Docket:	**R.12-03-014**
Witness:	**Julia May**
Exhibit No.:	

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans	R.12-03-014 (Filed March 22, 2012)

SUPPLEMENTAL PREPARED DIRECT TESTIMONY OF JULIA MAY ON BEHALF OF THE CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

JULY 23, 2012

This supplemental testimony, which is submitted on behalf of the California Environmental Justice Alliance (CEJA), is in response to June 25, 2012 Testimony of Southern California Edison (SCE) in the 2012 Long Term Procurement Plan proceeding (LTPP). This supplemental testimony also attempts to address some of the request by Commissioner Florio in this response to the assertions of SCE.

A. SCE Identified Many Uncertainties About LCR Needs in Its Testimony That Support Deferring Procurement.

In agreement with CEJA's Opening Testimony,[1] SCE's Testimony made repeated statements about uncertainty in predicting these future resource needs so far ahead of time, stating:

> The Commission should thus authorize SCE to have flexibility to:
> . . . ***defer procurement actions due to changed circumstances or if other cost-effective options become available***.[2]
>
> Finally, the Commission should ***defer procurement*** of the 430 MW identified by the CAISO to replace Once Through Cooling (OTC) generation ***in the Big Creek/Ventura*** **area** until the 2014 LTPP cycle ***because this need does not have to be addressed now***.[3]
>
> The CAISO results are quite sensitive to the input assumptions (i.e. resources scenarios and locations) that are used in the LCR modeling analysis. The CAISO's input assumptions are reasonable based on information available today. But, these input assumptions may change as new information becomes available. ***Some significant assumptions that can change the LCR need include changes to the reliability planning standards, demand forecast, resource scenarios, LCR generations sites, and transmission options.***[4]
>
> There is always the possibility that the lower forecast may occur, due to many economic and other planning factors. ***While a lower load will not totally eliminate the need for new LCR generation, it may substantially diminish the resource need amount by hundreds of megawatts.***[5]
>
> ***Despite SCE's general satisfaction with the CAISO analysis, any forecast of the future is uncertain.*** This section of SCE's testimony describes conditions which could lead to a higher or lower need for LCR resources than the CAISO has identified.
> ***The Commission should avoid making long-term commitments to new generation procurement that could subsequently be rendered significantly less valuable by changed circumstances.*** The Commission should authorize procurement, up to the range

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[1] *See* June 25, 2012 Testimony of Julia May in R.12-03-014 on Behalf of CEJA (J. May Opening Test.) at pp. 3, 15, 36, 40.
[2] SCE June 25, 2012 Opening Testimony of SCE in R.12-03-014 (SCE Test.) at p. 2 (emphasis added).
[3] SCE Test. at p. 3 (emphasis added).
[4] SCE Test. at p. 5 (emphasis added).
[5] SCE Test. at p. 6 (emphasis added).

identified by the CAISO, but not require procurement of a specific amount of MWs within a specific timeframe.[6]

There are many other examples of sources of uncertainty which SCE identifies in its testimony.[7]

Importantly, due to this uncertainty, SCE recommends that the Commission does not authorize procurement in the Big Creek/Ventura area. The Commission should follow SCE's recommendation for the reasons it identifies and the reasons discussed in my Opening Testimony.

Unfortunately, even after identifying these uncertainties, SCE came to the conclusion that despite these uncertainties, the Commission should give SCE authority to procure new resources in the LA Basin up to the full amount identified by CAISO with no economic risk:

> ***SCE proposes that the Commission authorize SCE to procure new LCR generation needed in the LA Basin area on behalf of all system customers.*** To be clear, SCE would prefer to not procure resources to meet system needs, and does not want to make long-term commitments that could subsequently be rendered less valuable by changed circumstances. ***For SCE to accept this obligation, the Commission must provide full cost recovery for such procurement and full cost allocation to all benefitting customers. Cost should be allocated to all customers benefitting from the grid reliability provided by the new LCR generation through the existing Cost Allocation Mechanism (CAM). No benefitting customers should be able to opt out of the CAM for any reason.*** Additionally, SCE should be permitted the opportunity to address its capital structure if LCR procurement contracts create a debt equivalence burden that harms SCE's creditworthiness.[8]

SCE's proposal should be rejected. It is a bad idea to take an economically risky (and environmentally harmful) scenario, and simply shift the burden of this risk to ratepayers. This takes the incentive away from SCE to make sure that it only invests in economically sound projects.[9]

The section below discusses a study demonstrating that the highest economic risk in energy development comes from fossil fueled and nuclear power plants. It also recommends against shifting this risk to consumers. This report, which is co-authored by a former public utilities commissioner, supports my opinion that SCE's proposal should be rejected.

