growth rate of demand response in order to estimate more accurately the future magnitude of demand response. (p. 12)

III. Proposed Findings

My recommendations are based on the following proposed findings.

1. The Commission has an obligation under Public Utilities Code Section (PUC §) 451 to protect ratepayers and to ensure that rates are just and reasonable. Consistent with PUC § 451, the Commission must protect ratepayers from resource over-procurement associated with uncertainties such as a decline in load faced by the IOUs. (pp. 4-5)

2. Decision (D.) 13-10-040 set up a system in which the IOUs would primarily meet energy storage targets through competitive RFO solicitations. (p. 8)

IV. Process Problems

The Staff Proposal has apparently been developed over a period of months in a series of closed-door meeting with limited public input or public access. The Staff Proposal is the result of a collaborative effort by the CPUC, the CEC, and the CAISO. Only one of these agencies (the CPUC) has a statutory mandate to ensure that rates are just and reasonable under Public Utilities Code Section (PUC §) 451. I note that there is no mention of just and reasonable rates in the Staff Proposal.

Full public access to the 2014 standardized planning assumptions was limited to a single workshop held on August 28, 2013.[2] This was a significant departure from the way in which past planning assumptions have been developed.

Staff has explained that: (Planning Assumptions and Scenarios, p. 6)

> CPUC Energy Division held several workshops in the summer of 2010, and in December 2010 the 2010 LTPP Standardized Planning Assumptions were issued via a Joint Scoping Memo and Ruling. Following a similar process of workshops and comments in 2012, the CPUC established LTPP planning assumptions for the 2012 LTPP that build upon the last four years of planning efforts to further improve the LTPP process.

Staff has also explained that "The CEC held a workshop on the revised CED base forecasts on October 1, 2013 and expects to adopt a final version on December 11, 2013." (Planning Assumptions and Scenarios, p. 9) However, some of the parties to the LTPP were not notified of or not invited to the October 1, 2013 CEC workshop.

[2] Parties are allowed to file comments and reply comments to the standardized planning assumptions. However, allowing a relatively small group of parties to comment does not constitute full public access.

Additional problems arose during the comment period. As mentioned previously, ALJ Gamson issued an email ruling on December 19, 2013 requesting comments. Parties were instructed to file workshop comments in R.13-12-010 if possible. Thus, parties initially had 20 days in which to file comments. The comment period quickly became compressed because not all of the relevant workshop files were available until December 31, 2013, and the Order Instituting Rulemaking was not available until December 30, 2013. Thus, a 20-day comment period was converted to an 8-day comment period.

V. Key Technical Questions

1. *Is the current range of scenarios sufficient to cover current policy issues facing the CPUC?*

Two additional scenarios should be performed: a Low Load Scenario, and an Early Nuclear Retirement Scenario. I discuss an Early Nuclear Retirement Scenario in my response to Question 3.

Staff recommends that a High Load Scenario be performed in order to explore the impact of higher demand on the system, with all other inputs held constant. (Planning Assumptions and Scenarios, p. 21)[3]

In Table 1, I provide a summary of the forecasts contained in the final California Energy Commission Staff Report (CED) concerning projected energy demand in California.[4]

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[3] The full title of this document is "Planning Assumptions and Scenarios for use in the CPUC 2014 Long-Term Procurement Plan Proceeding and CAISO 2014-15 Transmission Planning Process."

[4] See California Energy Commission Staff Final Report, California Energy Demand 2014-2024 Final Forecast, Volume 2: Electricity Demand by Utility Planning Area, pp. 2-3.

Table 1: CEC Energy Demand Forecast by 2024

Utility	Low Forecast (GWh)	High Forecast (GWh)	Percent Difference (High/Low − 1)
PG&E	121,804	132,510	8.79%
SCE	109,206	120,745	10.57%
SDG&E	23,337	25,983	11.34%
TOTAL	254,347	279,238	9.79%

The Commission has an obligation under Public Utilities Code Section (PUC §) 451 to protect ratepayers and to ensure that rates are just and reasonable. Consistent with PUC § 451, the Commission must protect ratepayers from resource over-procurement associated with uncertainties such as a decline in load faced by the IOUs.

Therefore, I recommend that the Commission order the Energy Division to perform a Low Load scenario using the values given in Volume 2 of the CED Final Staff Report.

