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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

REVISED SCOPING RULING AND MEMO OF THE ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE

The Scoping Ruling and Memo in this proceeding was issued on May 17, 2012. That Ruling determined there would be three Tracks in this proceeding. Track 1 (the Local Reliability Track) concluded with Decision (D.) 13-02-015. In Track 2 (the System Needs Track), D.12-12-010 was issued setting forth scenarios to be used for modeling system needs. In Track 3 (the Procurement Rules and Bundled Procurement Track), comments and reply comments have been filed regarding proposed procurement rules. We anticipate a proposed decision on procurement rules in the summer of 2013. No determination is made at this time regarding the timing of utility bundled procurement filings.

A Prehearing Conference (PHC) was held on May 10, 2013. Based on the discussion at the PHC, there is a need to update the scope and schedule of Track 2. The California Independent System Operator (CAISO) is now preparing studies based on the scenarios adopted in D.12-12-010. We expect the CAISO studies to provide information on the system's operating flexibility needs which can help determine whether to authorize further procurement. The CAISO studies are deterministic in nature, meaning that the results will provide us with fixed values with no associated probability (for example, the amount of Megawatts the system will be short over a given period of time).

Southern California Edison (SCE) is preparing studies based on the Commission-adopted assumption and scenarios. The SCE studies would be used for the same purposes as the CAISO studies. However, the SCE studies are stochastic in nature, meaning that the model output will have a probability distribution with results showing the likelihood of shortage by volume for a given time period. The CAISO intends to complete stochastic studies as well. The Division of Ratepayer Advocates (DRA) and other parties may complete Track 2 studies as well. All of these studies are within the scope of Track 2.

The workings of the CAISO's deterministic studies have been well-vetted with parties through workshops and informal exchanges of information over the last two years. While there is likely to be differences about certain aspects of these studies, they are well-understood and ripe for Commission consideration. By contrast, there has been only one workshop on SCE's stochastic studies and one on the CAISO's stochastic studies (both in May 2013). There is reason to believe that stochastic studies may be more robust than deterministic studies, as stochastic studies look at a range of inputs and the probabilities that such inputs will occur. By contrast, deterministic studies simply choose (hopefully reasonable and likely) data points for many inputs.

We intend to provide parties with the opportunity to present and scrutinize both deterministic and stochastic studies in Track 2. However, we recognize that stochastic studies may not be ripe for Commission adoption at this time.

At the May 10, 2013, SCE indicated that its stochastic studies would be available in September, 2013. The CAISO requested an extended timeframe

(October 2013) to allow its stochastic studies to be presented as well as its deterministic studies. The original Scoping Memo in this proceeding foresaw a decision in Track 2 by the end of 2013. That timeframe is no longer possible. However, it is important to complete Track 2 before underlying data becomes stale.

In seeking to balance time considerations and record development, we will allow stochastic studies if they can be presented within the timeframe below. If this is not possible, it will be an indication that such studies are not sufficiently developed for consideration in this proceeding at this time. The schedule for the remainder of Track 2 will be as follows:

<u>TRACK 2 REVISED SCHEDULE</u>

September 20, 2013	SCE and CAISO[1] Deterministic and/or Stochastic Studies and Opening Testimony
November 1, 2013	All Other Parties' OpeningTestimony and Reply to SCE and CAISO
November 15, 2013	All Parties' Rebuttal Testimony
November, 2013 (date to be determined) Commission Courtroom, State Office Building 505 Van Ness Avenue San Francisco, CA 94102	Prehearing Conference

[1] If DRA or any other party chooses to file a similar study, they must file it with Testimony no later than this date.

