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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	R. 10-05-006

COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION ON THE PRELIMINARY SCOPING MEMO AND SCHEDULE

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I. INTRODUCTION

The California Large Energy Consumers Association ("CLECA") welcomes this opportunity to offer its comments in response to the Preliminary Scoping Memo ("PSM") and schedule in this latest iteration of the Commission long-term procurement plan proceedings ("LTPP"). CLECA was actively involved in the last two LTPP proceedings (R. 06-02-013 and R. 08-02-007) and anticipates a similar level of involvement in this proceeding.

II. UNFINISHED MATTERS AND UNCERTAINTIES

The PSM addresses certain issues that were considered in R.08-02-007 as well as others that have been deferred to this proceeding. There remain unresolved issues even among those listed in the rulemaking as having been addressed in R.08-02-007. As one example, the treatment of combined heat and power ("CHP") in utility planning and in the GHG analysis was never fully resolved. CLECA believes that the modeling performed by E3, which was used in the prior rulemaking, has incorrectly assessed the costs and benefits of CHP. If the Commission chooses to proceed with the E3 greenhouse gas ("GHG") model in Track I of this proceeding, which is to address the assessment of system procurement issues, CLECA believes that the matter of the cost-benefit analysis of CHP must be revisited.

CLECA also notes that there continues to be substantial uncertainty as to the manner in which the California Air Resources Board ("CARB") will implement AB 32, the legislation mandating reductions in GHG. In particular, the manner in which cap and trade will go forward and whether GHG allowances will be allocated or sold for electricity production or allowance value provided to the utilities are open issues. In addition, CARB has not completed its Renewable Energy Standard ("RES") regulations or its CHP regulations under AB 32. These are critical elements in the future procurement options and decisions of utilities.[1]

Additionally, the California Independent System Operator ("CAISO") has been working on a study of the operational consequences of meeting the 33% renewable portfolio standard ("RPS"). This study, which was to have been available by now, is also expected to include some level of economic assessment. Further, this study is expected to provide important input on the type of generation facilities that can best be used to integrate intermittent renewable generation. It would be unwise for the Commission to authorize procurement of new generation by utilities without knowing what type of new generation will most cost-effectively provide this integration service.

The PSM identifies certain issues that were originally intended to be addressed in Phase 2 of R.08-02-007, including refinement of policies for distinguishing system vs. bundled resource needs and related cost allocation. The PSM suggests that this matter has been rendered moot by SB 695. CLECA begs to differ.

[1] We also note that a large group of utilities have protested to CARB that a disproportionate percentage of GHG reductions are expected from the electric sector.

SB 695, now P. U. Code Section 365.1(c)(2)(A), states:

> (2) (A) Ensure that, in the event that the commission authorizes, in the situation of a contract with a third party, or orders, in the situation of utility-owned generation, an electrical corporation to obtain generation resources that the commission determines are needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory, the net capacity costs of those generation resources are allocated on a fully nonbypassable basis consistent with departing load provisions as determined by the commission, to all of the following:
>
> (i) Bundled service customers of the electrical corporation.
> (ii) Customers that purchase electricity through a direct transaction with other providers.
> (iii) Customers of community choice aggregators.

Unless the Commission determines that the addition of *any* new generation will, by definition, benefit *all* customers, there should be some test of who benefits. If SB 695 means that the Commission will authorize the utilities to buy or build power for everyone, and charge them all the same net capacity costs, on a nonbypassable basis, two potential problems are created. The first is that the diversity of the generation capacity portfolios provided by various LSEs will be significantly reduced, and with it the level of retail competition. The second is that this allocation will not take into account any other generation capacity that other LSEs have procured for their customers and could result in the customers of these other LSEs paying for more capacity than they need.

