CMW/avs 2/13/2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development.	Rulemaking 01-10-024 (Filed October 25, 2001)

ASSIGNED ADMINISTRATIVE LAW JUDGE'S RULING (ALJ) ON THE SCOPE AND SCHEDULE OF RESOURCE ADEQUACY WORKSHOPS

1. Summary

This ruling provides a scope and schedule for handling the resource adequacy, reserve levels, and deliverability issues that the Commission directed in Decision (D.) 04-01-050 be handled in workshops.[1]

To facilitate the workshop process, the respondent utilities are directed to file written comments on all discussion topics listed in each section prior to the first workshop. Other interested parties may also comment; the Commission especially welcomes the contributions of the California Energy Commission (CEC) and the Independent System Operator (ISO). We encourage all parties in their reply comments to highlight topics they consider candidates for consensus agreement.

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[1] *See* Sections IVA.8 and 9 of D.04-01-050, mailed January 26, 2004. Unless otherwise stated, all page references are to D.04-01-050.

After receipt and review of the written comments, an initial workshop will be held on March 16, 2004. This workshop will first explore areas of potential consensus agreement and memorialize any agreements reached. Next, the workshop will proceed to discuss the topics identified as "first round" issues and for any of these issues not resolved at the workshop, identify and assign work tasks that will facilitate resolution of each issue at the next series of workshops. Following the conclusion of these workshops, a status report and recommendation will be prepared and filed with the Commission by the workshop coordinator, James Hendry of the Commission's Division of Strategic Planning.

The schedule for comments and workshops is:

Opening Comments Filed	March 4, 2004
Reply Comments Filed	March 11, 2004
Initial Workshop	March 16, 2004
Second Workshops	April 12, 13, and, if necessary, April 14, 2004

2. Background

In D.04-01-050 the Commission laid out the guidelines, policies, and principles that should guide each utility's long-term procurement plan filing as well as the requirements that all Load Serving Entities (LSEs) located in each utility's service territory should meet. As the decision states:

> The utilities shall file by the end of March 2004 a working outline of their long-term plans that includes the level of detail and specific scenarios addressed in this decision, the means by which they will incorporate the resource adequacy framework developed through workshops, and a showing that the material provided in the public filing will allow for meaningful participation by all parties.
> (Ordering Paragragh 1, p. 195)

The decision also states that:

> The long-term plans should reflect the outcome of the workshops on reserve requirements. If that process is not concluded, the utilities should make their best estimate of the outcome of that process and estimate accordingly. (Finding of Fact 52, 0. 185.)

3. Purpose and General Guidelines

> "As stated in D.02-10-062, we intend that the long-term plans of the utilities be the primary vehicles for their decision-making, planning, and procurement…Long-term plans that provide solid information in appropriate detail, and that are reviewed and approved by this Commission, can provide the basis for confidence on the part of consumers, of utility managers, of investors, and of the financial community…(p. 88)"

In addition to the above listed groups, the long-term plans should provide a basis for confidence for California's energy suppliers and other agencies and entities interested in reliability and resource planning such as the CEC, ISO, and the Federal Energy Regulatory Commission (FERC).

In order to assist the utilities in making their long-term procurement filings in a timely manner, the first workshop should focus on technical aspects such as how LSEs forecast demand, and how supply resources should be valued and considered in assessing an LSEs' resource adequacy.[2]

Finally, we should also add to the first workshop an initial discussion on the issue of "deliverability", recognizing that this issue may require further

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[2] This focus is consistent with the direction given in the September 22, 2003 ruling on resource adequacy issues.

examination in the April workshops. Subsequent workshops will address the issue of penalties and reporting requirements.[3]

In conducting the workshops we remind parties of our previous admonitions, namely:

- Don't "Re-invent the Wheel" -- a significant amount of forecasting, supply assessment, and other issues have already been performed by the utilities and others and should be utilized where appropriate.
- Build off of existing proceedings -- for example, parties should explore how the record developed in other Commission proceedings can be utilized in developing reserve requirements; and,
- No relitigation of issues already decided by the Commission.

