Application No.:	R.12-03-014
Exhibit No.:	ISO-3
Witness:	Robert Sparks

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

A.13-06-015

Application of San Diego Gas & Electric Company (U 902 E) to Fill Local Capacity Requirement Need Identified in D.13-03-029

Rebuttal Testimony of Robert Sparks on Behalf of the
California Independent System Operator Corporation
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).

Q. Why do you believe that load shedding is not appropriate under the circumstances of the loss of Sunrise followed by the loss of SWPL?

A. As I discussed in my rebuttal testimony, 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. In other words, relying on load shedding as part of the long-term plan leaves no allowance for unexpected circumstances such as generation retirements or higher load growth, other than additional load shedding which could lead to overly excessive amounts of load shedding. The ISO does not believe that load shedding should be used as a transmission planning tool for this particular contingency and for this densely populated area where - contrary to Mr. Peffer's testimony - widespread and possibly sustained outages could jeopardize public safety and have widespread economic consequences.

Q. Isn't load shedding permitted by NERC reliability standard TPL 003 in response to a Category C N-1-1 event?

A. Yes, and the ISO has special protection schemes (SPS) in place that employ some form of load shedding in small amounts on the sub-transmission system or for extreme category D contingencies. However, 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 requires the Planning Coordinator to consider system design and expected system impacts in deciding whether an automatic load shedding SPS is appropriate.

Q. Is the ISO's position with respect to load shedding in highly urbanized areas under the N-1-1 contingency unique to SDG&E?

A. No. Similar to the San Diego area, the ISO does not use load shedding as a long term mitigation solution for the N-1-1 contingency in areas of dense population throughout the SCE and PG&E service territories as well. Changing this position for SDG&E would lead the ISO to make sweeping changes from current and historical practices for the entire ISO controlled grid. Furthermore, the ISO's position with respect to load shedding in highly urbanized areas is consistent with current practices in the rest of the ISOs and, in general, in much of the United States and Canada.

Q. Does the N-1-1 limiting contingency reduce the reliability benefits of the Sunrise Powerlink line below the 1000 MW reduction in LCR claimed as a benefit when the line was approved, as argued by Mr. Peffer at pages 9-11 of his testimony?

A. No. The 1000 MW benefit was based on increasing the existing import capability from 2500 MW to 3500 MW after an outage of either Sunrise or SWPL. At that time, the ISO assumed that the 3500 MW amount would be based on establishing a 3500 MW WECC path rating to replace the 2500 MW WECC Path 44 rating. Since that time the 1000 MW Sunrise WECC path rating has been eliminated as well as any notion of pursuing a 3500 MW WECC N-1 Path Rating. Although these path ratings would have helped ensure that changes within neighboring systems could not impact the capability of the ISO system, and provided reasonable margin for this

urban load area which has only two reliable connections (SONGS and Imperial Valley) to the rest of the ISO and WECC, they also would limit the capability of the system. With Sunrise in-service the Imperial connection became more reliable, and the path ratings are not being pursued any further. Without the path rating limitations the N-1-1 is the most limiting contingency, and with only the N-1-1 considered, Sunrise provides more than 1000 MW of benefit. This information was shared by the ISO during the workshop for the San Diego procurement proceeding.

Q. Mr. Peffer accuses the ISO of a "lack of transparency" about its planning standards (testimony, page 12), noting specifically that the ISO objected to POC data requests on this subject. Do you agree that there is a lack of transparency regarding the ISO's reliability criteria?

A. No. As I have discussed above, and throughout the record in A.11-05-023, the N-1-1 limiting contingency for the San Diego area is firmly grounded in the LCR planning methodology and the NERC/WECC planning standards. It has been used for many years in the Commission's resource adequacy proceedings and is clearly described in numerous documents on the ISO's website. The N-1-1 issue was litigated in A.11-05-023 and resolved in D.13-03-029. For all of these reasons, the ISO objected to POC's data requests.

San Diego Local Capacity Area and Local Generation

Q. Mr. Peffer states that the ISO "wrongfully excluded" generation assets from the San Diego local area, thus overstating the LCR need (testimony, pages 5-7). Can you respond to this testimony?

