Table of Attachments

Attachment A: Prepared Direct Testimony Of Jaleh Firooz On Behalf Of The California Environmental Justice Alliance, served in A.11-05-023, May 18, 2012.

Attachment B: Supplemental Testimony Of Robert M. Fagan On Behalf Of DRA, served in A.11-05-023, May 18, 2012.

Attachment C: Rebuttal Testimony of Robert Sparks On Behalf Of The California Independent System Operator Corporation, served in A.11-05-023, June 6, 2012.

Attachment D: Opening Brief Of The California Independent System Operator, filed in A.11-05-023, July 13, 2012.

Attachment E: Reply Brief Of The California Independent System Operator, filed in A.11-05-023, July 27, 2012.

Attachment F: Supplemental Testimony Of Robert Sparks On Behalf Of The California Independent System Operator Corporation, served in A. 11-05-023, April 6, 2012.

Attachment G: Application Of San Diego Gas & Electric Company (U 902 E) To Fill Local Capacity Requirement Need Identified in D.13-03-029, filed in A.13-06-015, June 21, 2013.

Attachment H: Prepared Direct Testimony Of Bill Powers On Behalf Of Sierra Club, The California Environmental Justice Alliance, and Protect Our Communities Foundation, served in A.13-06-015, September 20, 2013.

Attachment I: Prepared Direct Testimony of David Peffer On Behalf Of The Protect Our Communities Foundation, served in A.13-06-015, September 20, 2013.

Attachment J: Rebuttal Testimony Of Robert Sparks On Behalf Of The California Independent System Operator Corporation, served in A.13-06-015, October 4, 2013.

Attachment K: California Public Utilities Code, Section 345.

Attachment L: Weare, Christopher. "The California Electricity Crisis: Causes and Policy Options." Public Policy Institute of California, 2003.

Attachment A: Prepared Direct Testimony Of Jaleh Firooz On Behalf Of The California Environmental Justice Alliance, served in A.11-05-023, May 18, 2012.

Docket:	**A.11-05-023**
Witness:	**Jaleh Firooz**
Exhibit No.:	

Application of San Diego Gas & Electric Company (U 902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power.	Application 11-05-023 (Filed May 19, 2011)

PREPARED DIRECT TESTIMONY OF JALEH FIROOZ

ON BEHALF OF

THE CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

May 18, 2012

TABLE OF CONTENTS

INTRODUCTION……………………………………………………………………………..…1

I. Summary and Recommendations……………………………………….………..….2

II. CAISO Testimony……………………………………………………………..……3

A. What Is "Reliability" and How Is It Measured?...3

B. The Probability of the Identified Reliability Criteria Violations………..……......5

C. Comparison of CAISO's and WECC/NERC's outage criteria…………….……..7

III. Other Options and Solutions for Meeting Capacity Needs…………………………...8

A. Load Drop and its Ramifications ………………………………………………...8

B. Retirement of Cabrillo II and Other Units……………………………………......9

C. Dynamic Reactive Support ………………………………………………………..10

D. Additional Import Through CFE…………………………………………………..12

E. Transmission Options……………………………………………………………...12

IV. Is There a Renewable Integration Need for New Capacity Inside the San Diego Area? ………………………………………………………………………………....14

V. CAISO's Analysis and Data ……………………………………………………...…14

VI. SDG&E's Testimony: Does It Appropriately Establish the Capacity Need? ...…...18

CONCLUSION…………………………………………………………………………21

INTRODUCTION

My testimony addresses and evaluates the local area need analyses performed by the California Independent System Operator (CAISO) and San Diego Gas & Electric Company (SDG&E) in Application 11-05-023. My testimony discusses the appropriateness of underlying reliability criteria and assumptions used for establishing the need. In addition, my testimony explores whether all feasible alternatives have been investigated and provides recommendations for next steps in evaluation of the need.

Before discussing my comments related to SDG&E's and CAISO's testimony, I will summarize my experience and qualifications.

I began my career working for the San Diego Gas and Electric Company (SDG&E) for twenty five years. At SDG&E, I worked in the engineering department, in grid operations, transmission operations and planning, resource planning, power procurement and regulatory affairs. I am familiar with the CAISO market rules, planning procedures and operational protocols. I was one of the key participants in California's electric industry restructuring process which took place in the 1995 through 1998 period. This restructuring process led to the formation of the CAISO in 1998. After leaving SDG&E, I worked for a wind resource development company in California for a year.

I have performed numerous transmission and resource planning analyses during my career. These analyses include determining the economic and operational feasibility of a 500 MW pumped storage hydro project along with a 500 kV transmission line. Recently I performed an analysis of the CAISO's proposed 2010/2011 transmission plan where, based on power flow studies, I determined that two of PG&E's proposed 500 kV transmission lines in the San Joaquin Valley are not needed. The CAISO consequently changed their initial determination of "need" in their 2010/2011 transmission plan, classified the project as "to be looked at in a future planning cycle." Most recently, I completed analysis of the need for generation at the location of the existing Redondo Beach power plant for the California State Coastal Conservancy. The existing Redondo Beach power plant uses Once Through Cooling (OTC) technology and is subject to the State Water Resources Control Board's requirements for the use of ocean water for cooling. My analysis evaluated whether Local Capacity Requirements for the LA basin and the western LA basin sub-area actually required that there be generation at the Redondo Beach location.

I published a paper in 2010 discussing problems with transmission planning in California funded by UCAN. I also published an article in the Natural Gas and Electricity journal on the same topic.

I am a registered Profession Electrical Engineer in CA with over 30 years of experience in the electricity industry. I have a BS in Electrical Engineering and an MBA in Finance. My resume is attached.

In this proceeding, CAISO provided two sets of testimony: original testimony on March 9, 2012, and supplemental testimony on April 6, 2012. The original testimony included testimony from

Robert Sparks discussing the Local Capacity Requirement (LCR) and from Mark Rothleder discussing renewable integration needs. Mr. Sparks' original and supplemental testimony discusses both the San Diego LCR area as well as the Greater Imperial Valley-San Diego LCR area.

The San Diego LCR area is the most limiting LCR area. Although the Greater Imperial Valley-San Diego LCR area has a higher LCR than the San Diego LCR area, the availability of existing dependable generation at Imperial Valley substation means it is easier to satisfy the Greater Imperial Valley-San Diego LCR area. The San Diego LCR area has the higher deficiency and is therefore the focus of this testimony.

My testimony mainly addresses the ISO's identified requirements for year 2021 since that is higher than the previous years. If it is shown that there is no capacity shortfall in the year 2021, then it can safely be assumed that there would not be any in earlier years. This assumption is premised on applicable solutions being implemented prior to when the need arises.

In my evaluation, I have found that several aspects of the CAISO's analysis and assumptions are questionable and inconsistent. In particular, later in my testimony, I demonstrate that use of 2500 MW as the limit for the South of Songs (Path44) is not appropriate. In addition, the CAISO's application of the Path 44 limit to the Greater Imperial Valley-San Diego LCR area, and not to the San Diego LCR area, is inconsistent.

I. Summary and Recommendations

My testimony shows that the probabilities of the contingency events used to calculate the need in San Diego are very low. Furthermore, it shows that if these contingency events did happen there are many other mitigating options available. These options follow the commission's loading order, are more economical, are less detrimental to the environment, and allow time for other more desirable resources to be developed. In contrast, the options recommended by the applicant remove the incentive for other alternative resources by making a costly twenty year commitment to fossil-fired generation. The alternatives, and their impact on the San Diego LCR area deficiency determined by the CAISO, are shown on the table below. My testimony also points out that the CAISO's renewable integration requirements do not require that new flexible generating capacity be built in the San Diego LCR area.

My testimony raises serious concerns regarding the adequacy of the CAISO's analysis and validity of its results.

The testimony shows that based on the CAISO's data, SDG&E's analysis showing an LCR deficiency in the San Diego area is not valid. It is therefore recommended that the CPUC (1) reject the applicant's request for approval of the three contracts and, (2) ask the CAISO to study the options listed in my testimony and for any options not accepted by the CAISO, provide a reason why they should not be implemented.

the contingency event of concern, the project sponsor or regulatory authority should be required to:

1. Assess the probabilities associated with the contingency based on ten years of relevant historical outage data.

2. Identify the consequences of the contingency event (e.g., amount and duration of uncontrolled load loss, economic impacts of such load loss, public safety concerns).

3. Provide a justification for applying more conservative reliability criteria than required by WECC and NERC.

3. Does Considering the Probability of the Outage Result in Lower Reliability?

No, since to be true it has to be assumed that all contingencies are equally inconvenient and harmful for consumers. The reality is that different contingencies have significantly different consequences. A probability-based reliability approach would result in higher consumer and environmental welfare than the current deterministic criteria since (i) capital would be spent on contingencies where the combination of probability and consequence would otherwise provide the worst outcome for consumers, and (ii) capital would not be spent on contingency events that result in minor consumer inconvenience.

III. Other Solutions and Options for Meeting the Capacity Need

A. Load Drop and its Ramifications

1. Does CAISO allow load drop as a mitigating solution?

Question 15 of CEJA's Second Set of Data Requests to the CAISO asked the following:

> "Does NERC, WECC, and/or CAISO reliability criteria prevent the use of controlled load drop for an N-1-1 transmission contingency? If so, where is this criteria documented? If not, what threshold does the CAISO use to determine when controlled load drop is acceptable mitigation and when it is not? Are there any limits on the amount of controlled load drop which is acceptable?"

The CAISO responded:

> "The ISO is required by NERC TPL 003 to plan its network so that it can be operated to supply projected customer demands for N-1-1 events regardless of their probability. NERC Transmission Planning Standards allow the use of controlled load drop depending on system design and expected system impacts. However, with all generation available at full capacity, the ISO would operate this generation to avoid the need to shed load for the Sunrise/IV-Miguel overlapping outage event. For the San Diego area, the ISO does not consider it acceptable to rely on load shedding to mitigate the category C outage of N-1-1 because there is no suitable Special Protection System designed or in place at this time. Further, the ISO decision to plan its system to operate available generation to ensure

stable operation of the system following the loss of Sunrise and IV-Miguel without reliance on an Special Protection Scheme is to minimize the risk of cascading outages due to disturbances on the grid and unreliable system conditions such as those that have occurred too frequently in recent years in the San Diego area. Load shedding would be utilized to address scenarios with reductions in resource availability due to generation outages that occurred prior to, during or after a Sunrise/IV-Miguel overlapping outage event."

2. Is the CAISO's reason for not allowing load drop in the San Diego area reasonable?

No. First the CAISO's initial statement above is not correct. As stated earlier, the NERC and WECC do allow the use of controlled load drop—with appropriate levels of triggering redundancy and review by potentially affected neighboring balancing authorities—under the G-1/N-1 and N-1-1 outage conditions.

Second, based on the reports published by the CAISO and FERC on recent San Diego area outages (April 1, 2010 and Sept 8, 2011), the outages were caused by either operator error[3] and/or by a lack of visibility and coordination among Balancing authorities.[4]

As mentioned earlier, although higher reliability margins should, in theory, lower the risk of brown-outs or black-outs, it is statistically impossible to eliminate this possibility altogether. A better and far more efficient use of capital would be to prevent errors by improved training, and by improved coordination and communication among balancing authorities. In contrast, building in higher reliability margins through new infrastructure imposes tremendous costs on consumers and the environment. This consumes capital that could otherwise be efficiently deployed to reduce California energy prices, thereby reducing cost of products and putting more money in consumers' pockets. More money in consumers' pockets translates into more job creation within California. Efficient use of capital results in a net gain in employment; inefficient use of capital has the opposite effect.

B. Incorrect Retirement Assumptions

1. Do you agree with the CAISO's and SDG&E's retirement assumptions for the Cabrillo II generating resources?

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[3] *See* Power Grid Operator Admits Mistakes In Shutoff, San Diego Union-Tribute (April 6, 2010) http://www.utsandiego.com/news/2010/apr/06/power-grid-operator-admits-mistakes-san-diego-shut/. ISO issued a statement after the shutoff: "The ISO said yesterday that was a big mistake. It shouldn't have allowed the plant, in Otay Mesa, to shut down. And that shouldn't have led to the intentional blackout."

[4] *See* FERC/NERC April 27, 2012 Report on September 8, 2011 Outage, https://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf. FERC/NERC's report found that the outage was due to transmission operator and a balancing authority error, lack of visibility and lack of coordination. Based on the facts of this outage, the most sensible and cost-effective solution is to improve operator training, enhance inter-balancing authority coordination and provide for greater electric system visibility; not to build more generation and/or transmission infrastructure.

Attachment B: Supplemental Testimony Of Robert M. Fagan On Behalf Of DRA, served in A.11-05-023, May 18, 2012.

Docket:	:	A.11-05-023
Exhibit Number	:	
Commissioner	:	Mark J. Ferron
Admin. Law Judge	:	Hallie Yacknin
DRA Witnesses	:	Robert M. Fagan

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

SUPPLEMENTAL TESTIMONY OF ROBERT M. FAGAN ON BEHALF OF DRA

Application of San Diego Gas & Electric Company
for Authority to Enter into Purchase Power Tolling Agreements
with Escondido Energy Center, Pio Pico Energy Center
and Quail Brush Power

(A.11-05-023)

San Francisco, California
May, 18 2012

TABLE OF CONTENTS

INTRODUCTION AND SUMMARY....1
THE CAISO'S LCR AND 2021 OTC STUDIES....3
CAISO AND SDG&E ESTIMATES OF LCR AND RESOURCE NEED....6
MR. FAGAN'S ESTIMATES OF LCR AND RESOURCE NEED....11
TRANSMISSION PLANNING STANDARDS....15
REVISIONS TO THE CAISO'S ORIGINAL TESTIMONY....18
IMPACTS OF LOAD SHED AND SPECIAL PROTECTION SCHEMES....19
DEMAND RESPONSE AND ENERGY EFFICIENCY....25
SENSITIVITY ANALYSES OF LCR RESULTS....27
FLEXIBLE CAPACITY....31
CONCLUSION....32
WITNESS QUALIFICATIONS....34

INTRODUCTION AND SUMMARY

Q. What is the scope and purpose of this testimony?

A. I examine the underlying methods and results of the California Independent System Operator (CAISO) and San Diego Gas and Electric (SDG&E) analyses of local capacity requirement (LCR) need and the effect of potential retirement of the Once Through Cooling (OTC) units at the Encina power plant, for the San Diego area for the period 2012-2020. My testimony focuses on the following:

- How the LCR and OTC studies are conducted.
- The way in which CAISO and SDG&E methodologies differ.
- How input assumptions drive the results of the analyses.
- Why input assumptions for demand response resources and levels of "uncommitted" energy efficiency are critical to estimations of resource need.
- How transmission planning standards, and their interpretation, influences projections of 2020 LCR need and estimates of resource shortages or surpluses.
- How LCR need and estimated surplus or deficiency of resources for 2020 is best represented as a range, based on the significant variability of a number of input assumptions that must be considered when examining a future resource need.
- The timing of the resource need, and how it impacts the timing for procurement.

Q. Please summarize your main conclusions.

A. Both SDG&E and CAISO's analyses overestimate the deficiency of resources needed to meet 2020 local capacity requirements. They overestimate primarily by excluding the effect that preferred demand side resources, including energy efficiency and demand response, can have on projected peak load for 2020. CAISO also takes a relatively conservative approach in planning for the ability of the transmission system to help support part of the local area needs. It does this by discounting consideration of using certain load-shedding tools, or special protection schemes (SPS) when planning for extreme circumstances or severe contingency events.

Table RF-1 below summarizes the range of resource deficiency (or surplus) that may exist in 2020, when considering all the variables and adjusting the CAISO values to 2020 by subtracting the additional demand from 2020-2021.

Table RF-1. List of Resource Deficiency Range, by Input Assumption Scenario, 2020, San Diego

Scenario	2020 Deficiency - need + surplus
CAISO OTC Study Results, Trajectory Case*	-654
SDG&E April Updated Analysis (Witness Anderson Supplemental Testimony, 4/27/2012)	-647
CAISO OTC Study Results, Base Case*	-554
DRA base (including LTPP assumptions for Uncommitted EE, DR, CHP, RPS and current load forecast) using G-1/N-1 contingency	-45
DRA base using N-1-1 contingency	+ 145
DRA base using N-1-1 contingency and use of SPS/SDG&E "Safety Net" load shed	+ 523
DRA base using N-1-1 contingency and use of SPS/SDG&E "Safety Net" load shed plus 100 MW of AMI resource	+ 623
DRA base using N-1-1 contingency and use of SPS/SDG&E "Safety Net" load shed plus 100 MW of AMI resource plus 500 MW from Carlsbad Energy Center or equivalent	+ 1,123
* adjusted to 2020 demand forecast by subtracting 76 MW from the OTC value.	

