ATTACHMENT A

BEFORE
THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	R.12-03-014

RESPONSE OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
TO THE THIRD SET OF DATA REQUESTS OF THE
DIVISION OF RATEPAYER ADVOCATES

Below are responses to the Third Set of Data Requests served by the Division of Ratepayer Advocates (DRA).

RESPONSE

The following questions are in relation to CAISO's May 23, 2012 and June 19, 2012 filings, Testimony of Robert Sparks.

Request No. 1.

a. Regarding West LA Basin sub-area, Table 2 of Mr. Sparks' Supplemental Testimony dated June 19, 2012 and Tables 2-5 in Mr. Sparks' Testimony dated May 23, 2012. Please confirm or explain otherwise that the limiting contingency (Serrano – Lewis #1 / Serrano – Villa PK #2) defining the computed LCRs for the sub-area is an N-1-1, category C contingency.

ISO RESPONSE TO No. 1.a

The limiting contingency (Serrano – Lewis #1 / Serrano – Villa PK #2) is a category B contingency with manual system adjustments following by a second category B contingency.

b. Does CAISO operate any Special Protection Schemes, or has CAISO planned for any SPSs, for this contingency, or similar contingencies affecting the 230 kV system in the Western LA Basin sub-area?

ISO RESPONSE TO No. 1.b

No.

c. If not, please state the reasons why not. If so, please describe the SPSs for the Serrano-Lewis #1 / Serrano – Villa PK #2 or similar contingencies.

ISO RESPONSE TO No. 1.c.

In past studies, the limiting component and the worst contingency to drive the LCR need for Western LA has changed from year to year. If we mitigate the Serrano-Lewis #1 / Serrano – Villa PK #2 contingency by SPS, other contingencies are expected to require a similar total LCR need depending on which units are meeting the need and their effectiveness factors.

d. What is the modeled (load + losses) value for the Western LA Basin sub-area for 2021?

ISO RESPONSE TO No. 1.d

13,842 MW.

Request No. 2.

2. Regarding Ellis, El Nido, Moorpark sub-areas, Tables 2-5 and Tables 7-10 in the Testimony of Mr. Sparks, May 23, 2012, and regarding the El Nido sub-area in Table 2 of Mr. Sparks' June 23, 2012 Supplemental Testimony.

a. Please confirm or explain otherwise that the limiting contingencies applicable to each of these sub-areas, for the LCR computations, are N-1-1, category C contingencies.

ISO RESPONSE TO No. 2.a

The limiting contingency for the El Nido sub-area is a common mode contingency of two circuits on the same tower. The limiting contingency for both the Ellis and Moorpark sub-areas is a category B contingency with manual system adjustments following by a common mode contingency of two circuits on the same tower resulting in voltage collapse.

b. Does CAISO operate any Special Protection Schemes, or has CAISO planned for any SPSs, for these contingencies, or similar contingencies affecting the 230 kV system in the Western LA Basin sub-area?

ISO RESPONSE TO No. 2.b

Please see response to 1b.

c. If not, please state the reasons why not. If so, please describe the SPSs for the N-1-1, Category C or similar contingencies.

ISO RESPONSE TO No. 2.c

Please see response to 1c.

d. What is the modeled (load + losses) value for each of these three sub-areas for 2021?

ISO RESPONSE TO No. 2.d

The ISO has not precisely defined these three small sub-areas, so the modeled load + losses for these areas is not defined.

Request No. 3.

3. Regarding West LA Basin sub-area, Big Creek sub-area, nested sub-areas.

   a. For any of the applicable limiting contingencies and related binding constraints for the western LA Basin sub-area, the Big Creek/Ventura sub-area, or the other nested sub-areas, has CAISO analyzed, or does CAISO know if others (SCE, LADWP) have analyzed options to reinforce the underlying 230 kV system(s) in the LA Basin region to mitigate against these contingencies, and lower the LCR for the sub-areas(s)?

ISO RESPONSE TO No. 3.a

The ISO has analyzed transmission related mitigation options. We do not know if others have analyzed options.

   b. If so, please provide any results of any such analyses. If not, please provide commentary on feasibility and costs of such reinforcement options, addressing in particular (but not limited to) options to increase the thermal ratings of 230 kV lines or add more 500/230 kV transformation capacity on the grid at appropriate electrical locations.

ISO RESPONSE TO No. 3.b

As described in Robert Sparks' Direct Testimony submitted in the LTPP, an existing SPS was identified that could eliminate the Ellis sub-area need, but due to the critical need for these units if SONGS were no longer available, the ISO does not recommend that this SPS be relied upon. In the Moorpark sub-area, the local capacity need could possibly be reduced by approximately 300 MW by installing a large amount of reactive support. The ISO does not have cost estimates for these transmission upgrades.

Request No. 4.

4. Has CAISO discussed, planned or analyzed alternative dispatch, commitment, or other operational procedures that could be undertaken in coordination with the LADWP control area operators that would more efficiently make use of the combined CAISO-controlled and LADWP-controlled generation and transmission assets in the LA Basin? Please explain the extent of any such analyses, if undertaken, and/or comment on the extent to which such increased coordination, by later in the decade, could contribute towards lower LA Basin or Basin sub-area LCRs.

ISO RESPONSE TO No. 4

Yes, the ISO has conducted such an analysis. The constraint for the Overall LA Basin, identified in tables 2 through 5 of Robert Sparks' testimony, is the overload of the Eagle Rock-Sylmar S 230 kV line following the contingency of the Sylmar S-Gould 230 kV line + Lugo-Victorville 500 kV line. Based on these results, the constraint for the Overall LA Basin are the tie-lines connecting the LADWP system to the SCE system. Thus, the LADWP generation is not effective at meeting the overall LA Basin local capacity needs. The LADWP generation is also not effective at meeting any of the sub-area constraints either.

ATTACHMENT B

Form 1.5d - Statewide

Final California Energy Demand Forecast, 2012 - 2022

1 in 10 Net Electricity Peak Demand by Agency and Balancing Authority (MW)

Form 1.5d - Statewide Final California Energy Demand Forecast, 2012 - 2022 1 in 10 Net Electricity Peak Demand by Agency and Balancing Authority (MW)

