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)

RESPONSE OF THE DIVISION OF RATEPAYER ADVOCATES TO THE ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON WORKSHOP TOPICS

NIKA ROGERS
RADU CIUPAGEA
ALAN WECKER
Analysts
Division 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

DIANA L. LEE
IRYNA A. KWASNY
Attorneys
Division 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

October 9, 2012

I. INTRODUCTION

The Division of Ratepayer Advocates (DRA) submits this response to the September 14, 2012 "Administrative Law Judge's Ruling Seeking Comment on Workshop Topics" (Ruling). The Ruling seeks comments on a series of topics related to workshop discussions held jointly in this proceeding and the energy storage rulemaking, R.10-12-007.

DRA's responses to some of the questions in the Ruling are set forth below, along with observations about preliminary issues that are important to consider in seeking the information sought in the ruling.

II. DISCUSSION

1. What changes should be made to the rules governing the Investor-owned Utilities' (IOUs') procurement process that would allow all resources (natural gas combined cycle, combustion turbine, storage, demand response, combined heat and power, renewable, etc.) to compete fairly in meeting identified needs? Please provide specific proposals for structuring an all-source procurement process.

The Commission should consider changes to the IOUs' procurement process to reinforce the direct linkage between the use of demand-side preferred resources and supply-side investment decisions, so that ratepayers do not procure redundant supply-side resources over the short- or long-term. Reinforcing the direct linkage between demand side resources and supply side investment decisions also furthers progress towards greenhouse gas (GHG) reduction goals and ensures compliance with the loading order.

The primary benefit of the Commission's demand-side programs is the avoidance or deferral of costs associated with generating and delivering energy (i.e., the energy utilities' 'avoided costs'). There may be a need in upcoming years to add some conventional generation to provide 'flexible' balancing of the grid with an increasing proportion of intermittent energy resources, most notably solar and wind. Thus, it is even more important to account properly for demand side savings reductions when considering supply side investment decisions so that ratepayers receive the benefits of their investments in both supply and demand side resources.

The Commission highlighted the direct linkage between supply-side investment decisions and consideration for demand-side alternatives in Decision (D.) 04-01-050, which established procurement guidance to the utilities and required that:

> utility procurement related energy efficiency program submissions be equal to or greater than those forecasted in their long-term plan forecasts for the forecast/program period in question. In making this requirement, we restate the importance of energy efficiency to the overall procurement activity and the need to ensure that projected savings are realized in programs aimed to help the citizens of the state save energy - thereby reducing the need for other non-renewable supply options."[1]

This linkage flowed through to demand-side decisions, most clearly in D.04-09-060, in which the Commission adopted energy savings goals for 2006 and beyond:

> The energy savings goals adopted in this proceeding shall be reflected in the IOUs' resource acquisition and procurement plans so that ratepayers do not procure redundant supply-side resources over the short- or long-term.[2]

The Commission and Energy Division (ED) staff have endeavored to reinforce this linkage, for instance through continuous refinements of standardized planning assumptions in each Long Term Procurement Planning (LTPP) proceeding. Nevertheless, the reliability of demand-side resources to reduce load forecasts to the full extent estimated (for portfolio and budget purposes) is apparently still in question. The California Independent System Operator (CAISO) thus far has refused to count incremental uncommitted EE in its Transmission Planning Process (TPP),[3] the results of which feed directly into the Commission's annual determinations of local capacity requirements in the Resource Adequacy (RA) proceedings. This has been less of an issue since the annual RA determinations do not result in construction of new resources, although RA contracts commit ratepayers to capacity payments regardless of whether the contracted generator ever gets dispatched. The CAISO, however, has developed a ten-year forecast of local capacity requirements; the Commission's adoption of such a forecast for utility

[1] D.04-01-050 at 109, emphasis added.

[2] D.04-09-060, Ordering Paragraphs (OP) 6 at 52 emphasis added.

[3] DRA notes, however, that the CAISO submitted an addendum to its 2011/2012 study to show the results of a *sensitivity* analysis reflecting increased estimates for both incremental uncommitted EE and combined heat and power (CHP). This is a noteworthy improvement, however further efforts are needed to reflect demand-side resources in the *base case*. *See* Addendum to: Board-Approved 2011/2012 Transmission Plan Section 3.4.2.1 Assembly Bill 1318 Sensitivity Reliability Study Results, June 12, 2012, p. 2.

procurement could result in the construction of new supply-side resources without allowing demand-side resources to reduce the need for such supply side resources.[4]

In order to maximize benefits to ratepayers, demand-side programs need to "track" supply-side planning, or rather the criteria grid planners use to determine need, more effectively. The current avoided cost methodology has helped to some extent in terms of specifying hourly and climate zone-level avoided costs, but further alignment with grid planning would improve demand-side stakeholders' appreciation of when and where demand-side resources will provide the greatest value to the system. More plainly, closer alignment with supply-side planning should enhance demand-side stakeholders' efforts to achieve actual avoidance of forecasted supply-side costs.[5]

2. What amendments, if any, would be necessary to the most recent long-term Request for Offers issued by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) to ensure that all resources are eligible to compete in meeting future Request for Offers (RFO)?

