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

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

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

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

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

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

Q. Have you previously provided testimony in this proceeding?

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

Q. What is the purpose of your rebuttal testimony?

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

<u>Modeling Incremental Demand Response (DR), Uncommitted Energy Efficiency (EE), Uncommitted Combined Heat and Power (CHP) and Energy Storage</u>

Q. What levels of DR, uncommitted EE, CHP and storage did the ISO use in its local capacity area studies?

A. The ISO used the 2009 CEC 1-in-10 load forecast, which includes certain levels of EE and CHP. Uncommitted EE was not included, and CHP generation was counted on for meeting local reliability needs only to the extent it was included in the CEC's officially adopted demand forecast.

The ISO shares the CEC's concerns about uncommitted energy savings from uncommitted resources. To the extent such uncommitted resources ultimately develop, they can be helpful in reducing overall net-demand, but the ISO does not believe it is prudent to rely on uncommitted resources for assessing future local system needs and ensuring the reliability of the bulk power system.

The load was not reduced for incremental demand response in the OTC and LCR studies and incremental demand response was not treated as an existing resource in these studies.

A small amount of energy storage (40 MW representing the Lake Hodges project) was also modeled.

Q. Can you provide a brief summary of the intervener testimony regarding the levels of DR, uncommitted EE, CHP and storage modeled in the ISO's local capacity area studies?

A. Yes. NRDC witness Martinez, DRA witnesses Ghazzagh and Spencer, and CEJA witness Powers all suggest that the ISO should have used 544MW of uncommitted EE, although DRA also recommended 284MW as part of the "high need" proposal. The DRA and CEJA witnesses also suggest that 302MW of DR identified in the planning assumptions in the R.10-05-006 LTPP proceeding be modeled in the ISO's local capacity studies. All of these witnesses claim that CHP should have been included as a supply resource. CEJA witness Powers also takes issue with the level of energy storage that the ISO included in its studies.

Q. What is the ISO response to the recommendations that additional amounts of uncommitted energy efficiency should have been included in the load forecast?

A. In considering all of these recommendations, we must first consider the different applications in which the load forecast information is used, and the consequences of the different assumptions. Deliberately conservative forecasts must be employed in the assessment of reliability requirements for capacity in constrained areas since the consequences of being marginally short versus marginally long are asymmetric. A marginal shortage means the loss of firm load, which puts public safety and the economy in jeopardy, whereas a marginal surplus has only a marginal cost implication. Thus, the ISO has a responsibility to carefully consider demand forecast assumptions and how they are developed, especially if such forecasts include assumptions about uncommitted resources that can only provide uncommitted energy savings, for planning purposes.

As CEC observed in a report issued in May 2010 entitled Incremental Impacts of Energy Efficiency Policy Initiatives relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast ("CEC EE Report"), there is substantial uncertainty regarding whether the amount of additional energy savings that will be achieved through uncommitted energy efficiency.[1] This conclusion is further supported by the CEC's more recent comment provided in the 2011 Integrated Energy Policy Report dated January 2012 ("CEC 2011 IEP Report"), which stated in its discussion of EE that "[u]ncommitted savings" for EE "while plausible, have a great deal of uncertainty surrounding the method, timing, and relative impact of their implementation."[2]

In this regard, the NRDC, DRA and CEJA witnesses appear to ignore the caution expressed by the originators of California's demand forecast. Heightening the ISO's concern for the lack of certainty regarding uncommitted energy efficiency, the ISO notes that even programs that are more successful than anticipated may fail to produce the required energy savings in the particular area specifically where they are needed and when they are needed– effectiveness on a broad system-wide basis can be invaluable from a total resource adequacy perspective, but can easily fail to provide the expected load relief if the programs are not successfully deployed when and where needed in the constrained local capacity area.

Q. Do you agree with CEJA that higher levels of energy storage should have been modeled along with other system resources?

