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)

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

JUNE 25, 2012

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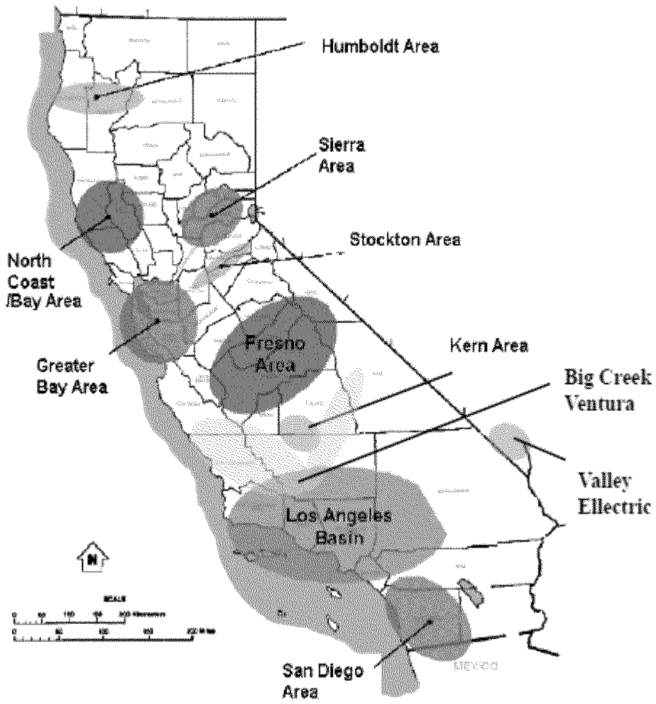
I. INTRODUCTION

My name is Julia May, and I am a Senior Scientist for Communities for a Better Environment (CBE), which is a member organization of California for Environmental Justice Alliance (CEJA). This report is produced on behalf of CEJA for the 2012 Long Term Procurement Proceeding at the California Public Utilities Commission (Commission or CPUC).[1]

My testimony evaluates CAISO's[2] claim that there is a Local Capacity Requirement (LCR) need for generation in 2021 in the LA Basin and Big Creek/Ventura area to replace the potential retiring Once-Through-Cooling (OTC) power plants. CAISO's claim is based on CAISO's 2011/12 Transmission Plan[3] ("Transmission Plan"), related documents, and materials presented at workshops of the Commission.



My background includes a bachelor's degree in Electrical Engineering and over 20 years evaluating technical issues of industrial regulation, permitting, electricity planning, renewable energy, transmission alternatives, energy efficiency, and air pollution assessment in state and local, regulatory proceedings. These include proceedings of the CEC, CPUC, CARB, SCAQMD, and BAAQMD[4] in California, as well as in other states and tribal regions. I have provided engineering analysis on behalf of CBE, other non-profit environmental organizations, and trade unions. A true and current copy of my CV is attached.

[1] While this report is directed to the CPUC and CAISO, I will attempt to provide occasional lay language background so readers such as community members might follow.
[2] CAISO – The California Independent System Operator, which manages California's electricity grid for reliability.
[3] 2011/2012 Transmission Plan, California ISO (March 23, 2012) *available at* http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf [CAISO 2011-2012 Transmission Plan]
[4] Respectively the California Energy Commission, California Public Utilities Commission, California Air Resources Board, South Coast Air Quality Management District, and Bay Area Air Quality Management District.

II. SUMMARY OF RESULTS

This table summarizes necessary modifications of CAISO's analysis of Southern California Edison (SCE) Local Capacity Requirements. These are based on additional mitigation for electricity outage contingencies, Energy Efficiency (EE), Demand Response (DR),[5] Distributed Generation (DG), Energy Storage, Combined Heat and Power (CHP),[6] and transmission resources that are available and need to be included pursuant to state law and policy, but were not included in CAISO's analysis. With these additions there should be no need for more LCR resources, and CAISO's conclusion that new conventional generation is needed to replace retiring Once-Through-Cooling (OTC) facilities, is unlikely.

Recommended Modifications to CAISO's LCR Analysis for the LA BASIN example (2021)

	Local Capacity Requirements (MW)				New Generation Need? / # (MW)			
	Traj.	Envir. Constr.	ISO Base	Time Constr.	Traj.	Envir. Constr.	ISO Base	Time Constr.
CAISO LCR numbers in original Transmission Plan	~~13,300~~	~~12,567~~	~~12,930~~	~~13,364~~	~~2,370 to 3,741~~	~~1,870 to 2,884~~	~~2,424 to 3,834~~	~~2,460 to 3896~~
Reduced LCR, using Mira Loma 600 MW load transfer	10,743	11,246	11,010	12,165				
Additional resources missing from CAISO's assessment that further reduce LCR deficit above:								
Insert LA Basin portion incr. **EE**					≈2,224 to 2,461			
Insert LA Basin portion **DR**					≈1,934 to 2,829			
DG up to LA Basin portion, 2020 IEPR 4,000 MW (LA County goal)					3,515	2,335	3,583	3,167
Additional **STORAGE** – proportion of state goal					≈1,000 MW			
Additional **CHP** – proportion of state goal, last in loading order before new generation					>285 MW			
Transmission fixes: (in addition to Mira Loma fix above)					▪ Del Amo loop in combination with EE& CHP eliminates Ellis deficit (at mid net) ▪ LCR reduced 2000-3000MW, installing sub-transmission facilities[7] & 500/230kV transformers. for load transfers ▪ ISO evaluating increasing Serrano-Villa Park 230 kV thermal rating (key to W LA constraint) ▪ **Need full assessment of options including reactive support, SPS, thermal protections, etc.**			
Modified resource need likely to be zero after these are included					Likely Zero	Likely Zero	Likely Zero	Likely Zero

[5] Demand response programs allow qualifying customers who reduce power when energy supplies are low (or prices rise) to earn financial incentives. This allows a drop of load exactly when needed, at peak electricity demand

[6] Combined Heat and Power uses gas and steam turbines combined with electricity generators to create electricity, while reclaiming waste heat exiting turbines to generate steam, instead of releasing to the atmosphere directly.

[7] Sub-transmission circuits of a distribution system deliver electricity from bulk sources to distribution substations.

The added resources above could be shown either as reducing electricity demand or providing supply. However they cannot simply be subtracted from the rows above to determine the final need, because electricity load, generation (and other resources such as efficiency improvements), and transmission are distributed geographically and might be available at different times. There are also physical and safety limitations such as how much power can be transmitted over specific transmission lines, and need for timely availability of resources (ramp up speed, etc.). The system must also be able to react immediately to meet needs. This is why computer modeling such as power flow and production cost modeling is performed to determine electricity reliability. CAISO never provided a sensitivity study showing the impact of all the available resources together.

However, CAISO's estimation of new generation need shown in the first row of the table (crossed out), ranges from a minimum of 1,870 MW in the Environmentally Constrained Scenario to a maximum of 3,896 MW in the Time-Constrained scenario.[8] Given those values, I conclude:

1) the resources listed above (DR, EE, DG, transmission fixes, etc., which are required by state law and policy) that should be added to CAISO's analysis add up to much more than CAISO's most extreme estimation of local new generation need;
2) these added resources (such as DG) tend to be available when most needed (summer peak) and are distributed geographically;
3) New information about flexibility needs unexpectedly favors solar (see DG section), and CAISO identified other means to meet flexibility (EE, DR, storage); and
4) CAISO based LCR requirements on an overly pessimistic 1-in-10 forecast (which means peak energy need during the worst year out of ten) long in advance of when these needs might occur, with multiple safety reserve margins on top of this worst case, making it very unlikely that modeled outage contingencies would ever occur .

These reasons provide convincing evidence that the generation need identified by CAISO is wiped out when taking into account these resources.

We are almost a decade out from the 2021 forecast with advancing alternative energy, energy efficiency, and demand response at rapidly declining costs. Under these circumstances and in light of the critical need to cut greenhouse gases due to worsening climate change and to cut smog-precursors known to exacerbate and cause asthma in a region with the worst air pollution in the country, it would be counter to state policies to approve new and unnecessary conventional fossil fueled generation. For example, in a data response, CAISO identified 4.25 million tons of CO_2 emissions (presumably per year) in the SCE area and a total of about 5.4 million tons of CO_2 emissions if San Diego additions are included, that result from added conventional generation recommended by CAISO to satisfy LCR needs.[9] This data doesn't include smog

[8] *See* Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation, R.12-03-014 at p. 6, Table 1 [Sparks Testimony]. .

[9] *See* Response of CAISO to the Data Request of Vote Solar Initiative, Response to Request No. 8. This response included a spreadsheet provided by CAISO entitled: *CO2 emissions by the LCR resources*, which was attached to the CAISO response to the Vote Solar Initiative data request. This request asked: "*What modeling, if any, did the CAISO perform that indicates the potential emissions profile for replacement OTC generation?"* ISO response: "*The attached file contains the emission profiles of the generic CCGT and GT modeled in the local areas." Id.* at p. 5.

precursor and PM2.5 (fine particulate matter) emissions known to increase asthma impacts and death rates. Premature deaths in California due to PM2.5 number almost 10,000 per year according to the California Air Resources Board.[10]

I constructed the table above for the overall LA Basin because I had access to information for this area. The same principles apply to the Big Creek /Ventura area, which should be evaluated for the same modifications. It is likely that the same conclusion would be reached because of the multiple resources not included and because of CAISO's extremely conservative assessment for each of the local areas. CAISO should modify its assessment for these smaller local areas as well.

III. CAISO Failed to Consider All Available Resources

A. Background

CAISO provided the following tables during the May 3, 2012 workshop,[11] in the Transmission Plan, and in its May 26 testimony,[12] showing LCR needs. In Slide 16, CAISO concluded that LA Basin LCR new generation need ranged from 1,870 to 3,896 MW:

Summary of Long Term (2021) LCR Study Results - Excerpt from CAISO presentation (Slide 16)

LCR Area	Local Capacity Requirements (MW)				New Generation Need? # If Yes, Range of New Generation Need (MW)			
	Trajectory	Envir. Constrained	ISO Base Case	Time Constrained	Trajectory	Environ. Constrained	ISO BASE Case	Time Constr.
Big Creek /Ventura (BC/V) Area	2,371	2,604	2,438	2,653	Yes (for Moorpark, a sub-area of the Big Creek / Ventura LCR Area)			
					430	430	430	430
LA Basin (this area includes subarea below)	13,300	12,567	12,930	13,364	2,370-3,741	1,870-2,884	2,424-3,834	2,460 - 3896
Western LA Basin	7,797	7,564	7,517	7,397				

It can be seen in CAISO's Slide 17 that the same figures from Slide 16 for "New Generation Need" were simply inserted exactly into the next table of long term OTC needs.

[10] *Estimate of Premature Deaths Associated with Fine Particle Pollution (PM2.5) in California Using a U.S. Environmental Protection Agency Methodology* (August 2010), *available at* www.arb.ca.gov/research/health/pm-mort/pm-report_2010.pdf at p. 1.
[11] *Long-Term Local Capacity Needs in the California ISO System,* Robert Sparks, Slide 16 (May 3, 2012) [May 3, 2012 Workshop Presentation].
[12] Sparks Testimony, at p. 7-9.

Summary of Long Term (2021) OTC Need - CAISO presentation (Slide 17)

LCR Area	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time Constrained (MW)	Notes
Big Creek / Ventura (BC/V)	430	430	430	430	
Western LA Basin / LA Basin	2,370 - 3,741	1,870 - 2,884	2,424 - 3,834	2,460 to 3896	W. LA Basin is part of larger LA Basin

In fact, "New Generation Need" should be described more generically, since resources other than new generation could fulfill this need. However, other than a few sensitivity studies, consideration was not given to means of meeting need other than replacing OTC generation with conventional power plants. For example, neither DR nor uncommitted EE were considered except for one sensitivity study. That sensitivity study is not mentioned or discussed in Mr. Spark's May 26, 2012 report in this proceeding, although his supplemental testimony (June 19) does identify updates to the studies (see below). Additional energy storage, DG, and CHP should have also been considered.

The Commission has listed as a Guiding Principle for this proceeding that parties will use a "[r]ealistic view of expected policy-driven resource achievement."[13] CAISO's omission of these realistic and policy driven resources is a major omission in the overall CAISO analysis, which skews it in favor of adding unnecessary fossil fueled generation.

The LCR numbers in the first table (above at p. 2) were also modified downward (for example, 13,300 MW down to 10,743 MW), as shown in the Transmission Plan and Mr. Spark's Testimony (Table 1 at p. 6). This modification is discussed below.

B. CAISO Should Assume 600 MW Load Transfer for the LA Basin

Starting with the basic LCR numbers presented as the result of its analysis, there is an additional mitigation identified by CAISO in its Transmission Plan. CAISO identified load transfer or curtailment of 600 MW as a solution to the most critical LA Basin outage contingency[14] if it can be carried out within 1 hour,[15] and identified significantly lower levels of LCR need if applied:

> *Overall LA Basin*
>
> The most critical contingency for the overall LA Basin for all four portfolios is an N-1/T-1contingency[16] of Chino-Mira Loma East #3 500 kV line and Mira Loma West 500/230 kV bank #2. The limiting element is Mira Loma West 500/230 kV bank #1 (24-hour

[13] 2012 Energy Division Straw Proposal on LTPP Planning Standards (May 10, 2012), p. 7 (emphasis in original).
[14] Contingencies are non-normal operation -- unexpected events that disrupt transmission and could cause power outages, including equipment failures, downed lines, transmission overload, voltage collapse, loss of a generator, etc. which is modeled to identify backup plans, additional generation sources, alternate transmission routes, voltage support needs, and other mitigation that could prevent outage even with these events.
[15] CAISO 2011/2012 Transmission Plan, at p. 229; *see also* Sparks Testimony at pp. 9-11.
[16] N-1 is a single transmission circuit outage, T-1 is loss of one transformer, G-1 loss of one generator.

rating). This constraint establishes the LCR numbers for the four RPS portfolios in Table 3.3-14 below:

Table 3.3-12: LCR for overall LA Basin with contingency affecting Mira Loam AA Transformers

Portfolio	LCR (MW)
Trajectory	13,300
Environmental	12,567
Base	12,930
Time	13,364

Mira Loma West 500/230 kV bank #1 has a 1-hour emergency rating. **This emergency rating can be utilized by assuming up to 600 MW of either load curtailment or load transfer within 1 hour. If this mitigation is feasible,** the next worst contingency for the overall LA Basin area is the outage of Sylmar S-Gould 230 kV line and Lugo-Victorville 500 kV line. The limiting element is Eagle Rock-Sylmar S 230 kV line. This constraint establishes LCR numbers for the four RPS portfolios as noted in the table below:

Table 3.3-13: LCR for overall LA Basin with contingency affecting Eagle Rock–Sylmar 230kV line

Portfolio	LCR (MW)
Trajectory	10,743
Environmental	11,246
Base	11,010
Time	12,165

This mitigation provided substantial reductions in overall LA Basin LCR. CEJA received this response to its data request to CAISO for clarification on this point, since it was unclear if CAISO planned to apply this mitigation:

(CEJA) Request No. 8
On page 229 of the 2011-2012 ISO Transmission Plan, CAISO describes the ability to assume 600 MW of either load curtailment or load transfer. Please whether state CAISO believes this mitigation is a feasible and reasonable scenario.