Balancing Authority	Agency	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Average Annual Growth 2011 - 2022
	CCSF	133	137	141	143	146	148	149	151	152	153	154	155	1.40%
	NCPA - Greater Bay Area	237	244	250	254	258	262	266	269	273	276	279	281	1.56%
	Other NP15 LSEs - Bay Area	3	3	3	3	3	3	3	3	3	3	3	4	2.65%
	PG&E Service Area - Greater Bay Area	8,153	8,346	8,550	8,673	8,798	8,928	9,037	9,145	9,266	9,391	9,512	9,632	1.53%
	Silicon Valley Power	452	463	475	484	491	497	503	508	511	515	518	519	1.26%
Greater Bay Area Subtotal		8,978	9,193	9,418	9,558	9,696	9,838	9,958	10,076	10,205	10,337	10,465	10,590	1.51%
	CDWR-N	264	264	264	264	264	264	264	264	264	264	264	264	0.00%
	NCPA - Non Bay Area	237	243	249	253	257	260	263	267	270	274	277	280	1.53%
	Other NP15 LSEs - Non Bay Area	93	95	97	98	99	101	102	104	105	106	107	107	1.28%
	PG&E Service Area - Non Bay Area	9,696	9,924	10,165	10,314	10,463	10,615	10,746	10,874	11,018	11,165	11,310	11,453	1.53%
	WAPA	248	254	260	264	268	271	273	275	277	280	281	282	1.17%
Total North of Path 15		19,516	19,974	20,453	20,752	21,045	21,350	21,607	21,860	22,140	22,427	22,703	22,977	1.50%
	CDWR-ZP26	315	315	315	315	315	315	315	315	315	315	315	315	0.00%
	PG&E Service Area - ZP26	2,411	2,468	2,529	2,565	2,602	2,641	2,673	2,706	2,741	2,779	2,813	2,849	1.53%
Total Zone Path 26		2,726	2,783	2,844	2,880	2,917	2,956	2,988	3,021	3,056	3,094	3,128	3,164	1.36%
Total Valley		13,264	13,583	13,900	14,114	14,308	14,510	14,681	14,852	15,042	15,240	15,430	15,621	1.50%
Total North of Path 26		22,243	22,757	23,296	23,632	23,963	24,306	24,595	24,879	25,194	25,521	25,832	26,141	1.48%
	Merced	90	92	94	96	97	98	99	100	100	101	101	101	1.05%
	Turlock Irrigation District	512	524	537	545	552	559	564	570	578	584	591	596	1.39%
Total Turlock Irrigation District Control Area		601	616	631	641	649	657	663	671	678	686	692	697	1.36%
	City of Shasta Lake	21	22	22	23	23	23	23	23	23	23	23	23	0.83%
	Modesto Irrigation District	680	697	714	726	734	743	752	759	768	777	786	792	1.40%
	Redding	248	255	260	265	268	272	277	280	285	290	294	299	1.71%
	Roseville	351	360	369	375	381	385	391	396	401	407	411	415	1.53%
	SMUD	3,305	3,384	3,465	3,512	3,558	3,609	3,657	3,699	3,745	3,789	3,831	3,869	1.44%
	WAPA (SMUD)	206	212	217	222	225	228	230	233	235	237	238	239	1.36%
Total SMUD/WAPA Control Area		4,812	4,930	5,047	5,122	5,189	5,261	5,329	5,390	5,458	5,523	5,583	5,638	1.45%
	Anaheim	605	619	634	646	655	664	673	681	690	697	703	710	1.47%
	MWD	21	21	21	21	21	21	21	21	21	21	21	21	0.00%
	Other SP15 LSEs - LA Basin	291	298	305	311	314	318	323	327	331	336	339	343	1.51%
	Pasadena	313	321	328	333	336	339	342	346	349	353	357	360	1.28%
	Riverside	594	610	624	635	643	652	661	671	681	689	698	706	1.58%
	SCE Service Area - LA Basin	17,489	17,931	18,362	18,626	18,884	19,167	19,418	19,670	19,938	20,209	20,478	20,740	1.56%
	Vernon	177	181	185	190	192	193	193	193	193	193	192	191	0.69%
LA Basin Subtotal		19,489	19,981	20,460	20,761	21,044	21,355	21,629	21,909	22,203	22,498	22,788	23,071	1.55%
	CDWR-S	422	422	422	422	422	422	422	422	422	422	422	422	0.00%
	SCE Service Area - Big Creek Ventura	3,374	3,458	3,542	3,593	3,643	3,698	3,746	3,795	3,846	3,898	3,951	4,001	1.56%
Big Creek/Ventura Subtotal		3,796	3,880	3,964	4,015	4,065	4,120	4,168	4,217	4,268	4,320	4,373	4,423	1.40%
	MWD	210	210	210	209	210	210	211	211	212	212	212	212	0.09%
	Other SP15 LSEs - Out of LA Basin	10	12	12	12	13	13	13	13	13	13	13	12	1.67%
	SCE Service Area - Out of LA Basin	674	691	707	716	728	738	747	757	767	778	788	797	1.54%
Total SCE TAC Area		24,179	24,774	25,353	25,712	26,060	26,436	26,769	27,106	27,462	27,822	28,174	28,516	1.51%
SDG&E Service Area		4,851	4,988	5,124	5,224	5,321	5,428	5,544	5,653	5,760	5,863	5,962	6,055	2.04%
Total South of Path 26		29,030	29,762	30,477	30,936	31,381	31,863	32,312	32,759	33,221	33,684	34,135	34,571	1.60%
	Burbank	349	357	366	371	376	380	385	390	393	399	403	408	1.42%
	Glendale	380	390	399	406	410	417	421	427	434	438	445	451	1.57%
	LADWP	6,451	6,601	6,760	6,851	6,929	7,009	7,088	7,165	7,258	7,351	7,439	7,527	1.41%
Total LADWP Control Area		7,180	7,348	7,524	7,628	7,716	7,805	7,894	7,982	8,085	8,188	8,288	8,385	1.42%
Imperial Irrigation District Control Area		1,073	1,105	1,136	1,155	1,174	1,192	1,210	1,231	1,252	1,276	1,275	1,289	1.69%
Total CAISO Noncoincident Peak		51,272	52,519	53,774	54,568	55,344	56,169	56,908	57,637	58,415	59,203	59,966	60,711	1.55%
Total CAISO Coincident Peak		50,042	51,258	52,483	53,257	54,016	54,820	55,542	56,253	57,012	57,782	58,527	59,254	1.55%
Total Statewide Noncoincident Peak		64,939	66,518	68,110	69,113	70,071	71,083	72,004	72,910	73,888	74,875	75,804	76,721	1.53%
Total Statewide Coincident Peak		63,380	64,922	66,475	67,453	68,389	69,377	70,275	71,161	72,115	73,078	73,984	74,880	1.53%

Table only developed for the mid case. Table develo ped based on weather-adjusted 2011 peak estimates

ATTACHMENT C

California ISO
Shaping a Renewed Future

2013
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT AND STUDY RESULTS

April 30, 2012

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[22]	295	0	295
Category C (Multiple)[23]	483	42	525

8. LA Basin Area

Area Definition

The transmission tie lines into the LA Basin Area are:

1) San Onofre - San Luis Rey #1, #2, & #3 230 kV Lines
2) San Onofre - Talega #1 & #2 230 kV Lines
3) Lugo - Mira Loma #2 & #3 500 kV Lines
4) Lugo – Rancho Vista #1 500 kV line
5) Sylmar - Eagle Rock 230 kV Line
6) Sylmar - Gould 230 kV Line
7) Vincent - Mesa Cal 230 kV Line
8) Vincent - Rio Hondo #1 & #2 230 kV Lines
9) Eagle Rock - Pardee 230 kV Line
10) Devers - Palo Verde 500 kV Line
11) Mirage - Coachelv 230 kV Line
12) Mirage - Ramon 230 kV Line
13) Mirage - Julian Hinds 230 kV Line

These sub-stations form the boundary surrounding the LA Basin area:

1) San Onofre is in San Luis Rey is out
2) San Onofre is in Talega is out
3) Mira Loma is in Lugo is out
4) Rancho Vista is in Lugo is out
5) Eagle Rock is in Sylmar is out
6) Gould is in Sylmar is out
7) Mesa Cal is in Vincent is out
8) Rio Hondo is in Vincent is out
9) Eagle Rock is in Pardee is out
10) Devers is in Palo Verde is out
11) Mirage is in Coachelv is out

[22] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[23] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

12)Mirage is in Ramon is out
13)Mirage is in Julian Hinds is out

Total 2013 busload within the defined area is 19,300 MW with 133 MW of losses and 27 MW pumps resulting in total load + losses + pumps of 19,460 MW.