The IOUs must follow "Least Cost-Best Fit" (LCBF) principles in all procurement activities they perform per Commission rules. As described by SCE, Request for Offers (RFO) evaluations include two major steps: (1) the valuation of each offer; and (2) the selection of offers. The valuation of each offer takes into account cash flow components for both cost and revenue. These components are then netted and discounted to yield a Net Present Value (NPV) for each offer. The NPV is the factor which is compared to other proposals or options to find the "Least Cost." "Best Fit" is achieved by ensuring that selected offers fill or manage a procurement need or risk. SCE presents the objective of each RFO to the Procurement Review Group (PRG) prior to launch. SCE identifies the exact metrics used to determine best fit prior to receipt of final offers and presents this information to the PRG. For example, in order to determine the best offers to select for SCE's All Source RFO, SCE sets up, in advance of final offers, an optimization process that will maximize the NPV of the selected offers. Simultaneously, this process takes into account "best fit" constraints such as capacity and energy

[4] DRA acknowledges that the Commission has deemed most DR programs as 'supply-side,' which DRA supports. To the extent these comments refer to DR as 'demand-side,' it means a demand reduction in the broader sense suggested by P.U. Code §454.5(b)(9)(C).

[5] DRA Comments in response to Administrative Law Judge's Ruling Seeking Post-Workshop Comments on Demand-Side Cost-Effectiveness Issues, R.09-11-014, October 1, 2012 at 8-10.

needs, as well as qualitative characteristics such as location, product type, procurement limits, and other "fit" criteria.[6]

PG&E states that LCBF provides for the selection of resource alternatives based on the resource's relative cost effectiveness and ability to meet the specific portfolio needs. A resource's cost effectiveness is determined relative to common market benchmarks or market value. A resource's portfolio fit can be a qualitative assessment or quantitative measure that represents how well its energy profile, location, and other operating characteristics meet the needs of the portfolio for a particular product in a given location. In planning and procurement decisions, PG&E applies a consistent evaluation methodology to both supply-side and demand-side resources. By applying LCBF principles to supply-side and demand-side alternatives, PG&E obtains the lowest cost for customers for a given set of portfolio needs. PG&E's procurement evaluation methodology considers both the market value and the portfolio fit of alternative resources that are available.[7]

DRA agrees that the LCBF principle is consistent with the Commission's role to ensure reliability while maintaining rates that are just and reasonable.[8] The Commission, however, must balance this role with its mandate to ensure compliance with the loading order.[9] The Energy Action Plan guides California's energy policies, and places cost-effective energy efficiency (EE) and demand response (DR), followed by renewable sources of power and distributed generation, such as combined heat and power (CHP), at the top of the loading order.[10] To the extent the application of the LCBF principle conflicts with the implementation of the loading order by impeding preferred resources from being able to compete in long-term RFOs, the Commission should revisit the evaluation criteria applied by IOUs in RFOs. As PG&E describes it, LCBF provides for resource alternatives to be selected based on their relative cost effectiveness and their ability to meet the portfolio's specific needs. Theoretically, a cost-effective preferred resource that meets the specific needs of the portfolio, but is relatively less cost-effective than a

---

[6] *SCE AB 57 Bundled Procurement Plan*, R.10-05-006, dated April 20, 2011, p. 22.

[7] *PG&E Bundled Procurement Plan*, R.10-05-006, dated March 25, 2011, pp. 40-41.

[8] Public Utilities Code Sections 451.

[9] Public Utilities Code Sections 454.5(b)(9)(C).

[10] *Energy Action Plan II,* p. 2.

conventional generation resource, would not be selected under LCBF. This outcome would appear to contradict compliance with the loading order.

Are there any changes specific to meeting Local Capacity Requirements (LCR)?