December 2 to 6 and December 9 to 13, 2013 Commission Courtroom, State Office Building 505 Van Ness Avenue San Francisco, CA 94102	Evidentiary Hearings
Dates to be determined at hearings	Briefs and Reply Briefs
Date of Reply Briefs	Last date to request Final Oral Argument; expected Submission date
March 2014 (projected)	Proposed Decision
No less than 30 days after Proposed Decision	Decision on Commission Agenda

We will also add a Track 4 to the scope of this proceeding at this time. Track 4 will consider the local reliability impacts of a potential long-term outage at the San Onofre Nuclear Power Station (SONGS) generators, which are currently not operational. The CAISO is developing a study to assess both the interim (2018) and long-term (2022) local reliability needs in the Los Angeles Basin local area and San Diego sub-area resulting from an extended SONGS outage. Parties should note that this differs from the Track 2 CAISO studies, which have scenarios with various SONGS availability over time for system reliability purposes. SCE and San Diego Gas & Electric Company (SDG&E) are also developing studies of local area needs without SONGS. DRA and other parties have indicated that they may also develop their own power flow studies.

The Track 4 inquiry can help inform the magnitude of local capacity requirements with and without SONGS. There also may be some interaction between any needs identified in the incipient Track 4 of this proceeding and any residual operational flexibility needs identified in Track 2 of this proceeding.

Similar to Track 1, building resources to meet local capacity needs is likely to help address systemwide flexibility needs.

Based on the discussion at the PHC, the schedule for Track 4 will be as follows:

TRACK 4 SCHEDULE

August 5, 2013	CAISO Study and Opening Testimony
August 26, 2013	SCE Study and Opening Testimony[2]
September 23, 2013	All Parties (except SCE and CAISO) Opening Testimony and Reply to SCE and CAISO
October 7, 2013	All Parties Rebuttal Testimony; final date to request evidentiary hearings; expected Submission date if no evidentiary hearings
October 2013 (date to be determined) Commission Courtroom, State Office Building 505 Van Ness Avenue San Francisco, CA 94102	Prehearing Conference, if needed
October 28 – November 1, 2013 Commission Courtroom, State Office Building 505 Van Ness Avenue San Francisco, CA 94102	Evidentiary Hearings, if needed
Dates to be determined	Briefing Schedule, if needed
December 1, 2013 or date of Reply Briefs (if applicable), whichever comes later	Last date to request Final Oral Argument

[2] If DRA or any other party chooses to file a similar study, they must file it with Testimony no later than this date.

Date of Reply Briefs (if applicable)	Last date to request Final Oral Argument (if evidentiary hearings are held)[3]
December 2013	Proposed Decision, if no evidentiary hearings are held
February 2013	Proposed Decision if evidentiary hearings are held
No less than 30 days after Proposed Decision	Decision on Commission Agenda

In Track 2 of this proceeding, an Assigned Commissioner's Ruling on June 27, 2012 set forth standardized planning assumptions to be used to develop scenarios for consideration of system needs for the next 10 to 20 years. For Track 4, this Scoping Ruling sets forth the assumptions to be used for considering the impacts of interim and long-term local reliability needs in the Los Angeles Basin local area and San Diego sub-area resulting from an extended SONGS outage. The assumptions are in Attachment A to this Ruling.

IT IS RULED that:

1. Evidentiary hearings (EH) may be needed for Track 4 of this proceeding. EHs are not needed for Track 3 of this proceeding.
2. The scope of Track 2 and Track 4 of this proceeding is as stated herein.
3. The assumptions in Attachment A to this Ruling shall be used to study interim (2018) and long-term (2022) local reliability needs in the Los Angeles

[3] Rule 13.13 states in applicable part: "In ratesetting and quasi-legislative proceedings in which hearings were held, a party has the right to make a final oral argument before the Commission, if the party so requests within the time and in the manner specified in the scoping memo or later ruling in the proceeding."

Basin local area and San Diego sub-area resulting from an extended SONGS outage.

4. Administrative Law Judge David M. Gamson shall continue to be the presiding officer in this proceeding.

5. The preliminary determination in Rulemaking 12-03-014 that this proceeding is categorized as ratesetting is again confirmed.

Dated May 21, 2013, at San Francisco, California.