Total units and qualifying capacity available in the LA Basin area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	174.56	1	Western		Market
ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	175.00	2	Western		Market
ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	332.18	3	Western		Market
ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	335.67	4	Western		Market
ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	497.97	5	Western		Market
ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	495.00	6	Western		Market
ANAHM_2_CANYN1	25211	CanyonGT	13.8	49.40	1	Western		MUNI
ANAHM_2_CANYN2	25212	CanyonGT	13.8	48.00	2	Western		MUNI
ANAHM_2_CANYN3	25213	CanyonGT	13.8	48.00	3	Western		MUNI
ANAHM_2_CANYN4	25214	CanyonGT	13.8	49.40	4	Western		MUNI
ANAHM_7_CT	25203	ANAHEIMG	13.8	40.64	1	Western	Aug NQC	MUNI
ARCOGN_2_UNITS	24011	ARCO 1G	13.8	54.28	1	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	54.28	2	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	54.28	3	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	54.28	4	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	27.14	5	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	27.15	6	Western	Aug NQC	QF/Selfgen
BARRE_2_QF	24016	BARRE	230	0.00		Western	Not modeled	QF/Selfgen
BARRE_6_PEAKER	29309	BARPKGEN	13.8	45.38	1	Western		Market
BRDWAY_7_UNIT 3	29007	BRODWYSC	13.8	65.00	1	Western		MUNI
BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.15	W5	None	Aug NQC	Wind
CABZON_1_WINDA1	29290	CABAZON	33	11.29	1	None	Aug NQC	Wind
CENTER_2_QF	24203	CENTER S	66	18.10		Western	Not modeled Aug NQC	QF/Selfgen
CENTER_2_RHONDO	24203	CENTER S	66	1.91		Western	Not modeled	QF/Selfgen
CENTER_6_PEAKER	29308	CTRPKGEN	13.8	44.57	1	Western		Market
CENTRY_6_PL1X4	25302	CLTNCTRY	13.8	36.00	1	None	Aug NQC	MUNI
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	0.00	1	Western, El Nido	Aug NQC	QF/Selfgen
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	0.00	2	Western, El Nido	Aug NQC	QF/Selfgen
CHINO_2_QF	24024	CHINO	66	7.83		Western	Not modeled Aug NQC	QF/Selfgen
CHINO_2_SOLAR	24024	CHINO	66	0.00		Western	Not modeled	Market
CHINO_6_CIMGEN	24026	CIMGEN	13.8	25.29	1	Western	Aug NQC	QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	27.15	1	Western	Aug NQC	QF/Selfgen
CHINO_7_MILIKN	24024	CHINO	66	1.37		Western	Not modeled Aug NQC	Market
COLTON_6_AGUAM1	25303	CLTNAGUA	13.8	43.00	1	None		MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		None	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		None	Not modeled	MUNI
DEVERS_1_QF	24815	GARNET	115	1.51	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25632	TERAWND	115	2.94	QF	None	Aug NQC	QF/Selfgen

DEVERS_1_QF	25633	CAPWIND	115	0.56	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25634	BUCKWIND	115	1.73	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	1.35	Q1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	2.50	Q2	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.59	Q1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	2.28	Q2	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.27	W1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25637	TRANWIND	115	6.68	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	2.01	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25640	PANAERO	115	1.79	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.53	EU	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	3.58	Q1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	2.41	Q2	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	0.80	Q1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	2.68	Q2	None	Aug NQC	QF/Selfgen
DMDVLY_1_UNITS	25425	ESRP P2	6.9	1.39		None	Not modeled Aug NQC	QF/Selfgen
DREWS_6_PL1X4	25301	CLTNDREW	13.8	36.00	1	None	Aug NQC	MUNI
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.15	3	None	Aug NQC	MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.15	4	None	Aug NQC	MUNI
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.35	1	None	Aug NQC	MUNI
DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.35	2	None	Aug NQC	MUNI
ELLIS_2_QF	24197	ELLIS	66	0.00		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
ELSEGN_7_UNIT 3	24047	ELSEG3 G	18	335.00	3	Western, El Nido		Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	335.00	4	Western, El Nido		Market
ETIWND_2_FONTNA	24055	ETIWANDA	66	0.81		None	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_QF	24055	ETIWANDA	66	14.86		None	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_SOLAR	24055	ETIWANDA	66	0.00		None	Not modeled Aug NQC	Market
ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	42.53	1	None		Market
ETIWND_6_MWDETI	25422	ETI MWDG	13.8	10.37	1	None	Aug NQC	Market
ETIWND_7_MIDVLY	24055	ETIWANDA	66	1.54		None	Not modeled Aug NQC	QF/Selfgen
ETIWND_7_UNIT 3	24052	MTNVIST3	18	320.00	3	None		Market
ETIWND_7_UNIT 4	24053	MTNVIST4	18	320.00	4	None		Market
GARNET_1_UNITS	24815	GARNET	115	0.71	G1	None	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.25	G2	None	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.51	G3	None	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.25	PC	None	Aug NQC	QF/Selfgen
GARNET_1_WIND	24815	GARNET	115	0.66	W2	None	Aug NQC	Wind
GARNET_1_WIND	24815	GARNET	115	0.66	W3	None	Aug NQC	Wind
GLNARM_7_UNIT 1	29005	PASADNA1	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 2	29006	PASADNA2	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 3	29005	PASADNA1	13.8	44.83		Western	Not modeled	MUNI
GLNARM_7_UNIT 4	29006	PASADNA2	13.8	42.42		Western	Not modeled	MUNI
HARBGN_7_UNITS	24062	HARBOR G	13.8	76.28	1	Western		Market
HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	Western		Market
HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	Western		Market
HINSON_6_CARBGN	24020	CARBOGEN	13.8	21.46	1	Western	Aug NQC	Market