ISO RESPONSE TO No 8
The ISO has had preliminary discussions with SCE and based on those discussions the ISO believes it is a reasonable assumption to base the 2021 local area generation needs on the proposed mitigation. However, we still need to obtain a cost and schedule for these upgrades from SCE. [17]

[17] Response of CAISO to the CEJA's Data Requests, Response No. 8.

The only caveat CAISO identified above is a need for evaluation of cost and schedule for upgrades from SCE, but CAISO still agreed that the 600 MW load transfer is a reasonable assumption for 2021. The difference between the tables for the different scenarios ranges from about 1,200-2,500 MWs. This mitigation would clearly reduce the overall LA Basin LCR. CAISO does list the lower LCR numbers as applicable in the Sparks testimony,[18] but does not modify the OTC Generation need as CAISO finds that this modification does not reduce the Western Basin subarea need:

<table>
<tr><th rowspan="2">Local Area</th><th colspan="4">Local Area Requirements (MW)</th><th colspan="4">Replacement OTC Generation Need (MW)</th></tr>
<tr><th>Trajectory</th><th>Environmentally Constrained</th><th>ISO Base Case</th><th>Time Constrained</th><th>Trajectory</th><th>Environmentally Constrained</th><th>ISO Base Case</th><th>Time Constrained</th></tr>
<tr><td>LA Basin (this area includes sub-area below)</td><td>10,743</td><td>11,246</td><td>11,010</td><td>12,165</td><td rowspan="2">2,370 – 3,741</td><td rowspan="2">1,870 – 2,884</td><td rowspan="2">2,424 – 3,834</td><td rowspan="2">2,460 – 3,896</td></tr>
<tr><td>Western LA Basin (sub-Area of the larger LA Basin)</td><td>7,797</td><td>7,564</td><td>7,517</td><td>7,397</td></tr>
<tr><td rowspan="2">Big Creek/Ventura (BC/V) Area</td><td rowspan="2">2,371</td><td rowspan="2">2,604</td><td rowspan="2">2,438</td><td rowspan="2">2,653</td><td colspan="4">(Need is for Moorpark only, a sub-area of the Big Creek/Ventura Local area)</td></tr>
<tr><td>430</td><td>430</td><td>430</td><td>430</td></tr>
</table>

CAISO should clarify that this mitigation will be carried out.

C. Sufficient Energy Efficiency to Meet State Goals Should Be Considered

CAISO representative Robert Sparks presented at the May 3, 2012 workshop and was asked whether EE and DR were considered in the scenarios presented. He explained that neither EE nor DR was considered to replace any of the generation need because it was unknown *where* these resources would be physically located in the future, and whether they would actually come into being. CAISO testimony also states:

> Q: How much demand response, uncommitted energy efficiency and uncommitted combined heat and power generation was assumed in these ISO studies performed during the 2011-2012 transmission planning process?
>
> A: **The ISO has no basis for expecting that uncommitted energy efficiency** and uncommitted combined heat and power generation can be counted upon for meeting local reliability needs beyond the committed programs that were included in the CEC's officially adopted demand forecast. Demand response was not modeled in the analysis,

[18] *See* Sparks Testimony at p. 6, Table 1.

> but it could be used to reduce the replacement OTC needs if the demand response is in electrically equivalent locations and if they materialize and are determined to be feasible for mitigation.[19]

Zero uncommitted EE was included and no DR, as CAISO reiterates below in the Transmission Plan.

CAISO, however, did include one sensitivity study on EE in the Transmission Plan, which was described in CAISO's slide presentation:

> AB 1318 Sensitivity Scenario
> - Estimated OTC generation level needed under a sensitivity scenario:
>   –Mid net load conditions for environmentally constrained portfolio
>   - CPUC and CEC staff provided projected incremental energy efficiency and incremental demand response
>   - Considered as sensitivity study by the ISO **as there is no basis to assume incremental EE, and DR amounts will materialize**[20]

I strongly disagree with CAISO's statement in the last bullet as state law and policy require that EE materialize. EE in particular is the top priority of the Commission, the CEC, and other agencies especially given its superior cost-effectiveness.[21] The Commission's "Loading Order," consistently reaffirmed, requires EE as the top priority.[22] The Commission has also previously stated its intention that EE should be more aggressively pursued even as costs increase:

> Energy efficiency is the first priority in California's loading order for energy resources.[23]
>
> Precisely because California and our utilities have been leaders in energy efficiency for over thirty years, our energy efficiency programs can no longer rely primarily on inexpensive, easy to obtain energy efficiency but must pursue more challenging and costly implementation efforts.[24]

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[19] *See* Sparks Testimony at p. 15 (emphasis added); *see also* CAISO Response to CEJA's Second Set of Data Requests, Request No. 3.
[20] May 3, 2012 Workshop Presentation, Slide 13 (emphasis added).
[21] *See* D.12-01-033 at p. 20 ("we expressly endorse the general concept that the utility obligation to follow the loading order is ongoing. The loading order applies to all utility procurement, even if pre-set targets for certain preferred resources have been achieved."); *see also* Energy Action Plan, California Energy Commission (Feb. 2008) http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF
[22] In 2003, **the Energy Commission and the CPUC agreed on a "loading order" for meeting electricity needs: the first resources that should be added are energy efficiency and demand response (at the maximum level that is feasible and cost effective), followed by renewables and distributed generation, and combined heat and power (also known as cogeneration),** and finally efficient fossil sources and infrastructure development. California Energy Commission 2008, *2008 Integrated Energy Policy Report Update*, (IEPR), *available at* CEC-100-2008-008-CMF); *see also State of California Energy Action Plan II*: *Implementation Roadmap For Energy Policies* (September 21, 2005) *available at* http://docs.cpuc.ca.gov/word_pdf/REPORT/51604.pdf at pp. 3-6
[23] Application 08-07-031, *Proposed Decisions Approving 2010 to 2012 Energy Efficiency Portfolios and Budgets*, http://docs.cpuc.ca.gov/published/AGENDA_DECISION/107378.htm#P209_7607 at p. 2.
[24] *Id*. at p. 3.

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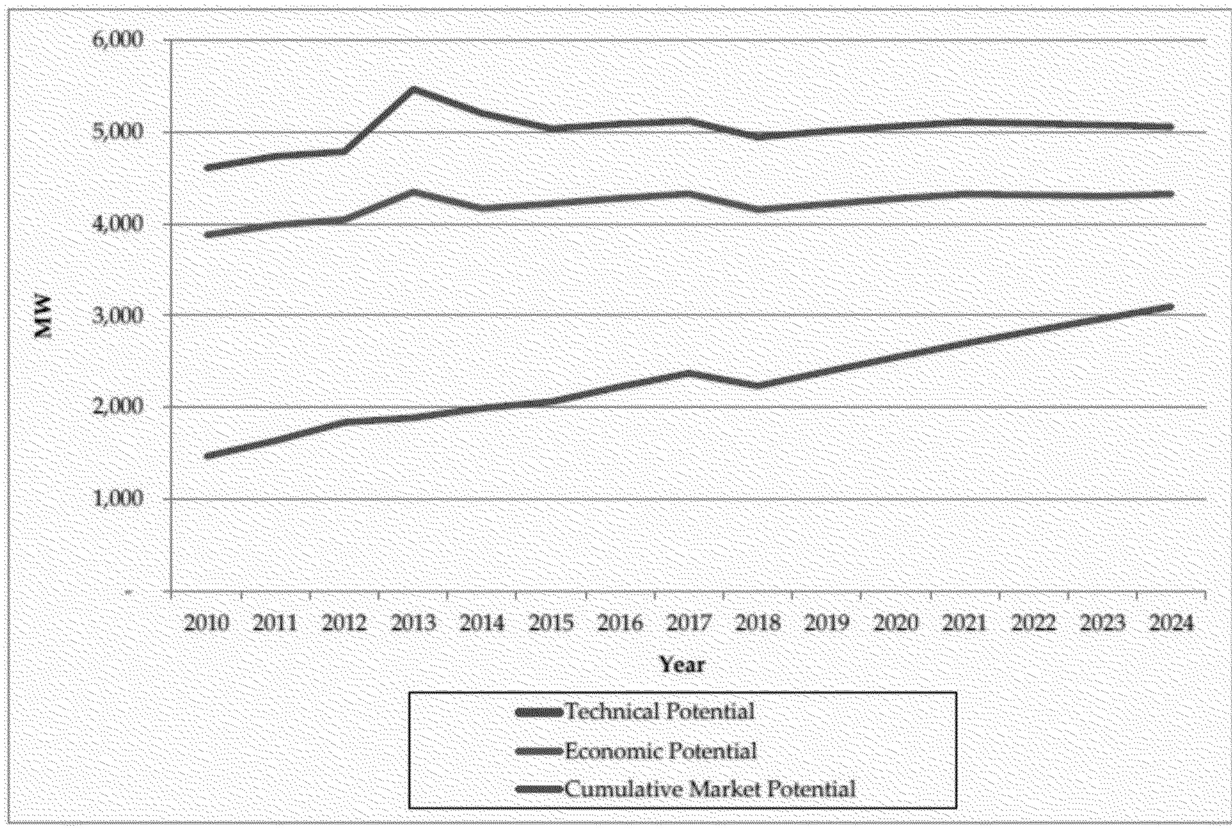
> The residential energy efficiency market has traditionally been difficult to penetrate deeply. The Strategic Plan endorses strategies to achieve deeper savings and to achieve specific targets in the residential sector; i.e., a 40% reduction in energy purchases from all homes by 2020. This target can only be achieved by moving toward comprehensive whole house retrofits, which is a significant departure from relying on massive single measure rebate programs such as a few light bulbs now, new high-efficiency windows later, a new high-efficiency refrigerator some other year, and a high-efficiency clothes or dish washer yet another year, with each incremental measure the subject of separate marketing, delivery, and program administrative costs.[25]

Others have found methods for projecting and quantifying increased EE over time. For example, the Commission provides an updated 2012 analysis of EE potential through 2024[26] that includes the following chart for the SCE area:

[25] *Id*. at p. 114.

[26] *Analysis to Update Energy Efficiency Potential, Goals, and Targets for 2013 and Beyond, Track 1 Statewide Investor Owned Utility Energy Efficiency Potential Study,* Prepared for the CPUC by Navigant, (May 8, 2012), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/6FF9C18B-CAA0-4D63-ACC6-F9CB4EB1590B/0/2011IOUServiceTerritoryEEPotentialStudy.pdf

SCE Total Gross Technical, Economic, and Cumulative Market Demand Potential for 2010- 2024 (MW)[27]



> Market Potential Analysis: The final output of the potential study is a market potential analysis which is defined as the energy efficiency savings that could be expected to occur in response to specific levels of program funding and customer participation based on assumptions about market influences and barriers. All components of market potential are a subset of economic potential.[28]

The technical and economic potential represents the trend in total energy savings available each year above the baseline of Title 20/24 codes and federal appliance standards; the market demand potential is the estimated cost effective EE expected to occur based on the consultant's assumptions about financing and barriers. The full technical potential is much higher than market potential; it would also be reasonable to assume achieving higher EE than the market potential if additional financing is put in place.

The report also provides the following table *(Incremental Market Potential Results)*[29] showing peak savings for SCE from incremental market potential (not technical potential) that accumulate from 2012 to 2021 to savings in the range of 1200 MWs:

[27] *Id.* at p. 110.
[28] *Id*. at p. 2.
[29] *Id*. at p. 6, Table 1, Incremental Market Potential Results.

Incremental Market Potential	IOU	2013	2014	2015	2016	2017	2018	2019	…	2024
Electric Savings (GWh/yr)	PG&E	599	593	599	609	596	583	587	…	629
	SCE	660	678	712	728	744	752	743	…	705
	SDG&E	162	156	152	143	142	158	153	…	138
	Total	**1,422**	**1,427**	**1,464**	**1,480**	**1,482**	**1,493**	**1,484**	…	**1,472**
Peak Savings (MW/yr)	PG&E	114	100	100	101	97	99	100	…	107
	SCE	149	144	148	147	146	147	141	…	129
	SDG&E	36	33	31	29	28	33	31	…	25
	Total	**300**	**277**	**279**	**278**	**272**	**279**	**272**	…	**261**
Gas Savings Including Interactive Effects (MMMT/yr)	PG&E	21.0	20.3	20.0	21.1	21.0	21.5	22.5	…	26.9
	SCG	24.0	22.3	21.4	21.0	20.9	21.3	21.8	…	25.2
	SDG&E	2.2	2.1	2.2	2.4	2.7	3.1	3.3	…	4.8
	Total	**47.2**	**44.8**	**43.5**	**44.5**	**44.6**	**45.9**	**47.6**	…	**56.9**

One recent study published in Science, *The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity,*[30] evaluates methods to achieve 80% Greenhouse Gas (GHG) cuts statewide by 2050. It found that 1.3% cuts per year from EE over forecast demand over the next 40 years is both achievable and necessary to reach a goal of 80% GHG cuts by 2050.

