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

Table of Contents

Table of Authorities

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.

II. Introduction and Procedural Background

San Diego Gas & Electric Company (SDG&E) seeks approval of three purchase power tolling agreements (PPTAs) with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power. The July 29, 2011, Scoping Memo and Assigned Commissioner Ruling (ACR) identified need for each proposed generation project as one of the issues to be resolved in the proceeding. Included in the need evaluation were such matters as guidance from other Commission proceedings (such as the long term procurement proceeding [LTPP] then in effect, R.10-05-006), resource retirements including units subject to once-through-cooling (OTC) requirements, transmission capabilities and information from the California Independent System Operator (ISO) regarding the formation of the Greater San Diego Locally Constrained Area.[2]

In a January 18, 2012, Joint Assigned Commissioner's Ruling (Joint ACR) issued in this docket and R.10-05-006, Commissioners Peevey and Ferron noted that SDG&E, in the LTPP case, had requested procurement authorization for 415MW of new resources to meet it Local Capacity Requirement (LCR). They pointed out that subsequent to hearings and briefs in R.10-05-006 but prior to a decision on SDG&E's LCR needs, the ISO issued a report directly relating to this issue and that it would be beneficial to the decision-making process for the parties to have an opportunity to address the report.[3] The Commissioners concluded that in order to ensure that the latest information from the ISO could be integrated into Commission processes, the issue of SDG&E's LCR needs would be addressed in this docket rather than R.10-05-006. The process for incorporating the ISO's findings and portions of the

---

[2] See ACR page 2-3.
[3] Joint ACR at 3.

record in the LTPP docket into this proceeding was left to the ALJ and the Assigned Commissioner.

On February 24, 2012, the ISO submitted a motion to become a party to this proceeding for the purposes of sponsoring the report referred to in the Joint ACR.[4] Pursuant to several Scoping Memos/ACRs, a schedule for testimony, hearings and briefs was established.[5] The ISO submitted the initial testimony of two witnesses, Mark Rothleder and Robert Sparks, on March 9, 2012 and the supplemental testimony of Robert Sparks on April 6, 2012. The rebuttal testimony of Robert Sparks was submitted on June 6, 2012, and both witnesses supported their testimony during evidentiary hearings held on June 19-22, 2012. In accordance with the procedural schedule, the ISO hereby submits its opening brief on SDG&E's local area capacity needs.

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

In his initial testimony,[6] Mr. Sparks described three local area capacity studies that the ISO conducted as part of the 2011/2012 transmission planning cycle.[7] As he explained, a local capacity technical study determines the minimum amount of resources within a local capacity area needed to address reliability concerns following the occurrence of various contingencies on the grid.[8] These contingencies, discussed in greater detail below, are defined by the North American Electric Reliability Corporation (NERC) and Western Electric

[4] This report is the ISO's OTC study, conducted in collaboration with the CEC and the CPUC and embodied in the 2011/2012 Transmission Plan.
[5] See Amended Scoping Memo/ACR issued March 12, 2012 and ALJ Ruling Resetting Procedural Schedule (March 29, 2012)
[6] Exhibit 9 is Mr. Sparks' initial testimony; Exhibit 10 is his supplemental testimony and Exhibit 27 is his rebuttal testimony.
[7] The ISO performs an annual transmission planning process but each cycle spans at least 15 months (January of year x through March of year x+1) and overlaps with the next cycle. Thus, cycle 2012/2013 began as the 2011/2012 cycle was being completed. The ISO Board of Governors considers and approves the recommendations in the transmission plan produced for each cycle at the March board meeting.
[8] Ex. 9, pages 3-4.

Coordinating Council (WECC) reliability and planning standards, as well as additional planning standards set forth in the ISO tariff. To comply with these standards and requirements, the ISO must plan for contingencies such as the loss of transmission while generation is out of service, as well as complying with other parameters.