HINSON_6_LBECH1	24078	LBEACH1G	13.8	65.00	1	Western		Market
HINSON_6_LBECH2	24170	LBEACH2G	13.8	65.00	2	Western		Market
HINSON_6_LBECH3	24171	LBEACH3G	13.8	65.00	3	Western		Market
HINSON_6_LBECH4	24172	LBEACH4G	13.8	65.00	4	Western		Market
HINSON_6_SERRGN	24139	SERRFGEN	13.8	28.38	1	Western	Aug NQC	QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	Western, Ellis		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western, Ellis		Market
INDIGO_1_UNIT 1	29190	WINTECX2	13.8	42.00	1	None		Market
INDIGO_1_UNIT 2	29191	WINTECX1	13.8	42.00	1	None		Market
INDIGO_1_UNIT 3	29180	WINTEC8	13.8	42.00	1	None		Market
INLDEM_5_UNIT 1	29041	IEEC-G1	19.5	335.00	1	Valley	Aug NQC	Market
INLDEM_5_UNIT 2	29042	IEEC-G2	19.5	335.00	1	Valley	Aug NQC	Market
JOHANN_6_QFA1	24072	JOHANNA	230	0.00		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
LACIEN_2_VENICE	24337	VENICE	13.8	4.45	1	Western, El Nido	Aug NQC	MUNI
LAFRES_6_QF	24073	LA FRESA	66	2.55		Western, El Nido	Not modeled Aug NQC	QF/Selfgen
LAGBEL_6_QF	24075	LAGUBELL	66	10.60		Western	Not modeled Aug NQC	QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	46.55	1	Western	Aug NQC	QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	1.10		Western	Not modeled Aug NQC	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	1.06		Western	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_CORONA				2.35		None	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_TEMESC				2.49		None	Not modeled Aug NQC	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	29.78	1	None	Aug NQC	QF/Selfgen
MIRLOM_6_PEAKER	29307	MRLPKGEN	13.8	43.18	1	None		Market
MIRLOM_7_MWDLKM	24210	MIRALOMA	66	4.60		None	Not modeled Aug NQC	MUNI
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	6.00	1	None	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	6.00	2	None	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	6.00	3	None	Aug NQC	Market
MTWIND_1_UNIT 1	29060	MOUNTWND	115	7.08	S1	None	Aug NQC	Wind
MTWIND_1_UNIT 2	29060	MOUNTWND	115	2.76	S2	None	Aug NQC	Wind
MTWIND_1_UNIT 3	29060	MOUNTWND	115	2.88	S3	None	Aug NQC	Wind
OLINDA_2_COYCRK	24211	OLINDA	66	3.13		Western	Not modeled	QF/Selfgen
OLINDA_2_QF	24211	OLINDA	66	0.78	1	Western	Aug NQC	QF/Selfgen
OLINDA_7_LNDFIL	24201	BARRE	66	4.50		Western	Not modeled Aug NQC	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	0.91		None	Not modeled Aug NQC	QF/Selfgen
PADUA_6_MWDSDM	24111	PADUA	66	7.70		None	Not modeled Aug NQC	MUNI
PADUA_6_QF	24111	PADUA	66	0.74		None	Not modeled Aug NQC	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		None	Not modeled Aug NQC	QF/Selfgen
PWEST_1_UNIT				0.15		Western	Not modeled Aug NQC	Market
REDOND_7_UNIT 5	24121	REDON5 G	18	178.87	5	Western		Market
REDOND_7_UNIT 6	24122	REDON6 G	18	175.00	6	Western		Market
REDOND_7_UNIT 7	24123	REDON7 G	20	505.96	7	Western		Market

REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	Western		Market
RHONDO_2_QF	24213	RIOHONDO	66	2.54		Western	Not modeled Aug NQC	QF/Selfgen
RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		Western	Not modeled Aug NQC	Market
RVSIDE_2_RERCU3	24299	RERC2G3	13.8	48.50	1	None		MUNI
RVSIDE_2_RERCU4	24300	RERC2G4	13.8	48.50	1	None		MUNI
RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	None		MUNI
RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	None		MUNI
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	None		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	6.08	1	Western, Ellis	Aug NQC	Market
SBERDO_2_PSP3	24921	MNTV-CT1	18	129.71	1	None		Market
SBERDO_2_PSP3	24922	MNTV-CT2	18	129.71	1	None		Market
SBERDO_2_PSP3	24923	MNTV-ST1	18	225.08	1	None		Market
SBERDO_2_PSP4	24924	MNTV-CT3	18	129.71	1	None		Market
SBERDO_2_PSP4	24925	MNTV-CT4	18	129.71	1	None		Market
SBERDO_2_PSP4	24926	MNTV-ST2	18	225.08	1	None		Market
SBERDO_2_QF	24214	SANBRDNO	66	0.14		None	Not modeled Aug NQC	QF/Selfgen
SBERDO_2_SNTANA	24214	SANBRDNO	66	0.27		None	Not modeled Aug NQC	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	1.28		None	Not modeled Aug NQC	QF/Selfgen
SONGS_7_UNIT 2	24129	S.ONOFR2	22	1122.00	2	Western		Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	1124.00	3	Western		Nuclear
TIFFNY_1_DILLON				5.63		Western	Not modeled Aug NQC	Wind
VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		Valley	Not modeled Aug NQC	QF/Selfgen
VALLEY_5_REDMTN	24160	VALLEYSC	115	2.00		Valley	Not modeled Aug NQC	QF/Selfgen
VALLEY_7_BADLND	24160	VALLEYSC	115	0.54		Valley	Not modeled Aug NQC	Market
VALLEY_7_UNITA1	24160	VALLEYSC	115	1.34		Valley	Not modeled Aug NQC	Market
VERNON_6_GONZL1				5.75		Western	Not modeled	MUNI
VERNON_6_GONZL2				5.75		Western	Not modeled	MUNI
VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	Western		MUNI
VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	Western		MUNI
VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	Western		MUNI
VILLPK_2_VALLYV	24216	VILLA PK	66	4.10		Western	Not modeled Aug NQC	QF/Selfgen
VILLPK_6_MWDYOR	24216	VILLA PK	66	0.00		Western	Not modeled Aug NQC	MUNI
VISTA_6_QF	24902	VSTA	66	0.17	1	None	Aug NQC	QF/Selfgen
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	47.07	1	Western	Aug NQC	QF/Selfgen
WALNUT_7_WCOVCT	24157	WALNUT	66	3.43		Western	Not modeled Aug NQC	Market
WALNUT_7_WCOVST	24157	WALNUT	66	2.98		Western	Not modeled Aug NQC	Market
WHTWTR_1_WINDA1	29061	WHITEWTR	33	8.26	1	None	Aug NQC	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	Western	No NQC - hist. data	Market
HINSON_6_QF	24064	HINSON	66	0.00	1	Western	No NQC - hist. data	QF/Selfgen
INLAND_6_UNIT	24071	INLAND	13.8	30.30	1	None	No NQC -	QF/Selfgen