> The rate of EE improvement required to achieve the target and enable feasible levels of decarbonized generation and electrification —1.3% yr reduction relative to forecast demand—is less than the level California achieved during its 2000-2001 electricity crisis (*22*), but is historically unprecedented over a sustained period. This level is, however, consistent with the upper end of estimates of long term technical EE potential in recent studies (*23*, *24*). In our model, the largest share of GHG reductions from EE came from the building sector, through a combination of efficiency improvements in building shell, HVAC systems, lighting, and appliances. EE improvements were complemented by other measures to reduce new energy supply requirements for electricity, transportation, and heating. EE in combination with on-site distributed energy resources in the form of solar hot water and rooftop PV reduced the net consumption of grid-supplied electricity and fuels in new residential and commercial buildings to zero by 2030 (*25*).

This detailed study highlights another point – not only is CAISO required at a minimum to meet state quantitative 2020 goals for EE, DG, DR, and storage, but there is no reason to stop in 2020, and in fact, it is necessary to continue, for example, to meet the 80% AB32 GHG reduction by 2050, and as a matter of necessity to help avoid catastrophic climate change. Feasible means to reach 80% cuts are described in *The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050,* but the Transmission Plan does not even profess to carry out the baseline state 2020 policies such as aggressive EE, meeting the 33% RPS or Governor's 12,000 MW DG goal.

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[30] *The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity,* James H. Williams, *et. al.,* 6 Science Vol. 335 (November 24 2011) pp. 53-59.

Many specific, cost-effective, existing technologies and methods are available. Another set of reports by Bill Powers, P.E., (the Bay Area Smart Energy Report, 2020[31] and the San Diego Smart Energy Report, 2020[32]) has documented many resources particularly suited to reducing peak energy, which is very effective at eliminating the need for additional generation, since CAISO identified the need based on the highest year in ten, peak load. For example, the report found that:

- Financing the difference in cost between minimally efficient new air conditioning and the most efficient available, would reduce electricity demand from these units by 50%.[33] He found that in the Bay Area, as much as 30% of peak electricity demand came from air conditioning,[34] and in San Diego air conditioning constituted a third of peak demand.[35] No similar report was developed for the SCE service area, but it is likely that similar results would be found.

The Testimony of Bill Powers for CEJA in this proceeding also describes the availability of EE, DG, DR, energy storage, and other resources.[36]

CAISO did perform one sensitivity analysis for the Environmentally Constrained Scenario in its Transmission Plan that found:

> 1. Reliability assessment of the LA Basin LCR area for four RPS portfolios at peak load conditions (high net load): The four portfolios are trajectory, environmentally constrained, ISO base case and time-constrained. The purpose of these studies is to identify whether there is a reliability need to run OTC plants, and if there is, what is the OTC generation level needed during peak load conditions. Studies at peak load conditions establish local capacity requirements for higher bound conditions. Additionally, these assessments utilized the official CEC-adopted demand forecast for 1-in-10 year heat wave load projection. **The CEC demand forecast includes committed energy efficiency.**
>
> 2. Per the request from the state agencies (CARB, CEC and CPUC), the ISO also performed an LCR assessment for mid net load conditions for the environmentally constrained study case as sensitivity studies: The results for this study provide for lower bound condition for informational purposes. **For this study, the ISO utilized uncommitted incremental energy efficiency, modeled at specific load buses, as provided by the CPUC and CEC. Incremental demand resources are treated as potential resources, if they materialize. Because of the uncommitted nature of these programs, the ISO considers these studies as sensitivity studies**. . . .

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[31] Bay Area Smart Energy Report, 2020, Bill Powers, P.E. (March 2012), http://pacificenvironment.org/downloads/BASE2020_Full_Report.pdf
[32] San Diego Smart Energy Report, 2020, Bill Powers, P.E., (Oct. 2007) http://www.sdsmartenergy.org/20-may-08_Smart%20Energy%202020_2nd%20printing_complete.pdf
[33] Bay Area Smart Energy Report at pp. 9.
[34] *Id*. at p. 8.
[35] San Diego Smart Energy Report at p. 35.
[36] R.12-03-014, *Prepared Direct Testimony of Bill Powers on Behalf of The California Environmental Justice Alliance* (June 25, 2012).

3.4.2.1 Study Results
The results of study items #1, 3 and 4 are provided in Section 3.3.2 (OTC Reliability Assessment Study Results). In this section, only new study results for item #2 above are reported. **The following table includes assumptions provided by the CPUC and CEC in regards to assumptions of incremental uncommitted energy efficiency and demand response values.**

Table 3.4-1: State energy agencies' provided assumptions on incremental EE & DR

Load Serving Entities	2021 Incremental EE (MW)	2021 Demand Response (MW)
PG&E	2,275	1,523
SCE	2,461	2,829
SDG&E	496	283

[37]

CAISO's discussion starting with #1 above refers to the LA Basin alone, but appears to switch in #2 to a discussion of entire IOU areas (such as the entire SCE area) for the sensitivity study so that study results of 2,461 MW EE and 2,829MW DR apparently refers to all of SCE, not just the LA Basin. The subarea increment is not provided, so we don't actually know how much incremental EE or DR was included in this sensitivity study in the LA Basin, or if the whole SCE number was included. However, the Transmission Plan states ***"Most of the SCE load is located within the Los Angeles Basin."***[38]

I made an estimate of the LA Basin proportion of 2021 load at about 79% of SCE's load, according to data provided in the Transmission Plan.[39] Assuming that the proportion of EE and DR in the LA Basin is similar to the proportion of SCE's load in the LA Basin, the LA Basin EE in 2021 would be approximately 1,934 MW and the DR would be approximately 2,224 MW.

CAISO could split such EE targets into SCE subareas as a replacement for a portion of generation need.

In its updated response to CEJA's first set of data requests, CAISO agrees that the amounts of EE in each subarea are roughly proportional to the load proportion in each subarea:

ISO RESPONSE TO No. 3
2461 and 496 MW of uncommitted energy efficiency were modeled in SCE and SDG&E areas the OTC sensitivity analysis, based on information provided by the CPUC and CEC staff. ***The amounts in the SCE local areas were roughly proportional to the***

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[37] CAISO 2011/2012 Transmission Plan at pp. 254-255 (emphasis added).
[38] *Id.* at p. 138 (emphasis added).
[39] For the SCE service area, the Transmission Plan finds at p. 138: *"The 2016 and 2021 summer peak forecast loads are 26,987 MW and **28,878 MW**, respectively."* (emphasis added). The Transmission Plan at p. 228 finds regarding **the LA Basin**: *"The total 2021 substation load (bus bar level) within the defined area is **22,686 MW**."* 22,686/28,878 = 78.6%

amount of load in the local area relative to the amount of load in the overall SCE area.[40]

It is still unclear from this response whether CAISO used the entire 2,461 MW, or a somewhat lessened portion in the sensitivity study, to reflect that LA Basin load is not quite as big as the whole of SCE's load. Also note that CAISO reiterates above that it considers the EE and DR evaluation as a sensitivity study only, for informational purposes, so it did not include these in the final results of LCR needs.

After this study was performed, and the results were reduced due to CAISO's estimated DR and EE, the LA Basin needs modeled at mid-net load (not peak)in the Environmentally Constrained Scenario are reduced from 12,567 MW to 10,761 MW, so this number would be higher if modeled at worst year in ten. This result was also broken down above for additional SCE subareas. Also note that for the LA Basin overall, this chart still lists the critical contingency that was demonstrated above to have a feasible mitigation using 600 MW load curtailment, so the LA Basin result of 10,761 MW LCR would be significantly lowered if this mitigation was applied. This offsets to some unknown extent the fact that this sensitivity was modeled at mid-net load, whereas the main scenarios were modeled at worst peak load in ten years.

Summary of sensitivity assessment of the mid net load condition for the CPUC environmentally constrained portfolio *(Table 3.4-2)*

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (Mw)	Total (MW)			
Environmentally Constrained (Mid Net Load Condition)	LA Basin Overall	9,242	1,519	10,761	No	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	5,589	869	6,458	Yes	Serrano - Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	Western LA OTC Range	802 - 1,275 MW					OTC need ranges from most effective to less effective generation
	Ellis	470	124	594	Yes	Voltage Collapse**	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	336	91	427	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

This table has been recently updated and replaced – see the next section on the modified results, which show Western LA at similar, but slightly higher LCR, but LA Basin overall at substantially lower LCR (about 2000 MW lower). Additional sensitivities were studied. Furthermore, CAISO also provided Supplemental Testimony, where Robert Sparks states that these sensitivity studies should not be relied on – see discussion below.[41]

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[40] CAISO Updated Response to CEJA's First Set of Data Requests, Request No. 3 (emphasis added).
[41] *Supplemental Testimony of Robert Sparks on Behalf of the California Independent System Operator*, 2012-06-19, R.12-03-014.

Also note that in the CPUC June 4, 2012 Flexibility workshop, CAISO Slide 130 entitled: "*Next Steps: Develop method for studying alternative to meeting needs*" acknowledges that ***"Additional energy may free up flexible resource capability,"*** and identifies EE as an energy resource solution (as well as demand response, and storage). This is important, as one of the reasons repeatedly stated for new conventional generation need (during each of the recent workshops), is to provide flexible resources that can respond quickly to changing net load. CAISO's Slide 130 identifies alternatives to conventional generation as legitimate options.

D. Modifications Were Recently Provided in the Addendum to the Transmission Plan

Recently, CAISO provided an *Addendum to the Transmission Plan*[42] ("Addendum") with updates to the sensitivity study discussed above. However, while CAISO has provided these new sensitivity studies, at the same time CAISO is denying that they should be used. In the Supplementary Testimony by Robert Sparks from June 19, 2012, CAISO's witness describes the sensitivity studies in the Addendum, but he also states that these studies should not be relied upon, because of CAISO's concerns related to counting the incremental EE or CHP being available due to uncertainties.

> **Q. Should the results of the sensitivity analysis be relied upon to make a determination as to local area needs in this proceeding?**
>
> **A.** No, it should not.
>
> **Q. Please explain why it would be inappropriate to use the sensitivity study to make decisions about procurement in the LA Basin and Big Creek/Ventura areas.**
>
> **A.** The ISO used the 2009 CEC 1-in-10 load forecast, which includes certain levels of EE and CHP. Uncommitted EE was not included in the CEC load forecast, and CHP generation was counted on for meeting local reliability needs only to the extent it was included in the CEC's officially adopted demand forecast.
>
> The ISO shares the CEC's concerns about uncommitted energy savings from uncommitted resources. To the extent such uncommitted resources ultimately develop, they can be helpful in reducing overall net-demand, but the ISO does not believe it is prudent to rely on uncommitted resources for assessing future local system needs and ensuring the reliability of the bulk power system.

While it is certainly true that there are many uncertainties involved over the next decade, CAISO is basically stating outright that it does not plan to comply with state policies that put EE foremost, or with state DG goals, by stating that it can't be sure these policies will ever be carried out. This is self-defeating, and guarantees expanded fossil fuel generation counter to

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[42] *Addendum to: Board-Approved 2011/2012 Transmission Plan, Section 3.4.2.1 Assembly Bill 1318 Sensitivity Reliability Study Results,* CAISO, dated June 12, 2012, but received by CEJA June 19, 2012, *available at* http://www.caiso.com/Documents/Addendum-Section3_4_2_1_ISO2011_2012TransmissionPlan.pdf.

policy, if CAISO will not analyze alternative resources, or stand by the analyses it has done. It also doesn't take into account the ready availability of EE technologies, which depend mainly on policy encouragements to be put into place.

At any rate, I will describe the Addendum sensitivity studies. These additions show that adding resources and certain transmission-fixes solve some of the local deficits. A new Table 3.4-1 (at p. 3) apparently replaces the table of the same number in the Transmission Plan discussed above.[43] It still includes 2,461 MW EE for SCE, but now DR is missing, and a small amount of CHP is added instead, without explanation.

Load Serving Entities	2021 Incremental Uncommitted EE (MW)	2021 Incremental Uncommitted CHP (MW)
SCE	2,461	209
SDG&E	496	14

CAISO updated the resulting LCR needs based on these new studies, and added transmission fixes and modifications to the analysis in combination with the added EE and CHP in a step by step fashion. I have added this section to my report to discuss these changes. However, the original sensitivity study still provided useful information, and since some information is missing from the update that was included in the original Transmission Plan, I have not removed discussion in this report about the original study. The original study should be considered as a separate study, not a replaced study.

CAISO replaced Table 3.4-2 from the Transmission Plan, and added two new tables (3.4-3 and 3.4-4), each one adding an additional resource onto the previous table's assessment.

1) **Replaced Table 3.4-2** – Includes incremental uncommitted EE, but also added generation in San Diego (not included in the original Transmission Plan sensitivity) that interacts with the LA Basin. CAISO states it has now determined this is necessary for stability in San Diego (a change from previous studies), and impacts LA Basin results. An error in a line rating in the first study was also corrected.[44]

   Results: Western LA shows similar but slightly higher LCR needs, but LA Basin overall shows substantially lower LCR (about 2000 MW lower). LA Basin, and Western LA and Ellis subareas still show "new generation" need for 2021 during contingencies.

2) **New Table 3.4-3** – Same as above, but also adds a small amount of incremental uncommitted CHP.

[43] Addendum to 2011/2012 Transmission Plan, Table 3.401, at p. 3.
[44] *"In the previous sensitivity studies, the ISO inadvertently monitored the Serrano – Villa Park #2 230kV line, which has higher rating than its parallel Serrano – Villa Park #1 230kV line. In this updated study, the ISO correctly monitored the lower rated constrained line (i.e., Serrano – Villa Park #1 230kV line). This resulted in higher new local generation requirements3 to mitigate identified overloading concerns."* *Id.* at p. 3

Results: New generation need in Western LA is lower than the previous study, but LA Basin increases slightly, due to "lower effectiveness of the additional CHP." LA Basin, and Western LA and Ellis subareas still show "new generation" need for 2021 during contingencies.