A local capacity area is a geographic area that does not have sufficient transmission import capability to serve the customer demand in the area without the operation of generation located within that area, and there must be sufficient generation in the local area available to grid operators to serve the load in times of stressed conditions. Thus, the purpose of a local capacity area technical study, which is conducted using the study tools described below, is to analyze these defined geographic load areas in order to determine the amount of resources needed to continue to serve load in times of high demand or the unexpected loss of generation and transmission facilities.

The ISO conducts a local capacity technical study, known as a Local Capacity Requirements (LCR) study, every year for resource adequacy (RA) procurement. While described in the annual transmission planning process study plan, the LCR studies are conducted in a separate stakeholder proceeding and the results are provided to the Commission for use in each RA proceeding. In addition to the annual RA LCR study, the ISO conducts a longer-term local capacity area evaluation as part of the transmission planning process. In the 2011/2012 cycle, the ISO analyzed local areas needs for 2016.[9]

The third study described by Mr. Sparks is the OTC study, which the ISO conducted during the 2011/2012 transmission planning cycle and reported the study results in the Transmission Plan. This study considered local capacity needs over a ten year planning horizon, in 2021, using various renewable portfolio assumptions and taking into consideration

[9] Ex. 9, pages 4-5.

the impact that California's policy on the use of ocean and estuarine water for power plant cooling purposes could have on the coastal generating units in local areas. The ISO anticipates that the OTC policy will ultimately force the majority of the gas-fired power plants using once-through cooling technology to come offline to retrofit or repower, or to retire. For the San Diego local area, the generating units at the Encina Power station are expected to retire.[10]

By way of background, Mr. Sparks explained that, to conduct the OTC study, the ISO, in collaboration with the CPUC and the CEC, developed and posted a load and resources tool that was used to screen and forecast the potential time frames in which the local resources were expected to be less than the resources needed to maintain local reliability. For this effort, the ISO evaluated the unavailability of each affected generating unit based on the compliance year for the unit as established by the SWRB OTC policy, or by the year the generator owner had identified in its implementation plans. The ISO then performed technical evaluations, using power flow and transient stability programs, to evaluate mitigation measures on a high level needed to maintain zonal and local reliability.[11] These mitigation measures included generation need, potential transmission mitigation measures, potential demand side management and other contracted resources such as combined heat and power.

For the San Diego area, the ISO also performed a sensitivity study, using the same four renewable portfolio scenarios as part of the ISO's analysis of the need for policy-driven transmission elements. For this sensitivity study, the ISO assumed that the Encina units were retired. 300MW were added at Otay Mesa and 100 MW were added at the Mission-Miguel line, which are similar locations to the resources for which SDG&E is seeking approval in this

---

[10] Ex. 9, pages 2, 5.
[11] *Id.* at page 6

proceeding. The sensitivity study showed a need for transmission upgrades to make the 400 MW of new generation fully deliverable to load.[12] However, Mr. Sparks noted in his supplemental testimony that if the Carlsbad Energy Center generation had also been added to the sensitivity study, the need for the additional transmission upgrades would be eliminated, except for stringing an additional conductor at one location.[13]

After the initial testimony was submitted in this proceeding, the ISO became aware of a change in WECC criterion for categorizing the severity of transmission line outages and therefore the mitigation solutions required to address such outages. This change in criterion required the ISO to reassess its local capacity technical studies for the San Diego area, and to submit supplemental testimony with the revised study results. Specifically, the revised WECC criteria resulted in the reclassification of the common corridor outage of the Sunrise line and the IV/Miguel portion of the Southwest Powerlink (SWPL) line from Category C to Category D because the towers between those two lines are spaced less than 250 feet apart for less than three miles (the new WECC criterion).[14] This change in classification changed the most limiting contingency for the San Diego sub-area from the simultaneous loss of the Imperial-Valley-Suncrest portion of the Sunrise line and the Imperial Valley-ECO portion of SWPL to the loss of the Imperial Valley-Suncrest portion of the Sunrise line followed by the non-simultaneous loss of the ECO-Miguel portion of SWPL (an N-1-1 contingency). This change lowered the local capacity needs in each of the four portfolio scenarios.[15]

Other parties also presented calculations of LCR needs for the San Diego area, using different load assumptions, different assumptions about demand response, uncommitted