							hist. data	
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	20.20	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24324	SANIGEN	13.8	6.80	D1	None	No NQC - hist. data	QF/Selfgen
NA	24325	ORCOGEN	13.8	0.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24327	THUMSGEN	13.8	40.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24328	CARBGEN2	13.8	15.2	1	Western	No NQC – hist. data	Market
NA	24329	MOBGEN2	13.8	20.2	1	Western, El Nido	No NQC – hist. data	QF/Selfgen
NA	24330	OUTFALL1	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24331	OUTFALL2	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24332	PALOGEN	13.8	3.60	D1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24341	COYGEN	13.8	0.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24342	FEDGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24839	BLAST	115	45.00	1	None	No NQC – hist. data	QF/Selfgen
NA	29021	WINTEC6	115	45.00	1	None	No NQC – hist. data	Wind
NA	29023	WINTEC4	12	16.50	1	None	No NQC – hist. data	Wind
NA	29060	SEAWEST	115	44.40	S1	None	No NQC – hist. data	Wind
NA	29060	SEAWEST	115	22.20	S2	None	No NQC – hist. data	Wind
NA	29060	SEAWEST	115	22.40	S3	None	No NQC – hist. data	Wind
NA	29260	ALTAMSA4	115	40.00	1	None	No NQC – hist. data	Wind
NA	29338	CLEARGEN	13.8	0.00	1	None	No NQC - hist. data	QF/Selfgen
NA	29339	DELGEN	13.8	0.00	1	None	No NQC - hist. data	QF/Selfgen
NA	29951	REFUSE	13.8	9.90	D1	Western	No NQC - Pmax	QF/Selfgen
NA	29953	SIGGEN	13.8	24.90	D1	Western	No NQC - Pmax	QF/Selfgen
HNTGBH_7_UNIT 3	24167	HUNT3 G	13.8	0.00	3	Western, Ellis	Retired	Market
HNTGBH_7_UNIT 4	24168	HUNT4 G	13.8	0.00	4	Western, Ellis	Retired	Market
New unit	29201	EME WCG1	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29202	EME WCG2	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29203	EME WCG3	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29204	EME WCG4	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29205	EME WCG5	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29901	NRG ELG5	18	175	5	Western, El Nido	No NQC - Pmax	Market
New unit	29902	NRG ELG7	18	280	7	Western, El Nido	No NQC -	Market

							Pmax	
New unit	29903	NRG ELG6	18	175	6	Western, El Nido	No NQC - Pmax	Market

Major new projects modeled:

1. 3 new resources have been modeled
2. Huntington Beach #3 and #4 have been retired
3. Del Amo – Ellis 230 kV line loops into Barre 230 kV substation
4. Recalibrate arming level for Santiago SPS

Critical Contingency Analysis Summary

LA Basin Overall:

The most critical contingency for LA Basin is the loss of one SONGS unit followed by Palo Verde-Devers 500 kV line, which could exceed the approved 6400 MW rating for the South of Lugo path. This limiting contingency establishes a LCR of 10,295 MW in 2013 (includes 810 MW of QF, 230 MW of Wind, 1166 MW of Muni and 2246 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned South of Lugo constraint within the LA Basin area:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24052	MTNVIST3	3	34
24053	MTNVIST4	4	34
24071	INLAND	1	32
25422	ETI MWDG	1	32
29305	ETWPKGEN	1	32
24921	MNTV-CT1	1	28
24922	MNTV-CT2	1	28
24923	MNTV-ST1	1	28
24924	MNTV-CT3	1	28
24925	MNTV-CT4	1	28
24926	MNTV-ST2	1	28
29041	IEEC-G1	1	28

29042	IEEC-G2	2	28
24905	RVCANAL1	R1	27
24906	RVCANAL2	R2	27
24907	RVCANAL3	R3	27
24908	RVCANAL4	R4	27
29190	WINTECX2	1	27
29191	WINTECX1	1	27
29180	WINTEC8	1	27
24815	GARNET	QF	27
24815	GARNET	W3	27
29023	WINTEC4	1	27
29021	WINTEC6	1	27
24242	RERC1G	1	27
24243	RERC2G	1	27
24244	SPRINGEN	1	27
25301	CLTNDREW	1	27
25302	CLTNCTRY	1	27
25303	CLTNAGUA	1	27
24299	RERC2G3	1	27
24300	RERC2G4	1	27
24839	BLAST	1	27
25648	DVLCYN1G	1	26
25649	DVLCYN2G	2	26
25603	DVLCYN3G	3	26
25604	DVLCYN4G	4	26
25632	TERAWND	QF	26
25634	BUCKWND	QF	26
25635	ALTWIND	Q1	26
25635	ALTWIND	Q2	26
25637	TRANWND	QF	26
25639	SEAWIND	QF	26
25640	PANAERO	QF	26
25645	VENWIND	EU	26
25645	VENWIND	Q2	26
25645	VENWIND	Q1	26
25646	SANWIND	Q2	26
29060	MOUNTWND	S1	26
29060	MOUNTWND	S3	26
29060	MOUNTWND	S2	26
29061	WHITEWTR	1	26
29260	ALTAMSA4	1	26
29290	CABAZON	1	26
25633	CAPWIND	QF	25

25657	MJVSPHN1	1	25
25658	MJVSPHN2	2	25
25659	MJVSPHN3	3	25
25203	ANAHEIMG	1	23
25211	CanyonGT 1	1	22
25212	CanyonGT 2	2	22
25213	CanyonGT 3	3	22
25214	CanyonGT 4	4	22
24030	DELGEN	1	21
29309	BARPKGEN	1	21
24026	CIMGEN	D1	21
24140	SIMPSON	D1	21
29307	MRLPKGEN	1	20
29338	CLEARGEN	1	20
29339	DELGEN	1	20
24005	ALAMT5 G	5	19
24066	HUNT1 G	1	19
24067	HUNT2 G	2	19
24167	HUNT3 G	3	19
24168	HUNT4 G	4	19
24129	S.ONOFR2	2	19
24130	S.ONOFR3	3	19
24133	SANTIAGO	1	19
24325	ORCOGEN	1	19
24341	COYGEN	1	19
24001	ALAMT1 G	1	18
24002	ALAMT2 G	2	18
24003	ALAMT3 G	3	18
24004	ALAMT4 G	4	18
24161	ALAMT6 G	6	18
24162	ALAMT7 G	R7	17
24063	HILLGEN	D1	17
29201	EME WCG1	1	17
29203	EME WCG3	1	17
29204	EME WCG4	1	17
29205	EME WCG5	1	17
29202	EME WCG2	1	17
24018	BRIGEN	1	16
29308	CTRPKGEN	1	16
29953	SIGGEN	D1	16
24011	ARCO 1G	1	15
24012	ARCO 2G	2	15
24013	ARCO 3G	3	15

24014	ARCO 4G	4	15
24163	ARCO 5G	5	15
24164	ARCO 6G	6	15
24020	CARBGEN1	1	15
24022	CHEVGEN1	1	15
24023	CHEVGEN2	2	15
24064	HINSON	1	15
24070	ICEGEN	D1	15
24170	LBEACH12	2	15
24171	LBEACH34	3	15
24094	MOBGEN1	1	15
24062	HARBOR G	1	15
25510	HARBORG4	LP	15
24062	HARBOR G	HP	15
24139	SERRFGEN	D1	15
24170	LBEACH12	1	15
24171	LBEACH34	4	15
24173	LBEACH5G	R5	15
24174	LBEACH6G	R6	15
24327	THUMSGEN	1	15
24328	CARBGEN2	1	15
24330	OUTFALL1	1	15
24331	OUTFALL2	1	15
24332	PALOGEN	D1	15
24333	REDON1 G	R1	15
24334	REDON2 G	R2	15
24335	REDON3 G	R3	15
24336	REDON4 G	R4	15
24337	VENICE	1	15
24079	LBEACH7G	R7	15
24080	LBEACH8G	R8	15
24081	LBEACH9G	R9	15
24047	ELSEG3 G	3	14
24048	ELSEG4 G	4	14
24121	REDON5 G	5	14
24122	REDON6 G	6	14
24123	REDON7 G	7	14
24124	REDON8 G	8	14
24329	MOBGEN2	1	14
29901	NRG ELG5	5	14
29903	NRG ELG6	6	14
29902	NRG ELS7	7	14
29951	REFUSE	D1	13