2. *Are there any technical errors in the proposed scenarios, scenario tool, or RPS Calculator?*

a. Scenario Tool Errors

I have identified the following errors in the Scenario Tool. (1) For ease of use, totals should use cell references rather than be hardcoded (e.g., cell C75 rather than 500). (2) In the CEC Siting Cases tab of the Scenario Tools document, "Under Review Total" should include the Sun Valley peaker project (cell E165), because the Sun Valley peaker project will be removed from suspended status in 2014.

b. RPS Calculator Errors

I have identified the following errors in the RPS Calculator:

- In the tab "Selected AllResources" the formula for cell N238 should be corrected to read =Sum(N182:N237). Analogous changes should be made in cells O238-V238.
- In the tab "DeliveredAndNQC_byYear", values should be provided for the RA zones (cells AF62-AN65).
- For many project types, a cost of equity of 15% is used. (See tab "a – ProForma," row 42) The actual authorized return on equity for the IOUs ranges from 10.30% to 10.45%. (D. 12-12-034, slip op. at 3)
- Insurance expense is set to $0 for many technologies. (See tab "a – ProForma," row 32)
- A discount rate of 15% is used. (See tab "a – ProFormaCalcPV," cell C89) This implies that projects will be financed with 100% equity rather than with a combination of debt and equity. Instead, the discount rate should be set to the project's Weighted Average Cost of Capital.
- An energy production of 0 is used. (See tab "a – ProFormaCalcPV," row 33)
- Divide-by-zero errors. (See tab "a – ProFormaCalcPV," cells C118 and C119)
- Note refers to the 2010 LTPP. (See tab "zz – Cost Impacts," row 1)

3. Should Diablo Canyon be assumed online or retired in the Trajectory case?

Diablo Canyon should be assumed to be retired effective December 31, 2014. This can be accomplished either in the Trajectory case or by a special Nuclear Retirement Scenario.[5]

The Commission has stated that "We will look to develop scenarios that explore a range of potential policy futures, including renewable portfolio standard (RPS) implementation, variations of load, distributed generation, **nuclear retirement**, transmission options and resource strategies to develop higher levels of preferred resources." (R.13-12-010, Order Instituting Rulemaking, p. 11, emphasis added)

An Early Nuclear Retirement scenario or sensitivity would provide valuable information to both the Commission and the parties and would assist in the Commission's resolution of the nuclear retirement issue. Therefore, I recommend that an Early Nuclear Retirement scenario or sensitivity be performed for the planning period 2014-2024. The Early Nuclear Retirement scenario or sensitivity should assume that the Diablo Canyon facility will be retired in 2015.

4. Is the treatment of energy storage for capacity value reasonable?

No. Energy storage capacity should be counted in both zonal production cost simulations and in power flow studies.

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[5] Staff has proposed an Early Nuclear Retirement Scenario which assumes that the Diablo Canyon Power Plant will be retired in 2024-2025.

Staff states that: (Planning Assumptions and Scenarios, p. 11)

> CPUC Decision (D.) 13-10-040 established 2020 targets of 425 MW for distribution-connected storage and 200 MW of customer-side storage. For the purposes of the planning assumptions, there is no expectation that distribution and customer sited storage will be deployed and operated in a manner that provides capacity value at times of system stress, nor is there any information about where these resources will be deployed. Therefore, the 625 MW storage target described above will only be modeled in zonal production cost simulations but will not count as capacity in power flow studies.

Staff is apparently concerned that "some types of customer-side storage may not be grid-connected and only store customer-side generation." (Planning Assumptions and Scenarios, p. 11) It is not reasonable to assume that all energy storage should be not be counted just because 200 MW of energy storage may be used to store customer-side generation.

D.13-10-040 set up a system in which the IOUs would meet energy storage targets primarily through competitive RFO solicitations. The first solicitation is scheduled for March 1, 2014.[6] Additional solicitations are scheduled for 2016, 2018, and 2020. The Commission has found that "The procurement targets set for PG&E, SCE and SDG&E are within three specific grid domains – transmission-connected, distribution-connected, and customer-side applications." (D.13-10-040, Finding of Fact 7, slip op. at 71)

[6] D.13-10-040, Conclusion of Law 7, slip op. at 74.

Therefore, I recommend that the Energy Division use the information from the IOUs' first energy-storage RFO to estimate the location and characteristics of future energy storage projects. For example, if the IOUs were to procure 125 MW of energy storage, and the projects were divided, say, between PG&E (50 MW), SCE (50 MW) and SDG&E (25 MW), then the following assumptions would be developed:

- 170 MW of energy storage capacity would be located in the PG&E service territory.
- 170 MW of energy storage capacity would be located in the SCE service territory.
- 85 MW of energy storage capacity would be located in the SDG&E service territory.