A. Once again, Mr. Peffer misunderstands the ISO's LCR study methodology, and also has confused planning criteria with operational requirements. As I discussed in my supplemental testimony in A.11-05-023, the ISO studies identified two local

capacity subareas in the SDG&E service territory: the San Diego LCR subarea and the IV-San Diego LCR area. From a transmission planning standpoint, the N-1-1 criteria discussed above is the most limiting contingency for the San Diego LCR subarea. 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). Generation at the Imperial Valley substation, such as La Rosita II and Sempra TDM is not effective at meeting the needs of the San Diego LCR subarea since that generation cannot flow into the area during the worst contingency. However, the generation at the Imperial Valley substation is effective at meeting the IV-San Diego LCR needs. Pio Pico is needed to meet the San Diego LCR subarea needs, and since the generation at Imperial Valley substation such as La Rosita II and Sempra TDM combined cycle projects (with generator ties to the Imperial Valley Substation) cannot meet the needs of this subarea, they are not substitutes for Pio Pico. Although from an operating standpoint, in order to protect against certain under frequency islanding situations, these generating units would be dispatched to meet the 25% internal generation requirement, as discussed in the FERC order Mr. Peffer describes in his testimony, this has nothing to do with the ISO's LCR study methodology, which does not consider islanding situations, and resource needs in the San Diego subarea identified in A.11-05-023.

Intervening Events Following D.13-03-029

Q. At pages 4-10 of his testimony, Mr. Powers suggests that the Commission should reconsider the local capacity need established in D.13-03-029 to take into account various changed circumstances since the decision was issued. Do you agree that the Commission should follow this course?

A. No, I do not. Mr. Powers has requested that Commission reconsider many of the study assumptions that were approved in D.13-03-029, thus necessitating that the studies be performed again so that new local resource needs can be identified. Using this approach will lead to never-ending studies with no conclusions because there will always be changed circumstances after a study is completed and decisions are rendered.

Q. Isn't the ISO evaluating local capacity needs in the San Diego and LA Basin areas in light of the SONGS retirement in Track 4 of the current LTPP, R.12-03-014?

A. Yes. The ISO's LCR studies underlying the resource needs identified in D. 13-03-029 did not take the SONGS retirement into account. The ISO's Track 4 studies have identified substantial needs in the LA Basin and San Diego that are in addition to the 298 MW approved for San Diego and the 1400-1800 MW approved for the LA Basin in Track 1. The ISO suggests that if preferred resources, energy storage and DG are developing at a rapid pace, as Mr. Powers suggests, the Commission can consider whether these resources can fill the residual needs identified by the ISO in Track 4.

ISO Recommendation

Q. What is the ISO's recommendation regarding the SDG&E request for approval of the Pio Pico PPTA?

A. Based on the ISO's local capacity studies, the Commission in D.13-03-029 determined there to be a 298 MW local need in the San Diego area, starting in early 2018. It is my understanding that the decision gave SDG&E the option of either re-submitting the Pio Pico and/or Quail Brush PPTA(s) with modifications to the commercial in-service dates to coincide with the retirement of the once-through-

cooling generation, or issuing a new request for offers. Given the lead time needed for new generation permitting and construction, it would seem that conducting a new request for offers could adversely impact the commercial operation date of new resources responding to the request, ultimately impacting local reliability if the resource is not available after January 1, 2018.

Q. Would other resources, particularly preferred resources, also be able to fill the 298 MW need determined in D. 13-03-029?

A. Yes, if such resources provide the characteristics needed by the ISO to respond to local contingencies. However, as SDG&E witness Eekhout noted, the Commission took into account certain assumed levels of demand response and uncommitted energy efficiency that would be available to meet local resource needs, and reduced the ISO's study results to reflect these additional assumptions. The ISO agrees with SDG&E that it would not be prudent to assume that even greater levels of these preferred resources could supplant the need for a conventional gas-fired resource such as Pio Pico.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTACHMENT 1
Excerpts from Rebuttal Testimony of Robert Sparks on Behalf of the
California Independent System Operator Corporation
in Docket No. A.11-05-023

Pages 10 - 11

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

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

ATTACHMENT 2
Excerpts from the Opening Brief of the
California Independent System Operator Corporation
in Docket No. A.11-05-023
July 13, 2012