A. No, although the ISO is interested in the ability of viable energy storage devices to address system reliability needs. However, such devices must not only provide sufficient capacity, but also that capacity must be in the correct location to be effective. At this juncture, there is not sufficient certainty that effective storage will be developed in the necessary locations to warrant including such uncommitted resources in the ISO's models. Moreover, the examples cited by CEJA's witness (Powers) suggesting these resources are already viable require further scrutiny. For example, Mr. Powers noted the

---

1 *See* CEC EE Report at 5, 53-54.

2 CEC 2011 IEP Report at 110.

incentive rates approved by FERC in 2010 for the Western Grid Development proposed storage projects to alleviate transmission issues identified by the ISO. He failed to note that the projects submitted to the ISO for consideration were found to be uneconomic alternatives to transmission projects and were not approved in the ISO's transmission planning process. Further, he cites examples of a Beacon Power flywheel being installed at a California wind farm and a 4 MW battery storage project being installed by PG&E as "a viable way to meet load requirements." However, reviewing the referenced sources indicates that both projects are being installed as demonstration projects.

Q. Do you agree that a certain level of uncommitted CHP should have been included as a system resource in the ISO's local area capacity studies?

A. The ISO does not consider it reasonable or prudent to rely on incremental combined heat and power programs beyond what has been considered in CEC forecasts due to the level of uncertainty that exists with regard to future increases in CHP development that was noted in both the CEC's 2009 IEP Report[3] and the 2011 IEP Report. The 2011 IEP Report further supports the conclusion that it is not prudent to count on any incremental CHP at this time; the forecast CHP additions to the system may simply offset retirements to existing CHP resources.[4]

Q. Why didn't the ISO model DR in its local area capacity studies?

A. The ISO does not agree that Demand Response can be relied upon to address local capacity needs, unless the DR can provide equivalent characteristics and response to that

---

[3] *See* CEC 2009 IEP Report at 97 ("The continued existence and viability of this power is a major issue …"), 236 ("The barriers to increased penetration of CHP technologies have been identified repeatedly in past *IEPRs*, but little progress has been made.").

[4] *See* CEC 2011 IEP Report at 108-110 ("For traditional combined heat and power (CHP) technologies, self-generation is assumed constant, so that retired CHP plants are replaced with new ones with no net change in generation in the current forecast.").

of a dispatchable generator. DR should be dispatchable when and where needed and for a specific megawatt quantity, to address local capacity needs. However, Demand Response does not have these characteristics as this time.

Demand Response programs have generally been considered an alternative to generation resources in meeting system-wide load and supply balances. Spread over a larger system, the exact amount of DR that materializes, and the location, is not relevant within certain bounds. However, to ensure that DR does not materialize in an area that compounds a system problem, and does materialize in the area needed to mitigate the system problem that drove the need for reliance on DR, the ISO strongly supports DR being location-based and dispatchable – in the past, the ISO has referred to this as "generation substitutable." Further, if it is being relied upon instead of construction of new generating plants, the DR programs must be dependable over a significant period of time equivalent to the construction of new generation resources – which the ISO has referred to in the past as "durable."[5] Demand Response is generally a very use-limited and use-restricted resource that has limited energy-delivery duration, callable hours and/or timely dispatch. These use-restrictions are generally inadequate to enable their inclusion in local capacity area studies, particularly related to satisfying reliability requirements triggered by transmission-related contingencies. Typically, following a contingency event, the ISO is faced with restoring the system to a state positioned for the next, worst contingency within 30 minutes. These types of requirements are location-specific and time-specific. Unlike the system needs, addressing local capacity requirements that are contingency driven require prompt and very dependable response – operators simply cannot wait to see what load reduction materializes, and still have time remaining to respond to address a shortfall.

---

[5] The ISO recently discussed the importance of durability in comments submitted in CPUC Proceeding A.11-03-001. *See* Comments of the California Independent System Operator Corporation on Alternate Proposed Decision Adopting Demand Response Activities and Budgets for 2012 through 2014, at 7-8 (April 9, 2012).