As table RF-1 illustrates, the parties in this case have developed far- ranging estimates of the resource need for San Diego, ranging from a potential deficiency, using worst-case assumptions, of 654 MW to a potential resource surplus, assuming in particular that California's investments in energy efficiency and demand response reap promised benefits, of over 1,000 MW in 2020. As will be explained in the testimony to follow, the variety of estimates results from varying input assumptions based on the 2010 LTPP, and differing approaches to application of transmission planning standards when estimating local area needs. It also illustrates that resources other than the PPTA plants under consideration in this application could be in place by 2020 to meet San Diego local area needs.

sequential loss of both 500 kV lines. In the prior results, the CAISO assumed load shed of approximately 370 MW was available to reduce the LCR need.

Q. Should the Commission utilize the LCR and "OTC Need" results presented in Mr. Sparks' original testimony?

A. No. The Commission should consider the revised results presented in Mr. Sparks's Supplemental testimony, in particular in the results from the last row in the table on page 3 (showing the result for N-1-1 (no load shed) with voltage collapse as the limiting constraint).

IMPACTS OF LOAD SHED AND SPECIAL PROTECTION SCHEMES

Q. What is "load shed" or "controlled load drop" and how do they relate to considerations of LCR need and "deficiency" of San Diego local area resources for 2021?

A. "Load shed" or "controlled load drop" are terms used to indicate a series of actions that can be taken by a transmission operator (e.g., the CAISO or SDG&E) to open circuits and shed load. This can be done automatically or on a manual basis. It can occur almost instantaneously in the case of automatic load shed, or can take place over a period of minutes or hours if done manually.[19] This is a type of special protection scheme, or remedial action scheme.

Q. What is a special protection scheme (SPS) or a remedial action scheme (RAS)?

A. A Special Protection Scheme (SPS) is an operational tool that is designed to detect a particular system condition that is known to cause unusual stress to the power system and to take some type of predetermined action to counteract the observed condition in a controlled manner. In some cases, SPSs are designed to

[19] For example, CAISO makes reference to load shedding or transferring that can occur "after 1-Hr." in the case of a limiting contingency that defines LCR needs in the LA Basin Area. See Attachment EE (May 3, 2012 LTPP workshop presentation by Mr. Sparks), slide 27. In that planning case, load transferring refers to not shedding load, but transferring it to another circuit to relieve the load on a critical transformer.

detect a system condition that is known to cause instability, overload, or voltage collapse. The action prescribed may require the opening of one or more lines, tripping of generators, intentional load shed or controlled load drop, or other measures that will alleviate the problem of concern.[20]

Q. Did the CAISO's original testimony rely on load shedding as a special protection system?

A. Yes, although the CAISO previously believed that the limiting contingency was a simultaneous loss of both 500 kV lines when one generator was out of service.

Q. Does the CAISO's updated results in Mr. Sparks's Supplemental Testimony assume the use of any load shedding when considering the LCR need for San Diego using the relevant N-1-1 contingency?

A. No. The CAISO has stated that because it does not <u>currently</u> have a suitable special protection system (SPS) in place, it does not consider it acceptable to use such load-shedding protections schemes when analyzing the LCR need for San Diego. However, the time frame for design of such a scheme is only a year. The CAISO has admitted that if it accepted the use of load shedding for this contingency in its planning studies, "then we would need to work with SDG&E and WECC on designing a suitable SPS. The length of time would depend on factors not under the control of the ISO, but we would estimate that this design would take less than one year."[21]

The CAISO therefore has not analyzed an OTC or LCR resource need in 2021 under the N-1-1 contingency conditions that assumes use of a special protection system or remedial action scheme (RAS) for load shedding.[22]

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[20] Attachment FF (P. M. Anderson, B. K. LeReverend: "Industry Experience with Special Protection Schemes", IEEE Transactions on Power Systems, Vol. 11, No. 3, August 1996).

[21] Attachment GG (CAISO Data Response to DRA-CAISO 16(b))

[22] Attachment GG (CAISO Data Response to DRA-CAISO-13(b)).

Q. Do the power system planning standards allow the CAISO to plan for load shedding in extreme circumstances or severe contingency events?

A. Yes, they do. A clear example is the initial G-1/N-2 results presented in Mr. Sparks' original Testimony, which included an assumption of load shed.[23] Further, the 2011/2012 CAISO transmission plan includes a section that describes the protection systems in place in the CAISO region and notes that:

> To ensure reliable operation of the system, many remedial action schemes (RAS) or special protection systems (SPS) have been installed in certain areas of the system. These protection systems drop load or generation upon detection of system overloads by strategically tripping circuit breakers under selected contingencies. Some SPS are designed to operate upon detecting unacceptable low voltage conditions caused by certain contingencies. Table 2.3-7 – 2.3.9 lists a sample of the SPS that were modeled and included in the study by area.[24]

Also, CAISO's 2013 Local Capacity Technical Analysis includes sections on grid reliability, application of N-1, N-1-1, and N-2 criteria, and CAISO's statutory obligations for reliable system operation. Those sections clearly indicate that planned or controlled load shedding is allowed.[25]

Q. Has San Diego Gas and Electric taken a position on whether it is acceptable to use load shedding when determining SDG&E's LCR?

A. Yes, SDG&E has stated that it considers "controlled load drop" (or load shedding) an acceptable practice to protect against the severe consequences of an N-1-1 contingency event for San Diego.

First, in comments submitted to the CAISO on the 2013 Local Capacity Technical Study Results, SDG&E argued for the acceptability of using load shed to reduce LCR needs for the N-1-1 contingency. SDG&E included a letter to CAISO confirming a plan to install a "Safety Net." The "Safety Net" serves to shed load

[23] For the G-1/N-2 contingency CAISO's modeling assumed 370 MW of load shed. CAISO Witness Robert Sparks Testimony, p. 7.

[24] Attachment HH (CAISO 2011/12 Transmission Plan excerpts), Section 2.3.2.11 Protection Systems, pages 35-36.

[25] Attachment O (CAISO 2013 Local Capacity Technical Analysis, Final Report and Study Results, April 30, 2012), p. 1. pp. 8-19.

in a controlled manner if the system experiences the sequential loss of the two major 500 kV lines into the area (an N-1-1 contingency).[26] The "Safety Net" is controlled load shedding that is allowed under the planning standards in place.

Second, SDG&E has also submitted comments at the Commission saying that it is working on WECC approval for a load-shedding SPS "to mitigate the adverse consequences of an 'N-1-1 contingency event', which is allowed under current reliability standards adopted and enforced by [NERC], the [WECC], and [CAISO] itself."[27] SDG&E stated that it "expects the load shedding SPS to be in place for the summer of 2012 and expects formal WECC approval and recognition of the proposed DPS in the fall of 2012."[28]

The CAISO has stated that it believes the N-1-1 contingency is more limiting for San Diego in 2021;[29] however if the G-1/N-1 would be more limiting after considering the impacts of a load shedding SPS, then questions (and uncertainty) remains about what the limiting contingency (and the corresponding LCR need result) is. To answer those questions, CAISO would need to test both the N-1-1 and G-1/N-1 conditions, assuming the presence of load shed, using its power flow modeling tools and not just a load and resources spreadsheet analysis. This has not yet been done.

Q. How does the CAISO's failure to include load shedding alternatives impact the LCR calculations?

A. In short, the CAISO's LCR calculation for San Diego is higher than it otherwise would be if the system were to be planned for use of an SPS or RAS to shed load if necessary, in the event of extreme circumstances or severe contingency events (such as the N-1-1 contingency).

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[26] Attachment II (Written comments with CAISO reply submitted after the April 12 Stakeholder Meeting regarding the 2013 Local Capacity Requirement (LCR) Results), SDG&E comments and attached SDG&E letter signed by Mr. John M. Jontry, P.E.

[27] Attachment K (Opening Comments of SDG&E on the Final 2013 Local Capacity Requirements Technical Study, R.11-10-023, May 7, 2012) p.2.

[28] Id., p. 3.

[29] Attachment BB (CAISO Data Response to CEJA's Third Set of Data Requests).

For example, for the 2013 LCR, SDG&E estimated that an SPS using 378 MW of load shedding to mitigate the N-1-1 contingency could reduce the LCR need in San Diego by 378 MW.[30]

Q. If the CAISO were to consider use of an SPS for operation after the set of N-1-1 contingency events removing the two 500 kV lines from service, how would that affect LCR need for San Diego for 2021, or earlier years?

A. Based on the response to DRA-CAISO 14(b), it appears that the level of reduction of LCR need would be similar in magnitude to the actual level of load shedding instituted for any given "Safety Net" arrangement. The level of LCR need reduction would be roughly equal to the level of load shed considered for the SPS.

For example, CAISO indicated that the amount of load shedding needed "would be roughly equivalent to the capacity of the generator that is already out of service."[31] Thus, if a Safety net were put in place for an N-1-1 event occurring when the largest generator in the San Diego area (Otay Mesa, 604 MW) is out of service, it would mean that an SPS would exist to shed load equal to 604 MW. With such an SPS already in place, it would be possible to consider its use in the event of an N-1-1 contingency sequence. In that instance, LCR need could be lowered by 604 MW. In the G-1/N-2 contingency considered by CAISO initially, it included load shed of 370 MW, indicating a LCR need reduction of roughly 370 MW for that circumstance.

Q. Does the CAISO have discretion to implement SPSs that includes load shed for transmission planning purposes, in order to reduce the generation needed to meet LCR?

A. Yes, for severe multiple contingency conditions such as the N-1-1 that defines the LCR need estimate in this proceeding, in accordance with its planning standards.

[30] Id., p. 2-3.
[31] Attachment GG (CAISO Data Response to DRA-CAISO 14 (b)).

Q. Mr. Sparks stated that in the revised 2021 OTC study results presented in his supplemental testimony the CAISO "did not think it would be prudent to plan the system that would rely on the same type of load shedding SPS." (Sparks Supplemental p. 4). Please comment.

A. In the response to DRA-CAISO 14(a), the CAISO essentially says that it would use load shedding SPSs under more severe contingency conditions than represented by the N-1-1[32], but that it is reticent to use them for just the N-1-1.[33] Thus CAISO takes a conservative approach to considering the use of load shedding as a planning option. That may be understandable, but it bears noting that there is no assessment of the costs to ratepayers in the makeup of CAISO's opinion that it would not be "prudent" to rely on an SPS for certain severe contingencies. Any such assessment of the relative costs must consider the overall likelihood of severe outages and the costs of the load shedding option, against the costs of buying more local resources. No such cost analysis has been conducted.

Q. Does CAISO conduct <u>any</u> form of cost/benefit analysis of planning to an increased LCR need, rather than considering use of a SPS or RAS to shed load in extreme circumstances?

A. Not to my knowledge. There is no direct analysis that compares the likely costs and benefits to ratepayers of planning to either the more conservative standard that CAISO uses, or planning that includes use of a load-shedding SPS or RAS to ensure system reliability in the event of a set of severe contingencies or extreme circumstances.

32 Attachment GG (CAISO Data Response to DRA-CAISO 14 (a)) ("A remedial action scheme that automatically sheds load in the San Diego area after a generator is already out of service and after the second contingency for the N-1-1 contingency would avoid the need for load shedding prior to the second line contingency.").

33 Attachment GG (CAISO Data Response to DRA-CAISO 14 (a)) ("As indicated in the response to 13 (b), the ISO plans to operate available generation to ensure stable operation of the system following the loss of Sunrise and IV-Miguel [the two 500 kV lines] without reliance on an SPS to minimize the risk of cascading outages due to disturbances on the grid and unreliable system conditions such as those that have occurred in recent years in the San Diego area.").

Q. Please summarize your opinion about the implications of using load shedding in transmission planning.

A. In the original testimony, when the contingency event under consideration was the simultaneous loss of two lines, the CAISO allowed for the shedding of 370 MW of load to "stabilize" the system after the event. This is allowed under the planning standards.

In the Supplemental testimony, the revised LCR analysis no longer considered the use of load shed for the most limiting contingency, which was changed from an N-2 (simultaneous loss of two major 500 kV lines) to an N-1-1 contingency (sequential loss of two major 500 kV lines). But the use of load shedding under this contingency is also allowed under the planning standards. If a load shedding scheme was to be put in place for the N-1-1 contingency, on the order of at least hundreds of MW of LCR need could be avoided for 2021, and earlier years.

DEMAND RESPONSE AND ENERGY EFFICIENCY

Q. What level of demand response does the CAISO assume is available for 2021 in the San Diego area, and how does this affect CAISO's computation of any deficiency of local area capacity need?

A. The CAISO assumes that 108 MW of demand response is available.[34] CAISO recognizes demand response as an available resource to meet local capacity requirements,[35] and shows how the 108 MW of demand response resources would lower CAISO's projected deficiency for 2021. For example, in the trajectory case, CAISO's lists a "deficiency" of 730 MW when demand response is "not counted", but the deficiency drops to 622 MW when demand response is counted, which is equivalent to subtracting out 108 MW of demand response resources.

[34] Attachment A (CAISO Data Response to DRA-CAISO 12(a)).
[35] Attachment H (CAISO Data Response to DRA-CAISO-04)).

Attachment C: Rebuttal Testimony of Robert Sparks On Behalf Of The California Independent System Operator Corporation, served in A.11-05-023, June 6, 2012.

Application No.: ________________
Exhibit No.: ________________
Witness: Robert Sparks

Application of San Diego Gas & Electric Company (U902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power	Application 11-05-023

REBUTTAL TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power	Application 11-05-023

**REBUTTAL TESTIMONY OF ROBERT SPARKS
ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
CORPORATION**

Q. What is your name and by whom are you employed?

A. My name is Robert Sparks. I am employed by the California Independent System Operator Corporation (ISO), 250 Outcropping Way, Folsom, California as Manager, Regional Transmission.

Q. Have you previously provided testimony in this proceeding?

A. Yes, I have. On March 9, 2012, the ISO served my testimony to parties in the proceeding, along with Mr. Rothleder's testimony, and supplemental testimony was served on April 6, 2012. We also sponsored a workshop on April 17, 2012.

Q. What is the purpose of your rebuttal testimony?

A. In this rebuttal testimony I will respond to certain statements and conclusions sponsored in testimony submitted by the California Environmental Justice Alliance (CEJA), the Division of Ratepayer Advocates (DRA) and the National Resources Defense Council (NRDC) on May 18, 2012.

deliverability problems on the transmission system. The initiative also expedites the DG interconnection study process so that DG will not have to wait for a deliverability study to be completed if they site their DG at a location predetermined to be deliverable and if it is contracted with a load serving entity that has a DG deliverability allocation at that location. However, the ISO's DG initiative does not ensure that the DG will be developed. For planning purposes, the ISO must make reasonable assumptions about future DG development as previously discussed in this testimony.

<u>Load Shedding and Special Protection Schemes (SPS)</u>

Q. Please summarize the ISO's position on using SPS involving load shedding to meet reliability needs in the San Diego local area, as well as the interveners' testimony on this issue.

A. In my supplemental testimony, I stated that with the change in the WECC criterion, causing the Sunrise/IV-Miguel double outage to be reclassified as a Category D contingency, the most limiting contingency for the San Diego sub-area is the loss of the Imperial Valley-Suncrest 500 kV line followed by the loss of ECO- Miguel 500 kV line (N-1-1). While the change in categorization of the double outage did not change the ISO's local capacity area study methodology, the more severe G-1/N-2 contingency that previously had been studied conceptually assumed that an automatic load shedding SPS would be installed and available to prevent voltage collapse. I explained that with the more likely N-1-1 as the most limiting contingency, the ISO did not believe that it would be prudent planning to rely on an automatic load shedding SPS.

This is because the history of transmission line outages due to fires and equipment failures in the area and the configuration of the system indicate that outage risks and consequences are high. The Imperial Valley substation is a major source of imported power for three different utilities: SDG&E, IID, and CFE. This is not only evidence of the criticality of this substation, but also the level of exposure to operational coordination issues and failures. Relying on load shedding as a primary mitigation measure is an indication that the system is being planned and operated at a very high stress level, and with very little margin for error. Based on this information, it is not prudent to plan and operate the Imperial Valley system with currently expected high outage risks and consequences at a very high stress level and with very little margin for error. On the other hand, the ISO would rely on the load shedding SPS during extreme operating conditions beyond the N-1-1 contingency scenario considered in the OTC studies, that would otherwise require pre-contingency load shedding.

Both DRA (witness Fagan) and CEJA (witness Firooz) have argued that the ISO's approach to load shedding under an N-1-1 contingency is too conservative, and that the local capacity needs in San Diego would be lower if the ISO planned for automatic load shedding in the event of extreme circumstances or severe contingency events. As described below, these arguments are misplaced.

Q. Has Ms. Firooz accurately described the ISO's position with respect to load shedding as an N-1-1 contingency mitigation for the most limiting contingency for the San Diego area?

A. No. First, at page 7 of her testimony, Ms. Firooz broadly states that the ISO will not rely on load shedding in the San Diego area as mitigation for N-1-1 contingencies. That is not correct. My testimony focused specifically on load shedding as mitigation for the ECO-Miguel 500 kV line and Sunrise contingency and it is for this contingency that I believe it would not be prudent to rely on load shedding.