Pages 13 - 16

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

Nancy Saracino
General Counsel
Anthony Ivancovich
Assistant General Counsel
Judith B. Sanders
Senior Counsel
California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel.: (916) 608-7143
Fax: (916) 608-7222
jsanders@caiso.com

Attorneys for the California Independent System Operator Corporation

ISO used for an import capability and the 3500 MW San Diego area import level used by SDG&E is 414MW and should be added back into the LCR deficiency calculation, DRA witness Ghazzagh's determination of the local area resource requirement for 2020 under the high load scenario- 2713MW- is actually higher than the ISO's calculation for 2021 in the ISO base case. Thus, while the ISO cautions the Commission against using the "apples to oranges" approach to establish the import capability for purposes of LCR needs, the final conclusions as to the LCR needs reached by DRA and the ISO are not so far apart.[30]

CEJA witness Ms. Firooz also mixed apples and oranges by suggesting that the 3500MW import limit recommended by SDG&E should be increased by 730MW, based on the ISO's analysis. While it is rather difficult to follow and understand her analysis, Ms. Firooz seems to suggest that ISO's post-contingency import flow of 3230MW in 2021 should be increased by 1000MW to reflect the additional import capability provided by Sunrise (which would produce an import capability of 4230MW, or 730 MW higher than the 3500 MW used by SDG&E and DRA).[31] Her apparent assumption is incorrect. Ms. Firooz seems to have overlooked the fact that the ISO's post-contingency import flow is based on the N-1-1 contingency with Sunrise out of service, so that there were no Sunrise flows in the ISO's analysis that produced the 3230 MW flow limit. As noted above, the 3500 MW import capability was based on the G-1/N-1 contingency with only SWPL out of service, and with 604 MW of local generation out of service. Thus, Ms. Firooz's recommendation of a higher import limit lacks justification and is not consistent with any study methodology.

[30] Mr. Fagan's overall spreadsheet conclusions as to the LCR deficiencies for San Diego are dramatically different than the ISO's because of other assumptions that he adds to the spreadsheet analysis such as assumptions about uncommitted EE, incremental DR and others.
[31] Ex. 20, page 19.

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.

ATTACHMENT 3
Excerpts from the Reply Brief of the
California Independent System Operator Corporation
in Docket No. A.11-05-023
July 27, 2012

Pages 9 - 12

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

Nancy Saracino
General Counsel
Anthony Ivancovich
Assistant General Counsel
Judith B. Sanders
Senior Counsel
California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel.: (916) 608-7143
Fax: (916) 608-7222
jsanders@caiso.com
Attorneys for The California Independent System Operator Corporation

July 27, 2012

> 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.

the 2013 Local Area Technical Study[19] and in the ISO's tariff.[20] It goes without saying that the LCR/OTC studies are conducted in accordance with NERC/WECC transmission planning standards.

Contrary to CEJA's assertions, the "2.5% reserve margin" is not related to the operational reserve requirements established by the Commission and was not unilaterally "added in" to the OTC study outside of the criteria used for an LCR/OTC study. Rather, the "2.5%" margin is a WECC transmission planning criteria that is followed as part of the LCR/OTC study methodology. Mr. Sparks explained this concept in response to questions from DRA about the OTC results table on page 3 of his supplemental testimony (Ex. 10).[21] Specifically, Mr. Sparks stated:

> …I also want to mention that [the] 2.5 percent margin…is required by the WECC or reliability criteria on top of the forecasted load. It is meant to be a margin for error because the studies are obviously not perfect.
>
> Q. And that criteria…is what you were just discussing with Ms. Behles a little earlier …the reserve margin?
>
> A. No, the reserve margin requirements are resource planning needs. The reactive power margin is more of a transmission planning need.
>
> And so there are two different problems. One is solved with reactive power or local resources in this case and is localized, very localized problem on the system. Resource adequacy is a much bigger picture. It is not necessarily a transmission issue. That is why they break them up into two disciplines, if you will.[22]
>
> ******
>
> As I mentioned earlier, the ISO is also a planning authority. So we are subject to the transmission planning standards. There are many standards. And so the transmission planning standards do need to be performed out to a 10 year horizon. And the WECC reactive power planning requirements specify this

[19] Ex. 18, Attachment O
[20] See ISO tariff § 40.3
[21] Tr.III, 579:17-585:2.
[22] *Id.*at 580:24-581:20.

