Rulemaking:	12-03-014
Witness:	Bill Powers
Exhibit No.:	

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

PREPARED OPENING TESTIMONY OF BILL POWERS ON BEHALF OF SIERRA CLUB CALIFORNIA

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

September 30, 2013

TABLE OF CONTENTS

I. Executive Summary

What are the main points of your testimony?

Even without considering the California Independent System Operator's ("CAISO") 2013/2014 transmission studies, there is no need for new generation. CAISO assumes a severe contingency scenario that encourages over-procurement, and ignores the presumed mitigation in the CAISO and the North American Electric Reliability Corporation ("NERC") reliability standards to address the severe contingency – controlled load shedding. The need that CAISO identifies in its power flow modeling disappears after considering load shedding, the Mesa Loop-In transmission upgrade, and the California Energy Commission's ("CEC") new demand forecast.[1] In addition, the energy storage proposed decision will require very significant procurement of energy storage resources in San Diego Gas & Electric ("SDG&E") and Southern California Edison ("SCE") territories by 2020.[2] Based on these considerations, no additional generation is necessary to address the permanent closure of the San Onofre Nuclear Generating Station ("SONGS").

II. Grid Reliability Standard Used to Determine Local Capacity Requirements ("LCR") Need

A. CAISO's Reliability Standard: N-1-1 contingency

What is the purpose of grid reliability standards?

NERC is the entity designated by the Federal Energy Regulatory Commission ("FERC") as the U.S. authority responsible for developing grid reliability standards. The purpose of grid reliability standards is to assure that a utility can continue to provide reliable power during peak demand periods with, at a minimum, one major element of infrastructure, either a transmission line, a power plant, or transformer bank, unavailable.[3] The unavailability of one major element of infrastructure is known as a Category B, "N-1" condition. Category A is normal operation with no elements unavailable.

The NERC N-1 reliability standard is a national standard. All U.S. utilities must meet the NERC minimum grid reliability N-1 standard. Public utilities in California, such as the Los Angeles Department of Water and Power ("LADWP") and the Sacramento Municipal Utility District, are subject to the NERC N-1 reliability standard. NERC standards also address actions to be taken to address a limited number of more serious multiple contingencies involving the loss of two elements. These are known as Category C contingencies. These multiple contingencies can

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[1] The load forecast issue is discussed in the Opening Comments of Sierra Club California on ALJ Gamson's Questions from September 4, 2013 Prehearing Conference that are served concurrently. The CEC demand forecast used in power flow modeling is obsolete and substantially overestimates peak load growth.

[2] Sierra Club's Opening Comments also discuss energy storage.

[3] NERC. Standard TPL-001-01 – System Performance Under Normal Conditions, Table 1, p. 4. Retrieved from http://www.nerc.com/files/TPL-001-1.pdf.

include, for example, one major power plant (G - generator) and one major transmission line (N) unavailable (G-1, N-1), or the loss of two transmission circuits on a common tower (N-2). NERC allows these multiple contingency situations to be met with controlled load shedding. Controlled load shedding means the utility interrupts power flow to a portion of its service territory sufficient to maintain reliable supply to the rest of its service territory until the contingency is resolved. Category D contingencies are extreme, very low probability events, such as the sequential loss of two transmission lines that are not adjacent to each other. Utilities are not expected to maintain grid reliability in the face of an extreme Category D event. As SCE states, "Category D contingencies are extreme events with no specific performance requirements other than an evaluation for risks and consequences."[4] An example of a Category D event that is directly relevant to Track 4 modeling is the double contingency of SDG&E's Sunrise Powerlink and Southwest Powerlink, an N-1-1 event.

Does CAISO require more than the N-1 reliability standard?
Yes. The CAISO transmission planning standard requires that PG&E, SCE, and SDG&E meet a G-1, N-1 limiting contingency with no load shedding.

What is the basis for the more stringent G-1, N-1 standard?
CAISO's practice is to require the more stringent standard. CAISO states in its transmission planning standard document that: "The ISO recognizes that this planning standard [G-1, N-1] is more stringent than allowed by NERC, but it is considered appropriate for assessing the reliability of the ISO's controlled grid as it remains consistent with the standard utilized by the PTOs prior to creation of the ISO."[5]

Does use of CAISO's more stringent standards assure higher reliability?
No. CAISO, SCE, and SDG&E have not made any showing that the more stringent CAISO G-1, N-1 planning standard has increased the reliability of the transmission grid.

SCE's statements that "CAISO's assumed performance requirements improve the reliability of the electric system" and "[t]hey assure system performance levels above NERC Reliability Standards" are unsupported with any evidence.[6] In contrast, LADWP, whose service territory is surrounded by SCE and whose annual and peak loads are greater than those of SDG&E, adheres to the NERC N-1 reliability standard and has maintained grid reliability performance as good as or better than SCE and SDG&E.[7]

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[4] SCE Testimony, p. 22, lines 4-6.
[5] CAISO. California ISO Planning Standards (Jun. 23, 2011), p. 10. Retrieved from http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf.
[6] SCE. Track 4 Testimony of Southern California Edison Company ("SCE Testimony")(Aug. 26, 2013), p. 27, lines 16-18.
[7] LADWP. 2012 Ten-Year Transmission Assessment (Dec. 2012.), pp. 5, 8. Retrieved from http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/docs/energy_comp/10yta_2012_5.pdf.

Why do CAISO and SDG&E assert that an N-1-1 contingency with no load shedding should be the limiting contingency applied to SDG&E in Track 4 modeling?

CAISO applies the Western Electricity Coordinating Council ("WECC") performance criteria for adjacent transmission lines. According to CAISO testimony, SDG&E's 500 kV Southwest Powerlink ("SWPL") and 500 kV Sunrise Powerlink are less than 250 feet from each other for a distance of less than 3 miles.[8] The WECC defines adjacent transmission circuits as two transmission circuits with separation of less than 250 feet between their centerlines.[9] However, adjacent transmission circuits that are less than 250 feet apart for less than 3 miles are exempt from WECC performance criteria that treat adjacent transmission lines as potential double outages (loss of both circuits).[10]

Are the Southwest Powerlink and Sunrise Powerlink subject to the WECC performance criteria for adjacent transmission circuits?

No. Southwest Powerlink and Sunrise Powerlink are exempt from this WECC system performance criterion applicable to adjacent transmission lines because they are less than 250 feet from each other for a distance of less than 3 miles. As CAISO correctly stated in prior testimony, "SDG&E told the ISO that the newly revised WECC criterion for common corridor circuit outages would result in a reclassification of the Sunrise/IV Miguel (Southwest Powerlink) double outage as a Category D contingency because the towers on the two lines are spaced less than 250' apart for less than 3 miles (which is the new WECC criteria)."[11]

Was CAISO correct in asserting that the newly revised WECC criteria for adjacent transmission circuits would result in a reclassification of the Sunrise Powerlink/Southwest Powerlink double outage as a Category D contingency?

Yes. The reason for the revised criteria is that WECC has found that the outage frequency of two separate transmission lines sharing the same right-of-way is not significantly different from the outage frequency for transmission lines that do not share a right-of-way with other transmission lines.[12] In other words, WECC has determined that the possibility of a loss of two

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[8] CAISO. Supplemental Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation, A.11-05-023, p. 1, lines 22-26. Retrieved from http://www.caiso.com/Documents/2012-04-06_A11-05-023_Sparks_SuppTest.pdf.

[9] WECC. TPL-001-WECC-CRT-2 — System Performance Criterion, p. 11. Retrieved from http://www.wecc.biz/committees/BOD/11302011/Lists/Minutes/1/PCC%2001%20WECC-0071%20TPL-001-WECC-CRT-2%20Clean.pdf.

[10] WECC. System Performance: TPL-001-WECC-RBP-2.1, Regional Business Practice (Dec. 1, 2011), p. 3. Retrieved from: http://www.wecc.biz/library/Documentation%20Categorization%20Files/Regional%20Business%20Practices/TPL-001-WECC-RBP-2.1.pdf

[11] Sparks, Robert. Application 11-05-023: Supplemental Testimony of Robert Sparks on Behalf of the California Independent System Operator
Corporation (Apr. 6, 2012), p. 1, lines 22-26. Retrieved from http://www.caiso.com/Documents/2012-04-06_A11-05-023_Sparks_SuppTest.pdf.

[12] WECC, TPL-001-WECC-CRT-2 – System Performance Criterion, Post for Planning Committee Approval, (Sept. 9, 2011), pp. 4-5. Retrieved from: http://www.wecc.biz/committees/BOD/11302011/Lists/Minutes/1/PCC%2001%20WECC-0071%20TPL-001-

transmission lines separated by less than 250 feet for less than 3 miles is so remote that it merits Category D "act of god" status. There are no requirements on transmission operators for dealing with Category D events other than assessing the implications if the event were to happen. However, in Track 4 power flow modeling, CAISO and SDG&E of their own volition have elevated a Category D "act of god" event to the contingency that must be met – without load shedding – in a post-SONGS world. Both CAISO and SDG&E are wrong in relying on the April 1, 2012 revision to the WECC system performance criteria for adjacent transmission circuits to assert that N-1-1 should be the critical contingency in SDG&E territory.

Is treatment of the Sunrise Powerlink/Southwest Powerlink N-1-1 as the limiting contingency a fatal flaw in Track 4 modeling?
Yes.