Another matter that has been held over from Phase 2 of R.08-02-007 is how to ensure fair competition in the procurement process between power purchase agreements ("PPAs") with third parties and bids for utility-owned generation. This is one of numerous issues related to the ongoing "hybrid" market which remain unresolved. While the Commission may not wish to address all of these issues in this proceeding, it should not forget that they exist and that they remain controversial.

III. THE PROPOSED THREE TRACKS OF R. 10-05-006

A. Track I

The PSM proposes three tracks for the proceeding, although the timing may not be consistent with the phase numbers. Track I is to address system planning issues, including local resource adequacy, renewable procurement goals, and replacement generation needed due to new regulations to eliminate use of power plants using once-through cooling ("OTC"). As noted above, there is still considerable uncertainty both as to how renewable requirements will be met (and related energy integrated) and how GHG emission mitigation will be addressed. There also continues to be uncertainty regarding the location of new transmission lines. In addition, replacement of generation using OTC will have to take into account voltage and inertia issues, particularly in Southern California.[2] We are not as far along in resolution of these matters as was hoped at the time D.07-12-052 was issued. Thus, scenario analysis will definitely be needed for Phase 1, and the assumptions used in that analysis will be critical to the results. What will be more difficult will be weighting the likelihood of the scenarios.

The PSM also mentions the role of distributed generation ("DG") in meeting system resource requirements. This is an important issue, particularly if the development of new transmission continues to be contentious. However, Commission policies and orders and some statutory requirements create impediments to the development of customer-owned generation, particularly CHP. (Examples include stand-by rate design, size limits for eligibility for certain incentive programs, and certain departing load charges.) CHP can be highly efficient and its role in the resource mix could be much greater, and it could provide significant GHG benefits, if these impediments were addressed. However, despite Commission indications in the past that it would address these issues, no rulemaking has even been forthcoming. CLECA suggests that there is a significant missed opportunity here and that customer-owned DG will not reach its economically justified potential until these impediments are addressed.

We would also suggest that there are procurement issues related to generation in local constrained areas ("LCAs"). The implementation of MRTU has not led to locational marginal prices ("LMPs") that are likely to induce new generation construction in LCAs, yet the number of LCAs and the MW requirements for them keep growing. It is not clear from the PSM what aspects of local RA are intended to be addressed as part of Track I. This point should be clarified.

B. Track II

Track II is to address the development and approval of individual utility "bundled" procurement plans, and is not to be delayed by Track I or Track III. However, Track II will certainly be influenced by the uncertainties mentioned above regarding new regulations and requirements that affect generation and transmission. Since the Rulemaking says that the inputs to Track II must be available by November 2010, it is unlikely that all of these uncertainties will be resolved. (We note, for example, that it is unlikely that any federal legislation for GHG mitigation will be passed by then and even less likely that there will be final regulations.) These circumstances suggest that some scenario analysis will be needed here as well. In addition, as the utilities continue to work toward their RPS goals, the issue of what type of generation can be most cost-effectively used to integrate intermittent renewables will be critical to the development of the appropriate plans for each utility.

C. Track III

Track III is to address the rule and policy changes that were not resolved in R.08-02-007. These are daunting. One of the specified issues for resolution is development of updates to procurement rules to comply with SB 695 and refinements to the D.06-07-029 cost allocation

[2] The scoping memo lists these issues on page 12.

methodology ("CAM"). As noted earlier, CLECA believes that SB 695 is not as definitive as the PSM would suggest. Updating these rules in conformance with SB 695 is likely to be contentious.

The PSM also states that procurement rules to comply with OTC policies will be addressed in Track III. It is not clear how they can be addressed in Track III and Track I simultaneously. Nor is it clear how they can be addressed without considering the location of new renewable generation and transmission, PM-10 regulation in the South Coast Air Basin, expectations for distributed generation, and voltage and inertia issues. These matters will determine the locational requirements and limitations for replacement generation. CLECA suggests that one or more workshops may be needed in order to determine how some of these overlapping issues should be addressed and where to do so.