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[6] SCE Test. at p. 4 (emphasis added).
[7] *See generally* SCE Test.
[8] SCE Test. at p. 2
[9] As discussed in my previous testimony, it also does not make sense to take this action considering the already severe burden of air pollution in the region, and state policies requiring that additional energy efficiency, demand response, distributed generation, and other options be put in place that could replace the need for such conventional generation. *See generally* J. May Opening Test.

B. Emphasis on Fossil Fuel Resources in Planning Represents the Highest Economic Risk to Investors, Which Should Not Be Shifted to Ratepayers.

SCE's desire to procure new resources based on CAISO's analysis would create a high risk for ratepayers if SCE invests in new fossil-fuel resources. This is especially true due to all the uncertainties that even SCE has highlighted. A report by Ceres (an advocacy organization for sustainable business practices and investment) provides a detailed assessment of economic risk of energy investments.[10] The report details the high economic risk associated with fossil fuel investments in long-term planning:

> With an estimated $2 trillion of utility capital investment in long-lived infrastructure on the line over the next 20 years, regulators must focus unprecedented attention to risk—not simply keeping costs down today, but minimizing overall costs over the long term, especially in the face of possible surprises.
> . . . Placing too many bets on the conventional basket of generation technologies is the highest risk route.[11]

The report demonstrates major losses to investors and ratepayers from planning decisions that do not include sufficient information about economic risk factors, especially for large, centralized power plants, for example:

> The NorthBridge Group estimates that ratepayers, taxpayers and investors were saddled with $200 billion (in 2007 dollars) in "above-market" costs associated with the build cycle of the 1970s and 80s.[12]

The report further describes how conditions today are likely *more* risky for energy investment in conventional energy technologies,[13] but finds that by taking specific risk factors into account, regulators can reduce risk including the planning risk of inaccurate load forecasts.[14] The planning risk is particularly of concern since CAISO is using highly unlikely double contingency outages projected over a long period as a measure of need for the type of large scale investment

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[10] July 22, 2012 Testimony of Julia May in R.12-03-014 on Behalf of CEJA (J. May Supplemental Test.), Attach. B (*Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know, How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility,* A Ceres Report (April 2012)) [Hereinafter Ceres Report].
[11] *Id.* at. p. 3.
[12] *Id.* at, p.7 n. 8.
[13] *Id.* at. p. 17 ("The credit quality and financial flexibility of U.S. investor-owned electric utilities has declined over the past 40 years, and especially over the last decade The industry's financial position today is materially weaker than it was during the last major ' "build cycle' that was led by vertically-integrated utilities, in the 1970s and 80s. Then the vast majority of IOUs had credit ratings of 'A' or higher; today the average credit rating has fallen to ' "BBB."') (internal citations omitted); *see also id.* at p. 27 ("Finally, while the financial calamities mentioned here rank among the industry's worst, the potential for negative consequences is probably higher today. Since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially. And, as noted earlier, electric utilities have entered the current build cycle with lower financial ratings than they had in the 1980s.").
[14] *Id.* at. p. 11.

found to be most risky.[15] Despite the great uncertainties in CAISO's analysis, which SCE acknowledges, SCE wishes to be given authority to procure resources, but not have to pay the economic consequences if they turn out badly.

The Ceres report concludes that sensible and safe investment strategies should include diversifying energy sources in favor of more renewables and energy efficiency rather than emphasizing large scale fossil fueled or nuclear sources. This type of economic approach supports CEJA's recommendations as reflected in my earlier testimony and runs counter to SCE's proposal. The Ceres report specifically recommends:

- Diversifying energy resource portfolios rather than "betting the farm" on a narrow set of options (e.g., fossil fuel generation technologies and nuclear);
- More emphasis on energy efficiency, which the report shows is utilities' lowest-cost, lowest-risk resource.[16]

The report also found that conditions are changing quickly in favor of distributed, renewable, and efficiency measures, and that the risk of investment in large centralized, fossil fueled projects is greatly increasing.[17] It further finds that "planning the lowest-cost, lowest risk investment route aligns with a low-carbon future." [18]