/s/ MICHEL PETER FLORIO	/s/ DAVID M. GAMSON
Michel Peter Florio	David M. Gamson
Assigned Commissioner	Administrative Law Judge

ATTACHMENT A

TRACK 4 ASSUMPTIONS

Background

The San Onofre Nuclear Generating Station (SONGS) has key impacts on the Los Angeles (LA) Basin local area and San Diego sub-area ("SONGS Study Area").[4] The following assumptions are established, consistent with the 2012 Long Term Procurement Plan (LTPPs) Scenarios and Assumptions,[5] the 2012 LTPPs Track 1 Decision,[6] and the San Diego Gas & Electric Power Purchase Tolling Agreement Decision.[7] These studies align with recent infrastructure authorizations made by this Commission and the California ISO and will provide a common reference point for any needs both with and without SONGS. We did explicitly acknowledge, however in the Track 2 Decision, that certain revised study assumptions were appropriate, including using a 1-in-10 versus 1-in-2 peak weather forecast for transmission and local area planning and allocation methodologies for assigning Energy Efficiency and Demand Response to busbars.

Study Parameters

Purpose The primary purpose of these studies is to determine the local resource replacement requirements for SONGS, if SONGS remains offline or if we make a policy decision to not pursue relicensing in 2022 when the license expires. A secondary purpose is to ensure local procurement can be optimized to address local capacity needs and flexibility should SONGS need replacement. Other broader studies of local needs such as zonal requirements or off-peak assessments, aside from local capacity requirements, are expected to be taken up by the California ISO (CAISO) in its Transmission Planning Process (TPP).

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[4] Due to the interdependency of the LA Basin local area and San Diego sub-area on the SONGS facility, one comprehensive set of studies will be conducted. Collectively this area is referred to as the SONGS Study Area.

[5] *See* D.12-12-010, available here.

[6] *See* D.13-02-015, available here.

[7] *See* D.13-03-029, available here.

Cases We request that the CAISO model three separate cases. The first is 2022 without SONGS; the second is 2022 with SONGS; and the third is 2018 without SONGS.

Assumptions The assumptions listed in the summary table below are consistent with the approach of the 2012 LTPP and should be used in the analysis of the SONGS Study Area. The assumptions reflect any adjustments necessary to be consistent with the scope of this analysis, for example, locational uncertainty of a resource, and geographical aggregations to match the study area. The derivations of these assumptions from earlier decisions are described later in this document.

To clearly identify where and how assumptions shall be used in the studies, assumptions are generally classified into three categories. The first category, "Model input", consists of assumptions that shall be embedded in the model as an input. The second category, "First Contingency", consists of assumptions representing resources that can be relied upon to address a post-first contingency situation. The studies shall model "First Contingency" resources as addressing the first contingency to prepare for a second contingency. The third category, "Second Contingency", consists of assumptions representing residual resources that could be used to meet subsequent post-contingency needs. "Second Contingency" resources are not modeled but would be accounted for as potential resources to address any residual need identified by a second contingency condition in the studies.

For example, incremental energy efficiency (EE) is a "Model input" assumption because it is accounted for by debiting the load input assumption. Currently funded fast response (30 minute or less) demand Response (DR) programs fit the "First Contingency" category because they can address a post first-contingency condition and would be triggered once the first major item trips offline. Price responsive and day-ahead DR programs or DR programs outside of the areas of most concern fit the "Second Contingency" category. We expect that those programs could become more capable of meeting needs by 2022, but without action to make that a reality, we cannot assume that they can meet the identified problem. The study results shall provide a broad assessment of local area needs that inform the programs of "Second Contingency" resources such that they can adapt to meet the residual need.

Not all resource types will be available or effective in meeting identified needs based on location or type of need. For example, demand response cannot exceed the forecast load at any given busbar, nor should industrial demand response programs be modeled at a busbar without industrial load.