What are the consequences of using the Sunrise Powerlink/Southwest Powerlink N-1-1 as the limiting contingency in Track 4 modeling?
SCE states that the N-1-1 Sunrise Powerlink/Southwest Powerlink contingency reroutes major imports through the SCE system and back to San Diego, and for that reason alone SCE's LA Basin load pocket and SDG&E are modeled as one de facto load pocket. SCE states: "The LA Basin Generation Scenario and the LA Basin Transmission Scenario both assumed that SDG&E would load shed for the critical loss of the Ocotillo – Suncrest 500 kV line [SDG&E Sunrise Powerlink], ECO – Miguel 500 kV line [SDG&E Southwest Powerlink] and the automatic cross-trip of Otay Mesa – Tijuana 230 kV line (Category C.3 also known as a N-1-1). The Otay Mesa – Tijuana 230 kV line overloads after the loss of the first two lines and is removed from service automatically by relay equipment. *This critical contingency reroutes all SDG&E imports, approximately 2,750 MW through SCE's transmission lines in Orange County*. However, SDG&E is assumed to load shed for this contingency."[13]

If the N-1-1 contingency criterion does not apply to Sunrise Powerlink and the Southwest Powerlink, how should grid reliability be modeled?
The SCE LA Basin and SDG&E should be modeled as "normal – no contingencies" in one area and either N-1 (NERC limiting contingency) or G-1, N-1 (CAISO limiting contingency) in the other area. The only reason for Track 4 modeling of the N-1-1 event as the limiting contingency is an erroneous assumption. It is incorrect to assume that sufficient generation and transmission assets must be in place to maintain grid reliability while absorbing a Category D, N-1-1 loss of the Sunrise Powerlink and the Southwest Powerlink. Transmission operators are not expected by NERC to address very low probability Category D events. The CAISO limiting contingency is

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WECC-CRT-2%20Clean.pdf. ("The TRD data in Tables 1 and 2 suggest that double-circuit outages per 100 miles of line for adjacent circuits (two circuits on the same right-of-way separate structures) are not significantly different than the number of double-circuit outages per 100 miles of line where the circuits are on separate structures not on the same right-of-way (e.g., 0.111 vs. 0.145 average outages per 100 miles of transmission lines per year with the same event ID).")

[13] SCE Testimony, p. 36, lines 18-25 (emphasis added).

G-1, N-1. A G-1, N-1 limiting contingency in SDG&E territory does not result in an instantaneous redirect north through SCE's system of all import flow from the east. It is the redirection of all of the import flow from the east being transferred along the Sunrise Powerlink and Southwest Powerlink that causes the N-1 overload in SCE territory. One major 500 kV east-west transmission line, either the Sunrise Powerlink or the Southwest Powerlink, remains operational in the SDG&E G-1, N-1 limiting contingency. Thus, under the CAISO G-1, N-1 limiting contingency, there would be minimal if any "ripple effect" into SCE's LA Basin as a result of a G-1, N-1 contingency in SDG&E territory.

B. SDG&E G-1, N-1 Reliability Standard

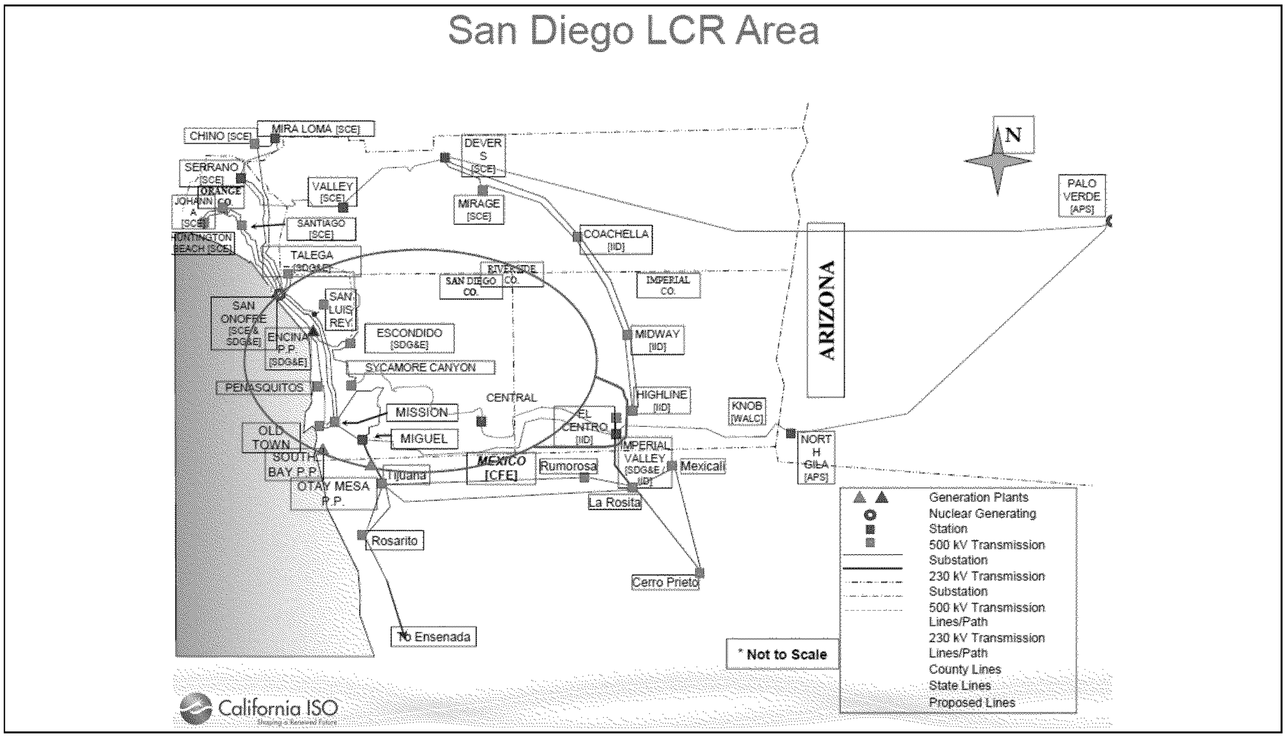
How is the G-1, N-1 limiting contingency defined in SDG&E territory?
It is the loss of the Otay Mesa combined cycle plant and loss of the 500 kV Southwest Powerlink.[14]

Should the SDG&E LCR area cutplane have expanded to include SDG&E's Imperial Valley substation following energization of the 500 kV Sunrise Powerlink ?
Yes. The Commission's assumption when it approved the $2 billion Sunrise Powerlink transmission line in December 2008 was that it would add 1,000 MW of reliability to meet the SDG&E LCR under a G-1, N-1 reliability standard.[15] Upon energization of the Sunrise Powerlink, which occurred in June 2012, the SDG&E LCR area was to be expanded to include SDG&E's Imperial Valley substation. SDG&E's Imperial Valley substation is the origination point for SDG&E's 500 kV Sunrise Powerlink and a transit point for SDG&E's 500 kV Southwest Powerlink. The proposed expansion of the SDG&E LCR area, to be known as the "Greater IV and San Diego LCR," is shown in Figure 1 below.

[14] Anderson, Robert.R.10-05-006, Prepared Track 1 Testimony of San Diego Gas & Electric Company (U 902 E) (Jul. 1, 2011), p. 2, lines 8-15. Retrieved from http://www.cpuc.ca.gov/NR/rdonlyres/3A8ACB26-7C6B-4883-A33B-43F99E678786/0/SDGETrackITestimony.pdf. ("Since the creation of the CAISO, SDG&E's service area has been treated as a single load pocket. Accordingly, the CAISO determines on an annual basis if there are sufficient resources in the load pocket to meet grid reliability criteria, referred to as the G-1, N-1 criteria. These criteria require that SDG&E be capable of serving the entire load in its service area on a hot summer day - which is defined as a summer day that is expected once every ten years – while the largest transmission line and the largest generator are both out of service. These criteria have been endorsed by the Commission, which has used them to set the LCR requirement in its resource adequacy program."); Barave, Sushant. 2012 Final LCR Study Results – San Diego Local Area (Apr. 14, 2011), p. 12. ("San Diego Area Contingency: Loss of Southwest Power Link with the Otay Mesa Combined Cycle power plant out of service")

[15] D.08-12-058, p. 28 "SDG&E's Local Capacity Requirement – both now and in the future – is a critical factor in determining whether Sunrise or other generation or transmission resources are needed to meet reliability criteria. Pursuant to reliability criteria established by the North American Electric Reliability Corporation (NERC), SDG&E must have enough local generation resources to reliably serve all load in its Local Reliability Area after the loss of the largest generating unit in its service area followed by the loss of its most critical transmission line (the "G-1/N-1" criteria). The G-1/N-1 criteria determine SDG&E's "Local Capacity Requirement" since the Local Capacity Requirement is the amount of local generation that SDG&E must have to continue operating reliably after a G-1/N-1 event."

Figure 1. CAISO Proposed Expansion of San Diego LCR Area Following Energization of 500 kV Sunrise Powerlink[16]



The inclusion of the Imperial Valley substation in the SDG&E LCR area following energization of the 500 kV Sunrise Powerlink would also add two existing combined cycle units to the Greater IV and San Diego LCR, Intergen's La Rosita plant and Sempra's Termoelectrica plant, with a total net qualifying capacity of approximately 1,080 MW, as shown in Table 1.[17]

Table 1. Additional Generation to Be Included in Expanded SDG&E LCR Area Following Energization of 500 kV Sunrise Powerlink[18]

Additional units available in 2011-13 for the Greater Imperial Valley-San Diego area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	NQC Comments	CAISO Tag
TERMEX_2_CTG1	22982	IV GEN2	18	156	1		Market
TERMEX_2_CTG2	22983	IVGEN2	18	156	1		Market
TERMEX_2_PL1X3	22981	IV GEN1	18	281	1		Market
LAROA2_2_UNITA1	22996	INTBST	18	157	1		Market
LAROA2_2_UNITA1	22997	INTBCT	16	165	1		Market
LAROA1_2_UNITA1	20187	LRP-U1	16	165	1		Market
2011-2013 Additional		**Total**		**1080**			

TERMEX = Sempra Termoelectrica, LAROA = La Rosita

[16] Barave, Sushant. 2012 Final LCR Study Results – San Diego Local Area (Apr. 14, 2011), p. 2.
[17] CAISO. 2011-2013 Local Capacity Technical Analysis Report and Study Results (Dec. 29, 2008), p. 92. Retrieved from http://www.caiso.com/20ad/20ad77d04d70.pdf.
[18] Ibid, p. 92.