The report recommends against the measure proposed by SCE to minimize its risks:

> ***Risk shifting is not risk minimization.*** Some regulatory practices that are commonly perceived to reduce risk (e.g., construction work in progress financing, or "CWIP") merely transfer risk from the utility to consumers. This risk shifting can inhibit the deployment of attractive lower cost, lower-risk resources. ***Regulatory practices that shift risk must be closely scrutinized to see if they actually increase risk—for consumers in the short term, and for utilities and shareholders in the longer term.***[19] ***Investor-owned utilities sometimes attempt to get out in front of the event risk inherent in large investment projects by seeking pre-approval or automatic rate increase mechanisms.*** As discussed later, these approaches don't actually reduce risk, but instead shift it to consumers. ***This may give companies and investors a false sense of security and induce them to take on excessive risk.*** In the long run this could prove problematic for investors; large projects can trigger correspondingly large rate increases years later, when regulators may not be as invested in the initial deal or as willing to burden consumers with the full rate increase.[20]

The proposal of SCE should be rejected based on the alternatives I discussed in my previous testimony, and based on this additional study about risk energy investments.

[15] *See* J. May Opening Test. at pp. 36-43; J. May Supplemental Test., Attach. B, at p. 27 (Ceres Report).
[16] J. May Supplemental Test, Attach. B at p. 3 (Ceres Report).
[17] *Id*. at pp. 5, 6, 7, 8, 9, 12, 17, and generally, the whole report.
[18] *Id*. at p. 3.
[19] *Id*. at p. 13 (emphasis added).
[20] *Id* at p. 22 (emphasis added).

C. SCE's Testimony Identified Uncertainty about CAISO's Use of Supplemental Requirements above WECC and NERC Reliability Requirements.

SCE identifies the need for more clarity about CAISO's planning standards:

> The CAISO's data request responses indicate that CAISO applied North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) Reliability Standards/Criteria in determining the LCR need. ***However, these responses also indicate that the CAISO augmented these standards with CAISO Planning Standards.*** The CAISO's data response states that: (1) the CAISO Planning Standards address specifics not covered in NERC and WECC Reliability Standards/Criteria, (2) provide interpretations of NERC and WECC Reliability/ Standards/Criteria to the CAISO control grid, and (3) identify whether more specific criteria should be adopted that are more stringent than the NERC and WECC Reliability Standards/Criteria. SCE generally agrees with CAISO's methodology and its finding of a need. ***However, the nature and effect of the additional CAISO Planning Standards included in the CAISO's analysis are unclear. Changes in these standards can change the level of replacement capacity needed.***[21]

I agree with SCE that clarity on the use of reliability criteria and standards is important in determining the actual replacement capacity needed. This is especially true here where the Commission has never evaluated a 10-year LCR study by the CAISO. As mentioned in my earlier report, CAISO's reliability definition here is an extreme and over-stringent methodology that unnecessarily favors new generation.[22] It is important for the Commission to determine what reserve margin is truly necessary for long-term procurement.

The issue of what reserves are necessary for long-term procurement is specifically discussed in a June 2012 report for ERCOT (Electric Reliability Council of Texas), which breaks down problems with basing future needs on a worst day in ten years (1-in 10 standard), which are ill defined and can be ill fitted to reliability goals.[23] (Notably, CAISO's LCR study defines the need by forecasting the worst day in ten years along with the two worst contingency events occurring.) First, the report finds that 1-in-10 is applied differently in different regions, not used in others, and identifies an alternative cost-benefit analysis used in some areas:

> It is also helpful to understand that the 1-in-10 standard is not applied uniformly throughout the industry. For example, ERCOT and many other system operators interpret the 1-day-in-10-years standard as "1 outage event in 10 years," while other system operators such as SPP[24] interpret the 1-day-in-10-years standard as "24 outage hours in 10 years." While the two interpretations sound semantically similar, the level of

[21] SCE Test. at p. 6
[22] *See* J. May Opening Test. at pp. 36-41.
[23] J. May Supplemental Test, Attach. C at p. 101 (*ERCOT Investment Incentives and Resource Adequacy*, The Brattle Group, June 1, 2012, Prepared for ERCOT (Electric Reliability Council of Texas) [Hereinafter ERCOT Report].
[24] Southwest Power Pool.

reliability they impose differs significantly. As shown in a recent case study of a 40,000 MW power system, the former definition requires a 14.5% reserve margin, while the latter requires only 10%. Finally, some regions, including TVA,[25] SERC,[26] and WECC,[27] do not use the 1-in-10 standard at all to set planning reserve margins, instead using a different approach or leaving this task to their member utilities. For example, utilities within SERC and TVA have determined planning reserves based on explicit benefit-cost analyses of the economically optimal reserve margin. A recent NRRI whitepaper explains how these studies can be conducted.