[12] Ex. 9, page 12.
[13] Ex. 10, page 8.
[14] *Id.*, page 1.
[15] *Id.* at 3-4.

energy efficiency, uncommitted combined heat and power (CHP) and mitigation solutions for the reliability issues associated with the OTC unit retirements. These proposals are discussed in the next section of this brief. Some of these proposals and possible solutions appear to be based on some confusion about the ISO's study methodology. Other proposals are simply not justifiable and should not be utilized for assessing reliability requirements and the need for additional generation in the San Diego area. In an effort to address some of these issues, more details about the ISO's studies and study resulted are presented below.

A. Summary of the ISO Findings

In his initial testimony (Exhibit 9), Mr. Sparks presented a table on page 7 that contained an "OTC range" for each of the renewable portfolios for the year 2021. Because the ISO reassessed these local needs due to the change in WECC criterion, this table was superseded by the one on page 3 of his supplemental testimony and set forth below[16]:

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**

[16] See Tr. IV at pages 604-605 where Mr. Sparks explained that the table in Exhibit 10 was meant to replace the table in Exhibit 9 so that minor discrepancies between the total LCR needs in each table were not corrected with an errata to Exhibit 9.

In this table, the ISO presents the LCR for each portfolio and under several binding constraints for two contingencies. "LCR" is used in this table to mean total generating (or equivalent) resources needed in the local area to reliably serve load in the event of the contingency. Once again, the OTC range corresponds to the incremental local capacity need with the loss of OTC generation (the rest of the LCR need is being met by existing resources). The lower number assumes that the SDG&E "Product 2" generation will be procured.[17] This analysis clearly demonstrates that there is a need for additional resources in each scenario except environmentally constrained, where the lower amount is 0 under the voltage collapse constraint if the "Product 2" generation is procured.

Mr. Sparks also explained that for the N-1-1 outage of IV-Suncrest followed by the loss of ECO-Miguel, assuming no load shed, the binding constraint becomes the South of SONGS separation scheme. This is shown with an 8000 Amp limit on Path 44 and a 7800 Amp limit on Path 44 with a 2.5% margin. Should the South of SONGS separation scheme be removed as a binding constraint, the next constraint is voltage collapse, shown in the bottom row of the table. For the less common G-1/N-2 constraint, the ISO assumed that load shed would be available. The first two rows of the table assume load curtailment of 370MW.

B. Mechanics of the OTC Study

As noted above, Mr. Sparks explained that to calculate the amount of local resources needed under normal ("steady state") and stressed conditions, the engineers conduct power flow and transient stability studies. DRA witness Robert Fagan accurately described a power flow program as a "complex piece of software that mathematically simulates the core electrical attributes of the power system." He pointed out that "[t]ransmission planners rely

[17] "Product 2" generation is the Quail Brush, Pio Pico and Escondido resources at issue in this proceeding.

heavily on power flow simulation tools," much like "a carpenter uses hammers and saws."[18] The planning engineers use these tools to conduct all of the LCR studies and the OTC study.

More detailed information about these studies can be found in the 2011/2012 Transmission Plan and the annual LCR study reports. Mr. Sparks provided references to the transmission plan (for the OTC and 2012 LCR studies) and the 2016 technical study in his initial testimony, as well as in documents provided at the April 17, 2012 workshop.[19] In addition, DRA included the 2013 LCR study as an attachment to the supplemental testimony submitted on May 18, 2012 as well as portions of Chapter 3 of the 2011/2012 Transmission Plan.[20] Descriptions of the study methodologies and underlying technical assumptions for all of these studies are set forth in an LCR Manual that is updated, with stakeholders, each year before the annual LCR study is conducted for RA purposes.[21] The reference to this document is found at page 211 of the Transmission Plan.[22]