Summary Table – SONGS Study Area Input Assumptions for 2018 and 2022

Variable	2018 Model input	2018 First Contingency	2018 Second Contingency	2022 Model input	2022 First Contingency	2022 Second Contingency
Load	27,522 MW	–	–	28,973 MW	–	–
Inc EE	524 MW	–	–	933 MW	–	–
DR	–	189 MW	997 MW	–	189 MW	997 MW
Inc CHP	0 MW	–	–	0 MW	–	–
Inc small PV installed capacity	–	_	477 MW	–	–	616 MW
RPS Portfolio	Commercial	–	–	Commercial	–	–
Resource additions	160 MW	–	2,098 MW	160 MW	–	2,098 MW
Resource retirements	All OTC plus 1,883 MW non-OTC	–	–	All OTC plus 1,883 MW non-OTC	–	–
Transmission	All ISO approved upgrades	–	–	All ISO approved upgrades	–	–

Load

The 2018 and 2022 1-in-10 peak load for the local area with 1-in-5 system load is appropriate to use. The mid-range economic and demographic assumptions are appropriate to use. The most recent forecasts are in the 2012 Integrated Energy Policy Report, August 2012 revision, forms 1.5c & d.[8]

[8] http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/Mid_Case_LSE_and_Balancing_Authority_Forecast.xls

Peak Load

	1-in-5 peak MW		1-in-10 peak MW	
	2018	**2022**	**2018**	**2022**
LA Basin Local Area	21,174	22,187	21,870	22,917
SDG&E Service Area[9]	5,528	5,922	5,652	6,056
Total	26,702	28,109	27,522	28,973

Incremental Energy Efficiency

Future energy efficiency programs are generally not crafted to specific locations. Therefore we adopt the low level of savings for use in this set of studies to account for this uncertainty, even though across the SCE and SDG&E areas we expect the mid-level of savings to occur.

Values in the table below show the low level of savings from the incremental EE forecast associated with the 2012 IEPR Update[10] and the adjustment for the SONGS Study Area, aggregated from busbar value forecasts consistent with the allocation methodology adopted in D.12-12-010.

Low Level of Incremental EE Savings in MW

IOU area	2018	2022	Study area	2018	2022
SCE	556	973	LA Basin	425	746
SDG&E	99	187	San Diego	99	187
SCE + SDG&E	655	1,160	SONGS Study Area	524	933

[9] There is no load at the Imperial Valley part of the Greater Imperial Valley-San Diego local area, therefore the SDG&E Service Area load is identical to the San Diego sub-area.

[10] http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/IUEE-CED2011_results_summary.xls

Demand Response

The Commission identified 200 MW of DR resources in 2022 in the LA Basin in the Track 1 Decision (13-02-015), and 219 MW in 2020 in the San Diego sub-area in the Power Purchase Tolling Agreement (PPTA) Decision (13-03-029). The Track 2 Scenarios and Assumptions Decision of this proceeding (D.12-12-010), identified the IOU Annual Load Impact Reports as the data source for DR projections.

As an interim approach for better quantifying and assessing DR for local reliability purposes in the LA Basin, we establish that fast[11] DR located at the most effective LA Basin locations shall be modeled as a "First Contingency" resource, i.e. a resource that can be relied upon post-first contingency to prepare for the second contingency. This amount of DR, 173 MW, is roughly consistent with the amount of DR identified in the Track 1 Decision, 200 MW. To be consistent with the 2012 Load Impact Report, the remaining amount of LA Basin DR forecasted in the report shall be accounted for as a "Second Contingency" resource, i.e. a resource that is available to prepare for subsequent contingencies.

The ISO has identified the most effective substations where DR should be located, as described in the table below.[12]

LA Basins Most Effective Locations For Mitigating Contingencies

Alamitos
Barre
Del Amo
Ellis
Johanna
Lewis
Santiago
Viejo
Villa Park

[11] Fast demand response programs in this context are programs that respond to dispatch instructions within 30 minutes or less, including notification time to customers.

[12] ISO studies as part of the 2012/13 Transmission Planning Process examined grid conditions in light of a continued SONGS outage. *See* here starting at page 170.

As an interim approach for better quantifying and assessing DR for local reliability purposes in the San Diego sub-area, we establish that fast DR located anywhere in San Diego shall be modeled as a "First Contingency" resource, i.e. a resource that can be relied upon post-first contingency to prepare for the second contingency. This amount of DR, 16 MW, is consistent with the approach that fast DR has the attributes required to address contingencies within the appropriate response timeframe. To be consistent with the San Diego PPTA Decision, the remaining amount of San Diego sub-area DR accounted for as a "Second Contingency" resource, i.e. a resource that is available to prepare for subsequent contingencies, shall be the difference between 219 and 16, or 203 MW. This amount of total DR is significantly greater than the amount of DR forecasted by the Load Impact Reports and therefore represents new programs or substantial program growth in San Diego by 2022.