This ERCOT report describes how the 1-in-10 standard is poorly defined in that it does not differentiate between small load shed events and large widespread events:

> The 1-in-10 standard is also poorly-defined with respect to the events it describes. For example, the "1 event in 10 years" standard that ERCOT and many other regions use is independent of the size or duration of outage events. ***Small load-shed events are given the same priority as widespread, large events. For example, two 2 MW events in 10 years with a duration of 1-hour each would not be acceptable, whereas one 3,000 MW event lasting 10-hours would still meet the standard.*** A better-defined metric would recognize that the latter case represents poorer reliability because it requires 7,500 times more MWh to be shed. Moreover, because outage events tend to affect a larger proportion of total load in smaller power systems, 1-in-10 does not provide the same level of reliability for customers in differently-sized power systems. These concerns led the NERC Generation and Transmission Planning Models Task Force to adopt the better-defined metric of *normalized* Expected Unserved Energy (EUE), which is the MWh of load shed divided by the total load if there had been no shedding.[213]

In addition to relying on the 1-in-10 forecast, CAISO also has forecast the two worst contingencies on the system.[28]

The ERCOT report further notes that use of very tight reliability standards for *bulk* power systems generally defined as transmission and associated connections greater than 100KV,[29, 30]

[25] Tennessee Valley Authority.
[26] Successor to the Southeast Electric Reliability Council.
[27] Western Electricity Coordinating Council.
[28] *See* J. May Opening Test. at pp. 36-41.
[29] FERC defines bulk electric systems: "SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission (Commission) proposes to approve a modification to the currently-effective definition of "bulk electric system" developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The revised definition of "bulk electric system" removes language allowing for regional discretion in the currently-effective bulk electric system definition. **The revised definition establishes a bright-line threshold that includes all facilities operated at or above 100 kV.** The modified definition also identifies specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of "bulk electric system." J. May Supplemental Test., Attach. D at p. 1 (Docket Nos. RM12-6-000 and RM12-7-000, *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure* (June 22, 2012)).
[30] SCE earlier comment: **"The definition of the term Bulk Electric System is important because transmission facilities within the definition are subject to NERC's Reliability Standards while non-BES facilities are not**

implies an average outage of less than a minute per customer per year. The report contrasts this with the hundred times higher actual outages that occur mainly on *distribution* systems (presumably not drastically different than California conditions), calling into question the assumption that the 1-in-10 standard is always reasonable:

> Another important consideration is the role of bulk power reliability in the context of overall customer reliability. In ERCOT, the 1-in-10 resource adequacy target implies average outages of less than 1 minute per year per customer.[214] This compares to average annual customer outages well in excess of 100 minutes due to outages caused by disturbances on the distribution system (and on the transmission system to a lesser extent). During severe storm events, annual outage durations can reach several hundred to several thousand minutes per customer, as shown in Table 17. . . . .
> For these reasons, the value of maintaining a high resource adequacy standard needs to be evaluated carefully in the context of distribution- and transmission-related outages, which have a much greater impact on customer reliability. Creating market structures that further increase resource adequacy may prove to be less cost-effective than investments to improve distribution reliability.[31]

The report finds that regulators should evaluate the appropriateness of using this standard to design the electricity market, and should consider balancing the cost and probability and impacts of outage occurrence:

> Despite these considerations, little empirical work has been done in the industry to quantify the economics of the 1-in-10 criterion to confirm that it reasonably balances the tradeoffs between the economic value of reliability and the system capital costs imposed. Nor have the economics of the 1-in-10 target been evaluated in ERCOT specifically. ***We recommend that ERCOT, the PUCT, and stakeholders re-evaluate the target in terms of its overall value, policy objectives, risk, and cost-effectiveness before re-designing the electricity market in an attempt to achieve that target.***[32]

D. Actual SCE Data Related to the Transmission Line Outages Illustrates the Unlikelihood of CAISO's Contingencies Ever Occurring.