3) **New Table 3.4-4** – Again building on the previous sensitivity study, this table includes the resources of the first two tables, but also adds a transmission fix – the Del Amo–Ellis 230kV line loop-in project which has been advanced to 2012 to address the current SONGS (San Onofre Nuclear Generation Station) outage.[45]

   Results: LA Basin and Western LA subarea still show "new generation" need for 2021 during contingencies, but Ellis subarea need (for this mid-net load sensitivity) is eliminated.

Here is the last table (3.4-4) which includes uncommitted EE, some CHP, increased generation in San Diego, and the Del Amo – Ellis loop-in project as additions to the Environmentally Constrained scenario:

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

This new Addendum table for the Environmentally Constrained scenario shows resulting need for "new generation" in Western LA (1,042-1,677 MW) substantially lower than the original Environmental Scenario (1,870 to 2,844 MW) but higher than the original Transmission Plan sensitivity study (802-1,275 MW). It completely eliminates the need that was present in the Ellis

[45] CAISO states in the Addendum, at p. 2: "The updates results also reflect the modeling of the Board-approved Del Amo – Ellis 230kV loop-in project that has been advanced to be in service in 2012. The Del Amo – Ellis 230kV loop-in project was not yet an approved project when the previous analyses took place, and was originally targeted to be in service in 2013" and also: "The Del Amo – Ellis 230kV loop-in of Barre substation project was accelerated for summer 2012 due to extended outage of the San Onofre nuclear generation. This project brings Del Amo – Ellis 230kV line into Barre Substation, creating Del Amo – Barre and second Barre – Ellis 230kV lines." at p. 3, footnote 1.

subarea during the listed contingencies. The overall LCR for the LA Basin drops further compared to earlier discussions from 10,761 to 8,807 MW.

It is interesting but unfortunate to note that previously identified fixes for local deficits were left out of this updated study, including an additional contingency mitigation and DR resources. For some reason CAISO did not include consideration of the 2,829 MW of DR for SCE , and CAISO also did not consider the Mira Loma West load transfer or drop identified by CAISO as reasonable, which reduced overall LA Basin LCR by about 1,200-2,500 MWs depending on the scenario. To predict the exact results of adding these two considerations, modeling is necessary. The result if these were added back in addition to the other changes above would reduce needs, and especially with other available resources discussed below, could eliminate them. Also, the CHP amounts that were included were small, especially compared to the DR amounts identified. (See the CHP discussion below.)

I recommend that CAISO include these resources in any additional modeling, and I recommend that the Commission does not come to a conclusion that there is need for adding new conventional generation when such resources, and others including additional DG, storage, CHP, and other potential transmission fixes, are left out of the analysis.

E. Sufficient Demand Response to Meet State Goals Should Be Considered.

Demand Response (DR) is a major tool which has been almost entirely left out of CAISO's analysis, except for one sensitivity study performed for the Environmentally Constrained Scenario for the LA Basin described above. (Furthermore, unfortunately in the Addendum, DR is even taken out of the sensitivity study, and a much smaller amount of CHP is inserted, without explanation.)

Since our understanding was that CAISO had not included DR in its LCR assessments, CEJA made the following data request to CAISO, and received this confirmation:

> Request No. 2.
> 2. Please explain what input assumptions the OTC and AB 1318 reliability studies summarized on pages 237-239 and 247-249 in the 2011-2012 ISO Transmission Plan assumed for demand response for all local areas in the LA Basin and the Big Creek / Ventura Area.
>
> ISO RESPONSE TO No. 2
> **Demand response was not modeled in the analysis, but it could be used to reduce the replacement OTC needs if the demand response is in electrically equivalent locations, and if they materialize and are determined to be feasible for mitigation.**[46]

DR is a standard tool recognized by the Commission, and many programs are already in place. Expanded DR should be considered a basic assumption for all scenarios beyond 2020.

[46] CAISO Response to CEJA Data Request, Response No. 2.

DR programs are now being integrated into the grid to compete with other resources. As the Commission recently summarized:

> **We are also taking steps to update our current Resource Adequacy program rules to conform to the CAISO's wholesale market and place DR on equal footing with generation resources.** In D.11-10-003, we directed that beginning in 2013 retail non-dynamic pricing DR resources must be dispatchable locally in order to qualify for local Resource Adequacy credits.[47]

According to SCE, it "offers a variety of Demand Response Programs to help qualifying customers reduce their energy usage during peak times while lowering their electricity costs."[48] SCE has 14 DR programs available now:

- 10 For 10 Program
- Agricultural and Pumping Interruptible Program (AP-I)
- Automated Demand Response (Auto-DR)
- Time-of-Use Base Interruptible Program (TOU-BIP)
- Capacity Bidding Program (CBP)
- Summer Advantage Incentive (SAI) also known as Critical Peak Pricing (CPP)
- Demand Bidding Program (DBP)
- Demand Response Contracts
- Optional Binding Mandatory Curtailment Program (OBMC)
- Summer Discount Plan (SDP)
- Technical Assistance and Technology Incentives (TA&TI)
- Real-Time Pricing (RTP-2)
- Pumping and Agricultural Real-Time Pricing (PA-RTP)
- Scheduled Load Reduction Program (SLRP)[49]

Demand response programs allow qualifying customers who reduce power when statewide energy supplies are low (or when energy prices rise) to earn financial incentives, and/or other benefits by participating in these programs.

The Commission provided the following discussion recognizing that (voluntary) load shedding through Demand Response programs of large industrial customers has historically been used for reliability purposes during emergencies, and that expanded DR use for all customers can avoid using energy during higher cost periods:

> Historically, DR was largely employed for reliability purposes during system emergencies in the form of interruptible programs for large industrial customers, which could be triggered when the California Independent System Operator (CAISO) would otherwise have to shed load during a system emergency or when a utility was faced with a serious distribution system emergency. However, the deployment of advanced

[47] D.12-04-045 at p. 16.
[48] Demand Response Programs, SCE Website, http://www.sce.com/b-rs/demand-response-programs/demand-response-programs.htm
[49] *Id.*

metering technology and development of new energy markets is enabling greater use and flexibility of demand response by all types of customers. Increasingly, customers are able to manage their loads to provide different levels of load reduction in response to price signals or other incentives. These load reductions provide value to the grid not only during emergencies, but also during times of high energy prices or in the ancillary services market. As a result, the methods we use to measure the costs and benefits of demand response must be flexible enough to capture these emerging benefits. [50]

A 2009 CPUC Ruling identified specific programs, budgets, and load reductions for each of the utilities.[51] This included the following expected DR load reductions for SCE 2009-2011, totaling 1,814 MW in 2011 and showing an expected increase of about 9% per year in reductions achieved from 2009 to 2011:

SCE Load Impact – Top 20 Highest System Load Days under 1-in-2 Weather Year

	2009	2010	2011
Reliability Program			
BIP***	774.7	855.8	945.4
OBMC/SLRP	*	*	*
SDP***	529.5	533.3	537.2
AP-I	40.0	41.3	42.2
Total Reliability Prog.	**1,344.2**	**1,430.4**	**1,524.8**
Price Response Program			
DBP	16.9	16.9	16.9
CPP	*	*	*
RTP	10.2	10.5	10.9
Total Price Response Prog.	**27.1**	**27.4**	**27.8**
Service Provider (Aggregators) Managed Prog.			
CBP	46.3	48.9	51.8
DR Contracts**	106.0	170.0	210.0
Total Service Provider (Aggregators) Managed Prog.	**152.3**	**218.9**	**261.8**
SCE Total All DR Programs	**1,523.6**	**1,676.7**	**1,814.4**

In a CPUC update of this information (April 20, 2012, *Decisions Adopting Demand Response Activities and Budgets for 2012 through 2014*[52]*)* the Commission finds regarding load reductions from DR activities that: *"With these programmatic proposals, SCE estimates to increase its load impacts from its current 1530 MW to 1824 MW by 2014,"*[53] which is an increase of 19% over about two and a half years.

The Commission also found in this update:

[50] 2010 Demand Response Cost Effectiveness Protocols, Attachment 1, *available at* http://docs.cpuc.ca.gov/WORD_PDF/AGENDA_DECISION/128212.pdf at p. 4.
[51] D.09-08-027 at p. 29
[52] D.12-04-045, at p. 20, Application 11-03-001, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/165317.htm
[53] *Id*. at p. 20.

For more than a decade, California's energy and air quality agencies have recognized the vital role of DR in meeting our shared responsibilities to provide clean, safe and reliable energy at reasonable rates. The foundational principal is the California's loading order policy, adopted by California energy agencies in the 2003 Energy Action Plan and reiterated in the Energy Action Plan II. The energy-sector measures articulated in the California Air Resources Board's Assembly Bill (AB) 32 Scoping Plan reinforce and amplify the central importance of the Loading Order. Energy Action Plan II delineates priorities for the deployment of cost-effective energy resources to meet California's energy needs and ranks energy efficiency and DR programs first in the "loading order."[54]

In CAISO's 2012 Summer load and resources assessment, CAISO also acknowledges the value of DR, and lists almost 2,300 MW of DR reductions available this year (not solely for SCE territory):

> **An estimated 2,296 MW of demand response and interruptible load programs will be available to deploy during summer 2012.** Demand response can reduce summer peak demands and provide grid operators with additional system flexibility during periods of limited supply. Demand response can provide economic day-ahead and real-time energy and ancillary service. [55]

CAISO's presentation at the June 4, 2012 Flexibility workshop, which, as discussed in the EE section above, also identifies additional DR as an energy resource solution that should be evaluated to fill flexible energy needs.

The potential for expanded DR has already made steady progress, and has only begun. By 2020 significantly expanded DR options can be considered a standard assumption, and yet CAISO included zero DR resources in 2021, even though it identified about 2300 MW of DR for 2012. Many studies have found basis for high future potential for DR. For example, a European paper *Demand Response: a Decisive Breakthrough for Europe* (which included review of US programs) found:

> **Demand Response methods are now quantifiably a success**
>
> ▪ **Energy Savings:** 20-50% (the later *[sic]* usually includes automated energy reductions) peak clipping and a 10-15% reduction of overall consumption have now been recorded repeatedly in a wide range of studies. This includes studies done over longer periods of time, where drop off or a loosing *[sic]* of interest by the consumer might be a problem. In some studies energy savings objectives have been exceeded by up to 200%.[56]

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[54] *Id*. at p. 11 (internal citations omitted).

[55] CAISO, *Briefing – Summer Loads and Resources Assessment* (March 15, 2012) *available at* http://www.caiso.com/Documents/Briefing_SummerLoads_ResourcesOperationsPreparednessAssessment-Report-MAR2012.pdf, at p. 6 (emphasis added).

[56] *Demand Response: a Decisive Breakthrough for Europe, How Europe could save Gigawatts, Billions of Euros and Millions of tons of CO2,* CapGemini in consultation with Vaasa Ett and Enerdata (2008), *available at* http://www.vaasaett.com/wp-content/uploads/2010/01/0805_Demand-Response_PoV_Final.pdf.

As discussed above in the EE section, CAISO's sensitivity study of EE and DR for the Environmentally Constrained scenario used 2,829 MW of DR in 2021 for SCE (Transmission Plan Table 3.4-1):

Load Serving Entities	2021 Incremental EE (MW)	2021 Demand Response (MW)
PG&E	2,275	1,523
SCE	2,461	2,829
SDG&E	496	283

As also discussed in the EE section above, CAISO has not made it clear what portion of this DR was included in the study as the LA Basin portion subset of the SCE territory, but using about 79% of this as the LA Basin proportion results in 2,224 MW DR. (Although as in the EE number used, it is again unclear whether CAISO is indicating that the entire 2,829 amount is the appropriate amount for the LA Basin, or if a somewhat lesser amount was used to reflect LA Basin as a subset of SCE load.) Thus I included a range of 2,224-2,829 as an appropriate basic assumption to be added to the list of resources 2021, as part of the alternative to new generation. Bill Power's Testimony for CEJA in this proceeding also describes available DR and estimates based on previous Commission estimates.

Strangely, the updated sensitivity study's new Table 3.4-1 in CAISO's Addendum now leaves DR out completely, not only from the scenarios, but from the sensitivity study:

Load Serving Entities	2021 Incremental Uncommitted EE (MW)	2021 Incremental Uncommitted CHP (MW)
SCE	2,461	209
SDG&E	496	14

[57]

This missing DR is inconsistent with increasing DR availability, and inconsistent with state policy, which was recently reaffirmed by the Commission. Perhaps this sensitivity study update is meant as a separate new study, and not as a replacement for the earlier one, but the reason for this is a mystery. Significant levels of DR should be included as an alternative to adding new conventional generation.

Considering that the remaining need in the LA Basin that was modeled in the new sensitivity studies ranged from 1,042-1,677 MW discussed above, I would imagine that DR in the range of 2,224 to 2,829 MW of DR could eliminate this need.

[57] Addendum to 2011/2012 Transmission Plan, Table 3.401, at p. 3.

F. Sufficient Distributed Generation (DG) Should Be Considered

CAISO included a far lower level of DG in its LCR analysis than is reasonable. Despite the Governor's goal of 12,000 MW statewide by 2020, CAISO only considered between 271MW to 1,519 MW in 2021 of DG.[58] Using these low DG estimates, CAISO showed the comparison for 2021 DG as far lower than existing OTC capacity (which is retiring or being retrofitted):

LA Basin Area Long-Term (2021) Load and Resources Summary

Itemized Details	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time Constrained (MW)
Total 1-in-10 Load + losses	22,867	22,838	22,872	22,862
		Generation		
Existing NQC (2012)	12,083			
Existing OTC Capacity (2012)	5,166			
Distributed generation	339	1,519	271	687

(May 3, 2012 workshop, CAISO Slide 25)

CAISO should consider all the available programs and their contribution to the local area, as well as specific state policy promoting DG. There is ample new evidence about the emerging economic competitiveness of DG, and benefits for supplying resources at peak load, discussed below. See Bill Powers Testimony which demonstrates a wide variety of available and economic options.