The use of an N-1-1 reliability standard eliminates the reliable pathway, the 500 kV Sunrise Powerlink, that would allow 1,000+ MW of existing generation to be incorporated into an expanded San Diego LCR area as intended under the G-1, N-1 transmission planning standard.

In the context of applying the G-1, N-1 standard to SDG&E territory, is CAISO correctly determining G-1 in SDG&E territory?

CAISO's assumptions regarding the operational capabilities of combined cycle plants are fundamentally flawed and should not be relied upon by the Commission to establish LCR need.

CAISO planning standards apply a very restrictive definition to combined-cycle outages, assuming for planning purposes that the entire plant will be lost during an outage.[19] Combined cycle plants typically consist of three elements, two gas turbines and a single steam turbine-generator. Hot exhaust gases from the gas turbines are directed to the steam turbine-generator to produce additional electric power. Many combined-cycle plants are designed to allow the gas turbines to continue operating even if the steam turbine generator(s) shut down. That is the case in SDG&E's service territory, where both combined cycle units, 550 MW Palomar Energy and 604 MW Otay Mesa, are designed to permit the gas turbines to continue operating when the steam turbine-generator is in forced outage.[20]

CAISO insists that because these combined cycle units periodically experience full plant outages, it cannot recognize the ability of these plants to operate in "gas turbine only" mode. CAISO's reliance on Otay Mesa having 14 full plant trips over the last three years sheds no light on the ability of Otay Mesa to operate as a "gas turbine only" plant under emergency conditions when power production is paramount and efficiency is secondary.[21] There is no economic or operational reason why Otay Mesa would have continued operating in an emergency "gas turbine only" mode.

CAISO's erroneous categorization of outages at Palomar Energy and Otay Mesa combined cycle plants as presumptive "whole plant" outages for planning purposes increases the LCR capacity needs in the SDG&E load pocket by approximately 344 MW.[22] This is more than the capacity of the proposed 300 MW Pio Pico project. SDG&E ratepayers could avoid the $1.634 billion cost

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[19] CAISO. California ISO Planning Standards (Jun. 23, 2011), p. 11. Retrieved from http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf.

[20] Wellinghoff, Jon. (FERC). Letter to Representative Bob Filner. ("Sierra Club Exhibit 1")(Feb. 20, 2009), p. 1. (Regarding corrected definition of G-1 in SDG&E service territory).

[21] Edson, Karen. CAISO Response to Follow Up Powers Engineering Questions ("Sierra Club Exhibit 2") (Nov. 7, 2012), pp. 7-8.

[22] If the CPUC or CAISO were to recognize the inherent operating capabilities of the 550 MW Palomar Energy and 604 MW (net qualifying capacity – NQC) Otay Mesa combined cycle plants, the largest single generator in SDG&E service territory (assuming the retirement of Encina by 2022) would be the 260 MW steam turbine generator at Otay Mesa. Therefore, the net increase in RA if the G-1 designation is shifted from Otay Mesa as a single 604 MW unit to the 260 MW Otay Mesa steam turbine generator would be: 604 MW – 260 MW = 344 MW. *See:* CAISO. 2011-2013 Local Capacity Technical Analysis Report and Study Results (Dec. 29, 2008), pp. 94-95; Anderson, Robert. R.10-05-006, Prepared Track 1 Testimony of San Diego Gas & Electric Company (U 902 E) (Jul. 1, 2011), Table 1, p. 5; Kravchuk, Luba. CAISO 2011 Draft LCR Study Results, San Diego Local Area (Mar. 10, 2010), p. 11.

burden of Pio Pico if the Commission were to take the straightforward step of recognizing the inherent capabilities of both Palomar Energy and Otay Mesa and properly crediting the local capacity contribution of these inherent capabilities.

What is the reduction in identified LCR need in SDG&E territory under G-1, N-1 with Imperial Valley substation included in the LCR area?
1,080 MW.

What is the reduction in identified LCR need in SDG&E territory under G-1, N-1, with a reclassification of G-1 to reflect the inherent characteristics of the two combined cycle plants in the San Diego area, Palomar and Otay Mesa, to operate as simple cycle plants in an emergency (assuming Encina is retired in 2022)?
344 MW.

By what amount would inclusion of existing generation located in the "Greater IV – San Diego" LCR area reduce the LCR need under a G-1, N-1 contingency? Please explain.
The reduction is 1,424 MW. It is the sum of the two existing combined cycle plants connected to the Imperial Valley substation (1,080 MW), and the partial output of the 604 MW Otay Mesa combined cycle plant with the two gas turbines operating in simple cycle mode (344 MW) and the steam turbine generator in forced outage (loss of 260 MW of capacity).

By what amount would inclusion of existing generation under an N-1 contingency in the "Greater IV – San Diego" LCR area educe the LCR need?
By 1,684 MW (1,080 MW of combined cycle units connected to IV substation and 604 MW from the Otay Mesa combined cycle plant).

C. SCE Reliability Standard

What is the effect of San Diego and SCE doing separate analyses?
Different reliability standards were applied by SCE and SDG&E. SCE assumed SDG&E would use load shedding to mitigate the N-1-1 contingency. That is in part why SCE found no generation procurement need under an N-1 standard. However, SDG&E only examined N-1-1 with no load shedding.

Please describe SCE's conclusion regarding the need for procurement using the N-1 reliability standard?
After running its power flow modeling assuming a N-1-1 event in SDG&E territory, the cause of the N-1 event in SCE territory, SCE concludes that no procurement of generation would be necessary to address the N-1 contingency in its territory. SCE states that, "The development of Mesa Loop-In and the strategically located Preferred Resources could displace the need for any additional new LCR resources, while still meeting NERC Reliability Standards."[23]

[23] SCE Testimony, p. 3, lines 10-12.

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Do you agree with the SCE assessment?

Yes. SCE is correct to base its power flow modeling on the NERC reliability standard. The NERC standard is N-1 (largest transmission line, transformer, or generator offline), and must be met with little or no load shedding. As SCE points out, this standard is applicable to all transmission operators in the U.S., and failure to meet the standard can result in monetary penalties.[24]

D. Commission-Adopted Reliability Standard

Has the application in Southern California of an N-1-1 limiting contingency consisting of a sequential outage of the Sunrise Powerlink and Southwest Powerlink been approved by the CAISO Board?

No. The use of the Category D Sunrise Powerlink/Southwest Powerlink N-1-1 event has not been vetted or approved by the CAISO Board of Directors as the limiting contingency for Southern California. Beyond this threshold issue, CAISO's Mr. Sparks provides no information on why load shedding would not be an appropriate response to a Category D N-1-1 contingency.[25] CAISO does not address the cost implications of attempting to plan for a Category D event in its testimony.

Has CAISO conducted a cost-benefit analysis of the more stringent reliability standard?

No. CAISO has conducted no cost-benefit analysis to determine if the additional cost to utility customers to meet the more stringent G-1, N-1 standard, which for all practical purposes is a double contingency standard, has produced any reliability benefits beyond the reliability achieved with the NERC N-1 standard.

Should the Commission rely on the NERC N-1 reliability criteria?

Yes. Neither the Commission nor CAISO have rigorously analyzed the costs and benefits of applying a more stringent reliability planning standard beyond N-1 to California investor-owned utilities. SCE does shed light on the cost in its Track 4 testimony, indicating that no additional procurement would be necessary if the NERC N-1 reliability standard is the controlling standard. SCE argues that 500 MW of procurement would be necessary if the CAISO G-1, N-1 standard is applied. If this 500 MW of need is met with LMS100 gas turbines, the cost over 25 years would be approximately $2.7 billion (in 2013 dollars).[26]

Is there precedent for the Commission to rely on NERC reliability standards rather than CAISO's standards?

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[24] SCE Testimony, August 26, 2013, p. 26, lines 5-11.

[25] SCE Testimony, p. 27, lines 9-11.

[26] *See* San Diego Gas & Electric Company Notice of Application 13-06-XXX To Fill the Local Capacity Requirement Need Identified in CPUC Decision 13-03-029. Retrieved from https://www.sdge.com/sites/default/files/documents/920709556/PioPico.pdf. SDG&E projects the cost of the proposed 300 MW Pio Pico LMS100 peaker project at $1.634 billion over 25 years. Scaling the SDG&E cost figure for Pio Pico, 500 MW of LMS100 gas turbine capacity would cost approximately $2.7 billion over 25 years (in 2013 dollars).

Yes, in the Track 1 decision the Commission authorized significantly less procurement that CAISO requested. SCE explains that the Track 1 "authorized procurement may have been adequate to meet NERC Reliability Standards, but was insufficient to meet the more stringent CAISO performance requirements . . . ."[27]

What is the effect on need for SCE if the Commission relies on the NERC N-1 limiting contingency rather than CAISO's G-1, N-1 limiting contingency?
There is no need for new LCR procurement through 2022 in SCE's LA Basin.

What is the effect on need for SDG&E if the Commission relies on the NERC N-1 reliability standard rather than CAISO's G-1, N-1 limiting contingency?
There would be no need for new LCR procurement whether the limiting contingency is N-1 or G-1, N-1. The need identified by SDG&E, if all need is met with conventional generation, is 1,320 MW.[28] A total of an additional 1,684 MW of existing generation would qualify to meet the LCR area need under an N-1 standard. This is sufficient capacity to eliminate the maximum purported SDG&E need of 1,320 MW and eliminate the proposed 300 MW Pio Pico power plant as online in 2022. Under the applicable post-Sunrise Powerlink N-1 or G-1, N-1 limiting contingencies, the SDG&E LCR cut plane expands to the "Greater IV – San Diego LCR area," which includes SDG&E's Imperial Valley substation and the two existing combined cycle units interconnected to it. This adds 1,080 MW of existing combined cycle capacity as SDG&E LCR capacity. The correct definition of G-1 in SDG&E territory (as discussed in detail on p. 8), which is the 260 MW steam turbine generator at the 604 MW Otay Mesa combined cycle plant and not the entire 604 MW plant, adds 344 MW of existing capacity to meet the LCR. Even under the applicable G-1, N-1 limiting contingency, the added existing local capacity of 1,424 MW exceeds SDG&E's maximum identified need of 1,320 MW.