The ERCOT study above, although coming from Texas, looked at use of the 1-in-10 standard for a reserve margin in different regions of the country including the West,[33] and made some generalized findings that generally apply to California. To demonstrate the relevance in California of the ERCOT report questioning the use of reserves, SCE data is also available related to the contingency that CAISO identifies as the most limiting contingency.

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subject to the Reliability Standards, although they remain subject to state and regional reliability standards." p. 1 and "SCE generally supports defining the Bulk Electric System to include all electric transmission facilities with a rating of 100 kV or above." J. May Supplemental Test., Attach. E, at p. 2 (*Comments of Southern California Edison Company on Notice of Proposed Rulemaking, Revision to Electric Reliability Organization Definition of Bulk Electric System*, Docket No. Rm09-18-000 (May 10, 2010)).

[31] J. May Supplemental Test, Attach. C at pp. 101-102 (ERCOT Report).

[32] *Id.* at p. 102

[33] The Southwest Power Pool, Tennessee Valley Authority, the Successor to the Southeast Electric Reliability Council, the Western Electricity Coordinating Council.

In response to a CEJA data request, SCE admits that no forced outages occurred for the last ten years in the lines associated with the worst contingencies in Western LA (Response to Question 08):[34]

> There were no forced outages on the Serrano-Villa Park # 1 for the last 10 years. . . .
>
> There were no forced outages on the Serrano-Lewis # 2 for the last 10 years.

This underscores the problem with procuring new resources based on a contingency that is highly unlikely to ever happen. The SCE data response #8 above is one more piece of the puzzle, since these particular transmission lines represent the worst constraint in Western LA. This is important, because CAISO has emphasized in its Transmission Plan that Western LA is the main limiting factor in the LA Basin:

> The Western LA Basin and Ellis sub-area drive the need for OTC units.[35]

Furthermore, as discussed in my earlier testimony,[36] CAISO identified resources in its Addendum Testimony that would eliminate the Ellis sub-area need as well (Table 3.4-4 below). Specifically, CAISO's LCR evaluation based its 2021 needs on the 1-in-10 worst demand occurring at the same time as specific double contingencies. Table 3.4-4 from CAISO's Addendum testimony[37] identified the Serrano-Villa PK #1 and Serrano-Lewis #1 / Serrano-Villa #2 as the worst constraint and contingencies for Western LA:

Portfolios	Area	LCR			New Gen. Required ? ^	Constraint	Contingency
		Non-D.G. (MW)	D.G. (Mw)	Total (MW)			
Environmentally Constrained (Mid Net Load Condition)	Western LA	6,155	869	7,024	Yes	Serrano - Villa PK#1	Serrano - Lewis #1 / Serrano - Villa PK #2
	LA Basin Overall	7,288	1,519	8,807	Yes %	Mira Loma West 500/230 Bank #1 (24-Hr rating) *	Chino - Mira Loma East #3 230kV line + Mira Loma West 500/230kV Bank #2
	Western LA OTC Range	1,042 - 1,677 MW plus SONGS					New generation need ranges from most effective to less effective locations
	Ellis	0	0	0	No	None	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	274	91	365	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

[34] *See* J. May Supplemental Test., Attach. A (SCE Response to CEJA Data Request 1); *see also* J. May Opening Test. at pp. 7, 14, 16, 17 (describing worst contingency in Western LA Basin).

[35] J. May Supplemental Test., Attach. F (2011/2012 Transmission Plan, California ISO (March 23, 2012)).

[36] *Id.* at p. 17

[37] J. May Supplemental Test., Attach. G (*Addendum to: Board-Approved 2011/2012 Transmission Plan, Section 3.4.2.1 Assembly Bill 1318 Sensitivity Reliability Study Results,* CAISO (June 12, 2012)).