Levels appropriate to state policies and programs need to be inserted, including Governor Brown's goal of the development of 12,000 MW of solar DG by 2020,[59] the SB 32 feed-in tariff program, the Commission's Renewable Auction Mechanism, and the goal laid out in the AB 32 Scoping Plan for one million solar roofs, or 3,000 MW of solar DG by 2017.[60]

Furthermore, CAISO and E3[61] have provided us new evidence about the added benefits of DG compared to conventional resources that was not previously accounted. CAISO and others have frequently highlighted concerns that there will be a higher need for flexible (conventional) resources to balance intermittent renewables such as solar and wind. But it turns out that DG actually needs *lower* levels of flexible resources compared to conventional resources, as shown

[58] *See* Sparks Testimony at pp. 7-9, Tables 2-5.
[59] *See* California's Climate and Energy Policy Under Governor Brown, California Air Resources Board, at p. 10 http://www.energy.ca.gov/2012publications/CEC-999-2012-008/CEC-999-2012-008.pdf
[60] *See* Climate Change Proposed Scoping Plan, California Air Resources Board (Oct. 2008) at p. 53 http://www.arb.ca.gov/cc/scopingplan/document/psp.pdf
[61] E3 - Energy and Environmental Economics, http://www.ethree.com/

by the "Deep Dive" study presented by both E3 and CAISO at the June 4, 2012 Commission flexibility workshop , and described in the workshop's slides.

In the June 4, 2012 flexibility workshop, the presenters explained that previous PLEXOS modeling had been questioned as inaccurate on this point because it showed that the Environmentally Constrained case had much lower need for flexibility than the "All Gas" [62] scenario modeled for comparison. This modeling result was counterintuitive to the expectations of CAISO, since it was assumed that the All Gas case would be inherently more flexible because conventional power plants can be designed to ramp up quickly when load increases. It had been assumed that the high solar case would need higher levels of flexible resources (i.e., fast ramp up provided by conventional sources) that would have to kick in when solar resources dropped out as the sun descended.

However, the fast net load ramp up due to solar dropout does not require higher levels of flexible resources. This is because the time of day that renewables are available (mainly during peak needs) changes the "constrained hours" in the renewables scenario to off-peak time when there is lower load. Thus, more existing flexible resources are available at the time when the steep ramp occurs, alleviating the need to add new flexible resources. In other words, solar provides resources are available when they are most needed. The presenter explained that this shaves about 3,000 MW off the most constrained hours, and allows avoiding building almost 6,000 MWs in generation. This result is illustrated in E3's Slide 35 of the presentation:

[62] The All Gas scenario is based on the Trajectory scenario, with renewables subtracted out to 2009 levels, so that this scenario is dominated by conventional natural gas generation facilities.

Breakdown of Differences – Environmental vs. All Gas (Slide 35)

Component	Environmental Case	All-Gas Case	Difference
Load	46,685	49,437	2,752
- Baseload Generation	9,045	9,012	(33)
- RPS Generation	8,339	4,982	(3,356)
+ Contingency Reserves	2,794	2,888	94
+ Regulation Up	668	619	(49)
+ Load Following Up	1,941	1,616	(325)
= **Flexibility Requirement**	**34,704**	**40,565**	**5,861**

High solar penetration pushes constrained hours off the peak period in the environmental case

Low RPS penetration in the All-Gas case results in much less RPS generation during constraints

Regulation and load following requirements are slightly higher in the Environmental case, driven by the higher penetration of intermittent resources

Table shows average requirements and resource performance over the top 50 constrained hours

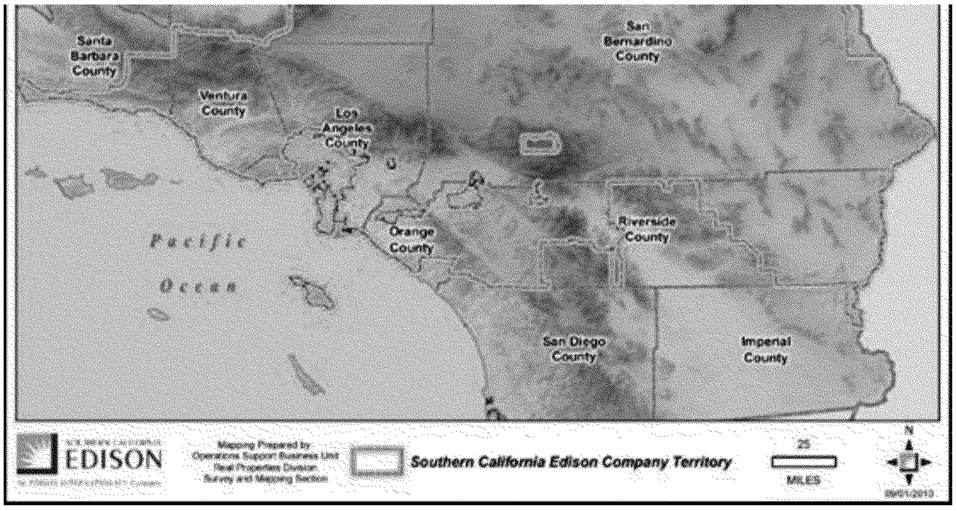
The 2011 Integrated Energy Policy Report (IEPR)[63] provides preliminary targets for DG, with localized estimates for different areas of the state of 2020 12,000 MW DG, including 4,000 MW for the City and County of LA (which is not exactly the same as LA Basin):

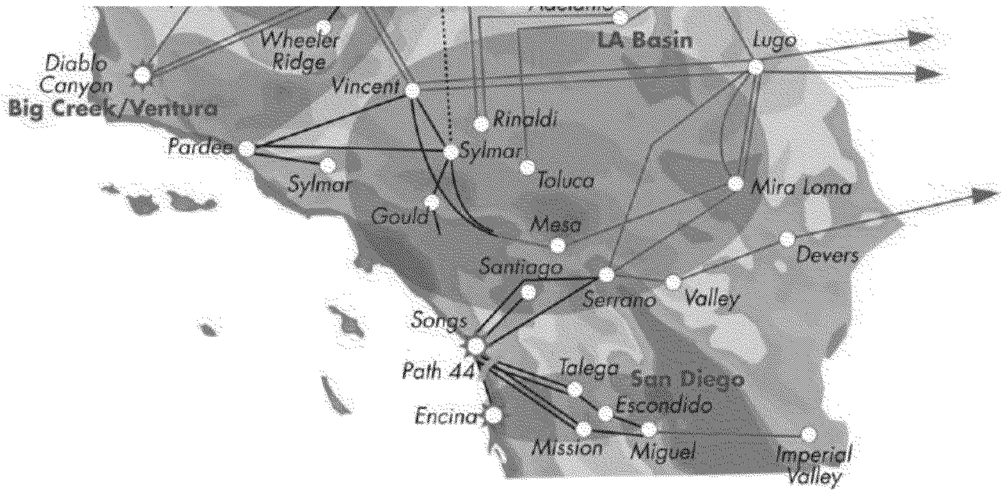
[63] 2011 Integrated Energy Policy Report, California Energy Commission (Feb. 15, 2012), Table 3 at p. 33, http://www.energy.ca.gov/2011_energypolicy/

Region	Behind the Meter (all technologies) (MW)	Wholesale (MW)	Undefined (mix of behind the meter and wholesale) (MW)	Total (MW)
Central Coast	280	90	0	370
Central Valley	830	1590	0	2,420
East Bay	420	30	0	450
Imperial	50	90	0	140
Inland Empire	480	430	0	910
Los Angeles (city and county)	970	860	2170	4,000
North Bay	220	0	0	220
North Valley	120	50	0	170
Sacramento Region	410	170	220	800
San Diego	500	50	630	1,180
SF Peninsula	480	10	310	800
Sierras	30	40	0	70
Orange	420	10	40	470
Total	**5,210**	**3,420**	**3,370**	**12,000**

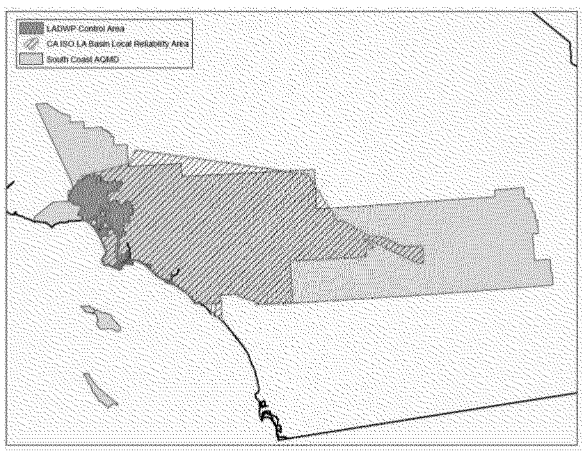
While a little cumbersome to illustrate because these areas are not all available on one map, this report presents different maps to allow comparison of the two areas. The County of LA is a smaller geographic subarea of the LA Basin, which means that levels of DG from other areas not included in the 4,000 MW should be added. See the maps below. The first map provided on the SCE website shows LA County,[64] the second, by CAISO in the Transmission Plan,[65] shows the LA Basin LCR Area making up a much larger portion of the SCE service area:

[64] Southern California Edison Territory Map, http://www.sce.com/AboutSCE/CompanyOverview/territorymap.htm
[65] CAISO 2011/2012 Transmission Plan, at p. 210.





However, the City and County of LA IEPR DG target must also include the Los Angeles Department of Water and Power (LADWP) Municipal Utility Control Area which covers the City of LA and a few other cities, and is not part of SCE. Thus, the LADWP area needs to be subtracted from the 4000 MW DG goal. CAISO also provided the following map in the May 3, 2012 CPUC workshop presentation (Slide 11) showing LADWP as a small subset of LA Basin:



Although the two geographic area tend to offset each other, the entire area does not have the same load density. CAISO could provide more definition and evaluation of the loads in each area to account for these mismatches. CAISO at a minimum should assume that the state goal of 12,000 MW is reached by 2020, and that a proportion consistent with the IEPR targets is included in all the LCR subareas evaluated, including the LA Basin, with specific proportions for any subareas that need to be separately modeled, consistent with the 12,000 MW goal.

While I did not locate a 2021 load forecast for the County of Los Angeles, the state of California website did provide 2010 million kilowatt-hour consumption (or GWh) by County, giving 67,323 million kWh for LA County,[66] and the separate listing by entity of 22,929 million kWh for the LADWP[67] or about 34% of County demand, so that the remainder of the County without LADWP would be 44,394 million kWh, 66% of County demand.

Using 66% of the 4,000MW City and County of LA DG target, leaves 2,640 MW for the non-LADWP portion of the County, but this doesn't cover the non-LA County portion of the LA Basin that needs to be added to this estimate to get a total for the LA Basin.

SCE shows a total of 82,197 million kWh consumption for 2010 on the same CEC website used for consistency.[68] Earlier in this report, I estimated the LA Basin peak load at about 79% of SCE peak, although this was for 2021. Assuming about the same proportion, using 79% of 82,197 million kWh for a 2010 estimate of the LA Basin, the LA Basin comes out to 64,935 million kWh. Compared to the non-LADWP portion of LA County, this includes an extra 20,541 million kWh over the 44,394 million kWh, or 46% extra consumption.

Adding a proportional amount of DG, or 46% extra to the non-LADWP portion of LA County (2,640+ 1220) results in approximately 3,854 MW.

These estimates include some minor inaccuracies (e.g. comparing million kWh proportions sometimes to MW proportions, using 2010 proportions when available instead of 2021, when the area outside LA County may be a larger proportion by 2021), but it shows that most if not all of the 4,000 MW DG should be included in CAISO's assessment if it is proportional to load. This should be a reasonable assumption, since DG is by definition distributed and close to load rather than centralized.

Using the 3,854 DG as the best available estimate of the LA Basin that complies with the state's IEPR targets, the following amounts need to be added to the scenarios:

	Trajectory (MW)	Environmental Constrained (MW)	ISO Base Case (MW)	Time Constrained (MW)
2011/2012 ISO	339	1, 519	271	687

[66] Energy Consumption Data Management System (ECDMS) of the CEC, http://ecdms.energy.ca.gov/elecbycounty.aspx

[67] *Id.*

[68] NOTE: There are LADWP consumption figures available for 2020 and 2022 in the CEC adopted forecast and updated forecast, but none for LA County. For consistency of assumptions, I am using the same CEC ECDMS website data that gave the LA County and LADWP 2010 numbers, to determine the relative proportions of LADWP, LA County, LA Basin, and SCE demand, except for the proportion of LA Basin compared to SCE total.

Transmission Plan Amount added if brought up to 3,854 MW	3,515	2,335	3,583	3,167

CAISO could further refine these values, but the table above provides a reasonable estimate. These amounts of DG should not be considered as solely part of an Environmentally Constrained scenario but should become part of standard assumptions, as DG provides power during peak needs, reduces the need for new flexible generation, is rapidly lowering in cost, and reduces transmission and distribution needs. Further, considering DG as part of standard assumptions would comply with state policies-.

The Testimony of Bill Powers in this proceeding and his previously cited BASE 2020 report describe the cost-effectiveness of DG. For example, he found that paying anything less than 22 cents per kWh for rooftop solar would benefit all ratepayers compared to paying for conventional power plant electricity, because of savings in transmission and distribution costs, time of delivery costs, and line losses.[69]

It is likely that additional policy will be in place requiring additional DG over the next years. For example, AB 1990 (Fong), the *Solar for All* bill,[70] just passed the Assembly Floor with a vote of 49-27. This bill is sponsored by CBE and other members of the California Environmental Justice Alliance. The bill would create feed-in tariffs for 375MW of small-scale renewable generation in disadvantaged communities between 2014 and the end of 2020. It begins with a modest amount of solar DG, but is structured to allow this number to grow with later authorizations.

G. Sufficient Storage to Meet State Goals Should Be Considered

CAISO appears to have considered no energy storage beyond pump water energy storage already available, for example as shown in ISO's response to CEJA's first data request:

> **ISO RESPONSE TO No 6**
>
> No new energy storage projects were assumed in the OTC studies for the LA Basin and the Big Creek /Ventura areas, and the ISO is not aware of any substantial planned or existing energy storage projects in those areas, that are included in the model. [71]

However CAISO's response to the first data request of the Vote Solar Initiative acknowledges the likelihood that storage could provide some of the need:

> d. Which contingencies could conceivably be addressed with a finite (2-8 hours) number of hours of 50-500 MW storage?