Is the worst G-1, N-1 limiting contingency modeled by SDG&E in fact a G-1, N-1 contingency?
No.

What type of contingency is it?
It is a G-1, N-1-1 contingency with load shedding. The difference between the G-1, N-1 limiting contingency applicable to SDG&E and what SDG&E has modeled as a G-1, N-1 contingency is shown in Figures 2 and 3. As seen in Figure YY, the applicable G-1, N-1 limiting contingency retains one 500 kV transmission line connection between SDG&E's Imperial County substation and San Diego, enabling 1,080 MW of combined cycle capacity connected to the Imperial Valley substation to qualify as local capacity in the "Greater Imperial Valley – San Diego" LCR area. As noted, an N-1-1 contingency involving outages of both the Southwest Powerlink and the Sunrise Powerlink is a Category D "act of god" extreme event per the April 1, 2012 WECC practice regarding adjacent transmission circuits. SDG&E's worst "G-1, N-1" limiting

[27] SCE Testimony, p. 26, line 23 – p. 27, line 2.
[28] SDG&E Jontry Testimony, Table 1, p. 10.

contingency modeled in Track 4 is in fact a G-1, N-1-1 event with load shedding, not the G-1, N-1 limiting contingency applicable to SDG&E. The critical difference is that the scenarios modeled by SDG&E in Track 4 sever the two 500 kV interconnections between San Diego and the Imperial Valley substation (N-1-1), which would exclude 1,080 MW of existing combined cycle capacity connected to SDG&E's Imperial Valley substation as local capacity that meets the LCR need.

Figure 2. Graphic of G-1, N-1 Limiting Contingency Applicable to SDG&E Territory[29]

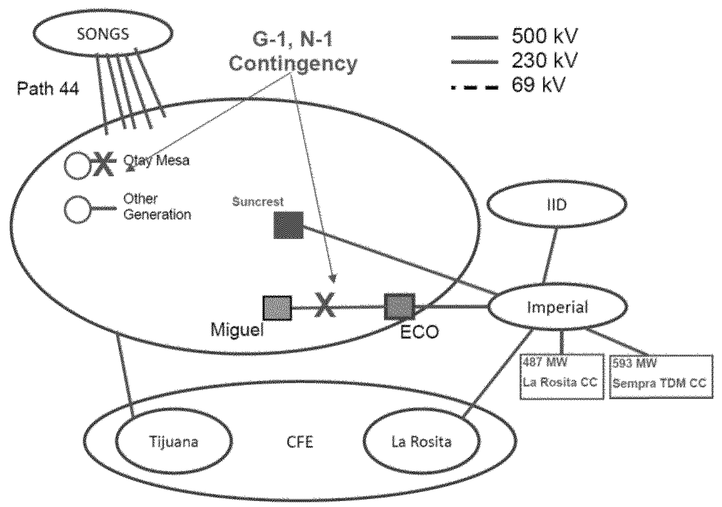
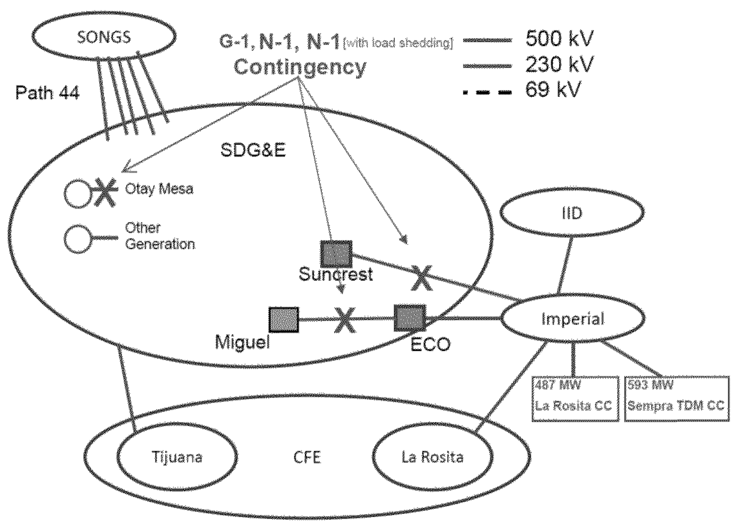


Figure 3. Graphic of G-1, N-1-1 with Load Shedding that SDG&E Identifies as G-1, N-1[30]



[29] Source of base graphic: Edson, Karen. CAISO Response to Follow Up Powers Engineering Questions ("Sierra Club Exhibit 2") (Nov. 7, 2012), p. 5. Combined cycle plant dialogue boxes and Suncrest (Sunrise Powerlink) line added by B. Powers.

[30] Ibid. Combined cycle plant dialogue boxes, Otay Mesa "X", and revised title added by B. Powers. ("Sierra Club Exhibit 2")

III. Transmission, Reactive Power, and Voltage Support Needs

A. Reactive Power and Voltage Support

What services did SONGS provide to the grid?

As stated in CAISO testimony, "SONGS provided a base load generation of 2,246 MW of real power and 1,100 MVAR of dynamic reactive support to both SCE and San Diego local capacity areas."[31] In addressing replacement voltage support for SONGS, CAISO explains that the optimal locations for these dynamic reactive support devices are at or near SONGS. This is because "the voltage needs to be supported to enable increased power transfer from SCE to SDG&E system under the critical contingency condition . . ."[32]

Has California taken action to address the voltage support issue raised by SONGS shut-down?

Yes, California implemented several solutions to ensure that there would be no short-term reliability problem. According to CAISO, the non-generation solutions to the near-term local voltage support issues created by the SONGS outage were online as of July 2013. These solutions included: 1) the addition of a total of 600 MVAR of voltage support at locations near SONGS and 2) one 220 kV substation was reconfigured from two lines to four lines. These non-generation solutions are listed in Table 2.

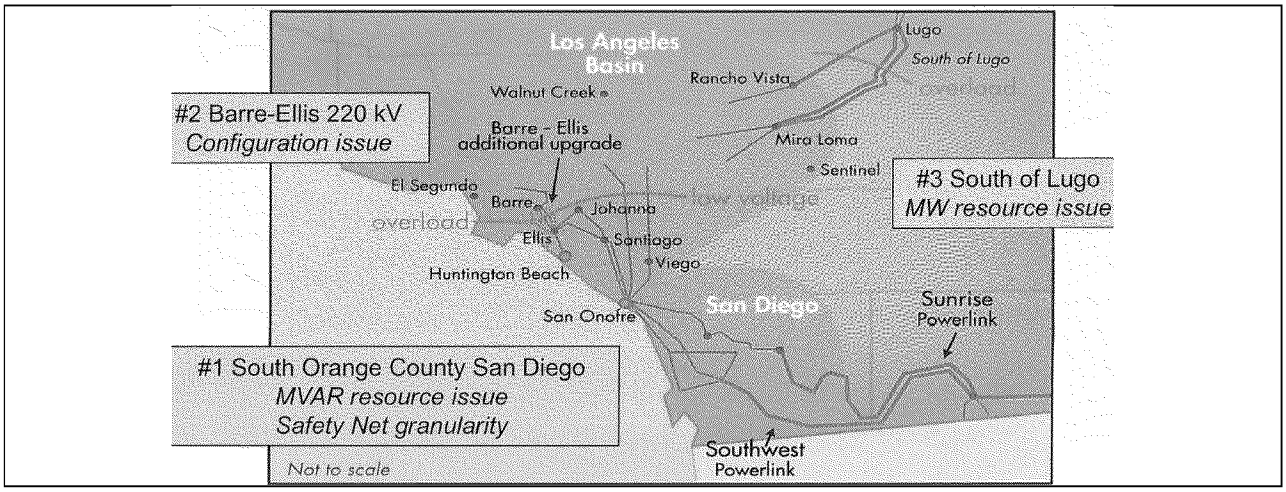
Table 2. Non-Generation Solutions to Voltage Support Issues Created by SONGS Outage[33]

Solution Element	Online Date
Convert Huntington Beach units 3 & 4 into synchronous condensers, 2×140 MVAR	June 1, 2013
Install capacitors: 80 MVAR each at Santiago and Johanna, 160 MVAR at Viejo	July 1, 2013
Split Barre-Ellis 220 kV circuits (from 2 to 4 lines)	mid-July 2013

Collectively these measures will assure adequate voltage support in the summer of 2013 in the southern Orange County region near SONGS. These measures will be adequate indefinitely if grid peak loads do not increase appreciably over time. The locations of these projects are shown in Figure 4.

Figure 4. Voltage Support Upgrades and New Generation that Offset Loss of SONGS[34]

[31] CAISO Testimony, p. 16, lines 4-6.
[32] CAISO Testimony, p. 16, line 28 – p. 17, line 1.
[33] Millar, Neil. (CAISO). Briefing on Summer 2013 Outlook – Update on SONGS Mitigation Planning, Board of Governors Meeting General Session (Feb. 7, 2013), p. 3. Retrieved from http://www.caiso.com/Documents/Briefing2013_Summer_Outlook-Presentation-Feb2013.pdf.
[34] Pettinggill, Phil. (CAISO). CEC/CPUC Joint Workshop on Electricity Issues Resulting from SONGS Closure – ISO 2013 Transmission Plan Nuclear Generation Backup Plan Studies (SONGS) (Jul. 15, 2013), p. 2. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-07-15_workshop/presentations/04A_CAISO_SONGS_Studies_7-15-13.pdf.