The fact that the contingencies that CAISO is relying on have never occurred in the last 10 years also calls into question SCE's general support of CAISO's LCR assessment. Notably, SCE has done no analysis to determine the reasonableness of the CAISO's values.[38]

In summary, SCE's data response and testimony further supports that none of the OTC needs identified by CAISO can be supported:

1) The driving Western LA contingency is not only theoretically extremely unlikely (with a probability of occurring for seconds per year, from my earlier testimony, p. 38), but shown in actual SCE data not to have occurred at all for the last ten years,
2) The Ellis sub area need was found in CAISO's sensitivity study to have a solution that completely eliminates the constraint (Table 3.4-4 above)
3) The El Nido subarea is also shown in this sensitivity study to have no need for new generation (Table 3.4-4 above)
4) The Big Creek / Ventura area (the other area outside the LA Basin identified by CAISO for replacing OTC sources) is proposed by SCE in its testimony (quoted earlier) to be unnecessary to determine until the 2014 LTPP, "because this need does not have to be addressed now" according to SCE.

These points are all *in addition* to the fact that very substantial levels of resources including EE, DR, DG, and transmission were completely missing from the LCR analysis, as discussed in my earlier testimony, which by themselves could have eliminated these constraints.

E. Additional SCE Outage Data Supports the Need for Scrutiny of CAISO's Over-stringent Reliability Assessment and SCE's Resultant Procurement Request.

Again, to compare the theoretical risk that CAISO is using to base its resource needs, additional SCE data on actual outage frequency and duration are available online. One of the largest outages that SCE has experienced is illustrative of the types of the worst-case type of scenario that SCE experiences. In 2011, wind storms in SCE's territory downed many trees onto local distribution lines.[39] SCE identified many ways to lessen the outage time due to such an event. Notably, none of the many ways that SCE identified included adding more generation to the system.[40] Adding new generation to the system will not prevent downed distribution lines that caused that outage.

That <u>local distribution systems, not high power bulk transmission lines</u> are the main cause of the minutes of outage experienced by customers was not only determined by the ERCOT study above, but also by the Lawrence Berkeley National Laboratory in a report regarding outages:

> An initial assessment of these events supports the conventional wisdom that ***the majority of power interruptions experienced by customers are not due to large events that affect***

[38] *See* J. May Supplemental Test., Attach. A (SCE Response to CEJA Data Request 1).
[39] J. May Supplemental Test. Attach. I (*December 2011 Outage Report,* SCE).
[40] *See id.* at p. 45-50.

the bulk power system; they are due to more localized events that affect only utility distribution systems.[41, 42]

These local distribution failures (mainly caused by weather, downed trees, etc.) were not the subject of the reliability assessment which formed CAISO's LCR needs determination that SCE relies upon as the basis for procuring thousands of new megawatts of fossil fueled plants. As in the ERCOT report, these numbers show that the actual outages, mainly from distribution system outages, are in the range of 100 minutes per year,[43] swamping the separate, theoretical transmission system 1-in-10 reliability standard probability of seconds of outage per year that CAISO is aiming for.

It is also a perverse result, that as the data above shows that distribution system outages have increased (which might be expected due to extreme climate-change related weather events), SCE and CAISO are also proposing increasing greenhouse gases by adding conventional generation to prevent highly unlikely outages on bulk transmission systems, that are generally *not* the cause of these reliability problems.

Furthermore, even though duration of Distribution system outages is much higher than transmission outages, even they only occur for a small fraction of the year, and only about one per customer per year. We generally have a reliable system, and we can maintain that without adding unnecessary polluting plants ten years in advance of the target planning date.

F. SCE's Testimony Does Not Support Allowing SCE to Procure Based on CAISO's Analysis.

SCE's testimony and data request responses raise several questions about the validity of CAISO's analysis. Yet, SCE has failed to demonstrate that CAISO's analysis is a reliable basis for authorizing procurement.

SCE did not do a LCR analysis even though it has admitted that it "does not agree with all the assumptions used by CAISO" and that it "has internal load forecasts and renewable resource generation assumptions that are not the exactly the same as those used by the CAISO in their LCR analysis."[44] Due to this, SCE prefers to keep its options open:

> SCE would prefer having flexibility in the procurement targets. So, if future studies with different assumptions change the LCR requirements, we can adjust the procurement accordingly.[45]

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[41] J. May Supplemental Test., Attach. H at p. xiii (*Tracking the Reliability of the U.S. Electric Power System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions*, Lawrence Berkeley National Laboratory, Joseph H. Eto and Kristina Hamachi LaCommare, (October 2008) LBNL-1092E).