Ms. Firooz goes on to mischaracterize an ISO data request response on this topic by suggesting incorrectly that the ISO stated that it is not permitted to shed load for N-1-1 events and, based on that mischaracterization, she concludes that the ISO's "reason for not allowing load drop in the San Diego area is not reasonable," (Firooz testimony, pages 8- 9). Specifically, CEJA posed the following question:

> Does NERC, WECC, and/or CAISO reliability criteria prevent the use of controlled load drop for an N-1-1 transmission contingency? If so, where is this criteria documented? If not, what threshold does the CAISO use to determine when controlled load drop is acceptable mitigation and when it is not? Are there any limits on the amount of controlled load drop which is acceptable?

The CAISO responded:

> The ISO is required by NERC TPL 003 to plan its network so that it can be operated to supply projected customer demands for N-1-1 events regardless of their probability. *NERC Transmission Planning Standards allow the use of controlled load drop depending on system design and expected system impacts...*

The rest of the ISO's response provided more explanation as to why, under the specific system configuration and consistent with NERC TPL 003, the ISO would operate all available generation to avoid the need to shed load to mitigate the category C Sunrise/ECO-Miguel overlapping outage, for the reasons I discussed above. In other words, although NERC TPL 003 *permits* load shedding as a mitigation for an N-1-1 contingency, the standard does not *require* the ISO, as the Planning Coordinator, to approve an automatic load shedding SPS under all such circumstances and instead allows for the Planning Coordinator to consider system design and expected system impacts in deciding whether an automatic load shedding SPS is appropriate. Ms. Firooz seems to misunderstand both the planning standard and the ISO response to the CEJA data request, and has provided no basis for her conclusion that the ISO's planning decision to avoid a load shedding SPS for the Sunrise/ECO-Miguel N-1-1 is "unreasonable."

Q. Do you agree with Ms. Firooz's suggestion at pages 7- 8 of her testimony that considering the probability that a contingency will occur- which allegedly would result in lower costs for consumers- would not lower grid reliability?

A. Absolutely not. In the first place, the ISO is required to comply with NERC planning requirements, which are deterministic and not probabilistic. More importantly, Ms. Firooz has not conducted a complete probabilistic analysis so she has no basis for her conclusion that local area needs would be lower and that costs to consumers would therefore be lower. It is possible that a probabilistic analysis could result in higher local needs.

To briefly summarize the issue, deterministic criteria apply specific tests to the system – with specific assumptions regarding load level and the "worst" contingency as set out in the various disturbance classifications in the NERC standards. A probabilistic approach examines the probability of a wide range of outages under a wide range of conditions, and compares the results to a predetermined criteria related to the acceptable level of risk one is willing to take on a probabilistic basis.

Simply applying probabilities to the "worst case" scenario ignores all of the other potential events that could result in loss of reliable service, under a wide range of scenarios, providing no effective means to assess the robustness of the transmission system on a probabilistic basis or deterministic basis.

Q. **DRA witness Fagan also takes issue with the ISO's position on load shedding, at pages 19-25 of his testimony. He notes that SDG&E has agreed to the use of controlled load drop under N-1-1 contingencies and intends to install a "safety net" that will shed load in the event of the sequential loss of two 500 kV lines. Do you agree that this "safety net" should be considered as a mitigation for the Category C contingency you described previously?**

A. No. A safety net is only acceptable for a Category D outage. The safety net would need to be upgraded to a WECC approved SPS before it could be used for the N-1-1. However, as I explained above, the current transmission system design in the Imperial

Valley area and the expected system impacts of overstressing this system make the reliance on load dropping SPS for the Category C overlapping outage of ECO-Miguel and Sunrise 500 kV an imprudent choice.

Q. Mr. Fagan also states that the ISO has not analyzed the difference in costs between procuring additional local generation and installing an SPS that would trigger load shedding under an N-1-1 contingency. Please respond to this contention.

A. The ISO does not compare the costs of these two approaches because they are not substitutes for each other. Unlike load shedding, there are significant benefits for additional generation beyond addressing an immediate reliability issue. The ISO believes that the cost of procuring additional local generation to meet the local area needs without shedding load, is offset by the benefits provided, both locally and system-wide. Generation is required to be procured for system needs and for renewable integration. Procuring generation in the local area to meet local needs, system needs, and for renewable integration has only a marginal cost and provides reliability under the studied system conditions as well as many other system conditions during planned and forced outages of generation and transmission resources.

<u>**Load Forecasts and Planning Horizons**</u>

Q. At page 17 of his testimony, Mr. Fagan states that the planning horizon for generation (supply) resources is from one to five years. Do you agree that this is the appropriate time horizon for consideration of the San Diego local needs?

A. No, Mr. Fagan is incorrect. The conventional lead time for constructing new generation or repowering existing facilities, such as the OTC units, is five to seven years. Encina OTC compliance is before 2018; thus there is considerable urgency in making procurement decisions as soon as possible and certainly no later than 2012. The

Attachment D: Opening Brief Of The California Independent System Operator, filed in A.11-05-023, July 13, 2012.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power	)))))	**A.11-05-023**

OPENING BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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Table of Contents

I. Executive Summary 1

II. Introduction and Procedural Background 3

III. The ISO's Testimony and OTC Study Results Support the Need for Additional Local Resources in San Diego Starting in Early 2018. 4

A. Summary of the ISO Findings 8

B. Mechanics of the OTC Study 9

C. Power Flow Study Results and Spreadsheet Analyses Of Other Parties 11

IV. Intervener Concerns With the ISO's Study Methodologies and Assumptions Are Misplaced. 14

A. Load Forecasts and Planning Assumptions 15

1. Probabilistic versus Deterministic Planning Studies 15

2. Load Shedding as a Mitigation Solution 16

3. Modeling Assumptions: Uncommitted EE, Incremental DR, Uncommitted CHP and Energy Storage 18

4. Modeling Distributed Generation (DG) 21

B. Other Transmission Planning Issues 22

1. Alleged Problems with the ISO's Study Methodology 22

2. Alternatives to Local Generation 23

3. Planning Horizon and Procurement Decisions 24

V. SDG&E Should Be Directed to Procure Flexible Generation. 25

VI. Local Area Needs For San Diego Must Be Addressed In This Proceeding. 26

*

Table * of * Authorities*

Orders *

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans
Rulemaking 12-03-014 (filed March 22, 2012) Assigned Commission Ruling May 17, 2012 27

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power	)))))	**A.11-05-023**

OPENING BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. Executive Summary

The Once Through Cooling (OTC) study conducted by the ISO as part of the 2011/2012 transmission planning process, is an analysis of the local area capacity needs (local capacity requirements or "LCR") in the San Diego and San Diego/Imperial Valley (IV) areas. In the OTC study, the ISO evaluated four renewable scenarios that were also used in the planning process to evaluate the need for policy-driven elements. The OTC study results showed a range of local capacity deficiencies in San Diego beginning early in 2018 when the units at the Encina power station are expected to retire due to State Water Resources Board (SWRB) requirements.

The ISO also ran a sensitivity study assuming that the Encina units had retired and adding generic capacity at locations similar to the locations of the resources at issue in this proceeding were approved. In three out of four scenarios the San Diego area still had incremental LCR deficiencies.[1]

A spreadsheet analysis presented by SDG&E also revealed LCR deficiencies similar to the amounts identified in the OTC study. Other parties to the proceeding challenged the ISO's planning assumptions, arguing that the ISO should have included higher levels of incremental demand response, uncommitted energy efficiency, distributed generation, energy storage resources and combined heat and power resources. These parties presented calculations showing that these load and supply resource assumptions offset the need for thermal resources. In addition, parties took issue with the ISO's LCR study methodology and proposed other mitigation solutions to the voltage and thermal constraints caused by the Encina power station retirement.

The ISO provided rebuttal testimony responding to the concerns raised by interveners and describing the flaws in their statements, arguments and analyses (or lack thereof). The record in this proceeding supports a finding by the Commission that, according to the ISO's base case scenario, there will be an LCR deficiency in the greater San Diego area of 630 MW. If the Commission approves the PPTAs, there will be an incremental deficiency of 211 MW and San Diego should be ordered to procure resources to this level as well. A procurement decision for the entire amount of the LCR deficiency should be issued in this proceeding as soon as possible because, in the ISO's experience, the lead time for new generation permitting and construction can be as long as seven years. Resources procured to meet local LCR deficiencies should have flexibility characteristics.

[1] In the environmentally constrained scenario there were no incremental deficiency needs beyond the PPTA "Product 2" capacity.

IV. Intervener Concerns with the ISO's Study Methodologies and Assumptions are Misplaced.

In addition to the power flow and import capability issues addressed above, interveners DRA, NRDC and CEJA raised other issues with the ISO's LCR/OTC studies. For the most part, these parties argued that the ISO's assumptions in the base case renewable portfolio- the case upon which the ISO is basing its recommendations- are too conservative and do not reflect reasonable levels of demand response (DR), energy efficiency (EE), distributed generation (DG), combined heat and power (CHP) resources and energy storage. They have also questioned the ISO's use of a 1-in-10 load forecast and urge the Commission to adopt other mitigation solutions in lieu of local generation. CEJA witness Firooz also discussed other aspects of the ISO planning studies.

In essence, each intervener recommended the adoption of revised planning assumptions and non-generation mitigation solutions that, on paper, would substantially reduce the local capacity deficiencies identified by the ISO. As discussed below, these recommendations should be approached with great caution. The risks to grid reliability are too significant -- and the time frame for procuring needed flexible thermal generation is too short -- to allow for any errors in judgment. Furthermore, some of the intervener's proposals, if adopted for the Commission's procurement decisions, would require fundamental and unjustifiable changes in the ISO's LCR study methodology and could introduce substantial, inappropriate variations between transmission planning and resource procurement assumptions.

A. Load Forecasts and Planning Assumptions

1. Probabilistic versus Deterministic Planning Studies

CEJA witness Firooz begins her testimony by questioning the entire LCR methodology- and indeed, all of the ISO's transmission planning studies-with arguments that the deterministic approach to planning is "overly conservative" and produces results that are too expensive for the ratepayers.[32] According to Ms. Firooz, starting with the use of the 1-in-10 load forecast, which uses peak loads that are "not expected," and then layering on the NERC/WECC mandated planning requirements (which "probably" won't happen at peak load conditions) and the planning reserve margin requirements adopted by the Commission, dictates unnecessary mitigation solutions that are not needed. Ms. Firooz suggests that the Commission adopt a "probabilistic" approach to resource procurement decisions, concluding that this will not lead to reliability issues but will save the ratepayers money.

Not only are such suggestions beyond the scope of this docket, but Ms. Firooz did not conduct a probabilistic analysis of the transmission grid that would support her conclusions. Her discussion of this topic is based on mere observations regarding the likelihood that the most sever N-1-1 contingency might occur at the 1-in-10 system peak and ignores the cumulative probability of the other potential contingencies and system conditions that could also result in loss of reliable service. Furthermore, as Mr. Sparks noted, it is entirely possible that a full-blown probabilistic analysis could result in higher local needs.[33]

In contrast, the NERC/WECC mandatory planning standards are deterministic; meaning that the system is tested with specific assumptions regarding load level and appropriate contingency levels to design the system to a target reliability level. A

[32] Ex. 20, pages 5-8.
[33] Ex. 27, page 11.

probabilistic analysis examines the individual probability of each contingency under a particular system condition over a wide range of scenarios. A deterministic criteria is similar to using one standard driving test for all drivers in California and a probabilistic criteria is similar to giving every driver an individualized test based on his or her expected driving plans. In this analogy it is difficult to predict whether the test failure rate would go up or down, or if the driving accident rate would go up or down, if the State switched from a standard driving test to individualized tests. Continuing with the analogy, while there may be some questions on the standard test that do not apply to many driving situations, this would not be a valid argument for lowering the passing score level. This is because the standard test is only a sample of potential questions that could have been asked, and the score is indicative of the knowledge level of the entire driver's handbook. Ms. Firooz's approach- which is to apply probabilities to the "worst case" under a deterministic evaluation- again mixes apples and oranges and is not an effective means by which to test the robustness of the system. Going back to the analogy, her argument is a little like finding one person and saying that since the test does not match his or her expected driving plans, the passing score for the test should be lowered for everyone.

2. Load Shedding as a Mitigation Solution

Both CEJA and DRA suggest that controlled load shedding in the event of an N-1-1 contingency should be viewed as an acceptable mitigation solution that would reduce the local capacity needs in San Diego; CEJA witness Firooz proposed dropping 378 MW and DRA witness Fagan proposed a 370 MW load drop.[34] Just to put these recommendations in perspective, this amount of load drop could equate to well over 300,000 homes.[35] To adopt the

[34] Ex. 17 (Fagan), page 12, table RF-3; Ex. 20 (Firooz), page 3, table 1.
[35] See Ex. 20, footnote 3 discussing an April 6, 2010 outage of 310 MW, which was 291,000 homes.

recommendations of DRA and CEJA, the Commission would have to find that cutting off power to 300,000 homes is an acceptable outcome. This goes far beyond targeted load shedding in a limited area.

NERC planning standard TPL 003 permits load shedding for an N-1-1 contingency, but does not require the ISO, as the Planning Coordinator, to approve automatic load shedding under all circumstances. Rather, the planning standards allow for prudent engineering judgment taking into consideration system design and expected system impacts.[36] As Mr. Sparks explained, the history of the IV substation area includes outages due to fires and equipment failures, and the configuration of the system shows that outage risks are very high. This substation is a major source of imported power for three utilities: SDG&E, IID and CFE, which is evidence of the level of exposure to operational and coordination issues. In response to questions by CEJA, he stated:

> …All three of those systems rely on that point in the grid as one of their two major sources of imports in their systems. So it's a very critical piece of the system. And our concern is that if we rely on load shed, we're certainly overstressing that part of the system.[37]

At a later point Mr. Sparks added that it is not the ISO's position that automatic load shed would not be allowed for any of the "hundreds of overlapping contingencies (N-1-1) on the system." It is just that "there are some where it's okay and there are some where it is not,"[38] and this analysis must be done on a case by case basis. Ms. Firooz admitted that there is a host of engineering criteria that should be taken into account in determining whether controlled load shedding should be adopted as a mitigation solution, such as the design of the system,

[36] Ex. 27, page 10.
[37] Tr.III, page 546.
[3838] *Id.*, page 550.

probability and severity of outages, and the existence of other special protection systems.[39] Thus, although Ms. Firooz clearly does not agree with the ISO's ultimate decision about load shedding, she provided no reasonable basis for disagreement with the engineering judgment that went into the analysis.

Similarly, Mr. Fagan offered no engineering basis for a load shedding scheme but pointed to SDG&E's consideration of a "safety net" as a mitigation solution for a Category C contingency. He further argued that the ISO should have performed a cost benefit analysis of the costs of a load shedding SPS versus procuring additional local generation. However, these two solutions are not substitutes for each other. Mr. Sparks explained that unlike load shedding, generation provides both local and system benefits, as well as renewable integration and reliability benefits for a marginal cost.[40] The wide-scale load shedding that would result from adoption of their proposals provides none of those benefits and only creates other problems.

3. <u>Modeling Assumptions: Uncommitted EE, Incremental DR, Uncommitted CHP and Energy Storage</u>

In addition to the other proposed reductions to the ISO's local deficiency findings, NRDC, CEJA and DRA all criticized the ISO's modeling assumptions regarding uncommitted EE and CHP, incremental DR and energy storage. They suggest that the ISO should have used assumptions from the planning standards used in the prior LTPP case (R.10-05-006). Specifically, these parties propose reductions in the ISO's local area requirements for 544 MW of uncommitted EE (DRA proposed an alternative 284 MW for "high need") and 302 MW of incremental demand response. CEJA and DRA also propose 64 MW of incremental

[39] Tr. III, pages 491-492.
[40] Ex. 27, page 12.

CHP and CEJA witness Powers proposes an incremental 14 MW of energy storage as supply side resources.

As has been discussed previously, the ISO used the 2009 CEC 1-in-10 forecast for the LCR/OTC studies. This forecast includes certain levels of EE and CHP.[41] The ISO did not include uncommitted EE in its modeling assumptions because it is just that -- hypothetical load reductions resulting from energy efficiency programs that have not even been funded yet and which have no performance history (and therefore have no certainty that the anticipated reductions will actually materialize). Their impacts are wholly uncertain at this time. Indeed, the CEC, in reports issued in both 2010 and 2012, expressed concern that uncommitted savings for EE, "while plausible," have a great deal of uncertainty regarding the timing and relative impact of their implementation."[42] Furthermore, Mr. Sparks noted that even when EE programs are successful, they may fail to produce energy savings in the particular area where they are needed and when they are needed. Although these programs may be effective on a broad, system-wide basis, they may have little impact on needs in local areas.