> 2.5 percent margin for Category C outages, and a 5 percent margin for Category B outages. And in a load pocket that means increasing the load…[23]

CEJA also cites the language of D.06-06-064 wherein the Commission selected the ISO's reliability planning Option 2, and argues that the ISO has not presented the Commission with "options" as part of the OTC study.[24] True, the description of the OTC study at Chapter 3 of the 2011/2012 Transmission Plan does not set forth the reliability planning options customarily set forth in the annual LCR study. However, since the issuance of D.06-06-064, the ISO has in fact consistently conducted its LCR studies in accordance with Option 2, as described at page 16 of the 2013 Local Capacity Technical Study[25]:

> Option 2 is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation capacity *after* considering all reasonable and feasible operating solutions (including those involving customer load interruption) developed and approved by the CAISO, in consultation with the PTOs…

Because the OTC study was conducted using the same criteria, the local capacity deficiencies were based on the Option 2 local capacity level. Further, as the ISO discussed extensively throughout the testimony and briefs in this proceeding, the ISO did in fact evaluate all "reasonable and feasible operating solutions," including load interruption, and concluded that additional local generation presented the most feasible mitigation solution. The OTC study is consistent with D.06-06-064 and the LCR studies that have been approved annually by the Commission since the issuance of that decision.

Besides misunderstanding the ISO's LCR study methodology, CEJA also appears to be confused about the NERC/WECC- required contingency analysis, which is the basis

[23] *Id.*at 582:15-583:4.
[24] CEJA opening brief, page 12.
[25] Ex. 18, Attachment O

of the OTC study. The CEJA opening brief contains an entire section entitled "*CAISO Assumes that Sunrise Powerlink, SWPL, and the CFE Line Provide No Import Capability.*"[26] Apparently in support of this statement, CEJA entered into the record as Ex. 41 the pre- and post- import flows for two scenarios provided by the ISO in discovery. These are reproduced on page 15 of CEJA's opening brief. This table shows that after the most limiting N-1-1 contingency, which is the loss of an element of the Sunrise line followed by the loss of an element of SWPL, the parallel CFE transmission line will be disconnected. CEJA misses the obvious fact that the when these transmission line are lost to due electrical short circuit conditions, they must be removed from service. When this occurs, the parallel CFE transmission line must be protected from overload, which requires that it be removed from service as well. When these lines are removed from service, no power can flow through them. However, prior to this contingency these lines were carrying over 2600 MW of imported power. Until these lines are repaired by SDG&E, there can be no import flows on these major connections into San Diego. That is how a contingency study is conducted-- the ISO must mitigate a situation where substantial import flows into the local area have been cut off by a transmission outage.[27] This has nothing to do with the substantial benefits that Sunrise brings to the local area that CEJA describes. Contrary to CEJA's section heading, the benefits of Sunrise are assumed in the ISO's study methodology.

III. Credibility of the CEJA Testimony

CEJA witness Firooz made certain statements in the introduction and *curriculum vitae* sections of her written testimony which the ISO believed were unsustainable or

[26] CEJA Opening Brief pages 14-16.
[27] The ISO provided an explanation about import flows and CEJA's misunderstanding about the role of Sunrise in an N-1-1 contingency at page 13 of its opening brief.

ATTACHMENT 4
Excerpts from Rebuttal Testimony of Robert Sparks
on Behalf of the California Independent System Operator Corporation
in Docket No. A.11-05-023
June 6, 2012

Pages 8 - 10

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

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.

Load Shedding and Special Protection Schemes (SPS)

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?

ATTACHMENT 5
Excerpts from the Opening Brief of the
California Independent System Operator Corporation
in Docket No. A.11-05-023
July 13, 2012

Pages 16- 18

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

Nancy Saracino
General Counsel
Anthony Ivancovich
Assistant General Counsel
Judith B. Sanders
Senior Counsel
California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel.: (916) 608-7143
Fax: (916) 608-7222
jsanders@caiso.com

Attorneys for the California Independent System Operator Corporation

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

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.