Are there additional solutions to meet the voltage support needs?

CAISO states that its focus is on non-generation alternatives to mitigate the risk of meeting forecast demand without SONGS.[35] CAISO has identified numerous non-generation Southern California strategies, beyond those already discussed, to address future voltage support needs if peak load growth occurs to the degree that such actions might be justifiable for grid reliability purposes. These non-generation actions are listed in Table 3. In addition, CAISO has created a new initiative to consider and support preferred resource alternatives to transmission or conventional generation,[36] as part of the transmission planning process. The CAISO is currently applying this approach to the Los Angeles Basin, San Diego and Moorpark substation local areas.[37]

Table 3. Additional Non-Generation Actions Identified by CAISO to Address Future Southern California Voltage Support Issues if Grid Peak Loads Increase Substantially[38]

Options	Description
1	Convert existing SONGS electric generators to synchronous condensers.
2	Provide 1,000 MVAR Static VAR Compensator support using existing SONGS and San Luis Rey/Talega facilities.
3	Maintain Huntington Beach Unit 3 and 4 synchronous condensers, 280 MVAR, in

[35] Edson, Karen. (CAISO). PowerPoint presentation to Sierra Club representatives, ("Sierra Club Exhibit 3") (Aug. 21, 2012), p. 5.

[36] CAISO. Consideration of alternatives to transmission or conventional generation to address local area needs in the Transmission Planning Process (Sept. 4, 2013).

[37] Flynn, Tom. (CAISO.) Consideration of alternatives to address local needs in the TPP, Stakeholder Web Conference (Sept. 18, 2013), p. 4.

[38] CAISO, *2012-2013 Transmission Plan*, March 20, 2013, Figure 3.5-5, p. 118 and p. 190. Retrieved from http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf; Pettinggill, Phil. (CAISO). CEC/CPUC Joint Workshop on Electricity Issues Resulting from SONGS Closure – ISO 2013 Transmission Plan Nuclear Generation Backup Plan Studies (SONGS) (Jul. 15, 2013), pp. 8-9. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-07-15_workshop/presentations/04A_CAISO_SONGS_Studies_7-15-13.pdf.

	service.
4	Reduce generation need in SDG&E territory by 700 MW by adding reactive support, transformer upgrades, and 66 kV transmission upgrades in the LA Basin, and upgrading line series capacitors and additional transformer upgrades.

What MVAR projects did CAISO model?

As noted, SONGS provided 1,000 MVAR of voltage support. CAISO modeled a total of 1,170 MVAR of voltage support in 2022 from the following reactive support projects:[39]

- A total of 320 MVAR of shunt capacitors in Southern Orange County at the Johanna, Santiago and Viejo Substations;
- A total of 480 MVAR Static VAR Compensator (SVC) near the San Onofre 230kV switchyard;
- A total of 240 MVAR of synchronous condensers at the Talega 230kV Substation; and
- A total of 150 MVAR of shunt capacitors at Penasquitos 230kV Substation currently under development by SDG&E.

What MVAR projects were excluded from CAISO's model?

CAISO did not model the 280 MVAR capacity of the Huntington Beach Unit 3&4 synchronous condensers in 2022, only in 2018. CAISO assumes that the Huntington Beach synchronous condensers will be shut down when the 900 MW Huntington Beach Generating Station commences operation in the 2019 timeframe. However, CAISO does not consider any voltage support being provided by this combined cycle plant in 2022.

In the 2012/2013 transmission planning cycle, the ISO evaluated, in an exploratory assessment, additional dynamic reactive support located at other substations in the San Diego area (i.e., San Luis Rey, Penasquitos and Mission). CAISO did not include additional voltage support at these substations in the model runs.

CAISO also does not model the MVAR contribution of the CPUC proposed decision requirement of 580 MW of energy storage in SCE territory and 165 MW of energy storage in SDG&E by 2020. This energy storage capacity can be preferentially located in both service territories to provide maximum MVAR support for the South-of-SONGS transmission pathway.

These new sources of voltage support need to be included in the next round of Track 4 power flow studies conducted by CAISO.

Is inadequate voltage support a concern in 2022 without new generation or transmission being built?

No. CAISO models 1,170 MVAR of new voltage support in 2022 without including Huntington Beach Units 3&4 synchronous condensers. When these 280 MVAR of synchronous condensers is included, the modeled amount of MVAR assets would be 1,450 MW. This compares to the 1,100 MVAR of voltage support provided by SONGS.

[39] CAISO Testimony, p. 15, lines 15-24.

CAISO states that, "The need for reactive power in the vicinity of SONGS is driven by power transfer from the SCE system to the SDG&E system. It is not driven by load growth in the immediate vicinity of SONGS switchyard."[40] Given this reality, 1,450 MVAR of new reactive power, plus 745 NW of energy storage additions in SCE and SDG&E service territories by 2020, would appear to be sufficient to replace 1,000 MVAR of voltage support lost with the permanent retirement of SONGS and the MVAR support lost with the potential retirements of 964 MW Encina and 188 MW Cabrillo II combustion turbines. Power flow modeling would be needed to confirm this conclusion.

Are there any resources CAISO, SCE, and SDG&E have included or excluded prematurely in Track 4 modeling?

Yes. The Commission assumed that the 640 MW Etiwanda 3 and 4 and 580 MW Coolwater 3 and 4 thermal plants in SCE territory would be retired in 2022 for Track 4 modeling purposes. SCE did not include these in modeling, stating the owners of the units have not announced their retirement.[41] CAISO assumed NRG's 260 MW Long Beach combustion turbine facility, refurbished in 2007, would be retired by 2022.[42] The proposed 300 MW Pio Pico project in SDG&E territory was denied by the Commission in March 2013 yet is included in Track 4 modeling as an available resource.[43] CAISO is currently negotiating an extension of the proposed shutdown date of the Cabrillo II combustion turbines (188 MW), yet these units are assumed retired in Track 4 modeling.[44] The 964 MW Encina Generating Station has submitted a compliance plan to meet its December 2017 OTC compliance date, yet the plant is assumed retired in Track 4 modeling.[45] CAISO does not include 280 MVAR of existing synchronous condenser voltage support at Huntington Beach, presuming retirement of this 280 MVAR supply following startup of a 939 MW combined cycle plant at the site by 2022.[46] However, no MVAR or MW is assumed in Track 4 modeling for the 939 MW combined cycle plant that would presumably replace and increase the MVAR available at Huntington Beach.

[40] CAISO. ISO Response to Sixth Set of Data Requests Related to Track 4 of DRA, CEJA, Sierra Club, and Clean Coalition in Docket No. 12-03-014, CAISO Response to No. 8, (Sept. 16, 2013).
[41] SCE Testimony, p. 14, lines 12-14.
[42] CAISO Testimony, Table 7, p. 12; NRG Energy. NRG Energy Repowers Long Beach Station: Helps Meet Southern California's Critical Reliability Needs (Aug. 1, 2007). Retrieved from: http://phx.corporate-ir.net/phoenix.zhtml?c=121544&p=irol-newsArticle&ID=1034764&highlight=.
[43] D.13-03-029.
[44] SDG&E. Sierra Club-SDG&E DR-01, Pio Pico-A.13-06-015, SDG&E Response ("Sierra Club Exhibit 4") (Sept. 6, 2013), SDG&E Response 19.
[45] Piantka, George. (NRG Energy). Once-Through Cooling Policy Implementation Plan Update for Encina Power Station, submitted to State Water Resources Control Board (Jan. 30, 2013). Retrieved from: http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/powerplants/encina/docs/nrg_en_01302012.pdf.
[46] CAISO Testimony, Table 6, p. 9; Reuters. California starts review of new AES Huntington Beach power plant (Aug. 10, 2012). Retrieved from: http://www.reuters.com/article/2012/08/10/us-utilities-aes-huntington-idUSBRE8790HA20120810.

B. Reactive Power and Transmission

CAISO argues that transmission planning should be considered before making a determination on need. Do you agree with this assessment?

Yes. Decisions on which transmission projects will be online in 2022 have a major effect on the amount of net generation necessary to meet the projected need. For example, assuming SCE's adjustments to the Scoping Memo assumptions,[47] if SCE builds the Mesa Loop-In transmission project, no new generation is necessary in 2022 in the LA Basin to meet an N-1 contingency, and 500 MW would be necessary to address a G-1, N-1 contingency. If the Mesa Loop-In is not built, 1,196 MW of additional generation is necessary in 2022 to meet an N-1 contingency and 1,747 MW is necessary for a G-1, N-1 contingency.[48] The nature of the transmission upgrades assumed drives the determination of how much generation will be needed.

Should additional reactive power be considered before making a procurement decision?

Yes. However, the lack of consistency amongst SDG&E, SCE, and CAISO in the definition of the critical contingency being evaluated makes it difficult to assess what amount of reactive power is adequate to meet the 2022 need. A necessary precursor to the next round of LCR need modeling will be consistency in the suite of scenarios modeled by SCE, SDG&E, and CAISO.

SDG&E looked at three additional voltage support projects near SONGS but did not model them. This reactive power must be included as it affects model results. The 280 MVAR of existing voltage support at Huntington Beach also must be included as a minimum amount of voltage support available at Huntington Beach in 2022.

How would the consideration of CAISO's transmission studies affect procurement need and additional reactive support?

The need, type and location of resources may change significantly after CAISO completes its 2013/2014 Transmission Planning. It appears if all the available resources that should be modeled for reactive power are modeled that there should be sufficient reactive power to support the "pre-SONGS retirement" transmission transfer capacity from SCE to SDG&E. Without considering its 2013/2014 Transmission Planning results, CAISO does not have sufficient technical basis to propose a minimum amount of procurement.

IV. ASSUMPTIONS AFFECTING NEED PROJECTIONS

What is the statutory and regulatory context for the decision?