For the San Diego sub-area, DR located anywhere within the area is considered effective for mitigating contingencies.

The following table summarizes the demand response projections relevant to the SONGS study area.

Demand Response Projections in MW

IOU area[13]	2018	2022	Study area, DR type[14]	2018	2022
SCE	1,252	1,252	LA Basin "First Contingency"	173	173
			LA Basin "Second Contingency"	794	794
SDG&E	75	77	San Diego "First Contingency"	16	16
			San Diego "Second Contingency"	203	203
SCE + SDG&E	1,327	1,329	SONGS Study Area "First Contingency"	189	189
			SONGS Study Area "Second Contingency"	997	997

This set of assumptions maintains consistency with recent Commission decisions, while also realizing the inherent locational uncertainties associated with programs for which we expect continued development and improvement. This also leaves room for program growth and system changes while acknowledging for the first time in local capacity requirement studies non-zero levels of demand response.

13 Values based on 2012 Load Impact Reports.

14 Values consistent with the LTPP Track 1 Decision 13-02-015 and the San Diego PPTA Decision 13-03-029.

Incremental Combined Heat and Power

For incremental combined heat and power programs, we maintain the current Track 2 assumption of no incremental combined heat and power.

Incremental Small Photovoltaics

For incremental small photovoltaics (PV), we assume up to an installed capacity of 1,300 MW of customer-side incremental PV by 2022, ISO-wide, consistent with D. 12-12-010. This capacity represents projected customer-side PV incremental to the amount embedded in the IEPR demand forecast. This incremental amount makes up for the shortfall in reaching the 3,000 MW CSI program target embedded in the IEPR demand forecast, and also reflects projected growth in customer-side PV due to Net Energy Metering expansion.

To adapt the ISO system-wide projection of 1,300 MW installed capacity to the SONGS study area, we adjusted this amount by load share ratios to estimate the amount of PV to allocate to the LA Basin and the San Diego LCR areas. Furthermore, the installed capacity amounts are adjusted by peak demand impact factors to yield an "NQC" value. These factors come from California Solar Initiative Impact Reports and are consistent with the factors used for small PV that is embedded within the IEPR demand forecast. The tables below summarize these amounts.

2018 customer-side incremental PV

Demand[15]	MW	Installed capacity	MW	Peak demand impact factor[16]	NQC MW
ISO Area	53,606	ISO Area	1,011	–	–
LA Basin Local Area	20,135	LA Basin	380	0.45	171
SDG&E Service Area	5,167	San Diego	97	0.46	45
		LA Basin + San Diego	477	–	216

2022 customer-side incremental PV

Demand	MW	Installed capacity	MW	Peak demand impact factor	NQC MW
ISO Area	56,245	ISO Area	1,300	–	–
LA Basin Local Area	21,098	LA Basin	488	0.45	219
SDG&E Service Area	5,536	San Diego	128	0.46	59
		LA Basin + San Diego	616	–	278

15 From 2012 IEPR Update demand forecast, Aug 2012, Form 1.5b, 1 in 2 peak loads for 2018 and 2022.

16 From Itron's CPUC California Solar Initiative 2010 Impact Evaluation Report, Table C-2.

The location where customer-side PV will get built is difficult to predict, therefore the capacity amounts described here will be modeled as "Second Contingency" resources. The ISO shall determine the most effective busbars where customer-side PV should be located in order to address those contingencies. Once those locations are identified, the Commission can then direct customer-side generation programs, like the California Solar Initiative or other efforts, to target those locations.

RPS Portfolio

The Renewable Net Short (RNS) for a 2018 LTPP Scenario Base Case Scenario run is 20,572 GWh. This 2018 RPS was calculated using the August 2012 Integrated Energy Policy Report (IEPR) statewide retail sales forecast of 287,109 GWh and the accompanying "Non RPS Deliveries" 12,443 GWh amount, deriving a "Retail Sales for RPS" amount of 274,666 GWh.