29209	BLY1ST1	1	13
29207	BLY1CT1	1	13
29208	BLY1CT2	1	13
24342	FEDGEN	1	13
24241	MALBRG3G	S3	12
24240	MALBRG2G	C2	12
24239	MALBRG1G	C1	12
29005	PASADNA1	1	10
29006	PASADNA2	1	10
29007	BRODWYSC	1	10

Valley Sub-Area:

The most critical contingency for the Valley sub-area is the loss of Palo Verde – Devers 500 kV line and Valley – Serrano 500 kV line or vice versa, which would result in voltage collapse. This limiting contingency establishes a LCR of 670 MW (includes 10 MW of QF generation) in 2013 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

Western Sub-Area:

The most critical contingency for the Western sub-area is the loss of Serrano-Villa Park #2 230 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in thermal overload of the remaining Serrano-Villa Park 230 kV line. This limiting contingency establishes a LCR of 5540 MW (includes 623 MW of QF, 6 MW of Wind, 582 MW of Muni and 2246 MW of nuclear generation) in 2013 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned constraint:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
29309	BARPKGEN	1	31

25203	ANAHEIMG	1	30
25211	CanyonGT 1	1	29
25212	CanyonGT 2	2	29
25213	CanyonGT 3	3	29
25214	CanyonGT 4	4	29
24005	ALAMT5 G	5	23
24161	ALAMT6 G	6	23
24001	ALAMT1 G	1	22
24002	ALAMT2 G	2	22
24003	ALAMT3 G	3	22
24004	ALAMT4 G	4	22
24162	ALAMT7 G	R7	22
24066	HUNT1 G	1	22
24067	HUNT2 G	2	22
24167	HUNT3 G	3	22
24168	HUNT4 G	4	22
24325	ORCOGEN	1	21
24133	SANTIAGO	1	16
24341	COYGEN	1	16
24011	ARCO 1G	1	15
24012	ARCO 2G	2	15
24013	ARCO 3G	3	15
24014	ARCO 4G	4	15
24018	BRIGEN	1	15
24020	CARBGEN1	1	15
24064	HINSON	1	15
24070	ICEGEN	D1	15
24170	LBEACH12	2	15
24171	LBEACH34	3	15
24062	HARBOR G	1	15
25510	HARBORG4	LP	15
24062	HARBOR G	HP	15
24139	SERRFGEN	D1	15
24170	LBEACH12	1	15
24171	LBEACH34	4	15
24173	LBEACH5G	R5	15
24174	LBEACH6G	R6	15
24327	THUMSGEN	1	15
24328	CARBGEN2	1	15
24079	LBEACH7G	R7	15
24080	LBEACH8G	R8	15
24081	LBEACH9G	R9	15
24163	ARCO 5G	5	14

24164	ARCO 6G	6	14
24022	CHEVGEN1	1	14
24023	CHEVGEN2	2	14
24048	ELSEG4 G	4	14
24094	MOBGEN1	1	14
29308	CTRPKGEN	1	14
24329	MOBGEN2	1	14
24330	OUTFALL1	1	14
24331	OUTFALL2	1	14
24332	PALOGEN	D1	14
24333	REDON1 G	R1	14
24334	REDON2 G	R2	14
24335	REDON3 G	R3	14
24336	REDON4 G	R4	14
24337	VENICE	1	14
29953	SIGGEN	D1	14
29901	NRG ELG5	5	14
29903	NRG ELG6	6	14
29902	NRG ELS7	7	14
24047	ELSEG3 G	3	13
24121	REDON5 G	5	13
24122	REDON6 G	6	13
24123	REDON7 G	7	13
24124	REDON8 G	8	13
29951	REFUSE	D1	12
24342	FEDGEN	1	12
24241	MALBRG3G	S3	11
24240	MALBRG2G	C2	11
24239	MALBRG1G	C1	11
29005	PASADNA1	1	9
29006	PASADNA2	1	9
29007	BRODWYSC	1	9
24063	HILLGEN	D1	6
29201	EME WCG1	1	5
29203	EME WCG3	1	5
29204	EME WCG4	1	5
29205	EME WCG5	1	5
29202	EME WCG2	1	5

There are numerous (about 40) other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area and have less LCR need. As such, anyone of them (combination of contingencies) could become binding for any given set of procured resources. As a result, effectiveness factors may not be the best indicator towards informed procurement.

Ellis sub-area

The Del Amo – Ellis loop-in project along with recalibration of the Santiago SPS eliminates the LCR need for the Ellis sub-area.

El Nido sub-area

The most critical contingency for the El Nido sub-area is the loss of the La Fresa – Hinson 230 kV line followed by the loss of the La Fresa – Redondo #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 386 MW in 2013 (which includes 47 MW of QF and 4 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

Changes compared to last year's results:

Overall the load forecast went down by 470 MW resulting in 570 MW decrease in LCR.

LA Basin Overall Requirements:

2013	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	1040	1166	2246	8675	13127

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[24]	10,295	0	10,295
Category C (Multiple)[25]	10,295	0	10,295

[24] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[25] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

ATTACHMENT D

CALIFORNIA
ENERGY
COMMISSION

THE ROLE OF AGING AND ONCE-THROUGH-COOLED POWER PLANTS IN CALIFORNIA—AN UPDATE

STAFF REPORT

February 2010
CEC-200-2009-018

Arnold Schwarzenegger, *Governor*

Table B-2: Aging and Once-Through-Cooled Power Plant Annual Capacity Factor (Percent)