4. List of Issues

The following issues are currently planned of the workshop process:

First Round (March Workshop)

- Forecasting issues
- Development of Electric Service Provider (ESP) forecasts
- Phase-in of Planning Reserve Margin requirements
- Development of "peak demand" forecasts for applicable summer months;
- "Counting" of Utility Retained Generation (URG) Resources
- Treatment of Qualifying Facility (QF) Resources

[3] With the decision's adoption of a 10-year planning horizon, cyclical review on a 2-year basis, and use of the ERRA for annual adjustments, many of the timing issues associated with any reporting requirement have been largely decided. The issue of what needs to be reported should be the main focus of any workshop.

- “Counting” of California Department of Water Resources (DWR) Contracts
- Availability of Spot Energy and Capacity
- “Counting” of other long-term contracts
- Treatment of Energy Efficiency, Demand Response, Distributed Generation
- Deliverability Requirements (initial discussion)

Second Round (April Workshop)

- All First Round Issues not otherwise resolved
- Deliverability
- Penalties
- Reporting

5. First Round Issues

The following is a review of issues for each of the first-round issues.

a. Forecasting

In their previously submitted procurement plans, all three utilities presented fairly detailed determinations of their forecasted energy needs. Generally, utility forecasts have involved the use of econometric models using a variety of inputs (population, economic growth, expected end-use electricity prices, natural gas prices which are an input to forecasting end-use prices, and other variables.) Often this analysis is performed for each customer class, and in some cases even for large individual customers. Energy production models and load duration curves are also developed which, in theory, provide forecasted hourly data on energy supply and demand.

As a threshold issue, the Commission has determined that:

> The utilities themselves are the ones responsible and accountable for meeting the loads and energy requirements of the customers in their service areas. The utilities, not the CEC, are required to meet an obligation to serve under

> several sections of the Pub. Util. Code…. Therefore, regulatory clarity and appropriate placement of responsibility requires that the utilities should have the responsibility of estimating their own future needs. (p. 96.)

During the procurement planning hearings in 2003, several parties complained of a lack of "consistency"[4] between the utilities' load forecasts, although it is unclear what this means. As D.04-01-050 notes: "although parties have complained about the lack of consistency of the forecasts, no party has substantively challenged the results." (p. 44-45.)

To some extent, the Commission has addressed the parties' concerns by requiring that the utilities each provide forecasts for the same set of scenarios (*e.g.* CEC base case,[5] core/non-core model, high gas prices,[6] etc.), as well as use the most recent gas price forecasts. We've also required that the utilities justify the use of assumptions other than those of the CEC base case.

Our development of a reserve requirement will require some additional consistency between utility forecasts. For example, we propose that utilities should use a "1-in-2"year forecast as their base case.[7] Additionally, the utilities and LSEs will need to address the issue of forecasting coincident peak demand

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[4] *See* for example, Sheffrin Tr. 4453-4454.

[5] "The CEC's IEPR "information and analyses" should form the base case. If a utility does not find it appropriate to use that as its base case, it should include the IEPR case along with its preferred base case. The utility should report how and why the assumptions underlying its forecasts differ from those of the CEC forecasts." (Finding of Fact 51, p. 185.)

[6] "We direct that future long-term procurement plans should reflect fully the expected range of prices of fuel and costs of purchased power at least up to the 95th percentile of the expected distribution." (p. 96.)

[7] This requirement is consistent with the methodology used by the CEC in its IEPR.

(*i.e.* the time of highest demand upon the ISO system as a whole) as opposed to each utilities' non-coincident peak demand (*i.e.* the time when each individual utility reaches its peak demand which may or may not be the same as the ISO system).