Rather than authorizing the IOUs to procure to meet LCR need on the assumption that preferred resources will not materialize, the Commission should assume those resources will meet LCR need, and direct the IOUs to develop their preferred resource programs in a manner that will produce those results. The Commission should direct the IOUs to work with CAISO to determine a priority-ordered listing of the most electrically beneficial locations for preferred resource deployment (supply or demand side) to maximize such resources' ability to reduce LCR need. Such a listing should use a reasonable level of electrical aggregation, such as, at minimum the LCR sub-area, or if possible, a finer electrical-location granularity such as substations. This determination would be to help identify all of the best locations "downstream" of certain substations or LCR sub-areas for preferred resource installation, so that the IOUs' programs to secure preferred resources could first focus on these better locations.

DRA recognizes that allowing energy efficiency to compete in RFOs could pose significant challenges. It is difficult, based on existing program design, for long term planners to determine where energy efficiency will result in reduced energy consumption at the locational granularity of conventional generation. Instead of the cost to *generate* a kWh, energy efficiency is based on the cost to *avoid generating* and delivering a kWh. The only way an energy efficiency program could currently compete in an RFO would be to assume the cost of generating and delivering a kWh, based on the forecasted resource need, and then construct an energy efficiency portfolio based on that price.

In addition, individual energy efficiency programs are generally not equivalent on a MW to MW basis with conventional generation. A collection of energy efficiency programs or an energy efficiency portfolio could match the nameplate capacity of a conventional generator. But it takes time to craft and design an adequate portfolio that will attain its projected savings and cost effectiveness. Currently, the IOUs are the only entities capable of creating these energy efficiency portfolios and California does not have a system to promote third party aggregators to participate in creating a portfolio to compete with the IOUs. Requiring the IOUs to include energy efficiency portfolios into the RFO process could raise similar issues to attempting to compare Utility Owned Generation with Power Purchase Agreements. Thus, the most efficient way to bid energy efficiency programs into the RFO process would be by third party energy efficiency aggregators.

The only instance that DRA is aware of where third party energy efficiency aggregators bid in California is through the IOU's Competitively Bid Third Party Programs. These programs are a result of a Commission mandate which requires 20% of IOU EE portfolios to be developed and managed by third parties. Allowing third parties to manage EE portfolios is a recent development, and it has not yet been determined whether these third party programs are more effective compared to traditional utility-run energy efficiency programs.

The challenges of allowing energy efficiency to meet LCR need in an RFO are also substantial. For example, conventional generation RFOs are based on a per kW basis, since they need to fulfill capacity obligations. Currently no energy efficiency programs could provide capacity on an as-needed basis due to the characteristics of the resource.

Energy efficiency programs are designed to maximize reduced energy use and lower energy bills. When energy use is reduced, the need for capacity is reduced by the same amount. Therefore, even though energy efficiency programs are not designed for capacity, reductions can be expected through current energy efficiency measures and lower LCR should be expected in the future through reduced load forecasts.

While it may be possible to design an energy efficiency program to maximize the reduction in local capacity need, no such programs exist and creating one would require a significant analysis of the feasibility and cost impacts. This study must be done before the Commission can decide that using energy efficiency to address local capacity requirements follows the same economic principles as using these resources to address energy reductions.

Energy efficiency programs and the cost effectiveness methodologies are designed for a system level perspective, not to provide locational attributes that could sufficiently reduce local capacity requirements to avoid building new generation. Adding this component into the methodology would require a significant change in program design. Similarly, an energy efficiency program that would make the location of the energy efficiency measures more visible to the CAISO and show the degree to which each measure reduces consumption would also require significant changes in program design. Thus, rather than trying to design EE programs that can compete in an RFO, DRA supports using forecasted demand side reductions to reduce LCR need, as recommended in DRA's Opening Brief filed September 24, 2012.

3. **What specific characteristics or attributes must any resource -- including demand-side, energy storage, or distributed -- provide in order to meet future procurement needs? In the absence of a Net Qualifying Capacity, what methodology should be used to determine a proxy capacity value for resources lacking a Net Qualifying Capacity for use in LCR capacity accounting? How can these characteristics or criteria be turned into criteria to evaluate resources bid into a Request for Offers to meet LCR or other needs? How should those criteria be weighted?**

DRA has no specific recommendations for developing a proxy capacity value for resources lacking a Net Qualifying Capacity rating or how criteria can be developed or weighted for purposes of evaluating resources in an RFO, but notes that there are significant challenges to developing such metrics. DRA reserves the right to respond to other parties' comments on this issue in its reply.

DRA understands that experts assisting Energy Division in the Storage proceeding, Rulemaking (R.) 10-12-007 may examine capacity factors and utilization factors, which are related to Net Qualifying Capacity, but it is too soon to know what the methodology and results will be if the work is performed. DRA suggests that the Assigned Commissioner and ALJ seek follow-up information on this process in the February 2013 timeframe, when the scope of work will be more clear.