The OTC study uses the same LCR methodology described in the 2013 Local Capacity Technical Study. As described in the transmission plan, the greater San Diego local area is made up of two local areas: the San Diego area and the Greater IV-San Diego area. Mr. Sparks explained that the reason for these two areas is the difference in limiting contingencies for each one. The San Diego area limiting contingency (N-1-1) separates the IV substation from the rest of the San Diego area, whereas the Greater IV-San Diego limiting contingency (G-1/N-1) does not. These two local areas make up the greater San Diego local area and resources located in this greater area are considered to be "local" (as opposed to "system" resources). Resources in the IV-San Diego area but not in the smaller San Diego local area

---

[18] Ex. 17, page 4.
[19] Ex. 9, page 2
[20] Ex. 18, Attachments O and AA.
[21] Mr. Sparks referred to the "LCR study methodology" in his rebuttal testimony (Ex. 27) at pages 13-14.
[22] Ex. 18, Attachment AA, page 211.

do not count as local resources in the San Diego local area. The transmission-lines forming the electrical boundaries for the San Diego area are the five 230 kV lines emanating southbound from San Onofre (Path 44), two 500 kV lines emanating eastbound from IV substation (SWPL and Sunrise) and a connection to the Mexican/Tijuana system. Mr. Sparks described these as basically two import pathways- IV and San Onofre- because all power imported into San Diego and the Mexican/Tijuana system must come through the IV or San Onofre substations.[23]

C. Power Flow Study Results and Spreadsheet Analyses of Other Parties

SDG&E presented a spreadsheet analysis, set forth in Table 1 of Mr. Anderson's supplemental testimony, showing a higher LCR need for the greater San Diego area.[24] A spreadsheet analysis requires an import capability to be established and used as an input for the analysis, and the accuracy of the analysis requires that the import capability does not fluctuate for different generation dispatch assumptions and contingency conditions. In most LCR areas in the ISO, the import capability of the area fluctuates significantly under different generation dispatch assumptions and contingency conditions, and therefore a spreadsheet analysis is completely inappropriate. The LCR study methodology is entirely based on a power flow analysis rather than a spreadsheet analysis and does not require that an import capability be established. However, for the San Diego area, a spreadsheet analysis can produce similar results compared to a power flow analysis, as long as the limiting contingency is properly accounted for.

Many of the assumptions used by SDG&E differ from those used by the ISO. In particular, Table 1 contains an updated load forecast based on the most recent CEC

[23] Tr. IV at 621-622.
[24] Ex. 11, page 5.

information whereas the ISO used the 2009 load forecast information.[25] The spreadsheet is also based on a G-1/N-1 contingency which, according to Mr. Strack, uses a post-contingency import limit (3500MW) into San Diego developed for the Sunrise Powerlink proceeding (A.06-08-010) and subtracts 604 MW for outage of the Otay Mesa unit, the single largest generator.[26] The ISO analysis is based on the N-1-1 contingency of two transmission lines, and because this contingency does not involve the loss of the Otay Mesa unit, it is not necessary to subtract 604 MW for the outage of that unit. The ISO determined, through its analysis, that the N-1-1 contingency was more limiting than the G-1/N-1 contingency. Because SDG&E assumed that load shedding would be used to mitigate the N-1-1 contingency, they determined that the G-1/N-1 contingency was more limiting. For reasons explained earlier, the ISO does not support the use of load shedding for this N-1-1 contingency.[27]

DRA's calculation is done for each year depicted on the spreadsheet. Mr. Fagan, on behalf of DRA, uses this same "higher import" level (3500MW) in his spreadsheet analysis, based presumably on testimony presented by DRA witness Ghazzagh that the ISO incorrectly used a "lower import limit" in the OTC study than was expected in the Sunrise proceeding.[28] However, as explained above, the simplistic use (such as DRA's) of a static "import capability" that can be subtracted from local resources, purportedly to determine the local area deficiencies, is a flawed analysis.[29] Interestingly, even though DRA witness Fagan, in his spreadsheet analysis, emphasized that the difference between his determination of what the

[25] Ex. 27, page 2.
[26] Ex. 12, page 9.
[27] To the extent that SDG&E determined LCR deficiencies similar to the level that the ISO found, the ISO agrees with this result.
[28] Ex. 15, pages 16-17.
[29] Tr. IV, 608.

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.