California law requires that 33 percent of retail electricity sales are procured from renewable resources by 2020. This 33 percent renewable portfolio standard (RPS) is one of the highest in the nation. In addition to the RPS, there are a number of programs, such as the rooftop solar California Solar Initiative, that promote the use of distributed generation.

[47] SCE Testimony, p. 13, line 6 – p. 14, line 22.
[48] SCE Testimony, p. 10, Figure II-2.

California's climate action legislation, Assembly Bill ("AB") 32 or the *California Global Warming Solutions Act*, was passed into law in 2006. AB 32 mandates that California reduce GHG emissions to 1990 levels by 2020. Executive Order S-3-05 sets a target of an 80 percent reduction below 1990 levels by 2050.

Consistent with the State's focus on renewables and greenhouse gas reduction, California has instituted an *Energy Action Plan*, which establishes the electricity resource priority list, or loading order, that defines how California's energy needs are to be met. *Energy Action Plan I* was published in May 2003.[49] A subsequent Energy Action Plan was published in October 2005.[50] The CEC and the Commission developed the *Energy Action Plan* to guide strategic energy planning in California. The loading order is summarized in Table 4.

Table 4. Energy Action Plan Loading Order

1. Energy efficiency and demand response 2. Renewable energy 3. Combined heat and power 4. Utility-scale natural gas-fired generation 5. Transmission (as needed to support other elements)

California law also requires utilities to file a procurement plan with the Commission. The plan is required to demonstrate that the utility, "to fulfill its unmet resource needs, shall procure resources from eligible renewable energy resources in an amount sufficient to meet its procurement requirements."[51] The plan is also required to demonstrate that the utility "shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."[52] The Commission confirmed that the "loading order applies to all utility procurement, even if pre-set targets for certain preferred resources have been achieved."[53]

A. SCE Assumptions

Does SCE account for all available preferred resources in the scenarios modeled?
No. SCE's assumptions for resource inputs contributed to its assessment of need in the LA Basin.[54] SCE used the August 2012 California Energy Commission ("CEC") "Mid-Case Load

[49] California Consumer Power and Conservation Financing Authority, California Energy Resources Conservation and Development Commission, and California Public Utilities Commission. Energy Action Plan I (May 2003). Retrieved from http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF
[50] California Energy Commission and California Public Utilities Commission. Energy Action Plan II (Oct. 2005). Retrieved from http://docs.cpuc.ca.gov/published//REPORT/51604.htm.
[51] California Public Utilities Code § 454.5(9)(A).
[52] California Public Utilities Code § 454.5(9)(c).
[53] D.12-01-033, p. 20.
[54] SCE Testimony, p. 13, line 7 – p. 14, line 3.

Serving Entity (LSE) and Balancing Authority" forecast to determine load in the LA Basin.[55] SCE considered distributed generation, energy efficiency, and solar PV only to the extent that those resources were embedded in the CEC forecast, and did not consider demand response resources at all. [56]

SCE's studies include one Preferred Resources scenario, in which limited amounts of energy efficiency, demand response, energy storage, and customer-side PV are added to the CEC load forecast.[57] This study does not provide a comprehensive evaluation of preferred resources available to meet need. For example, it assumes 50 MW of energy storage resources in compliance with the Track 1 decision, without considering the energy storage proposed decision, which currently requires 580 MW of energy storage in SCE territory by 2020.[58]

In comparison, the Scoping Memo required a similar load forecast, reduced by additional inputs of energy efficiency (746 MW), demand response (967 MW), and customer-side PV (219 MW).[59] Consequently, the SCE studies have failed to account for demand response, distributed generation, energy efficiency, and solar PV resources that will be available to reduce load in 2022.

What is SCE's conclusion regarding need for the preferred resources model?

SCE concludes that construction of Preferred Resources pursuant to this model would have a 551 MW effective reduction of LCR need from 678 MW of Preferred Resources.[60] SCE explains that "[t]his results in a remaining need of 1055 MW of combined need for Tracks 1 and 4, which is below the maximum amount of [gas fired generation] (1200 MW) authorized to be procured through Track I procurement."[61]

What would be the effect if SCE had used the Scoping Memo numbers?

Although I don't have the benefit of power flow modeling, it is apparent that the need would be hundreds of megawatts lower. Additionally, to more accurately reflect a preferred resources scenario, this scenario should have modeled procurement of preferred resources in addition to the resources in the scoping memo. This would further show a lack of need.

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[55] SCE. Data Request Set CEJA_DRA_Sierra Club-SCE-001, Response to Question 6 ("Sierra Club Exhibit 5") (Aug. 30, 2013).

[56] SCE. Data Request Set CEJA_DRA_Sierra Club-SCE-001, Response to Question 1 ("Sierra Club Exhibit 6"), Response to Question 2 ("Sierra Club Exhibit 7"), Response to Question 3 ("Sierra Club Exhibit 8"), and Response to Question 4 ("Sierra Club Exhibit 9") (Aug. 30, 2013).

[57] SCE. Data Request Set CEJA_DRA_Sierra Club-SCE-001, Response to Question 2 ("Sierra Club Exhibit 7) (Aug. 30, 2013). *See* SCE Testimony, p. 18, Table III-1 for amounts of preferred resources assumed.

[58] Proposed Decision of Commissioner Peterman, Decision Adopting Energy Storage Procurement Framework and Design Program, R.10-12-007 (Sept. 3, 2013), p. 15, Table 2.

[59] Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge ("Scoping Memo") (May 21, 2013), pp. 4, 7, 9.

[60] SCE Testimony, Figure II-2, p. 10.

[61] Id., p. 11, lines 2-4.

B. SDG&E Assumptions

Are SDG&E's assumptions the same as the Scoping Memo?
No, SDG&E assumes low estimates of DR, almost no wholesale DG PV, and no new energy storage, in its 2022 modeling. The principal difference in 2022 LCR need between SDG&E's study assumptions and the Scoping Memo assumptions is the SDG&E assumptions regarding gas-fired generation retirements and gas-fired generation additions.

What does a comparison of SDG&E's assumptions to the Scoping Memo reveal?
The comparison shows substantial differences between SDG&E's assumptions and the Scoping Memo assumptions. Table 5 illustrates the differences:

Table 5. Comparison of SDG&E and Scoping Memo Assumptions –Increased Need Primarily Due to Generation Retirements

Resources (in MW)	SDG&E 2022	Revised Scoping Ruling 2022
Incremental EE	-338	-187
DR	0	-219
Incremental CHP	-20	0
Incremental small PV installed capacity	-30	-128
Wholesale DG PV	-20	not included
Energy storage	0	0
Generation additions	-365	-45
Generation retirements	1275	238

What amount of Demand Response ("DR") does SDG&E model?
SDG&E assumes 0 MW of additional DR by 2022. The Scoping Memo required 219 MW of first and second contingency DR to be utilized.[62]

What amount of wholesale DG PV capacity does SDG&E model?
The Scoping Memo does not specifically address wholesale DG PV. SDG&E assumes that only 20 MW of wholesale DG PV "net qualifying capacity - NQC" additions will be in service by 2022 in the SDG&E LCR area.[63] The methodology used by SDG&E to arrive at the 20 MW of NQC is shown in Table 6.

Table 6. SDG&E Estimate of Wholesale DG PV in LCR Area in 2022[64]

[62] Scoping Memo, p. 7.
[63] SDG&E Anderson Testimony, Table 2, p. 9.
[64] SDG&E. SDG&E response to DRA et al data request question 2, Excel table attachment (Sept. 16, 2013) ("Sierra Club Exhibit 10").

Program	Projects	MW	Probability	Probability Weighted MW	Delivery at Peak	Local Capacity (MW)
RPS	Sol Orchard	15	75%	11.25	40%	5
SEP	Phase I Phase II	11 11	75% 50%	8.25 5.5	40% 40%	3 2
ReMAT	Peaking Non peaking	20 15	50% 50%	10 7.5	40% 40%	4 3
RAM	Peaking	10	75%	7.5	40%	3
Total:		**82**		**50**		**20**

The wholesale DG PV estimate is very low, even when compared to SDG&E's existing wholesale DG PV commitments. SDG&E has already signed PPAs for approximately 236 MW of wholesale DG PV projects in the SDG&E load pocket with start dates no later than the end of 2014. Some of these projects are already online, including two Sol Orchard PV projects in Ramona totaling 7.5 MW and the 26 MW NRG PV project in Borrego Springs.[65]

The CEC assigns a "dependable capacity" value, equivalent to the NQC, of 22 MW to the 26 MW nameplate capacity project in Borrego Springs. This is equal to a capacity factor at peak of 85 percent.[66] The capacity of each solar PV program listed in Table 6 is shown in Table 7. Applying the same NQC of 85 percent to the wholesale DG PV capacity in Table 7, by the end of 2015 the NQC available from either approved PPAs or mandatory Commission wholesale DG PV programs will be approximately 294 MW.

Table 7. Projected NQC of Wholesale DG PV Projects in SDG&E LCR Area by 2015

Program	Commitment	Capacity factor at	Net Qualifying Capacity,

[65] SDG&E. Sierra Club Data Request, Sierra Club – SDG&E DR-01, Pio Pico – A.13-06-015, SDG&E Response ("Sierra Club Exhibit 11") (Sept. 6, 2013), SDG&E Response 02; NRG Energy, NRG Begins Operations at 26 MW Borrego Solar Photovoltaic Facility (Mar. 5, 2013). Retrieved from: http://investor.nrgenergy.com/phoenix.zhtml?c=121544&p=RssLanding&cat=news&id=1792441; California Public Utilities Commission. Resolution E-4439 (draft) (Nov. 10, 2011), p. 2. Retrieved from https://www.pge.com/regulation/RenewablePortfolioStdsOIR-IV/Final-Decisions/CPUC/2011/RenewablePortfolioStdsOIR-IV_Final-Dec_CPUC_20111110_Res-E-4439_222598.pdf. (160 MW PPA, all start dates are December 31, 2014 or earlier.)