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[69] Bay Area Smart Energy Report, at p. 5.
[70] AB 1990, www.leginfo.ca.gov/pub/11-12/bill/asm/ab_1951-2000/ab_1990_bill_20120525_amended_asm_v95.html
[71] Response of CAISO to CEJA's First Set of Data Requests, Response No. 6.

ISO RESPONSE TO No. 4 (d)

> The ISO has not performed an analysis to determine the effectiveness of using storage to meet the LA Basin LCR need. **However, it is likely that some of the need could be met by the storage** specified in the question.

Many energy storage methods exist. This technology category is very likely to become more available over time, since storage solves so many problems and as Bill Powers discusses, many advances to energy storage technology have been achieved. Storage makes intermittent sources such as renewables available when needed, and also has the following additional benefits. In *Moving Energy Storage from Concept to Reality: Southern California Edison's Approach to Evaluating Energy Storage,*[72] SCE finds that storage is much more effective than conventional generation in meeting ramping requirements, and SCE also asserts that it solves some reduced system inertia issues that could occur as the proportion of conventional generation is reduced:

> Fast (defined as 10 MW per second) storage is two to three times more effective than conventional generation in meeting ramping requirements. Consequently, **30-50 MW of storage is equivalent to 100 MW of conventional generation**.[73]
>
> System inertia is provided today by large, conventional generation resources. The "spinning mass" of these devices can provide large amounts of power to the grid instantaneously in the case of a system reliability event. **While storage would not do this exactly, the power electronics associated with a device could be designed such that they *simulate* system inertia** by quickly discharging power onto the grid, if and when required.[74]

Bill Powers identifies many specific energy storage technologies in his testimony on behalf of CEJA, finds that thousands of megawatts of storage may be required according to SCE, and identifies 2020 levels originally included in AB2514 at about 2500 MW, or 5% of average peak.[75] He also identified a state goal of approximately 3,000 MW of energy storage that would be added to the grid to meet peak demand and support renewable energy generation under the Governor's *Clean Energy Jobs Plan*.

Given his testimony about current availability and development of storage as well as the related goals and policies, I included an estimate of at least 1,000 MW storage in my summary table, since LA Basin 2021 load makes up about 32% of state load (22,686 MW/70,000), or almost 1,000 MW out of 3,000 for the state.

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[72]Moving Energy Storage from Concept to Reality: Southern Califonria Edison's Approach to Evaluating Energy Storage, *available at* http://www.edison.com/files/WhitePaper_SCEsApproachtoEvaluatingEnergyStorage.pdf
[73] *Id*. at p. 14 (emphasis added).
[74] *Id*. at p. 21 (emphasis added).
[75] Prepared Direct Testimony of Bill Powers on Behalf of the California Environmental Justice Alliance (June 25, 2012) at p. 18.

H. Sufficient Incremental CHP Should Be Considered

CHP is less preferable in the Loading Order than EE, DR, and renewables, but it should be deployed before building new fossil fueled power plants. There is a large potential for CHP. For example, a 2004 Lawrence Berkeley National Laboratory study stated:

> The petroleum refining industry is one of the largest users of cogeneration or Combined Heat and Power production (CHP) in the country. **The petroleum refining industry is also identified as one of the industries with the largest potential for increased application of CHP. We estimate installed CHP capacity in Californian refineries at at least 1400 MWe**. [76]

In 2009, the Western States Petroleum Association (WSPA) estimated the CHP 2020 potential for the oil industry and presented a presentation to the California Energy Commission:

- **With supportive CHP policy WSPA members could add more than 1722 MW of** thermally matched CHP capacity
  - EOR:[77] 1070 MW
  - Refining: 652 MW
  - Potential varies materially by facility
- Additional CHP capacity would result in additional GHG savings of 1.7-2.0 MMtCO2e by 2020
- **Represents roughly half of the 3551 MW developed by 2020** under the ICF "all-in" scenario and two-thirds of the estimated 2.52 MMtCO2esavings estimated by ICF by 2020.[78]

This only includes oil industry CHP; many smaller sources are also candidates for CHP. There are some tradeoffs with CHP - while wasting heat at industrial facilities is inefficient, it would not be optimal to replace classic fossil fueled power plant electricity with fossil fueled refinery electricity, in lieu of cleaner sources. Such refinery CHP sources should be a much lower priority for implementation compared to clean renewables, cleaner EE, DG, storage, etc. However, generally making existing facilities with waste heat more efficient is a good goal, it is also a state goal, and part of a CPUC Settlement.[79]

Bill Powers' testimony identified levels of statewide CHP for 2020 used by the Commission, in his Testimony for CEJA (previously cited):

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[76] *Profile of the Petroleum Refining Industry in California, California Industries of the Future Program*, The Lawrence Berkeley National Laboratory (March 2004) *available at* http://ies.lbl.gov/iespubs/55450.pdf.at p. 45 (emphasis added). Note that units MWe are electrical megawatts, as opposed to thermal megawatts.
[77] Enhanced Oil Recovery.
[78] *Combined Heat and Power*, Western States Petroleum Association, Evelyn Kahl, CEC IEPR Workshop (July 23, 2009), Slide 9, *available at* http://www.energy.ca.gov/2009_energypolicy/documents/2009-07-23_workshop/presentations/03_Evelyn_Kahl_WSPA.pdf
[79] **Qualifying Facility / Combined Heat and Power Settlement Agreement** –D.10-12-035, (December 21, 2010) (resolved outstanding disputes between utilities and qualifying facilities and established a new CHP procurement program through 2020).

> In the 2010 LTPP, the Commission used an assumption of 322 MW for additional CHP in 2020, and 360 MW of incremental demand-side CHP for 2020 for SCE. (at. p. 28)

His testimony also identifies the 4,000 MW state goal of the California Resources Board AB32 Scoping Plan. As discussed in the section above on Energy Storage, the LA Basin makes up about 32% of state peak load for 2021, so the LA Basin proportion of this load would be about 1,300 MW, although this level of CHP has been heavily resisted by the utilities, more so than other state goals.

Given this information, some portion of incremental CHP should have been included in the Transmission Plan, and at least 79% of SCE's incremental portion, or at least 285 MW.

I. CAISO Should Identify Available Transmission Upgrades That Could Meet LCR Need

In comments on the 2012-2013 Transmission Plan, CPUC staff found[80] that CAISO should evaluate additional transmission improvements to reduce reliance on OTC plans, including particular transmission topology in LCR subareas in order to identify compliance alternatives. Staff found that CAISO has not systematically done so:

> ***9. The Generation Assumptions Should be Consistent with State Policy and Reasonable Expectations***
>
> Due to conflicting OTC requirements and local air emissions requirements, there arises the necessity to perform additional analysis related to meeting reliability needs by creating options other than generation retirement or repowering. **Transmission improvements specifically to reduce reliance on OTC plants as well as particular locations in the transmission topology (such as LCR subareas) are required in order to inform compliance alternatives** for generating asset owners who have the choice of either retirement inside the current ISO transmission topology, repowering inside the current ISO topology, or undertaking another alternative such as refitting their water intake structures. **Most importantly, transmission improvements for a future ISO transmission topology that reduce LCR requirements in sub-areas also needs to be examined, which the ISO has not addressed in a systematic manner.** It is critical to be able to evaluate these tradeoffs in order to minimize ratepayer costs and make the most efficient decisions possible about future resource investment.[81]

CAISO performed its analysis on this basis: *"The study included all existing transmission projects in service and the expected future transmission projects that have been approved by the ISO but are not yet in service."*[82] While this is certainly a reasonable place to start, CAISO should perform additional analyses after determining that additional resources are needed to meet LCR in certain subareas.

[80] *Id.* at p. 8.
[81] Comments of the Staff of the California Public Utilities on the Draft Study Plan (March 14, 2012) *available at* http://www.caiso.com/Documents/CPUCComments-Draft2012-2013StudyPlan.pdf at p. 7.
[82] Transmission Plan at p. 28.

The LCR results identify the need to evaluate additional options including transmission, as is made clear by CPUC staff above. There were also a number of comments about this at public workshops and in data requests, questioning whether CAISO had analyzed sufficient transmission fixes. CAISO did this in some cases (see the section above on the Addendum regarding updated sensitivities), but did not provide any analysis that attempted to more comprehensively address local deficits, especially using transmission improvements in combination with added resources such as DR, DG, etc. This is not to say that major new transmission projects should be the option of choice, but improvements to existing facilities, and prudent new facilities that are environmentally and economically responsible should be favored over large new conventional generation.

Methods for reducing specific transmission problems are well known, including examples below also identified by CAISO in the Transmission Plan:

- Special Protection Systems: *"These protection systems drop load or generation upon detection of system overloads by strategically tripping circuit breakers under selected contingencies. Some SPS are designed to operate upon detecting unacceptable low voltage conditions caused by certain contingencies."*[83]
- Reactive Support:[84] (such as shunt capacitors to offset induction, synchronous condensers,[85] synchronous generators, static VAR compensators[86]),
- Reconductoring lines (with higher-capacity conductors that can handle higher flow) or reconfiguring lines at risk of overload
- Monitoring loads near limits, and managing loads on these lines closely
- Adding looping: A looped system is usually inherently more reliable, since for example if line breaks, the line is still served from the other direction. Loops can be added to single-direction systems
- More examples are included in the Transmission Plan in different parts of the state

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[83] Transmission Plan at p. 35.

[84] Reactive power can be difficult to explain without providing charts and diagrams of AC power, but a presentation by Oakridge National Laboratories *(Reactive Power and Importance to Bulk Power Systems)* provides a basic summary: "*Reactive power (vars) is required to maintain the voltage to deliver active power (watts) through transmission lines. Motor loads and other loads require reactive power to convert the flow of electrons into useful work. When there is not enough reactive power, the voltage sags down and it is not possible to push the power demanded by loads through the lines." "When voltage and current are not in phase or in synch, there are two components, --Real or active power is measured in Watts, --Reactive (sometimes referred to as imaginary)power is measured in Vars,[volt-amperes reactive], --The combination (vector product) is Complex Power or Apparent Power, -- The term "Power" normally refers to active power"* Reactive power doesn't travel far, and so must be supported locally. (A crude analogy for laypeople that has been used is that a baseball's forward motion is like active power, the height of the arc is like reactive power – necessary to keep the ball in the air, but not part of its forward power.) *See* Reactive Power and Importance to Bulk Power System, Oak Ridge National Laboratory http://www.ornl.gov/sci/decc/RP%20Definitions/Reactive%20Power%20Overview_jpeg.pdf

[85] *Id.*, Synchronous Condensors - synchronous machines designed exclusively to provide reactive power support, - At the receiving end of long transmission lines, - In important substations, -In conjunction with HVDC converter stations, - Reactive power output is continuously controllable

[86] *Id*, Static VAR compensators – combine capacitors and inductors with fast switching (sub cycle, such as <1/50 sec) timeframe capability, - Voltage is regulated according to a slope (droop) characteristic.

CAISO states in the Transmission Plan:

> The majority of identified reliability concerns are related to facility overloads or low voltage. Therefore, many of the specific projects that comprise the totals in Table 2 include line reconductoring and facility upgrades for relieving overloading concerns, as well as installing voltage support devices for mitigating voltage concerns. Additionally, some projects involve building new load-serving substations to relieve identified loading concerns on existing transmission facilities. Several initially identified reliability concerns were mitigated with non-transmission solutions. These include generation redispatch and, for low probability contingencies, possible load curtailment.[87]

CAISO has identified some fixes, discussed below, but has not provided a comprehensive assessment, as identified by the CPUC staff, that could fix problems in lieu of additional generation, for example, more reactive voltage support, or other known methods to address deficiencies. This assessment including cost analysis and including modeling EE, DR, DG, and storage, compared to new generation is needed in order to determine whether any new generation is actually needed. Based on the fixes that CAISO has identified, which were shown by CAISO to reduce need by thousands of MW, and in some cases to eliminate need in subareas, additional transmission fixes could be highly effective.

CAISO's Transmission Plan did identify many specific bottlenecks, areas of potential voltage collapse, stability issues, thermal[88] issues, areas where reactive support or reconductoring could address specific transmission problems or limits. One example was the 600 MW load curtailment discussed earlier (Chino-Mira Loma East #3 500 kV line and Mira Loma West 500/230 kV bank #2 contingency), which CAISO identified as feasible, but did not clearly commit to including. This fix reduced overall LA Basin need between about 1,200 to 2,500 MW, depending on the scenario.

In response to CEJA's first data request, cited earlier, another fix was identified that would reduce local need by 2000-3000 MW:

> **Request No. 9**
>
> 9. For the limiting constraints identified in the LA basin, has CAISO evaluated whether transmission projects could mitigate or eliminate the constraints? Has CAISO evaluated the potential of adding reactive support to reduce or eliminate a need in the identified areas? . . .
>
> **ISO RESPONSE TO No 9**
>
> . . . **In addition, the overall LA Basin need could be reduced by 2000 MW to 3000 MW by installing sub-transmission facilities and 500/230kV transformers to facilitate load transfers between bulk substations within the LA Basin LCR area.** In

[87] Transmission Plan at p. 10.

[88] When power lines heat up, they sag, and can violate clearance limits (with trees, other lines, ets) Limits are specific to the line and conditions.

the Moorpark sub-area the local capacity need could possibly be reduced by approximately 300 MW by installing a large amount of reactive support.

CAISO also indicated in the following response to a CEJA data request, that it might have a fix to the most critical contingency for Western LA. This subarea of LA is driving most of the local need in the LA Basin according to CAISO's analysis, so a potential fix there is key information necessary to determine whether this need could be partially or completely eliminated on this basis alone:

> **Request No. 13**
>
> 13. In the 2011-2012 ISO Transmission Plan, CAISO states that "[t]he most critical contingency for the Western sub-area is the loss of Serrano-Villa Park #1 or #2 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in the thermal overload of the remaining Serrano-Villa Park 230 kV line."
>
> a) Has the CAISO evaluated whether transmission projects could mitigate this thermal overload? If so, please explain the results of the evaluation.
>
> ISO RESPONSE TO No 13 (a)
>
> The ISO has requested information from SCE to explore the possibility of increasing the rating of the Serrano-Villa Park 230 kV line.