[42] *Id.* Although the report did find that there are many differences in how data that it reviewed throughout the U.S. are reported, it found that "Differences in the definition of a sustained interruption do not appear to affect SAIDI or SAIFI in a statistically significant manner." *Id.* at p. 29

[43] J. May Supplemental Test., Attach. L at p. 3 (SCE 2011 Reliability Report).

[44] *See* J. May Supplemental Test., Attach. A (SCE Responses 1 and 2 to CEJA's First Set of Data Requests).

[45] *See* J. May Supplemental Test., Attach A (SCE Response 2 to CEJA's First Set of Data Requests).

SCE also has not determined its own preferred resource assumptions even though its testimony states that it "does not agree with all assumptions used by the CAISO."[46] When asked to provide SCE's preferred Load and Resource assumptions, SCE provided *no* assumptions for any resources, stating:

> If such data were available it would need to be broken down further into segments at each electrical substation in order for the CAISO to do modeling required to determine LCR need for both the "LA Basin" and "Western LA Basin". SCE cannot produce such data in time for this proceeding and in some cases it may be essentially impossible to create such data without making many arbitrary assumptions.[47]

In other words, even though SCE has stated that it disagrees with CAISO assumptions, it will not produce its own set of assumptions for this proceeding.

It also appears that SCE has not evaluated CAISO's power flow analyses. CEJA asked SCE: "Has SCE analyzed CAISO's power flow modeling in this proceeding? Has SCE done its own power flow modeling for this proceeding? If so, please provide the inputs that SCE used for its power flow modeling?" SCE responded as follows:

> SCE was involved in the initial stages and developed the initial power flow Base Case that the CAISO used for its power flow modeling in this proceeding. This is the extent of the work done by SCE for CAISO's LCR Studies. SCE did not conduct its own power flow studies for this proceeding.[48]

SCE's testimony thus raises serious questions about the assumptions used in CAISO's analysis. SCE's failure to produce any resource assumptions in this case is very problematic.

G. SCE Also Admits that the LCR Need Is Likely to Change and that Procurement Should Only Occur if Needed.

Raising additional issues about CAISO's analysis, SCE's testimony states that "CAISO's assumptions in the LCR analysis recognized neither the potential for increased distributed generation (DG) nor increased localized generation."[49] In response to a data request, SCE states that as a general statement of fact "[i]f more distributed/localized generation occurs in the local area, then the LCR need could potentially be reduced."[50] SCE further provides that:

> SCE expects that as future generation occurs to meet local reliability needs, new information on DG projects and programs may give justification to reducing the LCR procurement need. Hence, SCE has requested the CPUC grant it flexibility to procure up

[46] SCE Test. at p. 5.
[47] J. May Supplemental Test., Attach. A (SCE Response 2b to CEJA's First Set of Data Requests).
[48] J. May Supplemental Test., Attach. A (SCE Response 9 to CEJA's First Set of Data Requests).
[49] SCE Test. at p. 7.
[50] J. May Supplemental Test., Attach. A (SCE Response 3 to CEJA's First Set of Data Requests).

to the amount proposed by the CAISO (but not necessarily the total amount proposed by CAISO) so that it can reduce procurement if the new information provides confidence that the need for new generation in the LA Basin is less than what the CAISO is currently projecting.[51]

SCE is correct that the LCR value will change as additional information becomes available. As provided in my opening testimony, DG resources can be expected to increase and EE and DR values should be much higher than what CAISO assumed.

H. All Resources Should Be Counted to Meet LCR Need.

If the LA Basin has a need for LCR resources, it is important pursuant to environmental and energy policies for the request for offers to allow all resources to compete.

CEJA has previously requested that the Commission evaluate how all types of resources can be fairly considered in procurement decisions pursuant to the loading order, and this is again of crucial importance in this stage of the proceeding if procurement is authorized. In the 2010 LTPP, the Commission clarified that the "loading order applies to all utility procurement."[52] The Commission had "concerns regarding utility compliance with the loading order" as was also an issue cited in D.07-12-052, which found that the utilities were filling "their net short positions with conventional resources, rather than the preferred resources.[53] Due to these concerns, in the 2010 LTPP, the Commission directed the utilities to "procure additional energy efficiency and demand response resources to the extent they are feasibly available and cost effective."[54] The Commission further decided that "[t]his approach also continues for each step down the loading order, including renewable and distributed generation."[55]