Similarly, additional CHP generation was counted on to meet local reliability needs only if in the CEC forecast. Like uncommitted EE, the CEC also noted the level of uncertainty with respect to future increases in CHP development. Indeed, the 2011 IEP Report forecasted that CHP additions to the system may simply offset retirements to existing CHP resources.[43]

The ISO did not model incremental DR as a load reduction tool, nor was it modeled as a supply side resource, because DR cannot be relied upon to address local capacity needs

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[41] Ex. 27 page 2.
[42] *Id.* pages 3-4 citing the CEC "Incremental Impacts of Energy Efficiency Policy Initiatives"(May 2010) and the CEC 2011Integrated Energy Policy Report (January 2012).
[43] *Id.* page 5 citing the CEC 2009 IEP Report and the CEC 2011 IEP Report.

unless it can provide equivalent characteristics and response to that of a dispatchable resource. At this time DR does not have those characteristics.[44]

Specifically, in order for DR to be able to mitigate a local or system problem- and not compound the problem- it must be location based and dispatchable. Furthermore, if it is being relied upon instead of new generating plants, the DR programs must be dependable over a period of time equal to the generation resource it has displaced-known as "durability." The ISO has described its concerns with DR in other Commission dockets; most recently in comments submitted on the Alternate Proposed Decision Adopting Demand Response Activities and Budgets in Docket A.11-03-001. DR generally is very restricted with regard to location and energy duration or callable hours, making DR programs inadequate for inclusion in LCR/OTC studies. As Mr. Sparks describes, following a contingency event, system operators are faced with restoring the system within 30 minutes to a state positioned to face the next, worst contingency. They simply do not have time to wait and see what load reduction materializes and still have time to address shortfalls.[45]

Finally, with respect to energy storage, the ISO modeled a small amount of existing energy storage, but does not agree with CEJA witness Powers that forecasting greater quantities of energy storage is reasonable for the purposes of these studies. Again, not only must any storage facilities have sufficient capacity, but they must be in the right locations to be effective for local capacity needs. There is still much uncertainty surrounding the location and viability of storage projects, and the examples cited by Mr. Powers do not alleviate these

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[44] *Id.* pages 5-6.
[45] *Id.* page 6.

concerns.[46] Further, at this point in time, there are no storage facilities located on the ISO system.

The interveners have described the ISO's modeling assumptions as "overly conservative" but, as Mr. Sparks points out, deliberately conservative forecasts must be employed in the assessment of reliability requirements for locally constrained areas. This is because of the asymmetric risk of error in predicting the need for local resources. Overstating the need results only in marginal cost implications because the local needs have been identified due to generation that may be retired. On the other hand, understating the need can mean the loss of firm load, which puts public safety and the economy in jeopardy. The ISO has carefully considered the implications of using overly optimistic demand forecasts, and it is important that the Commission engage in the same careful consideration.

4. Modeling Distributed Generation (DG)

CEJA and DRA have also argued that the ISO should have included higher levels of DG in the LCR/OTC studies. However, reasonable levels of DG were included in three of the renewable portfolios that the ISO analyzed, ranging from 52 MW to 104 MW in three of the four scenarios. The ISO believes this range to reasonably reflect the level of DG for planning purposes to ensure grid reliability. The high DG scenario had 402 MW but, although this is a laudable goal, the ISO does not believe that this amount represents capacity that is reasonable to assume that it will be built and can be depended upon for planning purposes.[47]

DRA witness Spencer noted that the ISO's position on DG seemed to conflict with its recent DG initiatives, but the ISO does not agree. The purpose of the ISO's DG initiatives is to facilitate the development of DG, but that does not mean the significant and unsubstantiated

[46] Notably, the Western Grid storage projects proposed as *transmission alternatives* in the ISO's transmission planning process were found to be uneconomic in comparison to other alternatives. See Ex. 27 page 5.
[47] Ex. 27 page 7.

levels expected by DRA or CEJA will materialize, or be in the right locations for local capacity purposes. It is mere speculation at this time.

B. Other Transmission Planning Issues

In addition to criticism regarding the ISO's planning assumptions, discussed above, the interveners questioned the efficacy of the studies themselves. They also raised related arguments in support of delaying a decision on local capacity needs or substituting other alternatives for the requested generation resources. The ISO addressed many these arguments in rebuttal testimony.

1. Alleged Problems with the ISO's Study Methodology

CEJA witness Firooz argued that there are alleged and unexplained "inconsistencies" between the ISO's 2013 LCR study and the OTC study results for 2021, calling into question the validity of the ISO's studies. She also complains that the ISO has not sufficiently supported its complex analysis and concludes that the results of the ISO's power flow cases "cannot be trusted."[48] These comments are not well-founded.

The first purported "inconsistency" found by Ms. Firooz was a voltage collapse scenario identified in both the 2013 and the 2021 study. She observes that "[i]t would be expected that with higher in-area generation resources and lower loads in 2013 (compared to 2021), there should be no problem in avoiding a voltage collapse condition" and that the ISO provided "no explanation" for this supposed anomaly. However, the ISO explained the major differences between the 2013 and 2021 base cases several times- at the April 17, 2012 workshop and in a discovery response and in rebuttal testimony- and cautioned Ms. Firooz against engaging in an overly simplistic analysis based on load and resource differences

[48] Ex. 20, page 16-17.

Attachment E: Reply Brief Of The California Independent System Operator, filed in A.11-05-023, July 27, 2012.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power	)))))	**A.11-05-023**

REPLY BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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Table of Contents

I. Introduction 1

II. Argument 2

A. The ISO's OTC Study is Consistent with California's Loading Order and Renewable Energy Policies.. 2

B. Future Uncertainty Does Not Provide a Valid Basis Upon Which to Reject the ISO's OTC Study Results. 6

C. The ISO Evaluated, and Appropriately Did Not Recommend, Load Shedding and Other Non-Resource Mitigation Solutions to Reduce LCR in San Diego. 7

D. The ISO's OTC Study is Consistent with the LCR Methodology and the Contingency Analysis Required by NERC/WECC Planning Standards. 9

III. Credibility of the CEJA Testimony 12

IV. Conclusion 17

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power	)))))	**Docket A.11-05-023**

REPLY BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. Introduction

In this proceeding, the Commission will decide: 1) whether new generation resources are needed in the San Diego local capacity area to replace existing generation that may retire or come offline to repower due to the state's once through cooling (OTC) requirements; and 2) whether the three purchase power tolling agreements (PPTAs) submitted by SDG&E provide sufficient capacity to meet these needs and should be approved. The parties to this proceeding have diverse opinions on these topics, but there seems to be general agreement that the OTC requirements will impact resource needs in some way and at some time over the next 10 years.

To the California Independent System Operator (ISO), the combined impact of the OTC requirements and the influx of renewable generation coming on to the system to meet the state's 33% RPS directives presents unprecedented transmission planning and operational challenges. Rather than merely planning for incremental resource additions or transmission upgrades needed for retirements and load growth, the ISO is now faced with the prospect that substantial portions of its existing fleet will be replaced by 2021. To prepare for these changes, the ISO, in coordination with this Commission and the California Energy Commission (CEC), conducted the 10 year OTC study introduced for consideration in this proceeding. Although other parties presented recommendations about resources needed in the San Diego area, only the ISO tested the reliability of the transmission grid using the electric industry study tools- power flow and stability analysis- needed for compliance with NERC and WECC reliability standards. The ISO's study evaluated local area needs under four renewable portfolio scenarios developed by the Commission for the ISO's transmission planning process, using the CEC's load forecast and the local capacity requirements (LCR) study methodology considered and approved each year in the Commission's resource adequacy (RA) proceedings.

In addition to the ISO, opening briefs were submitted by SDG&E, DRA, CEJA, AReM/WPTF/DACC, UCAN, NRG and NRDC. For the most part, the intervening parties have focused their criticism of the ISO's OTC study results on the issue of whether the ISO should have included uncommitted energy efficiency (EE), uncommitted demand response (DR), uncommitted combined heat and power (CHP) and energy storage beyond the levels included in the CEC forecast. CEJA and DRA also challenged the ISO's study methodology. In an effort to simplify the issues under consideration, this reply brief will address the CEJA and DRA opening briefs.

II. Argument

A. The ISO's OTC Study is Consistent with California's Loading Order and Renewable Energy Policies.

DRA argues that the ISO's failure to include uncommitted EE and DR in the OTC study essentially "exempts" SDG&E from its statutory requirements to follow the loading the course of the OTC study. It goes without saying that a prolonged outage of this major generation resource (or any other major resource) could drive local area needs in the opposite direction than that predicted by DRA and CEJA. In contrast to this present reality, DRA's list of possible events that *might* reduce local area needs- such as "future transmission upgrades" or the "actual pace of economic recovery-" pale in comparison.[9] The ISO would caution the Commission that this is not an opportune time to take a "wait and see" approach to authorizing local procurement based on notions that the ISO has substantially over-estimated local area deficiencies.

C. The ISO Evaluated, and Appropriately Did Not Recommend, Load Shedding and Other Non-Resource Mitigation Solutions to Reduce LCR in San Diego.

Despite the rebuttal testimony provided by Mr. Sparks, and his answers to cross-examination questions, DRA and CEJA continue to insist that the ISO improperly failed to recommend a load-dropping SPS as means of reducing local area resource needs.[10] CEJA also insists that the ISO "failed to evaluate different potential options for lowering LCR requirements through transmission or operational measures" and "failed to explain why…it was not appropriate to rely on… load drop."[11] These statements, particularly those made by CEJA, are simply not correct. The ISO did in fact analyze load shedding as a mitigation solution and provided detailed explanation as to why it would be an imprudent planning decision. This evidence is summarized in the ISO's opening brief. [12] It is particularly ironic that CEJA completely ignores all of the information and analysis provided by the entity actually responsible for running the transmission grid and

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[9] DRA Opening Brief, page 37.
[10] *Id.*at pages 31-35; CEJA Opening Brief, pages 19-20.
[11] CEJA Opening Brief, pages 17, 19.
[12] ISO Opening Brief, pages 16-18.

maintaining reliaiblity, and instead urges the Commission to rely on the unsubstantiated opinion of witness Firooz- who applied her own version of a "probabilistic analysis" in an attempt to erode the deterministic criteria that is the basis of the NERC and WECC criteria- and decided that "a load drop was appropriate."[13]

CEJA also seems to misunderstand explanations provided by the ISO regarding other mitigation solutions. For example, with respect to installing phase shifters and a series reactor as a way to import more power from the CFE system, and in response to questions posed by counsel for CEJA, Mr. Sparks explained that this possibility had been reviewed as a mitigation solution to the loss of SWPL and Sunrise transmission line elements in the context of the ISO's transmission planning analysis. He went on to describe the impracticalities of this proposal and concluded by explaining to CEJA that the transmission plan is a comprehensive document and if a solution "doesn't work as part of the comprehensive plan, it's… not going to work."[14] Upon repeated questions by CEJA counsel about whether the ISO studied synchronous condensers as mitigation solutions, Mr. Sparks kept explaining that these condensers were studied as part of the transmission plan:

> Q. Have you studied whether or not synchronous condensers could reduce the LCR need in the San Diego area?
>
> A. We looked at—in our transmission plan, we looked at a number of scenarios, we look at our reliability analysis of the system. We also looked to see the capability of the system to deliver renewables. And also, we have—a part of our process looks at the economics of congestion and whether or not we should upgrade the system for congestion. Through that process, we did look at the synchronous condensers primarily I believe in the policy analysis. And again, we came to the conclusion that the most effective or preferred mitigation was to simply replace the OTC

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[13] CEJA Opening Brief, page 19.
[14] Tr.III, pages 543:27-544:4.

> in the area because with the large amount of renewable that we're expecting based on the renewable portfolio that we've studied…[15]

CEJA's statement that the "CAISO failed to evaluate the impact of four synchronous condensers that SDG&E proposed" appears to display a lack of understanding of the ISO's comprehensive transmission planning process and the testimony provided by the ISO.

D. The ISO's OTC Study is Consistent with the LCR Methodology and the Contingency Analysis Required by NERC/WECC Planning Standards.

CEJA has completely mischaracterized the ISO's local capacity area study methodology in an attempt to show that the ISO has engaged in a "backhanded attempt to increase procurement requirements" beyond those established by the Commission in D.06-06-064, the 2006 decision in which the Commission first addressed the LCR methodology.[16] This line of argument appears to be based on two general misperceptions: (1) that the ISO has "increased" the reserve margin by 2.5%, and (2) that the ISO has "failed to consider" operational solutions that would lower the LCR for San Diego.[17]

To begin with, while it is true that the ISO has never conducted a ten year local capacity technical study such as the OTC study, the OTC study is a "long-term LCR" study and it uses the same study methodology employed in the shorter term LCR studies described in Mr. Spark's initial testimony.[18] As discussed in the ISO's opening brief at pages 9-11, the ISO followed the study methodology for an LCR study, as described in

[15] Tr. III, 539:15-540:7

[16] CEJA Opening Brief, page 11.

[17] *Id,*at pages 11-13.

[18] See Ex. 18, Attachment AA, page 213; Ex. 9, pages 2-6.

Attachment F: Supplemental Testimony Of Robert Sparks On Behalf Of The California Independent System Operator Corporation, served in A. 11-05-023, April 6, 2012.

Application No.:	A.11-05-023
Exhibit No.:	
Witness:	Robert Sparks

Application of San Diego Gas & Electric Company (U902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power	Application 11-05-023

SUPPLEMENTAL TESTIMONY OF ROBERT SPARKS
ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power	Application 11-05-023

SUPPLEMENTAL TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Robert Sparks. I am employed by the California Independent System Operator Corporation (ISO), 250 Outcropping Way, Folsom, California as Manager, Regional Transmission.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have. On March 9, 2012 I submitted initial testimony addressing the need for generating resources in the San Diego area.

Q. Why have you submitted this supplemental testimony?

A. Specifically, after my initial testimony was served, 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 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). This re-categorization of the common corridor circuit outage as a Category D contingency required the ISO to re-assess its local studies. The purpose of my supplemental testimony is to describe the results of this re-assessment. In addition, in response to questions posed to me during an all-party conference call held on March 21, 2012, I will present some additional information about the ISO's local capacity studies.

Q. Were all of the local capacity area studies described in your initial testimony revised as a result of this change in the WECC criterion?

A. In my initial testimony, I described the results of the ISO's 2012 LCR study, which is an annual assessment conducted through a stakeholder process during the first two quarters of each year. I also discussed the ISO's once through cooling (OTC) study results for the year 2021. This study was conducted in cooperation with several state agencies as part of the 2011/2012 transmission planning process. Finally, I discussed a mid-term local capacity area study, conducted for 2016, that was posted separately on January 31, 2012 but discussed in the 2011/2012 transmission plan.

The ISO revised the OTC results for 2021 and I describe these results below. The ISO recently completed its 2013 local capacity studies with the G-1/N-2 and with the N-1-1 as the limiting contingency. Therefore, I am addressing the results of these studies in lieu of updating the 2012 results. In addition, as noted in the 2016 local capacity study report, the differences in results between the 2012 results and the 2016 results are due to load growth only which is a fairly predictable change. Therefore the change in 2016 study results can be reasonably extrapolated based on the change in 2013 study results provided below.

Q. Please explain how the change in the WECC criterion impacted the ISO's OTC local capacity studies for 2021 for the San Diego area.

A. Prior to the change in the WECC criterion, the most limiting contingency for the determination of LCR needs in the San Diego area was the simultaneous outage of the 500 kV Sunrise Powerlink and the Imperial Valley-ECO 500 kV line overlapping with an outage of the Otay Mesa combined-cycle power plant (G-1/N-2). The limiting constraint for this contingency is the South of SONGS Separation Scheme. With this change to the WECC criterion, the most limiting contingency for San Diego sub-area is the loss of Imperial Valley-Suncrest 500 kV line followed by the loss of ECO-Miguel 500 kV line (N-1-1).

The table below shows the difference in study results between the two different limiting contingency scenarios.

LCR Area	Contingency	Limiting Constraint	Traject(MW)	Env(MW)	ISO Base (MW)	Time(MW)
San Diego	G-1/N-2 (Assuming load shed)	8000 Amp limit on P44	**LCR = 2,883** **OTC = 531* - 950**	**LCR = 2,854** **OTC = 231* - 650**	**LCR = 2,864** **OTC = 231* - 650**	**LCR = 2,856** **OTC = 421* - 840**
		7800 Amp limit on P44 (2.5% margin)	LCR = 2,939** OTC = 520* - 939	LCR = 2,922** OTC = 299* - 718	LCR = 2,930** OTC = 299* - 718	LCR = 2,911** OTC = 470* - 889
San Diego	N-1-1 (No load shed)	8000 Amp limit on P44	LCR = 2,680 OTC = 318* – 737	LCR = 2,625 OTC = 0* - 402	LCR = 2,669 OTC = 218* - 637	LCR = 2,633 OTC = 201* - 620
		7800 Amp limit on P44 (2.5% margin)	LCR = 2,735 OTC = 373* – 792	LCR = 2,702 OTC = 60* - 479	LCR = 2,694 OTC = 243* - 662	LCR = 2,691 OTC = 260* - 679
		Voltage Collapse (accounting for 2.5% margin)	**LCR = 2,646** **OTC = 311* – 730**	**LCR = 2,524** **OTC = 0* - 300**	**LCR = 2,663** **OTC = 211* - 630**	**LCR = 2,553** **OTC = 121* - 540**

* Lower OTC range value corresponds to the use of SDG&E-proposed generation included in the Long-Term Procurement Plan. The numbers in the table identified as OTC refer to an incremental local capacity need in the San Diego area driven by the loss of OTC generation in the San Diego area. This need could be met by repowering the existing OTC generation or by other new generation that is connected to an electrically equivalent location.