[66] CEC. Summer 2012 Electricity Supply and Demand Outlook (May 2012), Appendix B, p. B-2 – B.4. Retrieved from http://www.energy.ca.gov/2012publications/CEC-200-2012-003/CEC-200-2012-003.pdf.

	(PPA) or Obligation, MWac	peak	MWac
RPS PPA/Soitec	160	0.85	136
SDG&E Solar Energy Project (utility-owned generation)[67]	~21	0.85	18
ReMAT	41	0.85	35
RAM[68]	124	0.85	105
Total	346		294

The existing Renewable Auction Mechanism[69] (RAM) and SB 32 feed-in tariff[70] (now known as the ReMAT program) distributed PV procurement mechanisms will add about 124 MW and 41 MW respectively of wholesale DG PV to SDG&E's portfolio. This additional DG PV capacity will be online no later than December 2014. Wholesale DG PV capacity built under SDG&E's 5-year SEP program is to be installed by the end of 2015.[71]

What amount of energy storage did SDG&E model for 2022?
SDG&E did not model any new energy storage, despite ongoing deployment of energy storage assets by SDG&E and the Commission's recent target established for SDG&E of 165 MW of additional energy storage by 2020.[72]

Is it reasonable for planning purposes to assume that more than 1,100 MW of existing generation in SDG&E territory will retire by 2017 in the wake of the SONGS retirement?
No. The presumption of the retirement of 964 MW Encina Generating Station and the 188 MW Cabrillo II combustion turbines in SDG&E territory is not valid.[73] The extension of the

[67] Multiplier to convert from direct current (DC) capacity to alternating current (AC) capacity = 0.80. See: U.S. Energy Information Administration. Utility-scale installations (> 1 MW) lead solar photovoltaic growth (Oct. 31, 2012). Retrieved from: http://www.eia.gov/todayinenergy/detail.cfm?id=8570.
[68] Ibid.
[69] D.12-02-002, pp. 1-2, 17 (26 MW DC utility-owned generation, 81 MW DC RAM combined with 74 MW DC Solar Energy Project PPAs for total of 155 MW DC RAM procurement allocated to SDG&E).
[70] SB 32, Section 399.20(f)(1). "The proportionate share (of 750 MW cap) shall be calculated based on the ratio of the electrical corporation's peak demand compared to the total statewide peak demand."; SDG&E. Smart Grid Deployment Plan, 2011-2020 (Jun. 6, 2011), p. 214 (41.1 MW allocated to SDG&E). Retrieved from: http://sdge.com/sites/default/files/documents/smartgriddeploymentplan.pdf.
[71] D.12-02-002, Attachment 1, p. 1.
[72] Proposed Decision of Commissioner Peterman, Decision Adopting Energy Storage Procurement Framework and Design Program, R.10-12-007 (Sept. 3, 2013), p. 15, Table 2.
[73] CAISO Testimony, Table 7, p. 12.

December 2017 Encina retirement date is under consideration. Lease extensions for 188 MW Cabrillo II peaking units are in negotiation.

The Commission premised its finding of need in Decision 13-03-029 for approximately 300 MW of local capacity in SDG&E territory in 2018 "only under the assumption that the Encina OTC units retire."[74] As the Commission then recognized, "with the outage at SONGS, this assumption may no longer be appropriate."[75] SONGS was responsible for approximately 90 percent of Southern California power plant OTC water withdrawals prior to its June 2013 retirement.[76] The retirement occurred nearly 10 years prior to SONGS OTC compliance date of December 2022.[77] NRG, owner of Encina, has submitted an OTC phase-out compliance plan to allow the plant to continue to operate beyond the 2017 compliance date.[78]

The Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) is also revaluating OTC retirement schedules and alternative compliance options in light of SONGS' retirement. If the projected retirement date for Encina is extended, there would be no local capacity need in SDG&E service territory through 2022.

SDG&E has claimed that 188 MW from the Cabrillo II combustion turbine units must retire by 2013.[79] Power flow modeling by CAISO, SCE, and SDG&E assume Cabrillo II is retired in 2022. The finding of need for 298 MW of generation in SDG&E territory in Decision 13-03-029

[74] D.13-03-029, p. 14, 15.
[75] *Id.* at 18.
[76] SONGS was a 2,254 MW baseload power plant with a seawater withdrawal rate of 1,591,200 gpm. *See* TetraTech. California's Coastal Power Plants: Alternative Cooling System Analysis (Feb. 2008), Chapter N, San Onofre Nuclear Generating Station, pp. N-3, N-14. (5-year average capacity factor = 83.1%, 1,591,200 gpm cooling water flowrate = 2.29 billion gallons per day at 100% capacity factor. At 83.1% capacity factor, actual cooling water flowrate = 2,290 million gallons per day × 0.831 = 1,900 million gallons per day.) Retrieved from: http://www.opc.ca.gov/webmaster/ftp/project_pages/OTC/engineering%20study/CA_Power_Plant_Analysis_Complete.pdf. In contrast, average 2011 capacity factor of approximately 8,000 MW of Southern California OTC steam boiler capacity was 4.1%. *See* CEC. Staff Report – Thermal Efficiency of Gas-Fired Generation in California: 2012 Update (Mar. 2013), Table 2, p. 5. (2011 coastal steam boiler capacity factor = 4.1%.) Retrieved from: http://www.energy.ca.gov/2013publications/CEC-200-2013-002/CEC-200-2013-002.pdf. [Using Scattergood Generating Station (TetraTech, Feb. 2008, Chapter O, p. O-3) 803 MW capacity and 344,000 gpm cooling water flowrate as scale, daily OTC flowrate of 8,000 MW of coastal steam boiler capacity at 4.1% capacity factor = [(8,000 MW/803 MW) × 0.041 × 344,000 gpm × (60 min/hr) × 24 hr/day] = 202 million gallons per day (mgd). Percentage of average daily OTC water withdrawals by SoCal coastal steam boiler (thermal) plants = [(1,900 mgd/(1,900 mgd + 202 mgd)] = 0.90 (90%).]
[77] Sparks, Robert. (CAISO). San Diego Local Capacity Needs, presented at CPUC Workshop: Application of SDG&E for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power (Apr. 17, 2012), p. 24. Retrieved from: http://www.cpuc.ca.gov/NR/rdonlyres/AEDFD614-B96D-4C26-8DAB-BB23046DB98C/0/April172012cpucworkshopv7.pdf.
[78] Piantka, George. (NRG Energy). Once-Through Cooling Policy Implementation Plan Update for Encina Power Station, submitted to State Water Resources Control Board (Jan. 30, 2013). Retrieved from: http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/powerplants/encina/docs/nrg_en_01302012.pdf.
[79] NRG Energy, Inc., Response of NRG Energy, Inc. to SDG&E Application (A.11-05-023) for Authority to Enter into Purchase Power Agreements with Escondido Energy Center, Pio Pico Energy Center, and Quail Brush Power, June 24, 2011, p. 8.

assumed these units would retire.[80] However, in response to recent data requests by the Sierra Club, SDG&E now states that it "is negotiating with NRG to allow the [Cabrillo II] units to remain in service for a limited period" following a request by CAISO.[81]

SDG&E's prior unwillingness to extend the land lease to allow Cabrillo II to continue to provide local capacity is no longer the determining factor in whether or not Cabrillo II continues to operate. These units should be included as available capacity in Track 4 power flow modeling.

V. Impact of Assumptions on Need Projection

Is there an urgency to procure more resources immediately?
No. The Commission has many low cost non-generation and non-transmission tools at its disposal now that it can deploy on an "as needed" basis if necessitated by load growth. CAISO's non-conventional alternatives initiative and SCE's Preferred Resources Living Pilot program will each expedite implementation of local preferred resources to serve load pockets. An additional option that should be modeled to avoid procurement of new fossil fuel generation is temporarily extending the operational lifetimes of existing gas-fired resources, especially in the San Diego load pocket, until the growth of preferred resources like DR, rooftop solar, and energy storage obviate the need to keep these existing resources in service. The need that has received the most focus with the retirement of SONGS is voltage support in the vicinity of SONGS. CAISO has indicated that its remedial actions to substitute for the voltage support function of SONGS have addressed the short- and mid-term need. Both the SONGS Units 2 and 3 synchronous generators are fully functional and relatively new (1980s vintage). One obvious long-term alternative is to convert either or both the SONGS Units 2 and 3 synchronous generators to synchronous condensers, as was done at Huntington Beach Units 3 and 4 in 2013, to provide voltage support if necessary.

Given the additional assumptions and the resources you believe should be included, what is the Total LCR need?
There is no LCR need in SCE and SDG&E service territories through 2022 when reasonable assumptions are made regarding the appropriate critical contingency and actual resource availability.

VI. Need Projections and Ways to Meet Need

If there is any need, what is the best approach to filling it?
SCE defines its strategy to address load growth in the vicinity of SONGS as "[m]anage load to zero net growth in the Johanna-Santiago vicinity."[82] This is the same strategy that should be

[80] D.13-03-029, pp. 1, 6-7.
[81] SDG&E. Sierra Club – SDG&E DR-01, Pio Pico – A.13-06-015, SDG&E Response ("Sierra Club Exhibit 4") (Sept. 6, 2013), SDG&E Response 19.

applied through the LA Basin using preferred resources and energy storage. I also agree with CAISO's recommendation that the best way to consider the "appropriate resource 'mix'" to meet local reliability needs is to include consideration of transmission solutions. CAISO rightly explains that "[s]uch a mix can include additional preferred resources and other alternatives to conventional resources, depending on location and effectiveness."[83]

Can the new storage requirement in the SCE territory eliminate the 500 MW need identified by SCE?
Yes. SCE's portion of the energy storage procurement target is 580 MW by 2020.