Power Plant / Unit	2002	2003	2004	2005	2006	2007	2008
Alamitos 1	10	8	7	3	3	2	2
Alamitos 2	11	8	7	2	3	2	2
Alamitos 3	35	37	24	9	17	18	23
Alamitos 4	24	21	19	5	8	9	18
Alamitos 5	34	20	25	9	9	9	21
Alamitos 6	19	18	11	10	11	7	11
Broadway 3	0	0	0	7	3	2	14
Contra Costa 6	28	2	4	1	1	1	2
Contra Costa 7	37	16	22	10	4	3	3
Coolwater 1	14	3	1	3	4	1	0
Coolwater 2	14	4	1	2	4	1	1
Coolwater 3	35	27	8	6	11	11	9
Coolwater 4	30	20	10	8	15	15	13
Diablo Canyon 1	72	98	74	85	102	91	100
Diablo Canyon 2	95	79	82	97	87	99	74
El Centro 3	10	13	5	16	14	8	8
El Centro 4	24	26	23	11	8	17	28
El Segundo 3	35	24	9	12	12	10	3
El Segundo 4	46	20	8	10	9	9	14
Encina 1	15	12	18	16	5	6	1
Encina 2	19	16	24	17	10	4	4
Encina 3	19	21	34	19	12	8	7
Encina 4	33	34	44	31	18	8	11
Encina 5	34	38	43	20	19	11	21
Etiwanda 3	18	5	2	14	16	11	17
Etiwanda 4	8	4	6	11	12	8	12
Grayson 3	0	1	6	3	0	15	1
Grayson 4	6	13	18	26	12	4	19
Grayson 5	36	19	14	11	25	27	19
Grayson CC	1	3	3	3	2	3	2
Harbor CC	0	19	12	10	7	6	8
Haynes 1	22	30	30	22	12	26	23
Haynes 2	28	22	30	18	22	20	20
Haynes 5	15	33	11	16	10	4	20
Haynes 6	19	10	12	3	5	15	4
Haynes CC	0	0	0	57	60	63	70

Power Plant / Unit	2002	2003	2004	2005	2006	2007	2008
Humboldt Bay 1	40	27	39	47	46	51	55
Humboldt Bay 2	39	19	38	45	46	48	53
Huntington Beach 1	32	37	38	26	20	23	28
Huntington Beach 2	37	37	41	22	17	7	20
Huntington Beach 3	N/A	8	19	19	12	27	17
Huntington Beach 4	N/A	9	17	14	11	13	14
Mandalay 1	25	14	15	7	8	7	12
Mandalay2	28	18	20	11	10	11	19
Morro Bay 3	18	5	8	6	7	12	1
Morro Bay 4	36	5	4	6	6	8	2
Moss Landing 6	36	9	6	4	6	6	9
Moss Landing 7	27	12	12	4	11	10	13
Moss Landing 1	30	60	50	50	57	67	64
Moss Landing 2	26	54	59	53	57	71	58
Olive 1	14	6	3	8	1	0	2
Olive 2	0	0	6	0	1	0	1
Ormond Beach 1	16	10	19	2	0	5	4
Ormond Beach 2	17	15	13	6	6	9	7
Pittsburg 5	19	26	23	12	7	3	2
Pittsburg 6	24	7	20	7	5	3	2
Pittsburg 7	43	17	9	2	1	1	1
Potrero 3	30	45	46	21	29	26	29
Redondo Beach 5	22	8	11	3	6	5	2
Redondo Beach 6	5	8	2	1	2	2	1
Redondo Beach 7	3	2	1	1	2	2	2
Redondo Beach 8	22	12	17	6	7	7	4
San Onofre 2	86	99	82	91	69	84	90
San Onofre 3	97	87	71	96	69	89	66
Scattergood 1	27	27	29	10	18	16	28
Scattergood 2	31	28	28	29	18	25	14
Scattergood 3	6	34	22	12	24	20	17
South Bay 1	36	34	43	46	32	14	18
South Bay 2	37	39	51	36	30	15	16
South Bay 3	16	22	30	24	7	13	22
South Bay 4	4	2	12	7	5	8	11

Source: Haynes and Scattergood unit generation 2002-2007 is based on EIA Continuous Emissions Monitoring Survey data. Unit generation data for other units is from Energy Commission Quarterly Fuel and Energy Report filings.

ATTACHEMNT E

CALIFORNIA ISO
2012-2013 TRANSMISSION PLAN

COMMENTS OF THE STAFF OF THE
CALIFORNIA PUBLIC UTILITIES COMMISSION
ON THE DRAFT STUDY PLAN
(FEBRUARY 21 DOCUMENT AND FEBRUARY 28 MEETING)

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March 14, 2012

Introduction

The Staff of the California Public Utilities Commission ("CPUC Staff") appreciate this opportunity to provide comments on the California Independent System Operator's ("ISO") 2012-2013 Transmission Planning Process ("TPP") Draft Study Plan ("Study Plan") dated February 21, 2012 and discusse d at the February 28 stakeholder meeting. We provide the following limited comments which mainly concern the need to provide greater transparency and disclosure in some areas, and especially the need to use the latest load forecast and to both include and take into account study cases that project continuing ("incremental") Demand Side Management (DSM) and Combined Heat and Power (CHP) measures over the 10-year planning horizon.

1. 2012-2013 TPP Studies Should Use the Latest Energy Commission Load Forecast and Should Include and Take Into Account Reasonably Expected Incremental (Uncommitted) DSM and supply- and deman d-side CHP.

It is essential that planning assumptions be as up to date as possible, and for that reason the studies should be based on the current than the Energy Commission revised load forecast released on February 21, 2012, and if possible, the Energy Commission's final forecast expected to be released by the end of March. Additionally, assessment of transmission needs ten years out could be significantly influenced by which Energy Commission load forecast is used. CPUC resource planning via the Long Term Procurement Plan (LTPP) process assumes that DSM[1] and CHP[2] programs will continue and not simply terminate or "drop off a cliff" when their currently authorized funding ends. Therefore, the LTPP process "manages" CEC load forecasts to include such "incremental" CHP and DSM reasonably expected to occur. The selected values are modified downward from goals or potential study assumptions to account for uncertainty through stakeholder processes. For consistency with resource planning and to avoid a narrowly conservative picture of 10-years-out transmission needs, the ISO's 2012-2013 TPP studies should meaningfully assess scenarios that include the above incremental DSM and CHP, and should not identify major 10-year transmission needs without assessing the extent to which those needs would exist under load forecasts that include incremental DSM and CHP.

2. The Generation Assumptions Should be Consistent with State Policy and Reasonable Expectations

The assumptions on generation retirements only include generation units that have announced plans for retirement. A significant number of older plants are subject to the Water Resource Control Board's policy on cooling water intake structures. As such, these plants will require significant upgrades to operate past the policy's compliance dates. Many of the plant owners have indicated[3] they would repower units if they receive a long term contract and will retire the unit if they do not. Previous ISO analysis has indicated that not all the older steam generators will be needed. Assuming none of these plants retire biases the TPP analysis and provides no information on the trade-off

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[1] Demand side management includes the impacts of future expected programs such as demand response and energy efficiency. While future year programs may not have specific programmatic designs or funding in place, savings are reasonably expected to occur in future years.

[2] Combined Heat and Power refers to both supply- and demand-side generation. Demand-side CHP reduces load on site without exporting extra energy off-site, while supply-side CHP would include exports from the host-site.

[3] The Water Resource Control Board required plant owners to file implementation plans for compliance with the policy.

between any needed transmission upgrades and new generation or repowers. Furthermore the retirement assumptions should be such that the generation is assumed retired consistent with current Water Resource Control Board policy compliance dates. It is important to note that to the extent these units are needed for proven reliability reasons, the Statewide Advisory Committee on Cooling Water Intake Structures is tasked with making annual recommendations to the Water Resource Control Board on any needed changes to the implementation schedule.