** Load curtailment of approximately 370 MW was simulated to achieve stability under G-1/N-2 contingency.

As can be seen in the results table, the continuing need for generation at the existing OTC site (Encina) or in an electrically equivalent location is reduced from 950 MW to 730 MW for the Trajectory 33% RPS portfolio study scenario. This assumes that the 8000 Amp limit due to the SONGS separation scheme is removed from being a binding constraint. With the 419 MW of SDG&E proposed generation procurement, the need amount is reduced from 531 MW to 311 MW. Need amounts are also provided with the 8000 Amp limit on the Path 44 (SONGS separation scheme) as a binding constraint and with a 2.5% margin from hitting that constraint. Need amounts based on the other three 33% RPS portfolio study scenarios are also provided in the table.

Q. Did this change cause the ISO to change its LCR study methodology in any way?

A. No. However, because the G-1/N-2 contingency is a severe contingency we conceptually assumed that an automatic load shedding scheme (SPS) would be installed and available to prevent voltage collapse for that contingency in our earlier results. With the more likely N-1-1 contingency we did not think it would be prudent to plan the system that would rely on the same type of load shedding SPS.

Q. Please explain how the change in the WECC criterion impacted the ISO's 2013 local capacity studies for the San Diego area.

A. Similar to the OTC 2021 studies, prior to the change in the WECC criterion, the most limiting contingency for the determination of LCR needs in the San Diego area was the simultaneous outage of the 500 kV Sunrise Powerlink and the Imperial Valley-ECO 500 kV line overlapping with an outage of the Otay Mesa combined-cycle power plant (G-1/N-2). The limiting constraint for this contingency is the South of SONGS Separation Scheme. With this change to the WECC criterion, the most limiting contingency for San Diego sub-area is the loss of Imperial Valley-

Suncrest 500 kV line followed by the loss of ECO-Miguel 500 kV line (N-1-1). The table below shows the difference in 2013 LCR study results between the two different limiting contingency scenarios.

Area	Contingency	Limiting Condition	LCR (MW)
San Diego	G-1/N-2: Otay + Sunrise + SWPL (No load shed)	Voltage Collapse	2863
San Diego	N-1-1: Sunrise followed by SWPL (No load shed)	Voltage Collapse	2570 (Accounting for 2.5% margin for N-1-1)

As can be seen in the results table, the San Diego area LCR needs were reduced from 2863 MW to 2570 MW. It is important to note that these studies assumed that both SONGS units were operating.

Q. Were the results for the IV-San Diego area and the Encina sub-area affected by the change in WECC criterion for Sunrise Powerlink/IV-Miguel?

A. No. The most limiting contingency in the Greater Imperial Valley-San Diego (IV-San Diego) area is described by the outage of 500 kV SWPL between Imperial Valley and N. Gila substations overlapping with an outage of the Otay Mesa combined-cycle power plant (603 MW), while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. The most limiting contingency for the Encina sub-area of the San Diego local capacity area is the loss of Encina 230/138 kV transformer followed by the loss of the Sycamore-Santee 138 kV line which could thermally overload the Sycamore-Chicarita 138 kV line. Neither of these limiting contingencies is affected by the new WECC criterion, and therefore the results of the studies were not affected in either of these areas.

Attachment G: Application Of San Diego Gas & Electric Company (U 902 E) To Fill Local Capacity Requirement Need Identified in D.13-03-029, filed in A.13-06-015, June 21, 2013.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 E) to Fill Local Capacity Requirement Need Identified in D.13-03-029.	Application 13-06-___ (Filed June 21, 2013)

APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E)
TO FILL LOCAL CAPACITY REQUIREMENT NEED
IDENTIFIED IN D.13-03-029

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June 21, 2013

TABLE OF CONTENTS

I. INTRODUCTION 1

II. PROCEDURAL HISTORY 2

III. SDG&E'S ELECTION TO ENTER INTO AN AMENDED PPTA WITH PIO PICO, A DESCRIPTION OF THE KEY TERMS OF THE AMENDED PPTA AND THE BENEFITS THEREOF 2

A. Key Terms and Conditions of the Amended PPTA 3

B. Benefits of the Amended PPTA and Alternatives Considered 4

1. Benefits of the Amended PPTA 4
2. The Likely Outcome of a New RFO and Other Alternatives Considered 5

IV. RATEMAKING AND COST ALLOCATION ISSUES 5

V. RELIEF REQUESTED 7

VI. SUPPORTING TESTIMONY AND ATTACHMENTS 7

VII. STATUTORY AND PROCEDURAL REQUIREMENTS 8

A. Rule 2.1 (a) – (c) 8

1. Rule 2.1 (a) - Legal Name 8
2. Rule 2.1 (b) - Correspondence 8
3. Rule 2.1 (c) 9
a. Proposed Category of Proceeding 9
b. Issues to be Considered 9
c. Need for Hearings 9
d. Proposed Schedule 9

B. Rule 2.2 – Articles of Incorporation 10

C. Rule 3.2 (a) – (d) – Authority to Change Rates 11

1. Rule 3.2 (a) (1) – Balance Sheet 11
2. Rule 3.2 (a) (2) – Statement of Effective Rates 11
3. Rule 3.2 (a) (3) – Statement of Proposed Rate Change 11
4. Rule 3.2 (a) (4) – Description of Property and Equipment 11
5. Rule 3.2 (a) (5) and (6) – Summary of Earnings 11
6. Rule 3.2 (a) (7) – Statement re Tax Depreciation 12
7. Rule 3.2 (a) (8) – Proxy Statement 12
8. Rule 3.2 (a) (10) – Statement re Pass Through to Customers 12
9. Rule 3.2 (b) – Notice to State, Cities and Counties 12

10. Rule 3.2 (c) – Newspaper Publication 13
11. Rule 3.2 (d) – Bill Insert Notice 13

VIII. CONFIDENTIAL INFORMATION 13

IX. SERVICE...13

X. CONCLUSION 14

Attachment A – SDG&E Financial Statement, Balance Sheet and Income Statement

Attachment B – SDG&E Presently Effective Electric Rates

Attachment C – SDG&E Statement of Proposed Rate Change

Attachment D – SDG&E Statement of Original Cost and Depreciation Reserve

Attachment E – SDG&E Summary of Earnings

Attachment F – SDG&E State, Counties and Cities List

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 E) to Fill Local Capacity Requirement Need Identified in D.13-03-029.	Application 13-06-___ (Filed June 21, 2013)

APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E)
TO FILL LOCAL CAPACITY REQUIREMENT NEED IDENTIFIED IN D.13-03-029

I. INTRODUCTION

In this Application, San Diego Gas & Electric Company ("SDG&E") respectfully requests authority from the California Public Utilities Commission ("Commission") to enter into an amended power purchase tolling agreement ("Amended PPTA") with the Pio Pico Energy Center, LLC ("Pio Pico") and for approval to recover the costs of the Amended PPTA through the Commission-approved Cost Allocation Methodology ("CAM").

As explained in more detail below, per the Commission's directive in Decision ("D.") 13-03-029 ("SDG&E's Local Capacity Requirement ("LCR") Decision"), the Amended PPTA has a revised PPTA start date of June 1, 2017, instead of the PPTA start date of May 27, 2014 proposed in Application ("A.") 11-05-023. The Amended PPTA also requires Pio Pico to achieve a Commercial Operation Date ("COD") of September 1, 2015. The September 1, 2015 COD will be supported by a separate Resource Adequacy ("RA") contract for 2016 and the first part of 2017 (until commencement of the PPTA start date) that SDG&E is in the process of negotiating with Pio Pico.[1] The September 1, 2015 COD has the added benefit of serving as a reliability insurance policy in light of Southern California Edison's ("SCE") June 7, 2013

[1] SDG&E intends to file a separate advice letter request for approval of the proposed RA contract.

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announcement regarding the retirement of the San Onofre Nuclear Generating Station ("SONGS").[2]

II. PROCEDURAL HISTORY

In A.11-05-023, SDG&E sought approval for three purchase power tolling agreements ("PPTAs") with the winning bidders of its 2009 Request for Offers ("RFO") for peaking or intermediate-class resources to fill SDG&E's local capacity requirement need beginning in 2014. These winning bidders were the Escondido Energy Center (45 MW), Pio Pico (305 MW) and the Quail Brush Generation Project (100 MW).

In SDG&E's LCR Decision, after an extensive litigation process that included evidentiary hearings, the Commission approved the Escondido Energy Center but denied without prejudice SDG&E's request to enter into PPTAs with Pio Pico and/or the Quail Brush Generation Project if SDG&E amended its request to match the timing of the remaining need of 298 MW that the Commission identified beginning in 2018 (343 MW less the 45 MW associated with the Escondido Energy Center). Alternatively, the Commission authorized SDG&E to conduct a new RFO to fill the 298 MW need.[3]

III. SDG&E'S ELECTION TO ENTER INTO AN AMENDED PPTA WITH PIO PICO, A DESCRIPTION OF THE KEY TERMS OF THE AMENDED PPTA AND THE BENEFITS THEREOF

As discussed in more detail in its testimony and supporting attachments, SDG&E has elected to fill the local capacity requirement need that the Commission identified in SDG&E's

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[2] Longer-term issues regarding SONGS will be addressed in Track 4 of the Long-Term Procurement Plan ("LTPP") proceeding. *See*, Commission Rulemaking ("R".) 12-03-014, "Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge" (May 21, 2013) at pp. 4-6.

[3] *See, e.g.*, SDG&E's LCR Decision at Ordering Paragraph 3 ("San Diego Gas & Electric Company (SDG&E) is authorized to meet a local capacity requirement need of up to 298 MW beginning in 2018. SDG&E shall meet this need either by issuing a new request for offers or, in the alternative, it may bring an application for approval of purchase power tolling agreements with either Pio Pico Energy Center and/or Quail Brush Power amended to coordinate with the anticipated retirement in 2018 of once-through cooling generation units. SDG&E shall adjust the commencement date, as appropriate, to coordinate with the anticipated retirement of once-through cooling generation units and other changing conditions in its service territory.") *See also id.* at pp. 2, 18 and Conclusion of Law 18.

Attachment H: Prepared Direct Testimony Of Bill Powers On Behalf Of Sierra Club, The California Environmental Justice Alliance, and Protect Our Communities Foundation, served in A.13-06-015, September 20, 2013.

Docket:	**A.13-06-015**
Witness:	**Bill Powers**
Exhibit No.:	

Application of San Diego Gas & Electric Company (U 902 E) to Fill Local Capacity Requirement Identified in D.13-03-029.	Application 13-06-015 (Filed June 21, 2013)

PREPARED DIRECT TESTIMONY OF BILL POWERS ON BEHALF OF SIERRA CLUB, THE CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE, AND PROTECT OUR COMMUNITIES FOUNDATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

September 20, 2013

Table of Contents

Page

I. Introduction..1
II. Qualifications Summary..3
III. Background: Decision D. 13-03-029..3
IV. Changed Circumstances Meet the LCR Need Identified in D. 13-03-029.................4
A. Distributed Generation.. 4
1. Rooftop Solar..4
2. Wholesale Distributed Generation...5
3. SG&E Also Now Projects Substantially More DG PV than Used to Determine LCR Need in Decision 13-03-029..7
B. The Commission is About to Adopt an Energy Storage Procurement Target of 165 MW for SDG&E..7
V. Retirement Assumptions Underlying the Need Determination in Decision 13-03-029 Are No Longer Valid..8
A. SDG&E Now Admits Lease Extensions for 188 MW Cabrillo II Peaking Units Are Under Negotiation..8
B. Extension of the Encina Retirement Date is Now Under Serious Consideration 9
VI. The PPTA is Not Just and Reasonable...10
A. Pio Pico Capacity Exceeds LCR Need..10
B. Existing Resources Can Meet LCR Need at Much Lower Cost than Procurement of Pio Pico...10
C. SDG&E Precluded Consideration of Lower Cost Preferred Resources and Energy Storage By Failing To Issue a New RFO...11
D. Extension of the PPTA from 20 to 25 Years is Not Just and Reasonable 12
VII. In Evaluating the Need for the Pio Pico Energy Center, the Commission Should Meaningfully Assess the Relative Costs and Benefit of Applying the Reliability Standard Used to Determine Need in Decision 13-03-029...13
VIII. Conclusion...14

I. Introduction

California and the San Diego region have recently made tremendous and unanticipated strides toward the low carbon future necessary to limit catastrophic climate impacts to San Diego, California, and the rest of the world. With the cost of photovoltaics plummeting, both behind-the-meter and wholesale distributed generation (DG) in SDG&E territory is being deployed far more rapidly than foreseen at the time the assumptions underlying the original LCR Determination in Decision 13-03-029 were developed. The most recent mid-case CEC forecast now projects that behind-the-meter DG will supply 100 MW more peak capacity in SDG&E territory than previously assumed – the same nameplate capacity as one of Pio Pico's three LMS 100 units. This latest assumption is likely overly conservative now that the Legislature has lifted the cap on net metering by passing AB 327. Wholesale DG has also witnessed rapid growth consistent with the environmental constrained scenario in the 2011/2012 TPP rather than the much lower trajectory case used to determine LCR need in Decision 13-03-029.

To the extent there is any remaining LCR need when the rapid growth in distributed PV generation is properly accounted for, storage procurement targets are being finalized that will require SDG&E to procure 165 MW of energy storage by 2020. Storage procurement was also not anticipated at the time Decision 13-03-029 was issued. The LCR determination only accounted for a single existing 40 MW pumped storage facility that will not count toward SDG&E's 165 MW storage procurement target. This unforeseen energy storage procurement will further reduce any remaining LCR need.

Decision 13-03-029 requires consideration of material intervening events and circumstances in reevaluating the need of any new PPTA. In simply resubmitting the existing Pio Pico PPTA based on a 2009 RFO with only minor modification, SDG&E ignored the significant transformation occurring within its service territory. SDG&E's failure to account for these changes will both improperly result in unneeded and costly overprocurement and undermine California's efforts to rapidly decarbonize its energy system.

Accordingly, the PPTA is not just and reasonable. The unexpectedly rapid deployment of distributed PV and energy storage means these resources will meet the LCR need identified in Decision 13-03-029. The procurement of the three LMS 100 units comprising the $1.6 billion Pio Pico facility is excessive and unnecessary in this context.

Even assuming there is a remaining LCR need, in refusing to issue a new RFO, SDG&E ignored the loading order and failed to give legitimate consideration to lower-cost resources. By relying on an RFO from 2009 in this application, SDG&E precluded competitive bidding by energy storage resources and preferred resources such as solar, both of which have experienced major price declines since the 2009 RFO was issued. The Commission now projects that utility-scale battery storage will have a significantly lower capital cost than the LMS100 gas turbine in 2020. In addition, the superior operational flexibility and range of uses of energy storage compared to the LMS100, especially in the context of modulating the flow of renewable energy, make it a clearly superior technology for meeting any LCR need that must be filled in SDG&E territory.

SDG&E also failed to consider changed circumstances regarding the potential continued operation of much lower-cost existing fossil fuel resources. These resources can meet any remaining LCR need at a fraction of the cost of Pio Pico and avoid the need for new long-term gas-fired resource commitments. Decision 13-03-029 assumed the 188 MW Cabrillo II facility would shut down because of the SDG&E decision not to extend the land lease for this facility despite its substantial remaining useful life. In response to data requests, SDG&E now admits that it is negotiating with owner NRG to allow the Cabrillo II units to remain in service.

A longer-term extension of the land leases to allow continued use of Cabrillo II is a much more economical solution to meet any remaining LCR need than construction of the $1.6 billion Pio Pico facility. Moreover, unlike the Pio Pico PPTA, which would not expire until 2042, a Cabrillo II extension could terminate with the inevitable increase in preferred resource and storage deployment. This would avoid the significant risk of over-procurement of gas-fired resources as increasing amounts of preferred resources are deployed.

The previous LCR finding was also expressly contingent on the retirement of the 964 MW Encina power plant. With the retirement of SONGS, which is outside the SDG&E local capacity area and provides no local capacity to SDG&E, extension of the Encina once through cooling (OTC) December 2017 compliance date is now under serious consideration by the State Water Resources Control Board.

Numerous voltage support projects have recently been completed by CAISO in the vicinity of SONGS to address voltage support issues related to the permanent retirement of the nuclear plant. The extension of the Encina compliance date, and mitigation measures implemented to address the SONGS retirement, may render Pio Pico superfluous and/or a non-optimal mitigation solution. Therefore, even assuming the Commission finds there continues to be an LCR need that cannot be met with lower-cost resources, the Commission should not authorize approval of Pio Pico until Track 4 of the LTPP is fully resolved.