Transmission fixes and procedures could completely eliminate deficits in meeting local capacity requirements in combination with added resources such as EE, DR, DG, and storage.

J. CAISO Should Modify Assumption that All OTC Facilities Would Be Retired

CAISO did not have a basis for making the assumption that all OTC facilities would be retired, and this is unlikely since these plants have options other than retirement including retrofitting. As quoted in the previous section, CPUC staff found that CAISO did not systematically consider transmission options that would provide alternatives to facility retirement, and staff also identified options for generating asset owners *"who have the choice of either retirement inside the current ISO transmission topology, repowering inside the current ISO topology, or undertaking another alternative such as refitting their water intake structures."*

In the recent *Reply Comments of Southern California Edison Company (U338-E) on the Standardized Planning Assumptions,*[89] SCE identifies the difficulty of determining which OTC plants will be retired:

> Various parties proposed different methods for determination of high and low once through cooling (OTC) retirement scenarios, all of which appear to be too simplistic, arbitrary, or incapable of being implemented into the production simulation modeling.[19] Retirement assumptions tend to be one of the most difficult assumptions to forecast

[89] For R12-03-014, SCE, June 12, 2012, at p. 11

> because plants are independently owned and the decisions on the plants' futures are made based on criteria that may be challenging to predict.

While I disagree in that I feel some reasonable assumptions might be made,[90] SCE's point about the independent decision making is well-taken, and the extreme assumption of CAISO that all OTC plants will be retired is unwarranted. SCE continues with the convincing points:

> **Assuming coincidence of retirements with high load would be inappropriate and would drastically and arbitrarily inflate the generation need.** Because regulators do have some discretion to extend OTC retirement dates due to grid reliability concerns, forecasting significantly higher need due to both high load and massive retirements does not seem justified.

SCE's statements highlight the tendency discussed later in this report for CAISO to choose too many worst case scenarios on top of each other far in advance of when such scenarios could be predicted with accuracy. SCE also identified the fact that there is no reason to jump the gun through over-procurement of new conventional generation almost a decade before any established need. Although conventional plant lead-time can take many years, a multitude of other options are available to preserve grid reliability without making such wholesale assumptions for rebuilding conventional facilities, as discussed throughout this report.

IV. CAISO's Over-stringent Reliability Methodology Unnecessarily Favors New Generation

A. CAISO's reliability definition is extreme, and could be harmful to the public

CAISO is using an unnecessarily tight measure of reliability to justify over-procurement of fossil fueled power plants counter to state environmental policies. This would cause actual harm to the public. CAISO's definition goes beyond the requirements of NERC (North American Electricity Reliability Corporation) and WECC (Western Electricity Coordinating Council).

It is certainly true that providing highly reliable electricity resources is an essential part of planning. I am also personally familiar with painful financial impacts that can occur during large electrical system failures – I happened to be in Michigan during the great 2003 Northeast blackout, one of the worst and largest, and had family members there who owned a struggling restaurant. They were financially devastated by the loss of power during the hot Detroit summer, when the electrical system failure caused the loss of their food stock and severely impacted their business, which they could ill afford. Many people were severely impacted by this event.

However, if we use CAISO's extreme definition of reliability with overlapping margins of safety over an extended period of many years, we are likely to over-predict long term resource needs. This will also cause other major harms to the public through over-procurement of polluting power plants, while unnecessarily costing the public billions of dollars without benefit. Justifying such polluting power plants means adding millions of tons per year in greenhouse

[90] *See* Bill Powers Testimony for specific plant's plans, beginning on p. 28.

gases plus smog precursors and particulate matter (which increases premature death rates), in a region of the country devastated by asthma impacts.

CAISO stressed in the Supplemental Testimony of Mr. Sparks that the dangers of overprocurement were lower than the dangers of underprocurement, but that is not so when taking into account the impacts of fossil fuel generation. (It is also irrelevant when resources that could meet need were not included in the CAISO assessment.) The Los Angeles Basin cannot afford CAISO's proposal from a health and environmental perspective. The CAISO proposal is also contrary to many state environmental policies, but CAISO justifies it as preventing theoretical contingencies highly unlikely to ever occur.

A discussion of transmission grid reliability requirements of NERC and WECC was provided in the parallel CPUC process covering San Diego, in the testimony of Jaleh Firooz, P.E., a former San Diego Gas and Electric (SDG&E) engineer for over 25 years and key participant in forming the CAISO.[91] In fact, the same issues very neatly discussed by Ms Firooz in the San Diego proceedings are relevant here, so I will quote from her testimony related to this proceeding, including identification of CAISO's use of reliability criteria more stringent than NERC's or WECC's:

> Federal regulations require that the transmission grid be planned and operated in accordance with reliability criteria developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC). These criteria generally specify that the grid must be capable of accommodating the outage of any one element of the grid (N-1)[92] without loss of load and the loss of two common elements (N-2) (e.g., two circuits on the same set of towers) without uncontrolled load loss. **Local balancing authorities may impose stricter criteria, and the CAISO has done so by implementing the requirement that the CAISO grid must also be capable of accommodating the outage of one generator followed by the outage of a transmission element (G-1/N-1) without loss of load or, in the current proceeding, outage of a transmission element followed by the outage of another transmission element (N-1/N-1; also referred to as N-1-1) without loss of load.** This criterion establishes the amount of generating capacity that the CAISO requires load serving entities in the San Diego area to place under contract (local capacity requirements) in order to ensure that there will be enough dependable capacity available to serve all forecast loads. These contracts impose costs on San Diego area consumers because the import constraints that result from the application of the G-1/N-1 reliability criteria limits competition among the local generators and therefore the incentive to negotiate lower contract prices.

Ms. Firooz identified alternatives also relevant to this proceeding that are more reliable than adding new infrastructure for preventing outages. For example, load drop is available to utilities and balancing authorities as a safety net but these provide little rate base and are rarely

[91] Testimony of Jaleeh Firooz for CEJA, May 18, 2012, Application 11-05-023, (Filed May 19, 2011).
[92] As earlier described - N-1 is a single transmission circuit outage, T-1 is loss of one transformer, G-1 loss of one generator

considered except as a last resort. She found that load drop is actually more reliable than a generating unit, because it may not be available at the time of the contingency condition:

> Typically, utilities and balancing authorities assume stressed system conditions such as **one-year-in-ten peak load conditions. As mitigation measures, these standards permit the use of pre-contingency generation redispatch, generator dropping and, for some less likely contingency conditions (N-2 outages), controlled load drop.** These operating procedures add little or no rate base and are usually the last mitigation options to be considered by IOUs, if they are considered at all. From the CAISO's perspective operating procedures such as load drop are a desirable backstop to new transmission or new in-area generation, but are not substitutes for new infrastructure even where the backstop is equally or more reliable. For example, **a load drop is more reliable than a generating unit that may not be available at the time it is needed.**

Ms. Firooz also performed various simple calculations showing the extremely small probability that the outages would ever actually occur, given CAISO's reliability definitions, the reliability of individual transmission and generation elements, the time of year when failures would have to occur, the particular year they would have to occur, and the other conditions that would all have to be present at exactly the same time to result in an outage:

> The combined probability of a G-1/N-1 overlapping outage occurring during any one of these peak hours would be .0005 x .00228 = .000001 or about 0.0001% in any given year. **This is equivalent to about 30 seconds in a year or 6 minutes in a ten year period.**

Likewise, for an N-1-1 contingency to cause an outage, she found it would only be expected to possibly occur during a little more than a minute in ten years:

> The combined probability of an N-1/N-1 (N-1-1) overlapping outage occurring during any one of these peak hours would be .0001 x .00228 = .000000228 or about 0.00002% in any given year. **This is equivalent to about 7 seconds in a year or a little more than a minute in a ten year period.**[93]

On top of this, CAISO is using an *additional* margin of safety for transmission line temperature ratings, even further reducing the likelihood that these failures could occur. Specifically, CAISO uses a 2.5% margin on top of the one-year-in-ten forecast. According to Ms. Firooz, the 2.5% margin is not identified by WECC as a requirement to be added on top of the one in ten year condition, especially since that already has a 10% margin above any given year. She also finds that a one-year-in-two load forecast plus a 10% cushion would instead be reasonable for long-term planning:

> Adding the effect of using conservatively-rated transmission lines; e.g., using ambient air temperatures that significantly exceed the air temperature that would exist during a one-year-in-ten peak load condition; shrinks the likelihood of actually encountering these limiting conditions even further. Notably for this proceeding, the CAISO is using another

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[93] Ms. Firooz reduced this estimate in her testimony in A.11-05-023 after reviewing information on the outage of a transmission line provided by SDG&E. *See* A.11-05-023, Thursday, June 25, 2012 Transcript.

2.5% margin on top of the one-year-in-ten load forecast; i.e., in the CAISO's LCR analysis, forecast one-year-in-ten forecast loads are increased by 2.5%.

> **Although WECC recommends the 2.5% margin (102.5% of load) be used for category C[94] contingency voltage studies there is no mention of applying this margin on top of a one-year-in-ten peak load condition.** The one-year-in-ten peak load condition is already about 10% higher than the highest expected peak load in any given year. . . .
>
> **In my experience long term resource planning was done using a one-year-in-two (expected) load forecast plus 10%** adder to provide an installed capacity cushion to account for unexpected generator outages and load forecast error at time of peak. Later, the cushion was raised to 15% to 17%. **The LCR analysis, which is based on a one-year-in-ten load forecast, is only binding for the upcoming year.** According to the CAISO tariff, longer term LCR estimates which are the main subject of this proceeding are informational and not binding.

Ms. Firooz also suggests that if such unlikely contingencies are to be used, the impacts associated with their occurrence should also be evaluated so that a distinction could be made between events that would be merely inconvenient, versus those that could cause real harm. I agree. Most everyone has experienced outages caused for example by downed trees during a local storm. These events are infrequent, power is usually quickly restored, and the impacts are generally merely inconvenient. It is only reasonable given the very harmful impacts associated with over-procuring conventional resources that any contingencies be evaluated in the light of whether the outage impacts would be great or small. Furthermore, the costs of new generation to meet these stringent criteria are huge:

> The CAISO's more stringent reliability criteria could cost consumers billions of dollars in contract costs -- the cost of new generation to meet LCRs with effectively no measurable increase in grid reliability. As a general matter, it does not make sense for California to have more stringent reliability criteria than the rest of WECC. This increases costs and puts load serving entities within the CAISO balancing authority at competitive disadvantage to other balancing authorities, both inside and outside of California. If there are special circumstances where more stringent reliability criteria may be required, those need to be brought up on an exceptional basis and justified rather than being the rule. Changing the CAISO's existing reliability criteria to match that of NERC/WECC would

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[94] CAISO states:. . . *during normal operating conditions Category A (N-0) the CAISO must protect for all single contingencies **Category B (N-1)** and common mode **Category C5 (N-2)** double line outages. Also, after a single contingency, the CAISO must re-adjust the system to support the loss of the next most stringent contingency. This is referred to as the N-1-1 condition. The **N-1-1 vs N-2** terminology was introduced only as a mere temporal differentiation between two existing NERC Category C events. N-1-1 represents NERC Category C3 ("category B contingency, manual system adjustment, followed by another category B contingency"). The N-2 represents NERC Category C5 ("any two circuits of a multiple circuit tower line") as well as requirement R1.1 of the WECC Regional Criteria ("two adjacent circuits") with no manual system adjustment between the two contingencies.* R11-10-023, Filed October 27, 2011, CAISO Submission of 2013 Local Capacity Technical Analysis, Final Report and Study Results, http://docs.cpuc.ca.gov/EFILE/REPORT/165689.PDFat p. 9.

only require action by the CAISO. Approvals from WECC, NERC or FERC do not appear to be necessary.[95]

The same large costs apply for the Los Angeles Basin and California in general. Conditions are rapidly changing in electricity planning, with renewables quickly penetrating the grid and rapidly declining in cost. It is unreasonable to do long term electricity planning given these conditions changing in favor of DG, EE and other alternatives, that requires commissioning new or replacement conventional generation that will be in place for decades, without actually evaluating the DG, EE, and other alternatives. The conventional generation will cost of billions of dollars plus major environmental impacts, in order to cover highly unlikely contingencies that CAISO is trying to predict a decade in advance.

CPUC staff has also identified CAISO's approach as problematic when CAISO relied on overly stringent contingencies for justifying additional transmission.[96] The comments below can be equally applied to the addition of unnecessary generation. Staff commented that using N-2 contingencies was not required by standards, must be justified in the particular circumstances, the impacts should be identified (including costs), and alternative solutions should be evaluated:

> ***7. Major Identified "Reliability" Transmission Needs Based on N-2 (Category C) Contingencies Should be Adequately Justified***
>
> Transmission planning studies have sometimes identified costly or difficult to permit transmission additions based on N-2 contingencies. NERC, WECC and ISO reliability and planning standards do not require avoidance of load shedding under N-2 contingencies, but provide that transmission additions to address such contingencies may be considered taking into account the specific circumstances of the contingences, consequences and mitigation. If considering major transmission additions to address N-2 contingencies, the ISO should provide substantial, transparent analysis and information regarding the contingencies and their likelihood; the magnitude, duration and costs of load shedding; and the costs and effectiveness of alternative solutions.

Such justification and evaluation of consequences, cost, and alternatives has not been provided, yet alternatives exist as earlier shown in this report.

B. Using NERC and WECC Standards would not Lower Reliability in California

Using NERC and WECC standards would not lower reliability in California by any sensible measurement, as shown by the very small probabilities calculated above, and as further stated by Ms. Firooz as a general matter in the state of California:

> **Not approving procurement for highly improbable contingency criteria would not lower reliability in California at any reasonably measurable level. The CAISO would still meet all applicable NERC and WECC reliability requirements and would be on**

[95] Firooz Test. at p. 7.