Q. Has the ISO provided information about the characteristics of demand response programs that can be used to meet grid reliability needs in other CPUC proceedings?

A. Yes. Specifically, demand resources can clearly aid reliability when these demand resources are available to the ISO when and where needed and for how much energy is needed.

<u>Distributed Generation (DG)</u>

Q. Both CEJA witness Powers and DRA witness Ghazzagh state that higher levels of DG should have been modeled in the ISO's local capacity area studies. Do you agree with this recommendation?

A. No. The ISO studied the need for replacement OTC generation under four 33% RPS scenarios during the 2011-2012 transmission planning cycle. The amount of DG in the San Diego area ranged from 52 MW to 104 MW for three of the scenarios. The high DG scenario had 402 MW. The ISO believes that the 52 MW to 104 MW range is a reasonable assumption for planning to ensure that the system will be reliable. Although the 402 MW high DG scenario may be plausible and an admirable goal; however, it is not a capacity amount that can be depended on for ensuring the reliability of the bulk power system.

Q. Is the ISO's position on the appropriate level of DG for the purposes of its local capacity area studies inconsistent with the ISO's DG initiative, as suggested by DRA witness Spencer's testimony at pages 10-11?

A. No. The ISO's DG initiative is designed to help facilitate the development of DG by providing useful information regarding locations to site DG that would not create 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?

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

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

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

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

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

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

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

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

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

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

A. No, Mr. Fagan is incorrect. The conventional lead time for constructing new generation or repowering existing facilities, such as the OTC units, is five to seven years. Encina OTC compliance is before 2018; thus there is considerable urgency in making procurement decisions as soon as possible and certainly no later than 2012. The transmission system will be designed around the resources that are procured and Mr. Fagan agrees that infrastructure development can take as long as ten years.

Q. DRA witness Gharrzagh takes issue with the ISO's use of the 1-in-10 load forecast for the purposes of this proceeding and suggests that the use of this forecast be deferred to the LTPP proceeding (pages 3-5). What is your response?

A. The ISO's OTC studies are based on the 1-in-10 2009 CEC load forecast [CEC-200-2009-012-CMF] which is actually lower than the latest CEC load forecast which was published on May 31, 2012 [CEC-200-2012-001-SF-VI]. In this regard, the forecast used by the ISO is low.

Furthermore, the ISO Planning Standards require the use of 1-in-10 load forecast for all local system reliability analyses. Because the load forecast appears to be increasing, the use of a more recent forecast would only increase the justification for the power contracts that SDG&E is requesting for approval. Therefore, the ISO does not believe that the load forecast assumption needs to be deferred to the current LTPP proceeding (R.12-03-014).

Other Transmission Planning Issues

Q. Both DRA witnesses Fagan and Ghazzagh state that the import limit into the San Diego area used by the ISO is too low and inconsistent with the ISO's testimony in the Sunrise Powerlink proceeding (A.06-08-010). Is this correct?

A. No. First of all, local area generation requirements are based on following the LCR study methodology. DRA focuses on import capability for the purpose of performing a spreadsheet calculation of local area generation requirements. DRA insists on establishing a number for import capability that can be subtracted from the area load to determine the local generation requirement. This approach is fundamentally inconsistent with the LCR study methodology, which does not rely on an import capability value to determine local area resource requirements. Therefore, there is no import capability number in the ISO study results that can be compared to the DRA study results. However, both the ISO studies and the DRA studies produce a local area resource requirement which can be compared. Table FG-1 of Mr. Ghazzagh's testimony shows that the DRA calculated resource requirement on line 7 is 2713 MW. It also shows the ISO resource requirement of 2663 MW. In addition the ISO resource requirement is based on a higher San Diego area load level than what is assumed by DRA. In summary, the ISO calculated resource requirement based on the LCR study methodology is lower than the DRA calculated resource requirement. The local area resource requirement is a measure of the local area transmission system capability. Given that the ISO studies produced a lower local area resource requirement than DRA, the ISOs assessment indicates that the transmission system capability is greater than what has been determined by DRA.