The "Additional Energy Efficiency" amount of 11,137 GWh, consistent with the mid value from the 2012 LTPP, was provided by the Energy Commission, which is an additional Energy Efficiency value composed of the 2012 IEPR Update for the IOUs and the 2011 IEPR for the POUs. The "Additional Rooftop PV" amount of 1,679 GWh for 2018 was taken from the CPUC's LTPP "Scenario Tool". Subtracting these additional EE and PV GWh amounts from the Retail Sales for RPS figure (Chart 1, line3) provides the 2018 "Adjusted Statewide Retail Sales for RPS" figure of 261,850 GWh.

CPUC Decision 11-12-020, Ordering Paragraph 3, indicates that the 2018 RPS target is 29% of adjusted retail sales. As such, the "Total Renewable Energy Needed for RPS" (261,850 GWh x 29%) results in 75,937 GWh. Netting out the "Total Existing Renewable Generation for CA RPS" amount of 55,364 GWh from the renewable energy needed results in a "Total Renewable net Short to meet 33% RPS in 2018" of 20,572 GWh.

Chart 1: 2022 RNS calculation & 2018 RNS calculation

	All Values in GWh for the Year 2022	Formula	2022 Base		All Values in GWh for the Year 2018	Formula	2018 Base
1	Statewide Retail Sales - June 2012 IEPR12 Final		301,384.0	1	Statewide Retail Sales - August 2012 IEPR12 Final		287,109.0
2	Non RPS Deliveries (CDWR, WAPA, MWD)		12,530.0	2	Non RPS Deliveries (CDWR, WAPA, MWD)		12,443.0
3	Retail Sales for RPS	3=1-2	288,854.0	3	Retail Sales for RPS	3=1-2	274,666.0
4	Additional Energy Efficiency		19,543.0	4	Additional Energy Efficiency		11,137.0
5	Additional Rooftop PV		2,158.8	5	Additional Rooftop PV		1,679.1
6	Additional Combined Heat and Power		-	6	Additional Combined Heat and Power		-
7	Adjusted Statewide Retail Sales for RPS	7=3-4-5-6	267,152.2	7	Adjusted Statewide Retail Sales for RPS	7=3-4-5-6	261,849.9
8	**Total Renewable Energy Needed For RPS**	**8=7* 33%**	**88,160.2**	8	**Total Renewable Energy Needed For RPS**	**8=7* 29%**	**75,936.5**
	Existing and Expected Renewable Generation				Existing and Expected Renewable Generation		
9	Total In-State Renewable Generation		40,304.7	9	Total In-State Renewable Generation		40,304.7
10	Total Out-of-State Renewable Generation		13,950.0	10	Total Out-of-State Renewable Generation		13,950.0
11	Procured DG (not handled in Calculator)		1,109.7	11	Procured DG (not handled in Calculator)		1,109.7
12	**Total Existing Renewable Generation for CA RPS**	**12=9+10+11**	**55,364.4**	12	**Total Existing Renewable Generation for CA RPS**	**12=9+10+11**	**55,364.4**
13	**Total RE Net Short to meet 33% RPS In 2022 (GWh)**	**13=8-12**	**32,795.8**	13	**Total RE Net Short to meet 33% RPS In 2018 (GWh)**	**13=8-12**	**20,572.1**

The orange highlighted cells in Chart 2 represent those 2012 LTPP Base Case scenario projects that are included in the RPS Calculator which satisfy the smaller RNS of 20,572 GWh estimated herein for 2018. Note that most of the projects that are pulled into the 2018 LTPP Base Case Scenario are on existing transmission lines; one project would require a new transmission line (Merced); and 10 out-of-state Renewable Energy Credit only projects fill-in the rest of the portfolio. No generic projects[17] are forecasted to be required in ordered to fill the 2018 RNS. As expected, the projects that fill the 2018 LTPP Base Case RNS are a subset of the projects that filled the 2022 LTPP Base Case RNS.

[17] A generic project is either lacking a complete application for a major environmental review, or an executed contract.