[96] *Comments of the Staff of the California Public Utilities Commission on the Draft Study Plan, California ISO 2012-2013 Transmission Plan (*March 14, 2012), at p. 7, http://www.caiso.com/Documents/CPUCComments-Draft2012-2013StudyPlan.pdf

par with the reliability standards of all other balancing authority areas. Where a project sponsor or regulatory authority believes existing NERC or WECC reliability criteria are not adequate, or that the assumptions and/or methodology for implementing those criteria are not sufficiently conservative to address the contingency event of concern, the project sponsor or regulatory authority should be required to:

1. Assess the probabilities associated with the contingency based on ten years of relevant historical outage data.
2. Identify the consequences of the contingency event (e.g., amount and duration of uncontrolled load loss, economic impacts of such load loss, public safety concerns).
3. Provide a justification for applying more conservative reliability criteria than required by WECC and NERC.

It would be sensible for this type of long term planning for the Commission to revise this practice to require utilities to rely on a 1-in-2 forecast consistent with prior Commission decisions. For example, in the 2004 LTPP decision,[97] the Commission found that:

> Existing resource planning uses average weather (1-in-2) and then adds a reserve margin which, in part, provides the cushion should hotter than average weather occur. This is the approach we adopted to implement our resource adequacy requirements and should also be applied here.

California's reserve margin of 15-17% is already higher than the 7% reserve margin required by WECC. Allowing utilities to plan using a 1-in-10 scenario for long term planning inflates the reserve margin and can lead to procurement of resources that are unlikely to ever be needed.

The CPUC website provides a history of the development of the reserve margins, where he Commission stated:

> In a 2004 LTPP decision, the Commission rejected a proposal to develop demand forecasts for LTPP purposes by using a 1-in-10 peak weather standard. (D.04-12-048, p. 28.) In doing so, it noted that the RA program is based on average weather (1-in-2) and that the PRM, in part, provides a cushion should hotter-than-average weather occur. [98]

The Commission discussion continued, to state that in special circumstances or particular regions, it may consider additional protections, but the Commission did not identify the long term planning process as one where the 1-in-10 peak in addition to the 15-17% margin would be required.

C. Load Drop Could Be Used to Satisfy Need in the Regions Evaluated in This Proceeding

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[97] CPUC, *Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company, Southern California Edison Company, and San Diego Gas & Electric Company's Long-Term Procurement Plans,* Rulemaking 04-04-003, (Filed April 1, 2004), Section III. Analysis Of Long-Term Procurement Plans, 3. Discussion of Load Forecasts, *available at* http://docs.cpuc.ca.gov/published/Final_decision/43224.htm#P182_5599
[98] R.08-04-012, Order Instituting Rulemaking (April 16, 2008) at p. 6.

Voluntary load shedding is recognized as having major economic benefits for businesses:

> **Load Shedding and Demand Control for Large Companies in California**
>
> Load shedding is a means of reducing demand usage in a facility and will reducing energy usage by up to 20%. **Many times demand charges exceed 50% of the total electric power bill. This makes demand control a very attractive option to reduce operating costs.**[99]

Load shedding can also be involuntary but controlled, as a backup safety net for such unlikely events as those identified by CAISO for 2021. CPUC staff made comments in February on the draft Transmission Plan,[100] and specifically identified load shedding as an option that CAISO could use instead of building large reliability projects (referring to large transmission projects that may not be necessary). Staff made comments about CAISO's avoidance of load drop, and found that although CAISO rules did not allow load drop for Category B events, they do allow it for Category C events, and clarified rules:

> . . . ISO's Planning Standards (June 23, 2011) state on page 6 that no single contingency (TPL-002 and ISO standard [g-1] [l-1]) should result in loss of more than 250 MW of load. **There is no stated ceiling on load shedding for double contingencies** (at p. 6)

Staff also found that NERC does not require avoiding load shedding (same page):

> . . . NERC reliability standards do not require avoidance of load shedding in the event of on N-2 (Category C) Bulk Electric System contingency, but rather state with regard to such contingencies that:
>
> > *Depending on system design and expected system impacts, **the controlled interruption of electric supply to customers (load shedding),** the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers **may be necessary to maintain the overall reliability of the interconnected transmission systems.***

Ms. Firooz also discussed load drop in her Testimony as an option approved by NERC and WECC for addressing these contingencies, but not used by CAISO:

> NERC and WECC reliability criteria permit load drop for G-1/N-1 outages and for N-1-1 outages, the CAISO does not.

As an example, a NERC guideline describes UVLS (Under Voltage Load Shedding) as an appropriate safety net for severe contingencies:[101]

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[99] June 30th, 2011, Energy Controls Limited (emphasis added), http://www.egenergy.com/load-shedding-and-demand-control-for-large-companies-in-california

[100] *Comments of the Staff of the California Public Utilities Commission on the January 31, 2011 Draft of the 2011-2012 Transmission Plan,* (February 28, 2012), *available at* http://www.caiso.com/Documents/CPUC_Comments_Draft2011-2012_TransmissionPlan.pdf

[101] *Guidelines for Developing an Under Voltage Load Shedding (UVLS) Evaluation Program,* NERC, (Sept. 13, 2006), *available at* http://www.nerc.com/docs/pc/tis/UVLS_Guidelines_approved_by_PC.pdf

This guideline is intended to address UVLS programs designed to prevent wide-area voltage collapse and cascading, whether the control is applied locally or by a centralized controller. Such UVLS programs are **intended as a safety net to stabilize the system** and prevent cascading outages for severe contingencies. . . .

- For category C and D contingencies, the application of BPS UVLS programs **should be considered as "safety nets," to avoid voltage collapse or voltage instability**, and studied to ensure that they adequately perform that function.
    - For NERC category C and D contingencies, application of locally applied UV relay schemes are acceptable to protect local load as described in the above introduction
    - The application of BPS UVLS programs also should be studied to address multiple unrelated outages (extreme events) and external contingencies.

CAISO also identifies load drop as a special protection for certain locations in the Transmission Plan,[102] but doesn't identify this as a general tool for dealing with these severe contingencies. Load drop could be centrally or locally controlled.

As a backup safety net, load shedding is a much more appropriate tool for addressing highly unlikely contingencies, than building major power plants to run for the next four decades, "just in case."

V. CONCLUSIONS

A sensible approach to providing a high reliability system that best protects the public and would be consistent with the Loading Order, involves first fully utilizing the cleanest sources (EE, DG, DR, storage, and CHP last), upgrading existing transmission, then using load shedding as a safety net for very unlikely contingencies, and only as a last resort adding any conventional power plants.

I applaud CAISO staff's hard work toward maintaining highly reliable power in California in the midst of competing demands. Yet the Transmission Plan consistently relies on conventional generation without sufficiently evaluating real alternatives. This is the method historically used, but inconsistent with fundamental state policies and need to avoid severe harms to Californians caused by climate change and air pollution.

The additional evaluations needed for quantifying cost-effective non-conventional resources to supply LCR will require more work of CAISO staff, but these evaluations are crucial to meeting basic environmental and health goals and should have been included in the original Transmission Plan. **The Commission should not approve the procurement of additional conventional resources based on this Transmission Plan.**

[102] *See* 2011/2012 Transmission Plan, at p. 107 and p. 124.

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Experience

1989-present **Energy and Industrial Air Pollution Engineering Evaluation**

ffi Evaluation of energy issues including electricity planning, natural gas and coal-fired power plant permitting and impacts, transmission and reliability issues, alternative energy and policy options.

ffi Industrial air pollution source evaluation including criteria pollutants, toxics, greenhouse gases, pollution prevention methods and engineering solutions.

ffi Research on best and worst industrial practices, chemical and fossil fuel phaseout methods, policy, and technologies.

ffi Analyzing permitting, emissions and air monitoring data; compiling available health and environmental impacts data. Evaluation of technical basis of regulatory compliance with environmental laws. Working through practical technical issues of regulation, negotiating with industry and government agencies to craft most health-protective policy and regulatory language.

ffi Translating inaccessible technical information into lay language and educational materials. Providing technical assistance and cumulative impacts analyses to communities of color that face severe pollution burdens. Assisting communities and workers in developing proposals for environmental health protection regulation, permitting, and policy.

ffi Managed science department for statewide environmental organization. Hired by regulatory agency as technical advisor to identify feasible air pollution control methods not previously adopted, and to assist communities submitting comments during regulatory proceedings.

Education

1981 **B.S. Electrical Engineering**, University of Michigan, Ann Arbor
Engineering principles, circuit design, mathematics, thermodynamics, physics, materials science, chemistry, and others

Project examples:

ffi Evaluation of California Long Term Procurement Plan (electricity planning) and California power plant permits, reliability, transmission alternatives, environmental impacts (e.g. Potrero, Hunters' Point, Oakley), and coal gasification proposals outside California (1990s to present).

ffi Evaluation of proposed refinery expansions, oil drilling and pipeline permitting: Emissions and solutions relating to feedstock switches to Canadian tar sands crude oil at ConocoPhilips Wood River, BP Whiting, Detroit Marathon, and proposed new MHA Nation, North Dakota, refineries, as well as dozens of refinery expansions in Northern and Southern California. Oil drilling operations, air impacts, in residential Los Angeles neighborhood. Pipeline transport impacts of crude oil, hydrogen, and other oil industry feedstocks in California and Midwest. Evaluation of coal gasification plant emissions. (1990s to present)

ffi Development of model California oil industry criteria pollutant regulation, and proposed greenhouse gas regulation and alternatives analysis: Oil refinery regulations for flares, pressure relief devices, tanks, leakless fugitives standards, petroleum product marine loading, and others. (1990s to present)

Positions

2004- present **Independent Environmental Consultant (2004 - ongoing) and Senior Scientist, Communities for Better Environment (2006 – present) –** Energy Use / Industrial pollution quantification / Alternatives analysis, including engineering analysis of proposed and existing industrial permits, analysis of statewide goals and energy planning, as well as policy analysis. Analysis of impacts and solutions to environmental problems including trends in energy use, oil industry feedstocks, associated equipment changes, emissions of criteria pollutants, toxic emissions, and greenhouse gases. Technical consultant and strategist in community campaigns on industrial regulation. Geographic areas include Southern California, Northern California, and multiple U.S. states.

2001-2003 **Statewide CBE Lead Scientist, CBE,** Oakland, CA
Responsible for accuracy and strategic value of CBE's technical evaluations within community and environmental law enforcement campaigns, also led statewide technical staffing. Identified underestimations in electrical power plant expansion air emissions in a community of color which had very high asthma rates; identified alternatives option including sufficient conservation, clean energy generation, and transmission available to prevent need for fossil fuel expansion, documented facts in California Energy Commission proceedings. Analysis of and recommendations on adding regulation to Bay Area Ozone Attainment Plan (concerning flares, pressure relief devices, wastewater ponds, storage tanks, and others) which were ultimately adopted. Evaluated Environmental Impact Reports and Title V permits for refineries and chemical plants; identified emissions, potential community impacts and alternatives. Successfully assisted negotiating Good Neighbor Agreements by identifying technical solutions to environmental violations to bring facilities into compliance.

1990-2001 **Clean Air Program Director, Northern California Region, CBE**
Analysis of permits, regulation, air pollution inventories and other emissions information for oil refinery, power plant, cement kiln, smelter, dry cleaner, consumer product, lawn mower, mobile source, and other air pollution sources, neighbor and worker health impacts, with pollution prevention policy development. Successfully advocated for national models of oil refinery regulation. Evaluated and documented root causes of industrial chemical accidents as part of community campaigns for industrial safety. Technical assistance to community members negotiating Good Neighbor Agreements with refineries. Successful advocacy for adoption of policies eliminating ozone depletors in favor of benign alternatives.

1987-1990 **Research Associate, CBE**
Led successful campaign working closely with maritime workers and refinery neighbors for adoption of strict oil refinery marine loading vapor recovery regulation, which became statewide and national model. Member of technical working group at BAAQMD evaluating emissions, controls, safety, and costs. Also analyzed school pesticide use and won policy for integrated pest management on school grounds.

1986 **Assistant Editor of appropriate technology publication, Rain Magazine**, Portland, OR
Production of publication on innovative energy and environmental success models around the U.S. and the world. Compiled, co-edited, wrote, and provided production for non-profit publication.

1981-1985 **Electrical Engineer, National Semiconductor Corp., Santa Clara, CA**
Electronics engineering design team member for analog-to-digital automotive engine controls for reducing air emissions. Troubleshooting hardware and evaluating fault-analysis software efficacy.

A few special activities

2002 & 2006	**Roundtable on Bay Area Ozone Attainment Progress and South Coast AQMD community technical advisor** Invited member of problem-solving group of decision makers including BAAQMD board members, industrial representatives, and government officials for reviewing progress and proposing action to control San Francisco Bay Area regional smog. Hired as Technical Advisor of SCAQMD to community organizations evaluating availability of alternative options in regional ozone attainment plan
1995-2003	**Air pollution monitoring projects including Optical Sensing Air Pollution Monitoring Equipment community "Bucket Brigade" low-tech monitoring projects** Provided technical analysis for community negotiators, resulting in permanent installation of a state-of-the art air pollution monitoring system on the refinery fenceline, using optical sensing to continuously measure air pollution and broadcast data to a community computer screen. Researched and reviewed manufacturer specifications, developed Land Use Permit language, and worked with refinery and manufacturer for better Quality Assurance/Quality Control. Worked with US EPA, Contra Costa County, and community groups evaluating the system and publishing report evaluating monitoring of emissions. Administered EPA-funded "Bucket Brigade" low-tech air pollution monitoring project for community groups of Contra Costa County Bucket Brigade project, who carried out training events in several communities surrounding major Bay Area refineries and chemical plants.
1997	**Installation of Photovoltaic Panels,** Solar Energy International, Colorado. Practical training on solar energy system design and installation for general electrical energy uses including water pumping, house cooling, etc, and applying energy conservation principles.
1993	**Chemistry of Hazardous Materials** course, U.C. Berkeley Extension, for environmental professionals