3. *Assumptions Underlying Local Capacity Requirements (LCR) and Once Through Cooling (OTC)/AB 1318 Studies Need to Be Clearly Explained within the Study Plan (and Ultimately within the 2012-2013 Transmission Plan), and Divergence from Planning Assumptions Used by the CPUC and CEC Should Be Justified.*

The draft 2011-2012 Plan referred to external planning materials when describing certain LCR and OTC[4] study assumptions. Combined with a more general need for greater clarity regarding assumptions for these studies, this made it difficult to assess exactly what inputs and assumptions were used.[5] This situation can complicate use and acceptance of the ISO's modeling results in other proceedings, and can impair ability to understand apparent discrepancies across different studies or projections. Therefore, CPUC Staff emphasize the need for clear documentation of LCR and OTC/AB1318[6]

[4] OTC refers to plants subject to the State Water Resources Control Board, "Statewide Policy on the Use of Coastal and Estuarine Waters for Plant Cooling"; see http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/policy.shtml

[5] The LCR Tool had at least two different vintages publicly posted; see http://www.caiso.com/2734/2734e3d964ec0.html

[6] AB 1318 (Perez, Chapter 285, Statues of 2009) requires the Air Resources Board, in conjunction with the Energy Commission, CPUC, ISO, and the State Water Resources Control Board, to prepare a report for the Governor and Legislature that evaluates the electrical system reliability needs of the South Coast Air Basin; see http://www.arb.ca.gov/energy/esr-sc/esr-sc.htm

study assumptions, within the 2012-2013 TPP Study Plan, and ultimately within the 2012-2013 Transmission Plan itself.

4. *There Should be Sufficient Description of Any Major Transmission Additions Brought into the Base Case from the Generator Interconnection Process (GIP).*

For several years the ISO, CPUC, and other stakeholders have been pursuing the challenging goal of reducing the role of piecemeal transmission planning via the generator interconnection process and relying more strongly on holistic and transparent planning via the TPP. Recent steps in this direction include Cluster 1-4 deliverability study refinements and the TPP-GIP[7] integration initiative.

Thus, it is essential to adequately describe and analyze from a system-wide perspective any major GIP-driven transmission additions that are being imported directly into the 2012-2013 TPP base case. The ISO should explain which executed interconnection agreements result in transmission upgrades and their inclusion or exclusion from the base case and why this determination was made. Furthermore, there should be clear explanation of the correspondence between generation additions driving (or supported by) GIP-driven transmission additions and the study plan's established resource portfolios. The consequences for the Renewable Portfolio Standard (RPS) portfolios if particular GIP-driven upgrades were to be omitted should also be described.

The above information would support better understanding of the overall role of the proposed GIP-driven transmission projects. Additionally and importantly, it would inform resource planning and portfolio development.

At a minimum, the additional information that should be reported for any GIP-driven transmission facilities included in the base case includes the following.

- The physical/electrical/economic characteristics of such facilities, including voltage, transfer capability increase, endpoints, in-service date and cost.

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[7] "TPP-GIP" means Transmission Planning Process-Generator Interconnection Procedures.

- The MW and locations of (1) the renewable (and other) generation having signed interconnection agreements for which the GIP-driven facilities are needed and (2) separately, the amount of *additional* generation (beyond that having signed interconnection agreements) that could be accommodated by such added transmission facilities.
- Whether the added GIP-driven facilities would be needed for reliability or deliverability purposes.
- The modeled 8760-hour utilization of the added facilities under the different RPS scenarios studied. Such utilization should also be reported for other major transmission additions.

5. Methodology, Assumptions and Ultimate Planning Role for RPS Resource-Related Reliability and Deliverability Studies Need to Be Adequately Explained and Justified

This is especially important in light of the anticipated increased importance of the TPP to plan *delivery* network upgrades under TPP-GIP integration reforms. The ISO should clarify the relative roles, in upcoming studies and 2012-2013 Plan development, of on-peak deliverability studies conducted for RPS portfolios versus 8760-hour simulations of potential resource curtailment (dump energy) for those same portfolios. Furthermore, the assumed output levels (relative to maximum capacity) for wind and solar generation should be more fully and quantitatively described than in the past, particularly for major resource areas and under scenarios (and in locations) where transmission additions are identified.

It appears that for the 2011-2012 Plan development, deliverability studies set wind and solar output levels somewhere between the 50% and 20% exceedance levels[8] over the Qualifying Capacity (QC) period[9]. This suggests that the amount of transmission capacity required for deliverability under such conditions would exceed what is needed to

[8] A 20% exceedance level represents a level of output during the QC period wherein output is beyond that level 20% of the time.

[9] Qualifying Capacity is defined as the maximum dependable capacity of a resource. The QC determination period, i.e., the hours between 12 p.m. and 6 p.m. during May through September.

deliver the resources at their resource adequacy (Net Qualifying Capacity[10]) levels. This should be clarified and justified.

It is unclear, and needs to explained and taken into account when performing and interpreting studies, what should be the role of *reliability* studies conducted for RPS portfolios within the TPP. For example, are such results only informational, in that reliability network upgrades will be planned via reliability studies conducted for specific resources in the interconnection process? Similarly, the relationship between the ISO's standard TPP reliability studies for different parts of the grid (based on North American Electrical Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability criteria) versus reliability studies conducted specifically for RPS portfolios should be made clear.

For reliability and deliverability studies:

- Differences in assumed wind and solar output levels (deliverability vs. on-peak reliability studies) should be clarified,
- The assumed output of thermal generation at risk of retiring by 2022 should be clearly identified and the consequences of including versus excluding this generation in the reliability and deliverability studies should be clearly explained.

6. Key Economic Study Parameters Should be Sufficiently Documented, and Transmission Additions Identified Pursuant to Economic Study Requests Should be Eligible to Substitute for Other Transmission Additions Under Certain Circumstances.

Transmission costs can be high and can exceed estimates, especially in California and especially when encountering major siting issues. When conducting and reporting on economic congestion studies including the anticipated multifaceted Fresno/Central Valley study, as well as studies responding to study requests, the ISO should describe the source and rationale for transmission cost estimates. Assumptions and methods used to convert direct capital costs to total ratepayer costs, and to calculate various kinds of benefits

[10] Net Qualifying Capacity is QC further reduced to account for deliverability.

against which costs are compared, such as summarized in Section 5.4.4 of the 2011-2012 draft Plan, should be documented and justified. Finally, given the uncertainties in both future circumstances and in appropriate selection of economic parameters, economic assessment of large potential transmission projects should be augmented with sensitivity analysis regarding key assumptions and economic parameters.

When an analysis performed for a study request identifies an efficient alternative to previously identified transmission additions[11], the ISO should evaluate which alternative produces the best value for ISO ratepayers.

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.

8. *Studies of Transmission Additions to Reduce LCR Subareas Should be Conducted*

Due to conflicting OTC requirements and local air emissions requirements, there arises the necessity to perform additional analysis related to compliance that may not just be generation retirement or repowering. Transmission improvements specifically to reduce reliance on OTC plants as well as particular locations in the transmission topology

[11] This applies to previously identified transmission additions that have not yet been permitted.

(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.

9. The Generation Assumptions Should be Consistent wit h 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.

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