Q. At page 11 of Ms. Firooz's testimony she suggests that reactive support devices (synchronous condensers) should have been studied as more cost effective alternatives to local generation. Does the ISO believe that these devices should be used to meet some of the local needs described in your testimony?

A. No. While the ISO, in its 2011/2012 Transmission Plan, found that the reactive support device proposed by SDG&E during that cycle would mitigate possible voltage issues in the Encina area, these devices do not provide the benefits that local generation provides, and therefore would not be more cost effective. Specifically, Ms. Firooz does not appear to have accounted for the system resource adequacy and renewable integration benefits of the generation that are not provided by the synchronous condensers.

Q. Ms. Firooz also suggests installing phase shifting transformers, at a cost of $50 million, to control loop flows on the CFE system, thus providing a cost effective and

environmentally superior means by which to reduce LCR needs in San Diego. Do you agree?

A. No, for several reasons. The cost of a 1000 MVA of phase shifters is expected to be much more than \$50 million. The ISO estimates the cost of a similar phase shifter to be approximately \$100 million based on the cost of a similar sized 500/230 kV transformer. In addition, Ms. Firooz again does not appear to have accounted for the system resource adequacy and renewable integration benefits of the generation that are not provided by the phase shifter.

Q. In addition, Ms. Firooz proposes a transmission alternative to local generation- the Talega-Escondido/Valley Serrano (TE/VS) interconnection facility associated with the Lake Elsinore Advanced Pumped Storage (LEAPS) project. She points to your March 9, 2012, testimony in which you note that the transmission alternative to the local capacity needs in San Diego would basically be a 500 kV connection between the SDG&E and SCE systems. What is your opinion of TE/VS as a viable alternative to local generation?

A. As with her other alternatives, the 500 kV line proposal also overlooks the system resource adequacy and renewable integration benefits of the generation that is not provided by the TE/VS line. Furthermore, while a 500 kV connection was identified as a possible transmission alternative, if local generation needs are not met, this transmission need- and the TE/VS line as a standalone project- has never been studied and approved through the ISO's transmission planning process. It is my understanding that the TE/VS application for a CPCN has recently been dismissed, so it is unlikely that a 500 kV connection between the SDG&E and SCE systems could be online by the 2018 Encina OTC compliance date.

Q. Starting at page 14 of her testimony, Ms. Firooz claims that the ISO has, in its testimony, "provided the end results of three series of complex analyses without discussing or providing much of the underlying data." She states that the ISO's studies therefore provide an inadequate basis upon which to make a decision in this proceeding. What is your response to these criticisms?

A. The study results addressed in my testimony are based on a 433 page Transmission Plan with hundreds of pages of appendices that is posted on the ISO's website. The ISO conducted an all day workshop at the CPUC offices in San Francisco on April 17, 2012 to present the analysis of local capacity needs in San Diego and provided data and information in the form of Powerpoint slides. In addition, dozens of powerflow models were posted that provide full detail of every assumption and were readily available to all participants in this proceeding. The ISO has consistently urged all interested parties to take advantage of the ISO's non-disclosure agreement arrangements so that the data and backup materials for our studies could be accessed as quickly as possible. All of this information and documentation has been available for scrutiny since the ISO submitted its testimony in early March. Although the OTC study was conducted for the first time in the 2011/2012 cycle, it is basically a longer term version of the LCR studies the ISO performs every year and with which Ms. Firooz should be very familiar.

Q. Ms. Firooz has identified several purported "inconsistencies" between the 2013 LCR study and the 2021 OTC study. On page 16 she focuses on a voltage collapse scenario, identified in both the 2013 study and the 2021 study, and claims that the ISO failed to explain the reasons why a voltage collapse for the same contingencies would be present in both 2021 and 2013. Can you address this issue?