The Commission adopted a Qualifying Capacity Methodology in the prior RA rulemaking, R.09-10-032. In Phase 1 of the current RA Rulemaking, R.11.10-023, the Commission adopted qualifying capacity rules for dynamically scheduled and pseudo-tie resources. In Phase 2 of R.11-10-023, beginning in 2013, rules for energy storage and distributed generation will be developed as part of the Phase 2 scope.

The methodologies for calculating qualifying capacity are complex and typically developed with stakeholder input. It is not reasonable to expect that qualifying capacity methodologies for resources currently lacking a Net Qualifying Capacity, such as energy storage, can be determined in Track I of the LTPP proceeding. This effort must either take place in a later phase of the LTPP or in the RA proceeding. Since all prior work on qualifying capacity methodologies has occurred in the RA proceedings, and with continuing discussions expected in

Phase 1 of the current RA proceedings, DRA recommends that this issue be determined in the RA proceedings rather than in the LTPP proceedings.

4. **What are the pros and cons of the following procurement methods with regard to: 1) local procurement considered in Track 1 of LTPP, and 2) operational flexibility and general system procurement considered in Track 2 of LTPP?**

   A. **Continuation of current practices for procurement with minor clarifications;**

   B. **A "portfolio approach" that allocates, based on strategic/portfolio considerations, the total quantity of new flexible resources among various eligible resources (for example, how could/should the allocations be adjusted periodically based on current or expected conditions?).**

DRA believes that evaluating cost effectiveness on a portfolio basis is reasonable and similar to the Commission's approach to energy efficiency. Although selection of resources consistent with the loading order should be the highest priority, supply side resources such as energy storage should compete on an equal footing once the preferred resources have been accounted for in meeting demand. If all things are equal in terms of cost-effectiveness, then individual resource types should not be given extra points that tilt the balance in their favor *unless* the parties have a chance to comment on and analyze data supporting such treatment. No set minimum amount of energy storage should be mandated or suggested. If the Commission adopts a "portfolio" approach, then it should not include a particular set aside for storage in the absence of a compelling justification.

      a. **SCE provided two proposed alternatives to filling any LCR need at the September 7, 2012 workshop, one with flexibility for SCE in procuring resources via two separate tracks, and another approach using an all-source RFO. Is there some way to blend these approaches? If so, how, and should the Commission attempt to do so?**

   C. **Establishing a set of minimum criteria for operational flexibility characteristics for all acquired resources;**

Parties to the RA rulemaking, R.11-10-023, are working to define flexible characteristics. DRA continues to support coordination between the RA and LTPP proceedings on this important issue, but believes it is premature to consider this topic in Track 1 of the LTPP proceeding. DRA recommends a schedule establishing a stakeholder process and reasonable timetable to develop flexible characteristics definitions and need assessment. DRA concurs with CAISO's calls for resources that "supply energy in the right amount at the right time and in the right place."[11] Ongoing studies and stakeholder processes are needed to inform decision-making on flexible characteristics and their forecasted need. At the very least, DRA would like to know

- what flexibility characteristics are needed;
- how the need assessments will be conducted;
- what assumptions will be used for those need assessments;
- what resources can participate in providing that need; and
- how these resources will be procured.

D. A "strong showing" requirement that the utility must demonstrate that its procurement process was substantially open to all resource types and appropriately considered all of the values discussed above and that the resulting portfolio of resources is an optimal solution.

DRA has no opening comments in response to this question, but may reply to the comments of other parties.

E. Adjusting existing procurement mechanisms, such as the Renewable Auction Mechanism, to focus on the physical locations with needs that can be met by that programmatic resource.

The RAM program currently allows only projects located within the IOUs' service territories to bid into the RAM auction and also permits the IOUs to target RAM procurement to "preferred locations," i.e. those areas located near load where there is likely to be surplus transmission or distribution capacity. Decision (D.)10-12-048 requires the IOUs to provide information about their preferred locations or this "available capacity" at the substation and circuit level to potential bidders in map format.

If the Commission finds it appropriate that RAM-eligible projects should also be eligible for operational flexibility or LCR, one option would be for the Commission to create a fourth product bucket within the current RAM program for bidders with resources that can be used to meet the IOUs' specific LCR or locational requirements. As with the current RAM program, the IOUs could allocate a megawatt amount they are seeking to procure per auction for LCR need. Projects that meet this LCR or locational requirement could compete against one another on a

[11] CAISO Opening Brief, September 24, 2012 at 46.

price and preferred locational basis, irrespective of technology type. Other projects could continue to compete against one another in the other product categories based on production profile (baseload, peaking as available, non-peaking as available), if they choose as this fourth product category would have no disruption to these auctions.