The Commission should not be rushed into a $1.6 billion ratepayer commitment, despite the pressure from SDG&E to expedite approval, and ignore the significant positive "high in the loading order" resource developments that have occurred since the original LCR determination was issued. To ensure any additional procurement is just and reasonable, the LCR determination should be revised to account for unanticipated growth in DG and energy storage, with any remaining LCR need met with a temporary operating lifetime extension for existing gas-fired facilities in the SDG&E load pocket and/or an all source RFO that allows meaningful competition by preferred resources and energy storage.

legislation giving the Commission the ability to exceed the 33% RPS requirement. Continued growth in preferred resources and energy storage, coupled with likely increases in the cost of carbon, raise serious concerns over the value of a PPTA for a fossil fuel resource that requires capacity payments 30 years into the future. Extending the PPTA to 25 years creates significant risk that ratepayers will be left paying for unneeded and unutilized fossil fuel capacity far into the future.

VII. In Evaluating the Need for the Pio Pico Energy Center, the Commission Should Meaningfully Assess the Relative Costs and Benefit of Applying the Reliability Standard Used to Determine Need in Decision 13-03-029

The LCR determination in Decision 13-03-029 relied on the unprecedented and unvetted application of reliability criteria in excess of WECC standards. Decision 13-03-029 did not independently assess or meaningfully address application of elevated reliability criteria. In failing to do so, Decision 13-03-029 fell short of the Commission policy "of balancing reliability objectives against the cost of achieving a particular reliability level."[47] Review of the PPTA presents the Commission with the opportunity to address this issue in evaluating the need for the Pio Pico Energy Center.

As a general matter, it does not make sense for California to have more stringent reliability criteria than the rest of WECC, much less informally apply an even more stringent standard. More stringent reliability criteria could cost consumers billions of dollars in contract costs to pay for new generation with no measurable increase in grid reliability. Increased costs also put load serving entities within the CAISO balancing authority at a competitive disadvantage to other balancing authorities, both inside and outside of California. If there are special circumstances where more stringent reliability criteria may be required, those must be brought up on an exceptional basis and justified rather than being the rule.

In its San Diego LCR analysis, CAISO determined need based on an unvetted N-1-1 contingency during a 1-in-10 peak year event with no load shedding. An N-1-1 event is classified as a "multiple contingency" event, or Category C event, and assumes simultaneous loss of two transmission lines. Controlled load shedding, with no specified cap, is one of the mitigation techniques allowed by NERC to address this type of multiple contingency event. The cost of controlled load shedding of non-critical electrical load, for up to several hours once every ten years in the unlikely event two transmission lines are both offline, may have no cost at all to the customers that are without power at the time of the event. However, the cost of meeting an N-1-1 event with only generation and transmission and no load shedding will be very high.

[47] California Public Utilities Commission, Decision 06-06-064, Opinion on Local Resource Adequacy Requirements at 17 (June 30, 2006) at 19, http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/57644.PDF

Notably, LADWP anticipates and authorizes load shedding to address multiple contingency events.[48] This Commission has also previously rejected an option to rely only on generation solutions (as opposed to operational solutions like load shedding) to address a Category C event in determining resource adequacy requirements as having "little justification."[49] Use of reliability criteria in excess of NERC standards and the ability to mitigate Category C events using load drop are decisions with billions of dollars in costs at stake. In this case, use of load drop as permitted by WECC and applied by LADWP would save ratepayers the $1.6 billion cost of Pio Pico. Having not meaningfully addressed and resolved this question in Decision 13-03-029, the Commission should do so now.

VIII. Conclusion

For all the reasons above, the Commission should not approval SDG&E's Application to enter into a PPTA with the Pio Pico Energy Center.

[48] LADWP, 2012 Ten-Year Transmission Assessment (Dec. 2012), http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/docs/energy_comp/10yta_2012_5.pdf

[49] California Public Utilities Commission, Decision 06-06-064, Opinion on Local Resource Adequacy Requirements at 17 (June 30, 2006), http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/57644.PDF

Attachment I: Prepared Direct Testimony of David Peffer On Behalf Of The Protect Our Communities Foundation, served in A.13-06-015, September 20, 2013.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 E) to Fill Local Capacity Requirement Need Identified in D.13-03-029.	Application 13-06-015 (Filed June 21, 2013)

PREPARED DIRECT TESTIMONY OF DAVID PEFFER ON BEHALF OF THE PROTECT OUR COMMUNITIES FOUNDATION

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September 20, 2013

Table of Contents

I.	Accelerating the PPTA start date to June 1, 2017 is unreasonable	 4
II.	The cost to ratepayers for Pio Pico to provide 300 MW at contingency conditions has not been disclosed to the Commission or ratepayers	……......................... 4
III.	The CAISO definition of the San Diego Local Area is inconsistent with past practice and unreasonably excludes generation assets	…………………….. 5
IV.	LCR projections based on CAISO's N-1-1 reliability standard are unreasonable	…………………….. 7
A.	Background on reliability standards	…………………….. 7
B.	Adopting N-1-1 will substantially harm ratepayers through increased rates for unnecessary procurement	…………………….. 9
C.	Adopting N-1-1 will substantially harm ratepayers by reducing the value of their investment in Sunrise Powerlink	…………………….. 9
D.	CAISO ignores load shedding in applying the N-1-1 standard	…………………... 11
E.	CAISO's lack of transparency	…………………... 12
F.	The N-1-1 standard has not been reviewed by the Commission	…………………... 12

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 E) to Fill Local Capacity Requirement Need Identified in D.13-03-029.	Application 13-06-015 (Filed June 21, 2013)

PREPARED DIRECT TESTIMONY OF DAVID PEFFER ON BEHALF OF THE PROTECT OUR COMMUNITIES FOUNDATION

Pursuant to Rule 13.8 of the Commission's Rules of Practice and Procedure, the Protect Our Communities Foundation ("POC") respectfully submits the following Testimony of David Peffer on Behalf of the Protect Our Communities Foundation for A.13-06-015.

POC's testimony addresses the following issues: 1) SDG&E's request to accelerate the PPTA start date to June 1, 2017 is unreasonable; 2) the cost to ratepayers for Pio Pico to provide 300 MW at contingency conditions has not been disclosed to the Commission or ratepayers; 3) the CAISO definition of the San Diego local area used to justify Pio Pico is inconsistent with past practice and unreasonably excludes generation assets; and (4) LCR projections based on CAISO's N-1-1 reliability standard are unreasonable.

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In light of the new evidence presented by the FERC decision, the OTC Study, which formed the basis of the Commission's LCR determination in D.13-03-029 is factually incorrect and as such cannot be seen as substantial evidence supporting the Commission's need determination. The Commission's LCR calculations should include both the La Rosita II and Sempra TDM plants. The 1,084 MW of energy represented by these facilities obviates the need for Pio Pico.

IV. LCR projections based on CAISO's N-1-1 reliability standard are unreasonable

Despite the multi-billion dollar implications of CAISO's switch to N-1-1, the Commission has not reviewed the reasonableness of the N-1-1 standard. The Commission cannot reasonably approve SDG&E's application for a PPA with Pio Pico based on CAISO's un-vetted N-1-1 reliability standard without first establishing, based on substantial evidence, that the N-1-1 standard is reasonable.

A. Background on reliability standards

The North American Electricity Corporation ("NERC") is the entity responsible for defining transmission planning standards in the United States. NERC's transmission planning standard is "N-1." Under a N-1 standard, utilities must procure sufficient generation to withstand the loss of a local area's single largest transmission line.[8]

Shortly after CAISO's inception in the late 1990s, CAISO's board of directors voluntarily opted to impose planning standards that were significantly more stringent than those required by NERC.[9] While NERC's G-1 standard requires utilities to procure enough generation to cover for the loss of an area's single largest power plant, CAISO's "G-1, N-1" standard

[8] NERC, *Standard TPL-002-0b — System Performance Following Los s of a Single BES Element*, October 24, 2011http://www.nerc.com/files/tpl-002-0b.pdf, attached hereto as Exhibit 6.
[9] K. Edson, CAISO, *CAISO Response to Powers Engineering*, November 7, 2012, attached hereto as Exhibit 7.

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required utilities to procure enough generation to cover for the simultaneous loss of both an area's largest power plant ("G"), and the area's largest transmission line ("N").

G-1, N-1 remains CAISO's official planning standard to this date. This standard was reaffirmed by CAISO in its most recent 2011 update to the planning standard.[10] According to the planning standard stakeholder webpage, the most recent update to the CAISO standards was the result of a stakeholder process, "*The ISO is revising its reliability planning standards, which will be consistently applied by all participating transmission owners within the ISO grid, to reflect current NERC and WECC standards and industry practices*."[11]

In A.11-05-023, CAISO witness Robert Sparks submitted Supplemental Testimony in which he revealed that CAISO had introduced an N-1-1 standard rather than its official N-1, G-1 standard for the San Diego Local Area. Under N-1-1, utilities must procure sufficient generation to cover the simultaneous outage of the local area's two largest transmission lines. CAISO justified this major shift in energy policy with multi-billion dollar implications on the grounds that "SDG&E told the ISO" that the shift was necessary to comply with new WECC power line spacing criteria.[12] CAISO did not cite to the actual WECC rule. On the strength of this justification CAISO's N-1-1 standard was used to determine the Local Capacity Requirement for the SDG&E service area.

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[10] CAISO, *California ISO Planning Standards*(http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf), June 23, 2011, p. 4, attached hereto as Exhibit 8. "2. Combined Line and Generator Outage Standard: A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002)." p. 10: "The ISO Planning Standards require that system performance for an over-lapping outage of a generator unit (G -1) and transmission line (L-1) must meet the same system performance level defined for the NERC standard TPL-002. The ISO recognizes that this planning standard 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."

[11] http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/TransmissionPlanningStandards.aspx

[12] Supplemental Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation, submitted in A.11-05-023, at pp. 1-2, attached hereto as Exhibit 9.

B. Adopting N-1-1 will substantially harm ratepayers through increased rates for unnecessary procurement

CAISO's switch from a G-1, N-1 standard to an N-1-1 standard for the SDG&E local area is unprecedented and represents a fundamental change in California energy policy. This change has a major impact on San Diego ratepayers.

The difference between CAISO's official G-1, N-1 standard and the proposed N-1-1 standard is stark. Under the G-1, N-1 standard, SDG&E assumes losss of the 600 MW Otay as one of two contingencies. Under the N-1-1 standard, SDG&E assumes loss of the 1,000 MW Sunrise Powerlink instead of loss of Otay Mesa. The N-1-1 standard imposes a "loss" of 400 MW of otherwise available local capacity. In addition, N-1-1 keeps SDG&E's Imperial Valley Substation out of the LCR, removing approximately 1,000 MW of combined cycle capacity connected to the Imperial Valley Substation from the LCR.

Despite the fact that the N-1-1 standard has not been reviewed for reasonableness by the CPUC and is not justified by substantial evidence, N-1-1 forces SDG&E ratepayers to cover the cost of 400 MW of generation capacity. This cost includes the Pio Pico PPA at issue in the instant proceeding, which will cover 305 MW of the 400 MW shortfall artificially created by the switch to N-1-1, at a cost of $1.6 billion over 25 years.[13]

C. Adopting N-1-1 will substantially harm ratepayers by reducing the value of their investment in Sunrise Powerlink

CAISO's switch to N-1-1 nullifies a significant portion of the reliability benefit to ratepayers used to justify SDG&E's $2 billion Sunrise Powerlink project.

[13] SDG&E Bill Insert, "Notice of Application 13-06-XXX To Fill the Local Capacity Requirement Need Identified in CPUC Decision 13- 03-029," attached hereto as Exhibit 10.

Sunrise Powerlink was presented to the public and justified to the Commission as a project that would significantly increase San Diego's long-term reliability. The Commission approved Sunrise Powerlink on the grounds that it would add 1,000 MW of Local Reliability under the G-1, N-1 standard. In the Commission's decision approving Sunrise Powerlink, the Commission noted:

> 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 reliably 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 its 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.[14]

The Decision's Finding of Fact 14 places a specific cash value on the Sunrise Powerlink's reliability benefit to ratepayers:

> 14. Modeling performed by the CAISO, updated for our baseline assumptions, demonstrates total projected reliability benefits of [Sunrise Powerlink built along] the Environmentally Superior Southern Route to be $214 million per year.[15]

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[14] D.06-08-010 at p. 28
[15] D.06-08-010 at p. 285겜□ŋ

The CPUC must not allow CAISO and SDG&E to pull a "bait and switch" on SDG&E ratepayers – justifying a $2 billion dollar transmission line based on claimed reliability benefits under the G-1, N-1 standard, then changing the standard to obviate the Sunrise Powerlink's reliability benefits to justify even more reliability procurement. Switching from G-1, N-1 to N-1-1 would effectively reduce the reliability benefit of Sunrise Powerlink by 40% (the 1000 MW reliability loss under the N-1-1 standard is partially offset by the 600 MW Otay Plant, which is not assumed out as it would be under N-1, G-1), and exclude existing combined cycle RA capacity connected to the Imperial Valley Substation. Ratepayers have invested $2 billion in Sunrise Powerlink. A 40% reduction of the value of this investment amounts to an $800 loss to ratepayers. Assuming that the Commission's Finding of Fact 14 is correct, a loss of 40% of the reliability value of Sunrise Powerlink will harm ratepayers at the rate of $85 million per year.

D. <u>CAISO's Ignores Load Shedding In Applying N-1-1 Standard</u>

Some level of controlled load shedding is allowable under the CAISO G-1, N-1 contingency. Under G-1, N-1, CAISO allows up to 250 MW of load shedding to address the contingency.[16] Under N-1, NERC also allows limited load shedding to assure grid reliability.[17]

N-1-1 events are classified as "multiple contingency" event, or Category C event, by CAISO and NERC. Controlled load shedding, with no specified cap, is a primary mitigation technique allowed by both CAISO and NERC to address a multiple contingency event. The cost of controlled load shedding of non-critical electrical load, for up to several hours once every ten

[16] CAISO, *California ISO Planning Standards*, June 23, 2011, p. 6. "No single contingenc y (TPL002 and ISO standard [G-1] [L-1]) should result in loss of more than 250 MW of load. This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system adjustment period) in order to position the electric system for reliable operation in anticipation of the next worst contingency."

[17] NERC, *Standard TPL-002-0b — System Performance Following Loss of a Single BES Element* (http://www.nerc.com/files/tpl-002-0b.pdf), October 24, 2011, Table 1, p. 4, footnote (b). "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the oveall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non -recallable reserved) electric power Transfers.'펩□ŋ

years, may have no cost at all to the customers that are without power at the time of the event. However, the cost of meeting an N-1-1 event with only generation and transmission and no load shedding will be very high.

E. CAISO's Lack of Transparency

POC has been unable to locate any evidence showing that CAISO's adoption of N-1-1 – a fundamental break from CAISO's official N-1, G-1 standard – was accompanied by any kind of stakeholder process or public engagement. This lack of public process is especially remarkable in light of the major energy policy implications of the shift to N-1-1 and the multi-billion dollar impact of this shift on ratepayers.

CAISO's lack of transparency regarding the switch to N-1-1 has continued through the instant proceeding. CAISO has objected to POC data request questions regarding: 1) the regulations, statutes, orders, and other rules governing its adoption or modification of grid reliability criteria; 2) the process through which CAISO switched from G-1, N-1 to N-1-1; 3) the technical reports, studies, and other objective information relied upon by CAISO in adopting N-1-1; (4) whether CAISO consulted with outside agencies, including FERC and the CPUC in adopting N-1-1; and (5) whether CAISO has conducted any analysis to determine the probability of an N-1-1 situation actually occurring.

F. The N-1-1 standard has not been reviewed by the Commission

Although in D.13-03-029 (resolving proceeding A.11-05-023) the Commission relied on CAISO's 2011/2012 Once Through Cooling ("OTC") study to reach an LCR determination for SDG&E. This decision does not constitute a reasonableness review of the N-1-1 standard, nor does this decision excuse the Commission from its regulatory duty to review the reasonableness of the N-1-1 standard before authorizing procurement based on studies using N-1-1.

The participants in proceeding A.11-05-023 did not develop an evidentiary record upon which the Commission could make a determination of the reasonableness of the N-1-1 standard. In A.11-05-023, CAISO was the only party proposing an N-1-1 standard. Neither CAISO's testimony nor associated exhibits provide sufficient evidence to support a finding that the N-1-1 standard is reasonable.

The evidentiary record in A.11-05-023 does not contain sufficient evidence to establish that a switch to a more stringent N-1-1 standard and resulting increased procurement will lead to increased reliability or any other clear benefit to ratepayers.

The claim that more stringent reliability criteria lead to increased reliability is contradicted by San Diego ratepayers' own experience. CAISO's rationale for its more stringent N-1, G-1 reliability standard is that it was the custom of California transmission operators prior to the formation of CAISO. The Commission has not conducted its own independent cost-benefit analysis to determine whether the high cost of this more stringent reliability standard has provided any increment increase in reliability relative to regions that utilize the NERC planning standard [CAISO DR response to PG&E in Track 4].