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

---

[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

---

[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.

between the two cases.[49] Other substantial differences between the two cases include transmission projects not online by 2013 that will affect voltage stability performance of the southern California system. Furthermore, the DG in the 2021 case is located in a heavily loaded sub-transmission area and improves voltage stability in the San Diego area. In the absence of these enhancements in the 2013 case, a voltage collapse scenario occurred notwithstanding the presence of Encina generation and the lower demand forecast.

Ms. Firooz also mistakenly interpreted the differences between the G-1/N-2 and N-1-1 contingencies and opined that while the two contingencies are "identical" except for the outage of Otay-Mesa generation, the study results are quite different.[50] However, the contingencies are also quite different, and apparently Ms. Firooz did not realize that they do not involve the same two lines.[51]

2. <u>Alternatives to Local Generation</u>

Finally, Ms. Firooz suggests alternatives to local generation that could provide more "cost effective" options for ratepayers. These include the reactive support devices analyzed in the 2011/2012 transmission planning cycle, installing phase shifters to control loop flows on the CFE system and approving a 500 kV transmission line connecting the SDG&E and SCE systems. Mr. Sparks explained that while the synchronous condensers studied in the transmission cycle would prevent a voltage crash, they do not provide comparable resource adequacy and renewable integration benefits, nor do they prevent congestion of thermal overloads on the lines. For 2021, the ISO observed that these devices would not solve all mitigation concerns.[52]

---

[49] Ex. 27, page 17.
[50] Ex. 20, pages 16-17.
[51] Ex. 27, page 18.
[52] *Id.*, page 14; Tr. III, pages 539-541.

The phase shifters suggested by Ms. Firooz were analyzed by the ISO in the transmission planning process but, as noted by Mr. Sparks, they are not necessarily more cost-effective than local generation and also do not provide the same benefits. For example, phase shifters cannot provide resource adequacy and renewable integration benefits that can be provided by generation in the load pocket but not by phase shifters. Furthermore, as explained by Mr. Sparks during cross-examination, phase shifters were analyzed by the ISO for the purposes of delivering large amounts of renewable from Imperial Valley into the ISO system, not for whether this approach would reduce LCR needs. In addition, addressing flow on the CFE system presents additional challenges because putting more impedance from the CFE source into their system could cause voltage collapse on the CFE system, clearly making CFE a reluctant participant. Thus, at best, the timing of this alternative would be uncertain.[53]

In the ISO's original testimony, the ISO identified a 500 kV line as a possible mitigation solution under a Category D contingency where the South of SONGs separation scheme was the binding constraint.[54] It is always possible that in the future such a transmission link might be needed. However, given permitting uncertainties and the fact that such a need has not yet been identified in the ISO's transmission planning process, this is not a feasible alternative to local generation needs starting in 2018.

3. Planning Horizon and Procurement Decisions

DRA witness Fagan has taken the position that the ISO's ten year planning horizon for OTC local area needs does not equate to ten year lead times for resource procurement. He states that while transmission additions generally do require longer lead times, the relevant time period for generation procurement decisions is generally 1-5 years. According to Mr.

[53] Tr. III, pages 541-544.
[54] Ex. 9, page 9.

Fagan, other supply resources such as incremental demand response can be secured "relatively quickly," citing to "year-over-year" increases seen in the PJM footprint.[55] Mr. Fagan summarized DRA's position on this issue in response to questions from ALJ Yacknin:

> My recommendation would be to make a finding that there is no need for these particular PPTAs. That there is extensive information out there that preferred resources that could be procured would first meet the need, and that when the time—and then just keep on revisiting the issue each year. See how we are doing for X number of years out.[56]

The ISO disagrees. Mr. Fagan does not provide a basis for his assertion that generation resources can be procured in a 1-5 year timeframe. It has been the ISO's experience that constructing new conventional generation or repowering existing units usually takes from 5-7 years. Indeed, this is the time frame driving the urgency for procurement decisions in this case and in the current LTPP proceeding (R.12-03-014); the Encina compliance is before 2018, necessitating procurement authorization by the end of 2012.[57] DRA's "wait and see" strategy is simply not tenable. If the Commission waits too long and the resources needed for reliable grid operation do not materialize, the ISO will be required use its backstop CPM procedures (if generation is even available) and this will substantially increase costs to ratepayers because they will have to pay both for RA capacity (that does not solve all of the ISO's reliability needs) and CPM capacity (to ensure that reliability needs are met).