To assure compliance with Commission's loading order directive in D.12-01-033, other resources need to be able to compete and be considered in procurement requests. However, as Request for Offers (RFOs) are currently framed with properties that relate specifically to natural gas facilities, other resources are at an inherent disadvantage. Other resources such as energy efficiency and energy storage do not have a ramp rate or specified "output" and cycling levels like natural gas facilities. Rather energy efficiency is a reduction of total load, and energy storage provides regulation services that can be ramped up, but the properties are defined differently. Renewable energy and distributed generation resources similarly are not defined in the same parameters as natural gas facilities. Specifications like the one above that are tailored to conventional generation do not allow other resources to fairly compete in RFOs.

Steps, like the ones CEJA has requested, have been taken in other areas of the country to allow demand-side resources, such as energy efficiency, to compete directly with electric power plants. For example, PJM and New England ISO have begun holding auctions where demand-

[51] J. May Supplemental Test., Attach. A (SCE Response 3 to CEJA's First Set of Data Requests).
[52] D.12-01-033 at p. 20.
[53] D.07-12-052 at p. 12, FOF 6 (citing in D.12-01-033 at pp. 21).
[54] D.12-01-033 at p. 21.
[55] *Id.* at p. 21-22.

side resources compete directly with conventional generation.[56] Notably, these auctions have already been cited as reducing "the costs of meeting the region's resource adequacy requirements."[57]

The Commission has previously evaluated metrics to assure fair consideration of bids in competitive RFOs. In the 2010 LTPP, the Commission evaluated the metrics for considering utility-owned generation relative to generation owned by independent generators. In this LTPP, the Commission should determine metrics for comparing: energy conservation, energy efficiency, demand response, renewable resources, energy storage, and conventional generation in a competitive RFO. Without metrics that put the alternative resources on the same playing field as conventional generation, it is highly unlikely that alternative resources pursuant to the loading order will be fully evaluated.

I. Conclusions

Perhaps the most important takeaways from these reports and discussion in response to SCE are the following:

1) The Commission should completely defer procurement resource determinations in the Big Creek / Ventura Area until 2014, in agreement with SCE's proposal.

2) I agree with SCE that CAISO should clarify which LCR needs are based on WECC and NERC requirements, and which are additional CAISO supplements.

3) In line with uncertainties identified by SCE and by myself and others in previous testimony, CAISO should be directed to shed more light on planning needs through:
    a. Quantifying the likelihood of G-1/N-1 and N-1/N-1 outages and explain where the data came from and how the calculations were performed
    b. Re-running the analysis using the WECC and NERC standards
    c. Quantify the likelihood of uncontrolled load loss if none of the OTC plants are replaced.
    d. Quantify the levelized annual cost of adding capacity at the OTC sites to meet both the WECC and NERC standards, and separately the CAISO's higher G-1/N-1 and N-1/N-1 standards, which falls mainly on SCE consumers.
    e. Compare these probabilities and costs of bulk transmission outages, if any remain after including all available resources, with the probability and costs of

[56] J. May Supplemental Test., Attach J at p. 3 (*The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources, The Regulatory Assistance Project (*May 2010)) ("Two organized markets in the US — PJM and ISO New England (ISO-NE) — now conduct forward capacity auctions that permit a wide range of demand-side resources to compete with supply-side resources in meeting the resource adequacy requirements of the region. The response of demand-side resources in the PJM and ISO-NE auctions is impressive and their participation is clearly demonstrating that reducing consumer demand for electricity is functionally equivalent to — and cheaper than — producing power from generating resources.").
[57] *Id.* at p. 19; *see also* J. May Supplemental Test., Attach K at p. 8 (*Selling Energy Efficiency as a Resource*, Lisa V. Wood, Electric Perspectives, (May/June 2009)).

distribution outages, and provide an overall cost-benefit analysis on building new fossil fueled power plants compared to these outage costs.

4) This modified assessment should also include added levels of EE, DR, DG, CHP and transmission fixes identified in my earlier testimony, in line with the previous clear direction from the Commission that utilities follow the loading order, and implement state policies.

5) After these additional assessments, CAISO should also clarify whether there are added options for solving any remaining needs through additional transmission fixes, as also highlighted by the SCE testimony.

6) The Commission should reject SCE and CAISO's proposal to procure any new fossil fueled generation until such analyses are performed and publicly shared.