Chart 2: Projects from the LTPP 2022 Base Case Scenario; and highlighted projects from the 2018 Base Case Scenario

The 327 projects which satisfy the 2022 LTPP Base Case (RNA of 32,796 GWh)											
*The 180 highlighted projects that satisfy the smaller 2018 LTPP Base Case (RNS of 20,572 GWh)											
Project ID - On Exiting Transmission								Project ID - Minor Upgrade	Project ID - New Transmission	Project ID - Out-Of-State RECs	Genric Projects - Minor Upgrades & New Transmission
POU - LA5	LDPV_2622	LDPV_2443	LDPV_11516	LDPV_9657	LDPV_17656	LDPV_8432	SC7018	SD0915	SC5008	POU - SMUD1	st26180
POU - MID1	LDPV_6362	LDPV_2926	LDPV_11257	LDPV_9825	LDPV_17747	LDPV_15152	SC7019	PG7084	SC5075	SD1102	REAT*0602549150
POU - IID1	LDPV_4802	LDPV_1173	LDPV_11466	LDPV_4477	LDPV_7996	LDPV_8652	SC7021	PG5122	PG6013	SC3007	REAT*06099001
POU - IID2	LDPV_2292	LDPV_3873	LDPV_11326	LDPV_9516	LDPV_7937	LDPV_8462	SCE_TBD	PG5123	PG5131	SC7029	REAT***06095006
POU - IID3	LDPV_4557	LDPV_5343	LDPV_11526	LDPV_8156	LDPV_9447	LDPV_15232	PG7071	PG5124		PG5115	REAT*06025008
POU - Ana1	LDPV_5042	LDPV_11616	LDPV_11055	LDPV_9947	LDPV_10256	LDPV_15212	PG5143	PG5090		PG5103	REAT*06025009
POU - Ana2	LDPV_992	LDPV_3525	LDPV_11436	LDPV_3677	LDPV_9326	LDPV_14012	PG2037	PG1046		PG5038	REAT*0602543965
POU - SVP1	LDPV_1662	LDPV_11766	LDPV_11244	LDPV_3566	LDPV_9466	SD0405	PG5100	PG5141		PG7038	geo_9
POU - SVP2	LDPV_2512	LDPV_11136	LDPV_11696	LDPV_7496	LDPV_9387	SD0915	PG6004	SD0913		PG7036	03Aug2008_106
POU - SVP3	LDPV_2272	LDPV_11297	LDPV_11076	LDPV_6236	LDPV_9377	SD1002	PG6005	SD1001		PG7037	REAT60370034
POU - SVP4	LDPV_2462	LDPV_5723	LDPV_11034	LDPV_8136	LDPV_9737	SD1003	PG5141				REAT*06071012
LDPV_227	LDPV_4692	LDPV_11364	LDPV_6164	LDPV_10216	LDPV_9487	SC3012	PG5083				REAT**06047002
LDPV_27	LDPV_5502	LDPV_2576	LDPV_4075	LDPV_2225	LDPV_8027	SC6003	PG6013				REAT**06047001
LDPV_97	LDPV_4492	LDPV_4944	LDPV_10976	LDPV_9577	LDPV_8196	SC5004	PG6000				REAT**06071002
LDPV_326	LDPV_3662	LDPV_11606	LDPV_7624	LDPV_8316	LDPV_8216	SC5003	PG6011				REAT*06071010
LDPV_37	LDPV_1512	LDPV_11416	LDPV_11374	LDPV_7114	LDPV_15046	SC5005	PG5082				REAT*06071015
LDPV_567	LDPV_6532	LDPV_11405	LDPV_11537	LDPV_7924	LDPV_7906	SC5012	PG5084				REAT607146805
LDPV_114	LDPV_4062	LDPV_11427	LDPV_4174	LDPV_8124	LDPV_15196	SC5006	PG5089				REAT*0605111667
LDPV_596	LDPV_2992	LDPV_11307	LDPV_2707	LDPV_9927	LDPV_8512	SC5010	PG5095				
LDPV_46	LDPV_3072	LDPV_11545	LDPV_8165	LDPV_8016	LDPV_17466	SC5077	PG2028				
LDPV_757	LDPV_6752	LDPV_11555	LDPV_9345	LDPV_10245	LDPV_8632	SC5071	PG6003				
LDPV_532	LDPV_3142	LDPV_11637	LDPV_9355	LDPV_9786	LDPV_14882	SC5072	PG5088				
LDPV_202	LDPV_1992	LDPV_11666	LDPV_7156	LDPV_10047	LDPV_15222	SC5070	PG2042				
LDPV_1262	LDPV_4132	LDPV_11357	LDPV_5917	LDPV_7956	LDPV_8572	SC5019	PG5085				
LDPV_5667	LDPV_5432	LDPV_11746	LDPV_8294	LDPV_9476	LDPV_8402	SC5073	PG5081				
LDPV_557	LDPV_2252	LDPV_11484	LDPV_9686	LDPV_10076	LDPV_14952	SC5074	PG6001				
LDPV_2792	LDPV_6877	LDPV_11217	LDPV_5446	LDPV_10037	LDPV_15332	SC5050	PG6002				
LDPV_4417	LDPV_1832	LDPV_11287	LDPV_1705	LDPV_8327	LDPV_15252	SC5051	PG5131				
LDPV_4422	LDPV_1812	LDPV_11625	LDPV_9766	LDPV_17426	LDPV_15072	SC5054	PG1049				
LDPV_2482	LDPV_6922	LDPV_11447	LDPV_6915	LDPV_7886	LDPV_14982	SC5061	SD7019				
LDPV_3132	LDPV_1782	LDPV_11027	LDPV_9835	LDPV_8277	LDPV_15052	SC5063	SD0505				
LDPV_1102	LDPV_7392	LDPV_10996	LDPV_4516	LDPV_9967	LDPV_8532	SC5064	SD1009				
LDPV_2432	LDPV_7212	LDPV_11117	LDPV_8105	LDPV_10125	LDPV_15082	SC5068	SD5037				
LDPV_3602	LDPV_2302	LDPV_11395	LDPV_8115	LDPV_10207	LDPV_8382	SC5080					
LDPV_1202	LDPV_3624	LDPV_7543	LDPV_9856	LDPV_10116	LDPV_8542	SC7015					
LDPV_6442	LDPV_6275	LDPV_11045	LDPV_9806	LDPV_9526	LDPV_8482	SC7017					