Given the inherent complexity in forecasting, we are not sure what more can be done to achieve "consistent" results. As the decision notes:

> As a general matter, SDG&E previously explained that there is an unnecessary preoccupation with 'common' or 'perfect' assumptions to be used by the utility in its long-term resource planning. In SDG&E's view, while assumptions clearly need to be reasonable, the more critical piece is the testing of the assumptions to accommodate uncertainty). In the end, the utilities must plan using the best data for their unique circumstances, as they are accountable for the results (p. 44-45 citing SDG&E's Reply Brief).

However, SDG&E, along with PG&E and SCE, are signatories to the Joint Recommendation and the issue of forecasting was included in the proposed scope of the workshops.

Therefore, parties should be prepared to discuss:

a) What additional guidance should be provided to the utilities in developing their forecasts in order to improve consistency?

b) How do LSEs propose to determine their coincident and non-coincident peak demands and what are the coordination issues associated with this?

c) How accurate have the utilities (as well as the ISO and CEC) been in forecasting demand?

d) Is "consistency" between forecasts more important than "accuracy"?

As part of this discussion, the utilities should submit appropriate descriptions and examples of how they currently prepare their forecasts. The ISO and CEC are also invited to make similar presentations.

b. Forecasting Load to Determine ESP Obligations

> In order to provide reliable service, each Load Serving Entity within [the utility's] should have an obligation to acquire sufficient resources for their customer load. (Ordering Paragraph 2, p. 195)
>
> …………
>
> In the workshop it will be necessary to identify the treatment of direct access load and who should be responsible for forecasting it. (p. 46.)

In their previous procurement filings, the utilities essentially performed a "top-down" forecast of load served by ESPs, first calculating total load for each customer class and then subtracting out the appropriate portion of each utility's load served by ESPs. An additional step that would need to be taken is to further assign to each individual ESP its proportionate share of load. An alternative to this approach would be a "bottoms-up" approach where each ESP would be responsible for forecasting its own load.

Both approaches have advantages and disadvantages. The utilities, for example, generally have access to much more sophisticated econometric and load profiling data while ESPs may have a better sense of usage trends among their particular customers.

Under either approach, the final result must ensure that all demand (utility and ESP) is fully accounted for. Additionally, under either approach, the final forecasts should be adopted by the Commission after the appropriate hearing and evidentiary process. This procedural process would ensure that the

Commission, as well as other parties, will have a full opportunity to assess the reasonableness of any forecast as well as any attempts to "game" the forecast.

Therefore, parties should be prepared to discuss:

a) What is the preferred approach for forecasting ESP load requirements (top-down, bottoms-up, some combination, other)?

b) How could conflicting load forecasts be reconciled prior to the hearing process?

c) Other implementation issues as appropriate.

c. Phase-In

In D.04-01-050, the Commission largely adopted the Joint Recommendation's proposal for a 15% Planning Reserve Margin (PRM) to be phased in by 2008, except that the Commission adopted a somewhat higher reserve margin of 15-17%.

In D.03-12-062 the Commission approved the Joint Recommendation's proposal that for 2004, the utilities would meet a 7% ***Operating*** Reserve Margin (ORM) and that this margin would not include "reasonably expected resource outages." This means that the ***Planning*** Reserve Margin for the utilities in 2004 (which includes expected outages) was quite likely higher than 7% (*See* discussion at the end of Section IV.A.5 of D.01-04-050).

D.04-01-050 requires that:

> …[T]he utilities and LSEs should meet this 15-17% [planning reserve] requirement by no later than January 1, 2008, with interim benchmarks established starting in 2005. ***The starting point for compliance will be determine[d] in the workshops.*** (p. 23.)