5. *If no COD is available, is it reasonable to assume the resource does not retire within the planning horizon?*

No. The CEC provides the status of all projects at http://www.energy.ca.gov/sitingcases/all_projects.html. Using this document, I calculated that the median project came online 821 days after the project was approved. Therefore, I recommend that staff assume a Commercial Operation Date (COD) of 821 days after a project has been approved.

6. *How should the capacity value of energy storage, demand response, and demand side resources (PV, CHP) be allocated to small geographic regions and/or busbars and how should the capacity value be adjusted to account for locational and operational characteristics uncertainty?*

I have no position on this issue at this time.

7. *How should the production profile of each category of storage identified in the CPUC Storage Target Decision be modeled – as a fixed profile or as a dispatchable resource?*

There are three categories of energy storage: transmission, distribution, and customer-sited. I recommend that transmission and distribution energy storage be modeled as a dispatchable resource and that customer-sited energy storage be modeled as a fixed profile.

8. *Should incremental small PV and small CHP on the customer side of the meter be modeled as demand-side load reduction or supply side generation?*

In 2012, The California Independent System Operator (CAISO) argued that: (Comments of the California Independent System Operator Corporation on Standardized Planning Assumptions and Study Scenarios (CAISO Comments), R.12-03-014, October 5, 2012, p. 4)

> Rather, energy efficiency programs should be considered like a supply-side solution to any identified need, rather than as a reduction to the load forecast. As a supply-side solution, energy efficiency can then be procured and committed via a robust procurement process that considers all solutions, enabling an uncommitted energy efficiency program to become a committed resource which can then be tracked and its performance measured.

The CAISO's 2012 arguments concerning energy efficiency are also relevant to small PV and small CHP today. Both small PV and small CHP should be treated as a supply-side resource and not as a simple reduction in demand. In resource modeling, there is a mathematical difference between a supply-side resource and a reduction in demand. Almost any resource could be treated as a reduction in demand. For example, a must-run fossil fuel plant could be treated as a reduction in demand.

Neither the output of fossil fuel plants, hydro plants, or demand response is subtracted from load when modeling supply and demand. I believe the Commission should treat small PV and small CHP in a nondiscriminatory manner, as a supply-side resource, so that the true value of different resources can be accurately determined.

The same modeling convention should be used in all 2014 LTPP and 2014-15 TPP studies. In this way, the overall modeling effort will be consistent across different studies. If different studies were to use different modeling conventions (i.e., both load reduction and a supply-side resource), parties might question the validity of certain studies or of the overall modeling effort.

9. *Is the forecast of incremental small PV (beyond what is embedded within the IEPR forecast) on the demand side reasonable?*

   Yes.

10. *Is the forecast of incremental CHP on the demand side and the supply side reasonable for the scenarios that include those forecasts?*

   Yes.

VI. Assumptions

A. Base and Incremental Forecasts

Staff proposes that "Assumptions originated from other state agencies, for example the CED [CEC], will not be re-litigated in this proceeding." (Planning Assumptions and Scenarios, p. 8)

Due to the process problems discussed in Section IV, the Commission should not prevent parties from litigating the forecast assumptions used by the CEC and other state agencies. The CEC's forecast assumptions will have a material impact on the CPUC's scenario results. Neither the parties nor the general public have had a fair opportunity to participate in the development of important forecast assumptions. Therefore, I recommend that the CPUC allow parties to litigate all forecast assumptions during the instant rulemaking.

B. Demand Response

Staff states that: (Planning Assumptions and Scenarios, pp. 13-14)

> Dispatchable demand response (generally event-based and emergency programs) shall be accounted for as a supply-side resource. The most recent Load Impact reports filed with the CPUC serve as the default assumption.

In other words, Staff assumes no change in the magnitude of demand response over the entire planning period. Scenario modeling should be a forward-looking exercise. Therefore, I recommend that Staff use the historical growth rate of demand response in order to estimate more accurately the future magnitude of demand response.

VII. Conclusion

The Commission should adopt Reid's recommendations for the reasons given herein.

* * *

Dated January 8, 2014, at Santa Cruz, California.

/s/

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VERIFICATION

I, L. Jan Reid, make this verification on my behalf. The statements in the foregoing document are true to the best of my knowledge, except for those matters that are stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Dated January 8, 2014, at Santa Cruz, California.

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