Additions and Retirements

D.12-12-010 assumed retirements based on facility age (more than 40 years old) and for compliance with the State Policy on Cooling Water Intake Structures. Per the once-through cooling (OTC) Policy, Encina is assumed retired, as are 238 MW of non-OTC generation in the San Diego subarea. The recently authorized repower of the Escondido Energy Center peaking plant is added as a 45 MW unit. These values are the same for 2018 and 2022.

For the LA Basin, no OTC generation is assumed retired in 2018 except for Huntington Beach units 3 & 4 and El Segundo unit 4 (unit 3 is currently being repowered). For 2022, all OTC generation is assumed retired in the LA Basin. In addition to the OTC generation, 1,645 MW of additional resources are assumed retired due to age in 2018 and 2022. This includes the Long Beach peakers, refurbished for operation in 2007, and three facilities owned by Pasadena. Based on Pasadena's resource plan, 115 MW are added in for both 2018 and 2022 accounting for the replacement of Broadway unit 3 and Glenarm units 1 and 2.

		2018	2022
LA Basin	Retirement	1645	1645
	Addition	115	115
San Diego	Retirement	238	238
	Addition	45	45

Due to locational uncertainty over the other resources recently approved by the Commission in D.12-12-010, and in the San Diego PPTA Decision (D.13-03-029), these resources should be accounted for in meeting "Second Contingency" needs. Between 1400 and 1800 MW in the LA Basin and 298 MW in San Diego are appropriate values.

Transmission Changes

The transmission system should be modeled based on previously and currently approved CAISO upgrades, including those in the recently adopted 2012/2013 Transmission Planning Process.

(END OF ATTACHMENT A)