What effect does the storage decision have in the SDG&E territory?
SDG&E will add 165 MW by 2020.

Is energy storage less costly than new gas-fired generation?
Yes. The Commission estimates the 2020 capital cost of 50 MW of battery storage with 2 hours of storage capacity at $1,056/kW, and with 3 hours of storage capacity at $1,406/kW.[84] The Commission estimates the 2020 capital cost of LMS100 units at $1,535kW.[85]

In contrast, SCE estimates a capital cost for a 10 MW battery facility of $1,983/kW with 4 hours of storage capacity. SCE assumes battery replacement occurs every 10 years.[86] A 4-hour capacity is excessive for local capacity purposes. For example, CAISO wholesale day-ahead demand response products must be able to respond to an event of up to 2 hours duration.[87] There is a substantial difference in the capital cost of 2- and 4-hours of battery storage.

Should SCE be given contingent generation contracts?
No. Contingent gas-fired generation contracts are used if it is likely that preferred resources cannot provide sufficient local capacity in a timely fashion and at reasonable cost. However, the Commission's own analysis of battery storage demonstrates it will be cost competitive with gas-fired generation in 2020.[88] Battery storage has numerous characteristics that make it superior in meeting reliability needs, both from a cost and a performance perspective, when compared with

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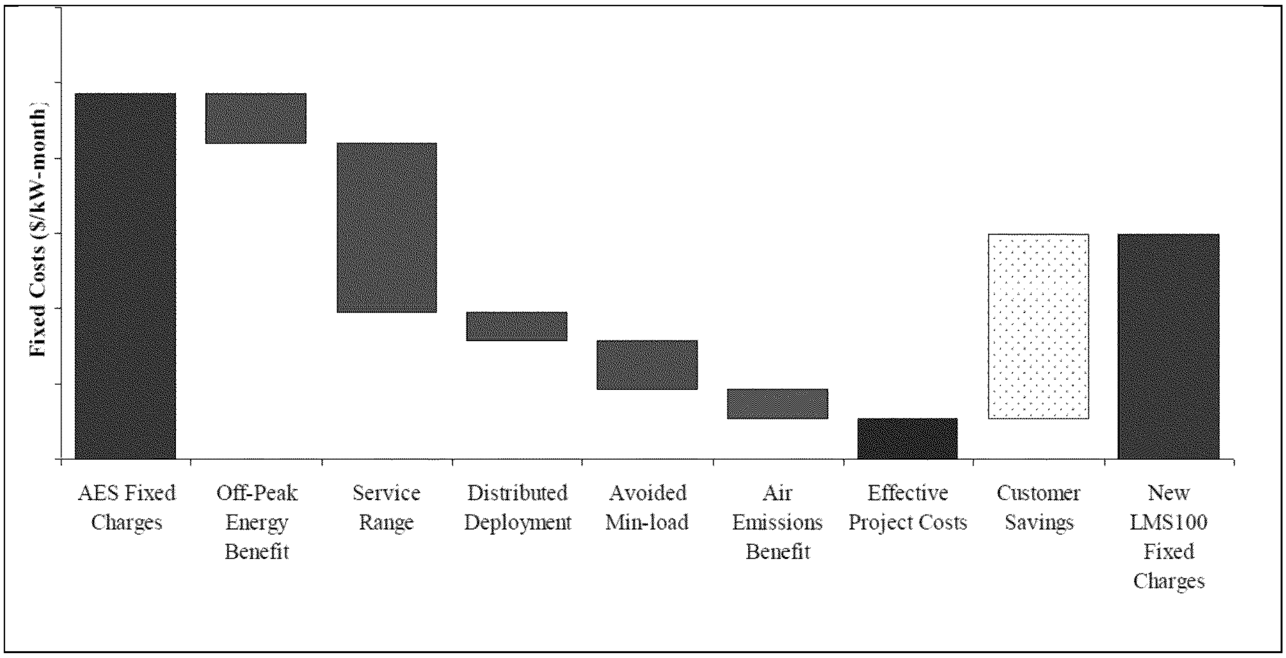
[82] SCE, Preferred Resource Pilot Targeted Scope, PowerPoint, September 26, 2013, p. 2, attached as "Sierra Club Exhibit 12"
[83] CAISO Testimony, p. 31, lines 4-5, 6-7.
[84] CPUC. CPUC Storage OIR Cost Effectiveness Modeling Input Template - Storage Plant Assumptions, line 83.
[85] CPUC, CPUC Storage OIR Cost Effectiveness Modeling Input Template - Conventional Plant Assumptions, LMS100 SAC - Total Overnight CAPEX, line 83.
[86] SCE. DATA REQUEST SET CEJA_DRA_Sierra Club-SCE-001, Response to Question 10 ("Sierra Club Exhibit 13") (Aug. 30, 2013).
[87] North American Energy Standards Board. Demand Response in Wholesale Electricity Markets: California Independent System Operator (CAISO) Demand Response Opportunities (Jun. 18, 2007), p. 2. Retrieved from http://www.naesb.org/pdf2/dsmee061807w3.pdf.
[88] CPUC, CPUC Storage OIR Cost Effectiveness Modeling Input Template - Conventional Plant Assumptions, LMS100 SAC - Total Overnight CAPEX, line 83 ("Sierra Club Exhibit 14"); CPUC. CPUC Storage OIR Cost Effectiveness Modeling Input Template - Storage Plant Assumptions, line 83 ("Sierra Club Exhibit 15")

gas turbines. These attributes are shown in the 2012 utility-scale battery storage-to-LMS100 cost comparison in Figure 5.

Figure 5. Cost- and Attribute Benefits of Utility-Scale Battery Storage versus LMS100 Gas Turbine[89]



Will air permitting in LA Basin affect new generation?
It will not if the new generation consists of non-gas preferred resources and energy storage.

VII. CONCLUSIONS

It is it reasonable to assume that SCE and SDG&E would experience their respective 1-in-10 year critical contingency events on the same day at the same time?
No.

Should SCE be authorized 500 MW of new procurement? Please explain.
No. It is unreasonable to assume any more than an N-1 contingency event occurring in SCE territory simultaneously with SDG&E experiencing its critical contingency. There is no guidance in either the CAISO standards or NERC standards that address the very remote possibility of simultaneous critical contingency events occurring in adjacent utility service territories.

[89] Kathpal, Praveen. (AES Energy Storage). Energy Storage for Flexible Peaking Capacity (Jun. 2012), p. 11. Retrieved from http://docketpublic.energy.ca.gov/PublicDocuments/Regulatory/11-AFC-1%20Pio%20Pico/2012/July/TN%2066154%2007-09-12%20Exhibit%20303%20-%20AES%20Energy%20Storage%20PowerPoint%20-%20June%202012%20Energy%20Storage%20for%20Flexible%20Peaking%20Capacity.pdf.

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The modeling in Track 4 is premised on an erroneous identification of the SDG&E contingency as N-1-1. SCE states that the SDG&E N-1-1 contingency would send large power flows though the SCE system and down to San Diego, and therefore necessitates a joint contingency modeling approach. The simultaneous loss of the SDG&E's Southwest Powerlink and Sunrise Powerlink is a Category D "act of god" event under current WECC criteria. Neither SCE nor SDG&E should be authorized to build any new generation or transmission to counter an extremely unlikely Category D event. Neither CAISO nor NERC standards require or even suggest that Category D events would be addressed with generation or transmission solutions.

If either the N-1 NERC standard is applied to SDG&E, or the G-1, N-1 CAISO standard is applied, there would be no power flow surge through the SCE system and no technical justification for the SCE LA Basin and SDG&E to be modeled as if they were one combined load pocket.

Should SDG&E be authorized 500 MW of new procurement? Please explain.
No. The appropriate contingency for SDG&E is the NERC N-1 contingency. CAISO has made no cost-benefit showing that reliability is improved by applying the G-1, N-1 reliability standard. However, applying the G-1, N-1 standard and correctly classifying the G-1 unit in San Diego in 2022 as the steam turbine generator at the Otay Mesa combined cycle plant would add 1,424 MW of existing generation as LCR area capacity. If N-1 is applied, 1,684 MW of existing generation would be added as LCR area capacity. There is no need for any new SDG&E procurement, or the modeled 300 MW Pio Pico project, if all existing LCR area generation currently excluded from the SDG&E LCR area capacity ledger is included.

VIII. QUALIFICATIONS

What are your qualifications?
I began my career converting Navy and Marine Corps shore installation power plants from oil-firing to domestic waste, including woodwaste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo. I am a registered professional mechanical engineer in California with over 25 years of experience in the energy and environmental fields. I have permitted five 50 MW peaking turbine installations in California, as well as numerous gas turbine, microturbine, and engine cogeneration plants around the state. I organized conferences on permitting gas turbine power plants (2001) and dry cooling systems for power plants (2002) as chair of the San Diego Chapter of the Air & Waste Management Association.

I am also the author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan. This plan uses the zero net energy building targets in the California *Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage by 2020. I authored the October 2007 strategic energy plan for the San Diego region titled

"San Diego Smart Energy 2020." The plan uses the state's Energy Action Plan as the framework for accelerated introduction of local renewable and cogeneration distributed resources to reduce greenhouse gas emissions from power generation in the San Diego region by 50 percent by 2020. I am the author of several articles in Natural Gas & Electricity Journal on the use of large-scale distributed solar photovoltaics (PV) in urban areas as a cost-effective substitute for new gas turbine peaking capacity. I currently serve on the San Diego Environmental and Economic Sustainability Task Force. The mission of the task force is to produce a Climate Mitigation and Adaptation Plan for San Diego. I have a B.S. in mechanical engineering from Duke University and an M.P.H. in environmental sciences from the University of North Carolina – Chapel Hill. My resume is attached as Exhibit 16 to this testimony.

Dated: September 30, 2013

Respectfully Submitted,

__________/s/__________
Bill Powers