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

Both ISO witnesses provided testimony about the need to procure flexible generation in the San Diego area. Mr. Rothleder explained that a flexible resource is one that has the ability to be dispatched and to respond to dispatches based on the resource registered ramp

[55] Ex. 17, page 17.
[56] Tr. III, page 522.
[57] Ex. 27, pages 12-13.

rate. Flexible resources should also have low minimum operating levels that provide dispatch flexibility between minimum and maximum operating level for the resource.[58] In response to questions from ALJ Yacknin, Mr. Rothleder explained the purpose of his testimony:

> The purpose of my testimony here is to support that the local resources, to the extent they are needed for local purposes, they should provide some flexibility attribute and there will be benefits to the system in the greater system needs of having those resources flexible. And that way you avoid having to potentially buy or need other resources outside the area to make up for the flexibility.[59]

Mr. Sparks also described the need for flexible local generation. He explained that the OTC generation characteristics include ramp rates and minimum output levels that allow the generation to be ramped-up quickly following the first transmission contingency in order to ensure reliable system operation following the next transmission contingency. The flexibility of the current OTC generation allows efficient system dispatch when all transmission equipment is in service, but still provides for reliable system operation following a transmission contingency. Mr. Sparks recommended that replacement generation should also have these flexibility characteristics.[60] The Product 2 generation at issue in this case provides the flexibility described in the ISO testimony.

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

The PPTAs that are before the Commission for approval total 450 MW. In all of the renewable portfolio scenarios except for the environmentally-constrained case, there are residual LCR deficiencies ranging from 311 to 121 MW.[61] The ISO recommends that the Commission base its procurement decision in this case on the ISO's base case renewable portfolio and find that the OTC deficiency in San Diego is 630 MW. If the Commission

---

[58] Ex. 8, page 4.
[59] Tr. II, pages 320-321.
[60] Ex. 27, pages 18-19.
[61] Ex. 10, page 3 at the table reproduced on page 10 *supra.*

approves the PPTAs, SDG&E should also be directed, in this proceeding, to procure an additional 211 MW of flexible generation in the San Diego load pocket.

It is important that all of the local area needs for the San Diego area be resolved in this docket for several reasons. In the first place, the January 18, 2012 Joint Commissioner Ruling specifically provided that "the issue of SDG&E's Local Capacity Requirement will be addressed in A.11-05-023 rather than in the LTPP proceeding."[62] Furthermore, in the May 17, 2012 ACR/ALJ Scoping Memo and Ruling in R.12-03-014, *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* filed March 22, 2012 Assigned Commission Ruling May 17, 2012, the Commission established that Track 1 would address Local Reliability, and specified, in footnote 4, that "[i]ssues related to infrastructure needs for the San Diego local area are being considered in Application 11-05-023 and will not be in the scope of this proceeding, except to the extent that any decisions in that proceeding inform the record." To that end, the list of issues to be considered in Track 1 include "whether additional capacity is required to meet local reliability needs in the Los Angeles Basin and Big Creek/Ventura area between 2014 and 2021, and, if so, how much.."[63]

[62] Ruling, page 4.
[63] Ruling, page 5.

Thus, DRA witness Spencer's recommendation that the Commission should not authorize "further procurement for SDG&E outside or ahead the conclusion of the 2012 LTPP"[64] is not consistent with the Scoping Rulings in this case or in R.12-03-014. The testimony that has been submitted to date in that proceeding is focused on the LCR needs for SCE only and not SDG&E. All of the LCR needs for SDG&E are under consideration in this case and not just the capacity represented by the PPTAs.

Respectfully submitted,

By: *<u>/s/ Judith B. Sanders</u>*

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 13, 2012

[64] Ex. 15, page 5.