Therefore, parties should be prepared to discuss:

a) What is the appropriate starting point for phasing in the 15-17% planning reserve requirement?; and,

b) What are the appropriate interim benchmarks for 2005 through 2008?

d. Development of "peak demand" for applicable summer months

D.04-01-050 requires that each LSE must forward contract one year ahead for 90% of their peak needs for the Summer months of May through September. This will require the development of peak demand estimates for each of these months. As previously mentioned, much of the data to calculate these peak demands may already exist in each utility's existing load forecasts. A question that needs to be addressed is for how much of the month must each LSE meet this 90% requirement.

In their original FERC filing, the ISO examined this issue and offered several options for meeting it. These options included either developing a load duration curve for each hour of the month or (as the ISO recommended) requiring LSEs to be able to meet the peak demand requirement for a set number of hours each month (*e.g.* the forecasted highest 1, 5, or 10 hours).[8]

This latter approach appears preferable and is the approach that we would recommend.

Therefore, parties should be prepared to discuss:

a) What is the appropriate method to determine peak monthly demand?

b) What is the appropriate coverage of this peak demand that LSEs must demonstrate?

e. Counting Resources – General Observations

As D.04-01-050 states:

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[8] The relevant excerpt of the ISO's filing is appended to this document at Attachment 1.

> To the extent possible, the workshop also should develop a common approach, or "template" as WPTF calls it, for evaluating each LSE's resource adequacy. While complete consistency between all LSEs' may not be feasible, at a minimum the workshop process should result in common approaches so that decision-makers and interested parties can evaluate and compare resource adequacy both between utilities and between all entities under Commission jurisdiction. (p. 44.)

As part of the Resource Adequacy Working Group (RAWG), an initial list of questions (attached) begins to address the issues associated with "counting" resources. Although preliminary and still a "work-in-progress" this document serves as a useful starting point to begin discussions over the evaluation of resources.

Additionally, we offer the following guidance and observations.

1. "Counting" of URG Resources

In their written comments, the utilities should show how they have determined the availability and dependable capacity of their resources and clearly document the underlying assumptions.

2. Treatment of QF Resources

As noted in D.04-01-050, in "reviewing the utilities' filings, it appears that they already implicitly discount QF availability by using historical deliveries to the grid"(p. 170). This approach appears desirable in that it already takes into account that at any given time some proportion of QFs are either not operating or are dedicating their energy use primarily to their host facility. Use of this approach thus appears consistent with the use of a "net" methodology to determine reserve requirements associated with QFs adopted in this decision (Finding of Fact 41 p. 195).

As part of the RAWG process, participants offered two modifications to this approach to better reflect QF operating conditions: (1) separating out QFs that are located outside of the utility's service territory (thus raising deliverability issues); and (2) new QFs (that lack a history of operation.) Parties should be prepared to discuss adoption of these modifications.

Issues associated with the long-term future of QF resources nearing their contract expiration dates will not be considered in this workshop as the Commission has announced its intent to develop new procedural forums to address this issue.

3. "Counting" of DWR Contracts

D.04-01-050 concluded that:

> California should receive full credit and value for the long-term contracts entered into by the DWR to help California meet its energy needs during the crisis. (Finding of Fact 22, p. 182)

Parties should be prepared to discuss how the utilities will implement this mandate.

4. Availability of Spot Capacity

> A better approach to ensuring reliable service is to limit each utility's reliance on spot market purchases less than a month in advance to be based on reasonable (and perhaps even conservative) estimates of the energy available in this market…Thus, reasonable estimates, taking into account expected loads/resources in the Western region, and the procurement strategies of energy purchasers in the West would be helpful to define a reasonable estimate of appropriate reliance on the short-term energy markets. It is precisely this sort of issue that the CEC is examining as part of the Western Resources Assessment Team (WRAT) and as

> part of its IEPR process. (Findings of Fact 14,15 at p.180.)