A. Yes. Ms. Firooz suggests that it is somehow inconsistent for the ISO to show a voltage collapse for the same contingencies in its 2013 study as in its 2021 study given that, in 2013, the Encina plant will not yet have been shut down and load projections are lower for 2013. This analysis is faulty because it improperly assumes that differences in total load and the total amount of local resources are the only factors to consider in determining whether a voltage collapse may occur. In response to a CEJA data request on this issue, I explained that it was not proper to compare these two studies in this overly simplistic manner because there are major differences between the 2013 and 2021 base case models. The largest difference is the addition of approximately 20,000 MW of installed renewable generation capacity by 2021, which causes substantial differences in system usage. There are, moreover, various other differences between the two scenarios that would be apparent from a review of the base cases.

For example, in addition to the approximately 20,000 MW difference in renewable resources between 2013 and 2021, there are several transmission projects that will not yet be on line by 2013 that affect the voltage stability performance of the southern California transmission system. These projects include Vincent-Mira Loma 500 kV, Sycamore-Bernardo 69 kV line, and various reconductoring projects. There is also substantially more generation dispatched in the Western LA Basin in the 2021 model than in the 2013 model. In addition, with the large amount of renewable generation, the Path 26 flow from northern California to southern California is over 1000 MW lower in the 2021 case than in the 2013 case. Furthermore, the DG in the 2021 case is located in a heavily loaded sub-transmission area and improves voltage stability of the San Diego area. All of these differences result in significantly increasing the capability of the transmission system to serve San Diego load in 2021 relative to 2013. Because these enhancements will not be available in 2013, they are not included in the 2013 base case, and in the absence of such improvements a voltage collapse scenario occurs in 2013 notwithstanding the availability of Encina and the comparatively lower demand forecast.

Q. Ms. Firooz identifies another purported "inconsistency" on pages 16-17 involving a comparison between the G-1/N-2 and N-1-1 contingencies identified in your April 6, 2012, supplemental testimony in the table on page 3. She states that these

contingencies are identical except for the outage of Otay Mesa for the G-1/N-2, but that the study results for each contingency are quite different, which should not be the case. Has she correctly identified a problem with the ISO's power flow models?

A. No. In fact, Ms. Firooz has misstated my testimony and has incorrectly described the G-1/N-2 contingency. The entire basis for her to claim that there is a discrepancy apparently is a misunderstanding on her part. The G-1/N-2 and the N-1-1 contingencies do not involve the same two lines. The G-1/N-2 involves the simultaneous outage of the 500 kV Sunrise Powerlink and the Imperial Valley-ECO 500 kV line. The N-1-1 involves the loss of Imperial Valley-Suncrest 500 kV line (Sunrise Powerlink) followed by the loss of ECO-Miguel 500 kV line. This was described on page 2 of my April 6, 2012, testimony. The difference in the transmission components associated with the two contingencies is the reason that the study results were different under these two contingencies.

Need for Flexible Resources

Q. Both DRA witnesses Fagan and Spencer state that there is no basis upon which the Commission could find a need for flexible local resources. What is your response to these statements?

A. New generation developed at sites that are electrically equivalent to the former OTC generation sites would meet the local area generation needs as well as repowering the former OTC generation. Chapter 3 of the ISO's 2011-2012 Transmission Plan provides effectiveness factors for various electrical locations inside the local area boundaries that can be used to facilitate the identification of electrically equivalent sites. 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 OTC generation allows efficient system dispatch when all transmission equipment is in-service, but still provides for reliable system operation following a transmission contingency. Replacement generation should have similar flexible characteristics. Quick starting generation would also provide for efficient system dispatch, but still provide for reliable system operation following a transmission contingency.

Conclusion

Q. Based on your review of the testimony submitted by DRA, CEJA and NRDC, is there any reason for the ISO to modify its recommendations in this proceeding?

A. No. The ISO studies show a need for flexible thermal generation in the San Diego area starting in 2018, and, consistent with my testimony, the generating projects at issue in this proceeding are deliverable and would satisfy a portion of these local needs.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.