DRA suggests that a starting point for exploring how to expand the RAM program would be for the Commission to direct the IOUs to update their RAM maps to include information on preferred locations for LCR need or operational flexibility need (once operational flexibility need is determined/defined).

5. **At the September 7th workshop, some parties discussed retrofits to existing generation assets as a potential source of incremental capacity. What, if any, changes would need to be made to the most recent long term RFO issued by PG&E, SDG&E, and SCE to allow for incremental capacity associated with retrofits to existing generation to compete to meet Local Capacity Requirements? Are there any differences in payment streams that should be given for existing capacity, as opposed to upgraded capacity?**

DRA has no opening comments in response to this question, but may reply to the comments of other parties.

6. **At the September 7th workshop, both SCE and Enernoc raised concerns that it would be difficult to procure demand response resources that match the online dates (2017 to 2020) and duration (e.g., 20 years) of the conventional generation that is being contemplated as a source of LCR capacity. How could a demand side program be authorized through this LCR procurement process that delivers an on-line date and a duration that is comparable to conventional generation? What additional values are currently attributed to demand response resources in other markets that are currently not accounted for in California, and that might be taken into account as part of an LCR procurement process?**

The question asks how a demand side program could be authorized through the LCR procurement process that delivers an on-line date (2017 to 2020) and a duration (e.g., 20 years) that is comparable to conventional generation. This question appears to imply that the short lead time and the flexibility that demand response resources provide, could somehow become a hurdle in the LCR procurement process. To the contrary, demand response resources' short lead time and flexibility ensure that locally dispatchable demand response resources would be available when needed, in the right location and amounts.

The current procurement paradigm of long lead times and long duration is necessitated by conventional generation that requires long lead times, permitting, and "steel in the ground" physical construction that lasts for decades. If the supply/demand balance changes radically by 2020, there is little the Commission and the utility ratepayers can do to avoid either the redundancy or inadequacy of the conventional generation already procured and paid for in 2012. On the other hand, the demand response resources for 2020 need not be procured in 2012 – they could be procured as late as 2017 or 2018. Furthermore, the procurement of demand response resources could be designed to ensure local dispatch and the quantities procured could be adjusted up or down as the forecasted LCR need for 2020 becomes more accurate as 2020 approaches. This unique procurement flexibility of demand response resources would afford more efficient planning and management of all generation resources without compromising the Commission's reliability standards.

Over the last three demand response program cycles (2006-2008, 2009-2011, and 2012-2014), a span of nine years, the utilities, with the help of third-party demand response aggregators, have demonstrated that they can procure and maintain thousands of megawatts of demand response resources continuously.[12] Now with years of experience with demand response, all of the stakeholders to the procurement process should consider demand response resources as a supply side alternative to conventional generation. Over the next several years, demand response resources are expected to be fully integrated into the CAISO's wholesale market. Demand response resources, with their short lead time and flexibility, are also ideally suited to help integrate the increasing amount of renewables that will be added to the IOUs' resource mix.

The Energy Action Plan guides California's energy policies, and sets forth a loading order of preferred resources to meet energy needs, which places energy savings from or reduction in need due to EE, DR, and distributed generation such as CHP at the top of the loading order. In this context, DRA believes it is essential to capture all the cost-effective demand response resource potential before contemplating the procurement of conventional generation. The Commission's commitment to meeting five percent of peak demand with price

[12] For example, in the current 2012-2014 DR cycle, in D. 12-04-045, the Commission has funded demand response programs that will provide more than 2,700 megawatts for the three IOUs by 2014.

responsive DR[13] and the continued ratepayer investment in demand response ensures that these preferred resources will show up in the right place and at the right time without necessitating long lead time and duration. However, if the Commission believes it is advisable to evaluate longer funding cycles, then it should consider that issue in related proceedings, including the DR Rulemaking. In any case, given California's strong commitment to the loading order and the requirement of Public Utilities Code Section 454.5(b)(9)(C), it is unreasonable to assume that the Commission will not fund demand response programs for the years in which LCR need is predicted.

III. CONCLUSION

DRA looks forward to responding to the comments of other parties on the complex issues raised in this Ruling.

Respectfully submitted,

/s/ DIANA L. LEE

____

DIANA L. LEE
Staff Counsel

Attorney for the Division 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

October 9, 2012

[13] D.12-04-045 at 11-12.