5. "Counting" of other long-term contracts

This issue was raised by AReM and identified as a workshop issue. Parties should specifically identify "other" long-term contracts and discuss how each type of contract should be counted.

f. Treatment of Energy Efficiency, Demand Response, Distributed Generation

In D.04-01-050 we stated that:

> In guiding the workshops, we reiterate our concern that these non-traditional resources be fully and fairly evaluated, and that any resource adequacy framework not unintentionally limit the procurement of these resources or bias resource procurement solely toward generation-only resources. Not counting these type of "soft" resources in the traditional resource adequacy frameworks could result in California having to pay twice for capacity thus limiting the cost-effectiveness of these programs. (p. 46)

We also noted that the workshop process should not be used to duplicate work that is currently being conducted in other Commission proceedings. For example, measurement and evaluation (M & E) criteria for energy efficiency are currently being developed in R.01-08-028. We do not see significant benefit in duplicating work already being performed elsewhere. Instead, parties should focus on how the results of these other proceedings can be incorporated into a resource adequacy framework.

D.04-01-050 already recognizes these other on-going proceedings, directing that:

> We require utilities to present to the Commission in this rulemaking within twenty-days of this decision the methodologies they will use to ensure that forecasted measured savings of energy efficiency savings and

> demand reductions in utility long-term plans in this rulemaking are equivalent to the savings calculated for measures used in utility savings assumptions for procurement related energy efficiency programs submitted in R.01-08-028. (Ordering Paragraph 8, p. 196.)

> And that:

> In D.03-06-032, the Commission adopted demand response goals for each utility and directed that the IOUs include the MW targets for calendar years 2003 through 2007 in their procurement plans, *specifically stating the filings in this proceeding should include: numeric targets coinciding with the findings in this decision; documentation of the amount of demand response (price-triggered) to be achieved by July 1 of each calendar year (with the exception of 2003, where the goals shall be met by the end of the calendar year); which programs and/or tariffs the IOU will rely upon to achieve the targets; and a contingency plan for covering capacity needs should the utility fall short of meeting the demand response goals.* (Finding of Fact 64.)

> Therefore, parties should be prepared to discuss:

> a) What work is being done in other proceedings that is useful here?
>
> b) How can this work be incorporated here?
>
> c) What additional work is needed?

g. Deliverability Requirements (initial discussion)

The initial workshop will be used to begin the discussion of deliverability issues associated with energy resources, with particular emphasis on identifying options to be explored in the next April workshops.

Therefore, **IT IS RULED** that:

1. The respondent utilities, and any interested parties, shall file and serve written comments on all discussion issues identified above by March 4, 2004. Electronic service should be provided James Henry at jeh@cpuc.ca.gov.

2. All interested parties shall file and serve reply comments on March 11, 2004. Parties should focus their comments on identifying areas of potential consensus agreements.

3. A workshop will be held at the Commission's San Francisco offices on Monday, March 15, 2004, beginning at 9:00 a.m.

4. Further workshops will be held at the Commission's San Francisco offices on Monday, April 12, 2004 and Tuesday, April 13, 2004. If necessary, an additional workshop will be held on Wednesday, April 14, 2004.

5. Following the workshops, a written status report and recommendation for the Commission should be prepared by the workshop coordinator, James Hendry of the Division of Strategic Planning.

Dated February 13, 2004, at San Francisco, California.

/s/ Christine M. Walwyn
Christine M. Walwyn
Administrative Law Judge

ATTACHMENT 1

ATTACHMENT 2

CERTIFICATE OF SERVICE

I certify that I have by mail and by e-mail this day served a true copy of the original attached Assigned Administrative Law Judge's Ruling on the Scope and Schedule of Resource Adequacy Workshops on all parties of record in this proceeding or their attorneys of record.

Dated February 13, 2004, at San Francisco, California.

/s/ Antonina V. Swansen
Antonina V. Swansen

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

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If specialized accommodations for the disabled are needed, *e.g.*, sign language interpreters, those making the arrangements must call the Public Advisor at (415) 703-2074, TTY 1-866-836-7825 or (415) 703-5282 at least three working days in advance of the event.