On the contrary, the SDG&E load pocket has experienced two major blackouts in the last three years. Both blackouts occurred under single contingency conditions. The first blackout was caused by the CAISO when it erroneously scheduled a generator that was in forced outage. This blackout was caused by a G-1 condition that was not addressed in a timely manner. FERC ordered CAISO to pay a $200,000 fine for this error.[18]

[18] FERC, December 14, 2012.

The second blackout occurred on September 8, 2011 and resulted from the loss of a single 500 kV transmission line.[19] Planning to adjust to the loss of a single transmission line with little or no load shedding is the NERC planning standard. CAISO's more stringent transmission standard has not in practice avoided blackouts that resulted from single contingency events. The benefit of maintaining high levels of capacity reserves, if any, has not been critically evaluated by the CPUC. The number of blackouts in SDG&E territory has risen concurrently with the cost of maintaining high levels of capacity reserves.

Further, the evidentiary record in A.11-05-023 does not contain sufficient evidence to establish that procurement based on the N-1-1 standard is cost-effective. The A.11-05-023 record is insufficient to establish any clear benefit to ratepayers, much less a benefit significant enough to justify the billions of dollars of new procurement that the N-1-1 standard would require.

Lacking a sufficient evidentiary record to establish the reasonableness of the N-1-1 standard, the Commission did not make any findings of fact or law regarding the N-1-1 standard in D.13-03-029, leaving the reasonableness of the N-1-1 standard an unresolved issue that must be fully addressed before the Commission can reasonably authorize procurement based on the N-1-1 standard.

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[19] FERC, *Arizona – Southern California Outages on September 8, 2011: Causes and Recommendations*, April 27, 2012, attached hereto as Exhibit 11. See: http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf

Attachment J: Rebuttal Testimony Of Robert Sparks On Behalf Of The California Independent System Operator Corporation, served in A.13-06-015, October 4, 2013.

Application No.: A.13-06-015
Exhibit No.:
Witness: Robert Sparks

Application of San Diego Gas & Electric Company (U 902 E) to Fill Local Capacity Requirement Need Identified in D.13-03-029	Application 13-06-015 (Filed June 21, 2013)

REBUTTAL TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of the San Diego Gas & Electric Company (U902E) to Fill Local Capacity Requirement Need Identified in D.13-0-029	Application 13-06-015

REBUTTAL TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Robert Sparks. I am employed by the California Independent System Operator Corporation (ISO), 250 Outcropping Way, Folsom, California as Manager, Regional Transmission.

Q. Please describe your educational and professional background.

A. I am a licensed Professional Electrical Engineer in the State of California. I hold a Master of Science degree in Electrical Engineering from Purdue University, and a Bachelor of Science degree in Electrical Engineering from California State University, Sacramento.

Q. What are your job responsibilities?

A. I manage a group of engineers responsible for planning the ISO controlled transmission system in southern California to ensure compliance with NERC, WECC, and ISO Transmission Planning Standards in the most cost effective manner. With the California transmission system undergoing a major transformation, there are significant uncertainties that must be considered. In particular, I have been involved in the studies conducted by the ISO to evaluate systems needs in light of the environmental requirements placed on once-through-cooling generating facilities by the State Water Resources Board and the absence of the San Onofre Nuclear Generating Station (SONGS).

Q. Have you provided testimony about local capacity needs in the San Diego area previously in other proceedings?

A. Yes. I submitted opening, supplemental and rebuttal testimony addressing the ISO's assessment of local area needs in San Diego in Docket A.11-05-023 which was based on the ISO's once through cooling studies developed during the 2011/2012 transmission planning process.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to some of the topics raised by the testimony of William Powers on behalf of Sierra Club, CA; California Environmental Justice Alliance (CEJA); Protect Our Communities (POC) and the testimony of David Peffer on behalf of POC.

Q. What are the issues that you intend to address in this testimony?

A. Both Mr. Powers and Mr. Peffer have made factually inaccurate statements about the ISO's LCR study methodology that underlies the 298 MW local capacity resource need established by the Commission in D.13-03-029. While I do not believe that the ISO's study methodology is an issue to be considered in this proceeding because it was extensively litigated and approved in D.13-03-029, the ISO is concerned that without a response, such incorrect information may be taken out of context and relied upon in other venues or proceedings. I will also address Mr. Power's testimony about intervening circumstances that he recommends should be taken into consideration by the Commission in deciding whether to approve the Pio Pico PPTA.

Probabilistic versus Deterministic Transmission Planning Requirements

Q. Mr. Powers and Mr. Peffer have characterized the ISO's contingency planning methodology as relying on a "highly improbable" and overly conservative reliability contingency in developing the local area needs in A.11-05-023. Was this topic addressed in A.11-05-023?

A. Yes. I provided rebuttal testimony explaining transmission planning requirements, responding to the witness sponsored by CEJA. I was extensively cross-examined on my testimony, and the ISO devoted a portion of its opening brief and reply brief to these topics. Contrary to Mr. Peffer's assertions at pages 12-14 of his testimony, I believe that the Commission had a very complete record upon which to rule on these issues in D.13-02-015. I am attaching these materials as exhibits to my testimony, and will include them in the record in this proceeding.

Q. Does the ISO's local capacity requirements (LCR) study methodology consider the probability that a reliability contingency will occur?

A. Not in the sense used by Mr. Powers at page 4 of his testimony. The contingencies and required system performance levels that are applied are based on the NERC transmission planning reliability criteria, as augmented by WECC regional standards and California-specific standards. These mandatory standards are deterministic, not probabilistic. Assumptions are made regarding load levels and system conditions prior to a disturbance and then specific disturbances are simulated to test modeled performance against performance requirement scales. In general, a broader range of system impacts are permissible for more extreme, and less likely, types of contingencies.

The deterministic test is exactly that – a test. It is a test that is developed through broad industry and stakeholder participation to arrive at an appropriate balance between reliability and cost. It is not an assessment of every possible operating condition and the anticipated system response to each possible operating condition.

This is an important distinction, because the probabilistic methodologies that are more common in system-wide resource adequacy analysis focus primarily on all possible combinations of generation outages, but for the most part assume an unconstrained and highly reliable transmission system. The two types of analyses have fundamental differences and applying probabilistic arguments to one possible transmission outage system condition without considering all other possible outage conditions is a fundamentally flawed application of the probabilistic study technique.

Q. What is the difference between a deterministic study and a probabilistic analysis?

A. A deterministic transmission planning study, used by the ISO for the OTC/LCR studies and its transmission planning studies, makes a number of idealized assumptions, and then tests the system performance following simulated contingencies, whether in the steady-state power flow analysis or dynamic stability analysis. The required performance for each level of contingency is established through years of industry-wide experience and stakeholder input, resulting in a testing methodology that has been adopted by NERC and FERC and provides consistent and acceptable system performance across the United States, Canada, and the interconnected portions of Mexico. Those performance levels differ for different broad categories of contingencies, recognizing the significantly different likelihood of occurrence for each of those categories of contingencies.

Probabilistic analysis, in contrast, sums the probabilities of a number of events, each with its own probability of occurring, occurring at a particular time or in combination and assesses the anticipated impacts of all of the potential events. System-wide resource adequacy analysis lends itself to this type of approach. Individual generators each have their unique performance characteristics, including the probability of forced outages, and the combined effect of the individual performance characteristics can be considered on a probabilistic basis.

Studying a transmission system on a probabilistic basis has not replaced deterministic assessments for a number of reasons. These include the complexity of needing to consider the individual performance of a significantly larger number of transmission and generation components, considering the interaction on the transmission system between those components, and also the wide range of operating conditions that could exist at any point in time. Also, and to some extent because of these complexities, there is no meaningful industry standard to compare forecast performance against, unlike the deterministic criteria adopted by NERC and WECC. Probabilistic techniques are emerging that can be applied to transmission system planning working in conjunction with deterministic analysis. To this point, however, these techniques have been utilized more frequently to assist in the selection of the optional alternative to address a reliability issue, or to consider the merits of transmission reinforcements to address economic or policy-related issues. Haphazardly or selectively applying probabilities of a particular event occurring in the midst of a deterministic analysis is not a probabilistic analysis –indeed it is neither. Arbitrary adjustments to exclude certain contingencies from analysis, as suggested in the referenced testimony, simply weaken and undermine the test being applied in the deterministic analysis.

Applying probabilities selectively, which would weaken the deterministic test, would be analogous to a medical student seeking to have his or her grades improved, by pointing out that the likelihood of being confronted with a particular disease or condition that was the subject of a test question is quite low, and therefore should be removed from the grading. It defeats the entire purpose of testing the integrity of the transmission system through a deterministic analysis, and fails to provide the comprehensive view of risk under a wide range of operating conditions that probabilistic analysis would provide.

Q. Was this information provided to the Commission in A.11-05-023?

A. Yes, I discussed deterministic versus probabilistic methodologies in my rebuttal testimony at pages 10-11, as well as the ISO's opening brief at pages 13-16, both of which are attached as exhibits to my testimony here.

Q. Has the Commission approved the ISO's LCR study methodology in other proceedings in addition to A.11-05-023?

A. Yes. The Commission made determinations in D.06-06-064 regarding the criteria and test contingencies, as the ISO discussed in its reply brief in A.11-05-023, pages 9-12 (attached). Furthermore, the Commission approves the ISO's annual LCR study each year for purposes of resource adequacy. The Commission also considered these issues in Track 1 of the current LTPP proceeding, R.12-03-014, and once again supported the ISO's study methodology in D.13-02-015.

N-1-1 Planning Criteria and Load Shedding

Q. Mr. Powers and Mr. Peffer have questioned the reasonableness of the ISO's transmission planning practices with regard to load shedding as a mitigation solution for the N-1-1 contingency in the San Diego local area. Was this issue also addressed in A.11-05-023?

A. Yes, the witnesses presented by CEJA and DRA made the same arguments that have been raised by Mr. Powers and Mr. Peffer. I addressed the topic of the N-1-1 reliability planning criteria in my rebuttal testimony in A.11-05-023 (pages 8-10, attached), and the ISO briefed the issue in its opening brief (pages 16-18, attached). The ISO provided the Commission with ample information about how engineers at the ISO develop mitigation solutions for the N-1-1 contingency and the circumstances under which load shedding is not a prudent planning option. The ISO's position is that load shedding in the densely populated San Diego area should not be used as a transmission planning tool for the N-1-1 NERC Category C contingency of the 500 kV lines between the Imperial Valley, Miguel and Suncrest substations. This is due to the significant amount of load that would be subject to load shedding, the sensitivity of urban loads to large blocks of shedding, the complexity of operating arrangements in the area, and the proximity of the particular transmission lines.

Q. Has either witness provided new factual information about the ISO's planning criteria that would cause the Commission to reconsider D.13-03-029?

A. No. In fact, Mr. Peffer in particular appears to be quite confused about NERC, WECC, and ISO planning standards and how LCR studies are conducted. His testimony should not cause the Commission to re-evaluate its previous decision establishing a need for 298 MW of local resources. Similarly, Mr. Powers' testimony simply repeats the argument raised by the witnesses in A.11-05-023 that the ISO should have used load shedding- in the highly urbanized San Diego area- as a mitigation solution in lieu of generation or other local resources (see Powers testimony, page 4).

Q. Mr. Peffer states that the ISO "switched" from a G-1/N-1 planning criteria to the more severe N-1-1 and that this "fundamental switch" was "revealed" for the first time in your Supplemental Testimony in A.11-05-023. Did the ISO

change from a G-1/N-1 standard to an N-1-1 standard for the San Diego area, as described by Mr. Peffer at pages 8 and 9 of his testimony?

A. No. Both the G-1/N-1 and the N-1-1 are part of the LCR criteria, and the most limiting test sets the requirements – in this case, the N-1-1 contingency. Mr. Peffer seems to conclude that when the ISO ceased to consider the even more demanding G-1/N-2 as the worst outage which then shifted the N-1-1 to being the worst outage, as described above, that the ISO had changed its standards and began applying a higher more demanding requirement . However, eliminating the test of the more onerous contingency was in response to a change in WECC criteria and not a change to ISO planning standards. Furthermore, the ISO's consideration of the N-1-1 as the most limiting contingency resulted in a less demanding test being the limiting condition.

Q. Can you briefly summarize the information provided in your Supplemental Testimony?

A. After performing a comprehensive contingency analysis of all contingencies required to be assessed in an LCR study, the ISO found that the G-1/N-2 contingency was demonstrated through the study results to be the worst contingency. As described in my supplemental testimony, prior to the change in the WECC criterion, the most limiting contingency for the determination of LCR needs in the San Diego area was the simultaneous outage of the 500 kV Sunrise Powerlink and the Imperial Valley-ECO 500 kV line overlapping with an outage of the Otay Mesa combined-cycle power plant (G-1/N-2). The limiting constraint for this contingency is the South of SONGS Separation Scheme. With the change to the WECC criterion, the most limiting contingency for San Diego sub-area becomes instead the loss of Imperial Valley-Suncrest 500 kV line followed by the loss of ECO-Miguel 500 kV line (N-1-1).

Attachment K: California Public Utilities Code, Section 345.

PUBLIC UTILITIES CODE
SECTION 345-352.7

345. The Independent System Operator shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Electric Reliability Council.

345.5. (a) The Independent System Operator, as a nonprofit, public benefit corporation, shall conduct its operations consistent with applicable state and federal laws and consistent with the interests of the people of the state.

(b) To ensure the reliability of electric service and the health and safety of the public, the Independent System Operator shall manage the transmission grid and related energy markets in a manner that is consistent with all of the following:

(1) Making the most efficient use of available energy resources. For purposes of this section, "available energy resources" include energy, capacity, ancillary services, and demand bid into markets administered by the Independent System Operator. "Available energy resources" do not include a schedule submitted to the Independent System Operator by an electrical corporation or a local publicly owned electric utility to meet its own customer load.

(2) Reducing, to the extent possible, overall economic cost to the state's consumers.

(3) Applicable state law intended to protect the public's health and the environment.

(4) Maximizing availability of existing electric generation resources necessary to meet the needs of the state's electricity consumers.

(5) Conducting internal operations in a manner that minimizes cost impact on ratepayers to the extent practicable and consistent with the provisions of this chapter.

(6) Communicating with all balancing area authorities in California in a manner that supports electrical reliability.

(c) The Independent System Operator shall do all of the following:

(1) Consult and coordinate with appropriate state and local agencies to ensure that the Independent System Operator operates in furtherance of state law regarding consumer and environmental protection.

(2) Ensure that the purposes and functions of the Independent System Operator are consistent with the purposes and functions of nonprofit, public benefit corporations in the state, including duties of care and conflict-of-interest standards for officers and directors of a corporation.

(3) Maintain open meeting standards and meeting notice requirements consistent with the general policies of the Bagley-Keene

Open Meeting Act (Article 9 (commencing with Section 11120) of Chapter 1 of Part 1 of Division 3 of Title 2 of the Government Code) and affording the public the greatest possible access, consistent with other duties of the corporation. The Independent System Operator's Open Meeting Policy, as adopted on April 23, 1998, and in effect as of May 1, 2002, meets the requirements of this paragraph. The Independent System Operator shall maintain a policy that is no less consistent with the Bagley-Keene Open Meeting Act than its policy in effect as of May 1, 2002.

(4) Provide public access to corporate records consistent with the general policies of the California Public Records Act (Chapter 3.5 (commencing with Section 6250) of Division 7 of Title 1 of the Government Code) and affording the public the greatest possible access, consistent with the other duties of the corporation. The Independent System Operator's Information Availability Policy, as adopted on October 22, 1998, and in effect as of May 1, 2002, meets the requirements of this paragraph. The Independent System Operator shall maintain a policy that is no less consistent with the California Public Records Act than its policy in effect as of May 1, 2002.

346. The Independent System Operator shall immediately participate in all relevant Federal Energy Regulatory Commission proceedings. The Independent System Operator shall ensure that additional filings at the Federal Energy Regulatory Commission request confirmation of the relevant provisions of this chapter and seek the authority needed to give the Independent System Operator the ability to secure generating and transmission resources necessary to guarantee achievement of planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Electric Reliability Council.

347. The Independent System Operator governing board may form appropriate technical advisory committees composed of market and nonmarket participants to advise the Independent System Operator governing board on issues including, but not limited to, rules and protocols and operating procedures.

348. The Independent System Operator shall adopt inspection, maintenance, repair, and replacement standards for the transmission facilities under its control no later than September 30, 1997. The standards, which shall be performance or prescriptive standards, or both, as appropriate, for each substantial type of transmission equipment or facility, shall provide for high quality, safe, and reliable service. In adopting its standards, the Independent System Operator shall consider: cost, local geography and weather, applicable codes, national electric industry practices, sound engineering judgment, and experience. The Independent System Operator shall also adopt standards for reliability, and safety during periods of emergency and disaster. The Independent System Operator shall report to the Oversight Board, at such times as the Oversight

Attachment L: Weare, Christopher. "The California Electricity Crisis: Causes and Policy Options." Public Policy Institute of California, 2003.