Another matter identified for Track III is CAISO-market-related procurement implementation. Certainly, congestion revenue rights ("CRRs") and convergence bidding are important. However, the MRTU has not demonstrated the ability of LMP to send price signals as to the desired location of new generation.[3] In addition, the CAISO has not implemented scarcity pricing, which would provide good price signals for demand response. Thus, so far, the absence of wholesale price signals from the CAISO is reducing the effectiveness of different retail pricing signals that were expected to be important in the electricity sector. It is not clear if parties should assume that this lack of price signals will continue, or whether it should be assumed to be a temporary circumstance.

CLECA believes that it will be very difficult to have the results of Track I and III available in time to have any significant influence on Track II. The PSM points out that a Commission decision would be required by November 19, 2010, if it is to influence Track 2. This leaves just five months for a decision in either of these other Tracks, a result that is likely infeasible. This is troubling, because there are some critical unresolved issues related to GHG mitigation, to renewable integration, and state

[3] Indeed, the CAISO has deemed most transmission paths within its balancing authority area to be non-competitive, unless found otherwise, and subject to price mitigation.

energy policy related to renewable energy, CHP, transmission siting, etc., that are important for development of a cost-effective resource plan for each utility. While we understand that the actual procurement will take place in the future, at a time when some or all of these issues will be resolved, it is important that the decisions regarding procurement be the most cost-effective for customers, because resolution of all of these issues is likely to result in substantial cost and rate increases.

The PSM also identified GHG compliance products and risk management strategies as issues for Track III. We hope that there will be some clarity as to their requirements for GHG mitigation, the role of cap and trade, and the treatment of allowances before this matter is addressed. We note again the great uncertainty related to any possible federal regulation and how that might affect California.

IV. WHICH MATTERS MUST BE RESOLVED BEFORE TRACK II

CLECA fears that there is simply not enough time to resolve many, and perhaps none of the matters affecting Track II before November 2010. This is particularly true if the CAISO 33% RPS study results are not available until August, as appears likely, and if a PD must be put out in early October to permit issuance of a decision by November 19, 2010.

One critical issue is what planning reserve margin ("PRM") the utilities will be planning for. The CAISO just released a new study on PRMs for utilities in its balancing area that is likely to be quite controversial. CLECA recommends that the utility LTPPs filed in this proceeding use the current PRM unless there is a Commission proceeding and a formal decision adopting another PRM.

Another important input is one or more decisions updating Resource Adequacy ("RA") requirements in R.09-10-032. A Phase 1 decision is expected this summer but the treatment of additional issues that might require a Phase 2 proceeding and decision might not occur in time for a decision before November 2010.

V. CONCLUSION

The proposed schedule for this proceeding is extremely ambitious. The deadline of a November 19, 2010 decision in Track I or Track III, and presumably for any other related matters, suggests that the utilities will be able to avoid the mandate of consistency of assumptions and comparability that D.07-12-052 attempted to impose on this round of LTPP. CLECA strongly supported a movement toward such consistency and comparability, and failure to achieve it would be unfortunate for the Commission and the parties. We recommend that the Commission consider once again whether the November 19, 2010 deadline is essential to permit adequate utility bundled procurement given the fact that so many of the key factors that are expected to constrain utility procurement going forward remain uncertain.

Dated: June 4, 2010

Respectfully submitted,

/s/

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CERTIFICATE OF SERVICE

I, the undersigned, declare that I am employed in the County of Contra Costa, California, that I am over the age of eighteen years and not a party to the within action. My business address is 67 Carr Drive, Moraga, California 94556.

On June 4, 2010, I electronically served a true copy of the document described as **COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION ON THE PRELIMINARY SCOPING MEMO AND SCHEDULE,** attached hereto, on the accompanying service list:

Executed on June 4, 2010 at Moraga, California.

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

/s/
Christine Dable
Legal Assistant to William H. Booth

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