The California Electricity Crisis: Causes and Policy Options

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Christopher Weare

2003

PUBLIC POLICY INSTITUTE OF CALIFORNIA

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Summary

With the passage of AB 1890 in 1996, California led the nation in efforts to deregulate the electricity sector. The act was hailed as a historic reform that would reward consumers with lower prices, reinvigorate California's then-flagging economy, and provide a model for other states. Six years later, the reforms lay in ruins, overwhelmed by electricity shortages and skyrocketing prices for wholesale power. The utilities were pushed to the brink of insolvency and are only slowly regaining their financial footing. The state became the buyer of last resort, draining the general fund and committing itself to spending $42 billion more on long-term power deals that stretch over the next ten years. The main institutions of the competitive market established by AB 1890, the Power Exchange and retail choice in particular, have been dismantled.

The debate over the exact causes of the crisis continues. Many wish to distill the genesis of the crisis to simple themes. Some, most notably major political actors in California, lay principal blame on market manipulation by the merchant generators. Others, including the Federal Energy Regulatory Commission and energy firms, point to flaws in the state's restructuring plan and a fundamental supply and demand imbalance. Any search for simple answers, however, risks misperceiving the intricacies of the systemic failure of California's electricity sector. A satisfactory explanation for the severity of the crisis and its consequences cannot be composed based on any single factor. Rather, a number of factors must be considered. These include:

- A shortage of generating capacity,
- Bottlenecks in related markets,
- Wholesale generator market power,
- Regulatory missteps, and
- Faulty market design.

No single factor can fully account for the crisis. The fault cannot be pinned entirely on the shortage in generating capacity. The worst of the crisis occurred during the winter of 2000–2001, when demand was low and plenty of capacity should have been available. Similarly, market manipulation by generators does not tell the whole story. There is evidence of the exercise of market power, but increased input costs and demand also pushed market prices higher. Although the division of regulatory authority between California and the federal government led to catastrophic policy paralysis in response to the crisis, it cannot be blamed for the run-up in wholesale rates that instigated the crisis. Finally, flaws in the restructuring of the electricity sector did exacerbate the crisis, but the market had been working reasonably well for the first two years of its operations.

Because California's experience was unique and because a number of factors were simultaneously at play, it is not possible to disentangle fully how each distinctly contributed to the blackouts, major financial crisis, and the systemic breakdown of market institutions. Some important conclusions can, nevertheless, be offered.

First, California's electricity sector was rocked by a number of events unrelated to restructuring: the rise in national natural gas prices, higher costs for pollution permits, and a drought in the Northwest which reduced available imports of electricity. Even if the electricity sector had remained regulated, prices would have increased, and some blackouts would have possibly occurred between May 2000 and June 2001. Second, although regulators have yet to uncover a smoking gun clearly establishing that merchant generators strategically manipulated wholesale market prices, market and regulatory conditions created an environment ripe for the exercise of market power.[1] The shortages in generating capacity played a critical role, increasing the bargaining strength of merchant generators and signaling the enormous profits that could be gained through supply shortages. At the same time, the excessive reliance

[1]Recently, regulators have uncovered evidence of market manipulation strategies employed by Enron and other electricity trading firms. These strategies, however, targeted small ancillary markets, such as those that manage congestion on transmission lines. They did not uncover any evidence of manipulation of the main market for wholesale power.

on the spot market increased the opportunities and incentives for generators to increase their prices well above the costs of generating power. Third, California relied far too much on the spot market for wholesale power instead of securing power through more stable long-term contracts. This choice exposed the utilities to exceptional risks, producing a full-blown financial fiasco. Finally, the division in regulatory authority between state and federal regulators impeded policymakers from developing a rapid, coordinated, and effective response before major damage was inflicted on the electricity sector, the California economy, and all Californians.

Because the crisis has left California's energy sector in such disarray, policymakers face the daunting task of reconstructing the market and regulatory institutions of the electricity sector almost entirely from scratch. Decisions over the long-run institutional structure of California's electricity sector are complicated by the complexity of the issues that the crisis unearthed and the wide range of options being debated. Serious proposals representing almost the entire spectrum of economic philosophies are receiving significant attention. These include calls for increased public ownership of the electricity sector, a return to the system of regulated, vertically integrated utilities, and recommendations for further deregulation. We examine the costs and benefits of these major options, focusing on six primary goals for the electricity sector:

- Low prices,
- Stable bills for customers,
- Efficient use of resources by producers and consumers,
- A reliable supply of electricity,
- Administrative feasibility, and
- Protection of the environment.

Overall, policymakers face a choice between the greater stability, reliability, and administrative feasibility provided by public ownership or regulated regimes versus the prospects for greater efficiency gains through competitive markets. In terms of environmental protections, no regime clearly dominates the others, mainly because environmental results depend on complex interactions between each regime and existing environmental regulations.

Eventually, movement to reinstate elements of the competitive regime, in particular competitive wholesale generation, is almost inevitable. The federal government continues to push for greater wholesale competition through the creation of regional trading organizations. In addition, technological advances create ever-smaller plants that can generate electricity at competitive costs, facilitating entry by new firms and enabling large customers to self-generate. Efforts to bottle up these sources of power through public ownership or regulation become increasingly difficult and inefficient. In the short run, policymakers may choose to restrain the development of competitive generation markets if they wish to promote a more stable electricity sector and are wary about ceding control to the Federal Energy Regulatory Commission for mitigating the market power of competitive generators. Nevertheless, they should exercise caution in making short-run choices that erect barriers against loosening these constraints on competition in the future.

On the retail side of the market, the tradeoffs between regulated and competitive structures depend on consumers. Potential efficiency gains from competition are derived by changing consumer behavior, making them more aware of the real costs of electricity and allowing them to change their consumption accordingly. These gains can come about, however, only if consumers are exposed to price volatility and are willing and able to manage that volatility. If consumers wish to be shielded from such volatility and wish to remain passive consumers of energy, the benefits of a competitive regime are reduced. Concerns over the ability of consumers to manage electricity price volatility suggest that hybrid models that introduce retail competition in stages, first to larger customers and only later to smaller customers, offer important advantages.

The report also offers three recommendations for policy changes that can improve the performance of the electricity sector under any particular regulatory and market structure. The first is to strengthen and institutionalize demand-management programs. Electricity sector restructuring ignored and often undermined demand-side management.

Regulators failed to promote retail competition. Funding for conservation programs was reduced, and consumers were shielded from price fluctuations. As policymakers continue to seek ways to balance the supplies and demands within California's electricity sector, demand management cannot be left out of the equation. These programs can lower energy costs, improve efficiency, and enhance system reliability. In addition, promoting demand management can make individuals and firms more intelligent consumers of electricity, facilitating the introduction of retail competition and enabling them to benefit from competitive offerings.

The second recommendation is to develop a capacity for more comprehensive planning and oversight of California's energy infrastructure. Inadequate transmission capacity, overreliance on natural gas plants, bottlenecks in natural gas pipelines, and inadequate natural gas storage all contributed to the state's troubles. An overarching review of these interlocking infrastructure components is necessary to ensure that private investments are adequate and to identify areas in which public investment or coordination is required.

The third recommendation is to reassess and reorganize the complex set of administrative structures that currently exist. Electricity sector restructuring followed by crisis has led to an ad hoc and confusing mix of state agencies and departments. This fractured and overlapping set of agencies leads to inefficiencies, conflicts, and policy confusion. It must be redesigned for effective policy development and implementation and to provide a more certain environment for producers and consumers.

California policymakers need to take away a number of hard-earned lessons from the crisis. The complexity of electricity markets cannot be underestimated, and seemingly inconsequential details of market design can have significant and unexpected consequences. Specifically, heavy reliance on spot markets is extraordinarily risky. Policymakers must also appreciate the extent to which the state's control over the electricity sector has been circumscribed by the split of regulatory authority between the state and federal governments. Finally, if market-based reforms are to be successful, firms and consumers must become more responsive to market incentives and risks. During the restructuring of the electricity sector, however, utilities and consumers continued to operate as if the stable and secure rules of regulation still held, leaving California woefully unprepared for the price spikes in 2000.

At this juncture, policymakers must focus on forging a consensus on the future direction of California's electricity sector. Continued ambiguity and conflict lead to market uncertainty, stifle investment in critical infrastructure, and risk repeating errors that precipitated the crisis. Agreement on the broad outlines of a regulatory and market structure, even without the details specified, would do much to improve the investment environment and enable California to move forward.

Contents

Foreword iii
Summary v
Figures xiii
Tables xv
Acronyms xvii

1. INTRODUCTION 1

2. REGULATORY CONTEXT 7

3. ROOT CAUSES OF THE ELECTRICITY CRISIS 15
   A Shortage of Generating Capacity 15
      Unforeseen Events 19
      Regulatory Failures 23
      Market Failures 26
   Bottlenecks in Related Markets 28
   Wholesale Generator Market Power 32
   Regulatory Missteps 37
      Excessive Exposure to Spot Markets 38
      Inaction in the Face of the Impending Crisis 44
   Faulty Market Design 47
   Conclusion 48
   Addendum: The Crisis Fades 51

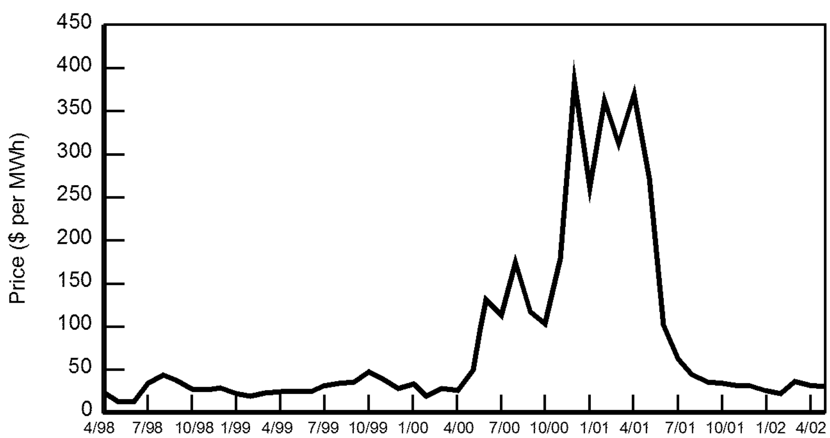
4. REBUILDING THE CALIFORNIA ELECTRICITY SECTOR: INSTITUTIONAL CHOICES 55
   Goals for the Electricity Sector 57
   Public Power 59
   Return to Regulation 63
   Fix Markets and Proceed with Restructuring 66
      Infrastructure Policy 69
      Controlling Market Power 73
      Market Design 79
      Retail Competition 81
      Transition Strategy 84

Hybrids 85
Conclusions 87
5. OVERARCHING RECOMMENDATIONS 93
Improve Demand Management 93
Develop Comprehensive Infrastructure Planning 102
Reorganize Policy Apparatus 103
6. CONCLUSIONS 107
Appendix: The Effect of Price Caps on Firms Exercising Market Power 111
References 115
About the Author 119
Related PPIC Publications 121

1. Introduction

In 1996, California passed AB 1890, a bill calling for the radical restructuring of the state's electricity sector. Competitive markets for wholesale power were inaugurated in April 1998, and in those early years, the markets appeared to function relatively well. As predicted, the wholesale price of electricity declined and average rates fluctuated moderately between $20 and $50 per megawatt hour (MWh) (see Figure 1.1). Customers benefited from a 10 percent rate reduction and were protected by a temporary rate freeze. The utilities benefited at the same time, as they were able to pay off the costs of transitioning to a competitive environment.

In the late spring of 2000, however, the electricity sector began to malfunction severely. In June, average prices suddenly rose precipitously, breaking the $100 per MWh mark. They remained at extraordinarily high rates through the spring of 2001 before they moderated rapidly and



SOURCE: Joskow and Kahn (2001b).

Figure 1.1—Average Wholesale Electricity Prices in California, 1998–2002

unexpectedly in June 2001 (see Figure 1.1). Although total energy costs for wholesale power were $7.4 billion in 1999, they were about $27 billion per year from 2000 through 2001, burdening California consumers and businesses with almost $40 billion in added costs.

The lights flickered throughout the crisis. On June 14, 2000, rolling blackouts in San Francisco caused by a Bay Area heat wave signaled the beginning of rough times. In 2000, electricity was turned off to customers with special interruptible contracts on 13 other days. During 2001, "load shedding" occurred on 31 days. On nine of these days customers experienced involuntary rolling blackouts for a total of 42 hours of outages. During these nine outages, California experienced an average shortfall of 600 MW of electricity, enough energy to power over 450,000 households. On the worst day, January 18, the equivalent of almost one million households lost electricity. The costs of these blackouts are difficult to enumerate, but they are undoubtedly significant.

The soaring prices on the wholesale market wreaked financial havoc on the electricity sector. The customers of San Diego Gas & Electric (SDG&E) felt the brunt of the cost increases immediately. The retail rate freeze imposed on the utilities had been lifted for SDG&E in July 1999. Thus, SDG&E customers were paying electricity rates based on wholesale prices and saw their bills double and triple during the summer of 2000. Customers of Pacific Gas & Electric (PG&E) and Southern California Edison (SCE), in contrast, were shielded from these increases by the retail rate freeze. These two utilities, however, were caught in a financial vise, forced to buy expensive power on the wholesale market and sell it cheaply to retail customers. Soon, SDG&E joined them in this predicament when the legislature passed AB 265, which reimposed a rate freeze for SDG&E customers retroactively.[1] The three major utilities racked up debt at a rapid pace. In January, as their credit worthiness evaporated, the state was forced to become the purchaser of last resort.

[1]AB 265 included provisions to enable SDG&E to recoup the uncompensated costs of buying wholesale power. Thus, it was not placed in the same financial peril as were PG&E and SCE.

A long list of debts is still being sorted out. Pacific Gas & Electric declared bankruptcy and is arranging in bankruptcy court how to pay creditors about $13 billion. Southern California Edison accepted a deal with the California Public Utilities Commission (CPUC) in which it will pay off $5 billion to $6 billion in debt with a combination of ratepayer contributions, cash on hand, and decreased dividends. The state spent $8.7 billion on wholesale power in the first half of 2001 and projected that it would spend $17.2 billion by the end of the year. $7 billion for these purchases came from the general fund, and the state is still struggling to float a $12 billion bond to repay the fund. In addition, during the height of the crisis the state began signing long-term contracts for power to secure a source of supply, and it is now committed to purchase $42 billion worth of electricity over the next ten years.

Beyond this financial turmoil, the crisis caused by the surge in wholesale prices devastated the institutional structures governing the California electricity sector. The private utilities are no longer the main purchasers of power. Instead, the state is more tightly entwined in the electricity market than it has ever been before. The Power Exchange (PX), the central market for trading wholesale power, went bankrupt and closed operations. The Independent System Operator (ISO), designed to manage the electricity grid, has become politicized and is under fire. The state has curtailed retail choice, putting competition on hold, and regulatory authority is now more fragmented, leading to overlaps and conflict. The destruction wrought by the financial crisis and system failure has been so complete that California must re-create the regulatory and market institutions of its electricity sector almost from scratch.

To gain some perspective on the damage inflicted on the California economy, one can compare it with other significant economic failures. This crisis has cost $40 billion in added energy costs over the last two years. Increased costs will continue as long as the prices in the long-term contracts signed by the state exceed wholesale rates. On top of these costs, one must add the costs of blackouts and reductions in economic growth caused by the crisis.[2] Thus, conservatively, the total costs can be

[2]The national recession has complicated estimating the macroeconomic effects of the crisis, but in June UCLA projected that the crisis would slow the California economy

placed around $40 billion to $45 billion or around 3.5 percent of the yearly total economic output of California. Before this crisis, the preeminent example of failure of an electricity system was a default by the Washington Public Power Supply System. It overinvested in nuclear plants and defaulted on its bonds. This default cost the state about $800 million or 1.5 percent of its total economic output. The Savings and Loan debacle was considered a staggering deregulatory failure, but its total costs of about $100 billion amounted to only one-half of 1 percent of the total U.S. economy.

Repairing this damage poses a daunting task to California policymakers. Much of the debate and legislative action has focused on the financial dimensions of the crisis. In contrast, the manner in which the state is going to extricate itself from its role as the power purchaser of last resort, reorganize the electricity sector, and regulate it remains imprecise. This report seeks to focus attention on these important institutional questions.

After a brief overview of the regulatory reforms that led to this crisis, this report examines the root causes of the crisis. It finds that blame cannot be easily leveled at any single actor. A combination of unforeseen events, poor decisions, opportunistic behavior, and fragmented regulatory authority all conspired to aggravate the magnitude of the crisis.

Based on this analysis of the root causes of the crisis, Chapter 4 of the report examines a number of frameworks that may guide the reorganization of the electricity sector: increased public ownership, return to a regulated environment, continuing with competitive markets, and hybrids of these options. It concludes that some form of competition should be reinstated, at least for certain industry segments and customer classes. In the short run, however, policymakers may choose to curtail the role of competition for the sake of stability and

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in 2002 by between 0.7 and 1.5 percent and would increase unemployment by 1.1 percent. See Cambridge Energy Research Associates (2001b).

administrative ease and to provide a smoother transition path back to a competitive environment. Chapter 5 then discusses specific policy options that are appropriate no matter which reform path is chosen.