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BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations.	)	R.09-10-032

REPLY COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO COMMENTS ON 2012 LOCAL CAPACITY REQUIREMENTS

In accordance with the Order Instituting Rulemaking (October 29, 2009) issued by the California Public Utilities Commission ("CPUC" or "Commission") and the Revised Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge Determining the Scope, Schedule, and Need for Hearing in this Proceeding (February 3, 2011), the California Independent System Operator Corporation ("ISO") submitted its 2012 Local Capacity Technical Analysis ("LCT Report") on April 29, 2011. Comments on the report were filed on May 6, 2009 by The Utility Reform Network ("TURN") and the San Diego Gas & Electric Company ("SDG&E"). The ISO hereby submits these brief reply comments in response to the issues raised by these parties.

I. SUMMARY

In these reply comments, the ISO discusses the comments of TURN and SDG&E and takes the following positions on the issues raised:

- In recognition that the ISO and SDG&E are already working together to achieve the maximum LCR benefit from the Sunrise Powerlink transmission line ("Sunrise"), it is unnecessary for the Commission to direct the ISO and SDG&E to take such steps as requested by TURN.

- SDG&E's proposal to establish a seasonal local RA requirement should not be adopted because it is unsupported, infeasible, and would likely lead to increased costs.

II. EFFECT OF SUNRISE POWERLINK ON LCR

In its comments, TURN expresses disappointment that the LCT Report (referred to as the "2012 LCR Study") does not quantify significantly reduced local capacity requirements ("LCR") in the San Diego area as result of constructing the Sunrise. TURN suggests that the CPUC direct the ISO and SDG&E to take steps to achieve the expected LCR benefits from Sunrise.[1]

TURN's comments are inconsistent with CPUC Decision 08-12-058, which granted SDG&E a Certificate of Public Convenience and Necessity to construct Sunrise. TURN misconstrues Sunrise's impact on Local Capacity Requirements. TURN incorrectly compares the 2012 LCR reduction of 140 MW, when the project will have been in-service for less than one year, with the potential LCR reduction of 1,000 MW for the entire project when fully subscribed. D.08-12-058 clearly established the 1,000 MW LCR reduction as a potential, not guaranteed amount.[2] Further, the CPUC commended the ISO for its modeling efforts and analysis on the Sunrise project. The CPUC observed, that "while lacking the environmental, engineering, and updated RPS cost components included in the Renewable Energy Transmission Initiative (RETI) analysis [which did not exist when SDG&E filed its 2006 Application for Sunrise], ISO's modeling of renewable resource savings associated with various renewable resource areas

1 TURN Comments, pp. 1 - 4.

2 "SDG&E will avoid up to 1,000 MW of new capacity" (D.08-12-058, p.114). "[I]n estimating Sunrise's impact on SDG&E's Local Capacity Requirement … these increased import limits result in a potential reduction in SDG&E's Local Capacity Requirement…" (D.08-12-058, pp.110-111).

provides useful information regarding Sunrise's cost impacts on renewable development in the Imperial Valley."[3]

In addition, TURN's comments ignore the fact that, as discussed below, the ISO is actively working with SDG&E to maximize the LCR reductions that will result from Sunrise. There is no reason for the CPUC to direct the ISO and SDG&E to take action that is already in progress. Further, TURN's comments ignore the fact that the LCR benefits expected from Sunrise will not be instantaneous; they will be achieved in stages as renewable resources in the Imperial Valley are developed and delivered to load in San Diego. The ISO's LCR studies to date make it clear that Sunrise will reduce the LCR in the San Diego area. The studies show that the reductions will occur in stages beginning in 2012 (assuming that Sunrise becomes operational on June 1, 2012 as expected) and throughout future years.

The LCR studies also show that the reliability needs for 2013 and beyond within the existing footprint of San Diego alone will decrease by 1,000 MW or more after Sunrise becomes operational and the WECC path rating for Sunrise is increased or eliminated. However, additional resources within the ISO balancing authority area, currently connected at Imperial Valley substation, will then be required in order to meet the LCR requirements and provide reliable service to San Diego customers. That need is determined by the next worst local constraint -- the loss of the Imperial Valley-North Gila 500 kV line with the biggest resource in this area out of service due to potential overload on the South of SONGS 230 kV path. This new requirement will likely be higher than the LCR need for the existing footprint of San Diego specified above and may significantly impede achieving a reduced LCR for the area. However, even if

3 D.08-12-058, p. 129.

Sunrise does not immediately reduce the LCR MW need, the ISO estimates that there will numerous local benefits attributable to Sunrise, including the elimination of reliance on old, high heat rate, once- through- cooling units within the existing footprint, replaced by renewable or new state of the art combined cycle technology located at Imperial Valley.

The current ISO LCR studies represent a snapshot in time because only approved transmission projects, and those generation projects with a high degree of development certainty, are modeled.[4] For 2012, ISO studies show that the immediate LCR reduction attributable to Sunrise will be limited due to the binding path rating of 1,000 MW that the Western Electricity Coordinating Council ("WECC") has established.[5] The ISO is required to comply with path ratings set by WECC. However, the ISO is working with SDG&E to address this issue by upgrading the WECC path rating or eliminating it, as discussed at the March 9 and April 14, 2011 ISO stakeholder meetings regarding the 2012 LCT Report. This may take some time and is based on WECC timelines. Accordingly, for 2012, the ISO believes that is appropriate to impose the currently established San Diego LCR requirement even if the path rating for Sunrise is changed or eliminated by WECC. The ISO believes this is appropriate because the next worst local constraint (Greater San Diego-Imperial Valley discussed below) has about the same LCR need and it would not be reduced by changing the Sunrise rating.[6]

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[4] This modeling criteria can be found in ISO Tariff, Section 40.3.1.2, as well as the latest LCR Manual at: http://www.caiso.com/2867/286794795d0b0.pdf.

[5] *See* the 2012 LCT Report, page 103 at http://www.caiso.com/2b6f/2b6f8be32da20.pdf

[6] For the last five years in a row, the ISO has presented to stakeholders the potential for extension of the existing San Diego local area to the Greater Imperial Valley-San Diego local area. These study results can be found at: http://www.caiso.com/287c/287ca3cc28a80.pdf for studies done in 2010, http://www.caiso.com/2495/2495c63b23450.pdf for studies done in 2009,

By imposing the current San Diego LCR requirement, in the event that Sunrise does not become operational by June 1, 2012, the LCR needs for the San Diego area will increase by 140 MW from 2,849 MW to 2,989 MW. This incremental amount is rather small and may be made up easily through procurement by the effected load serving entities ("LSEs"), or if that procurement is not successful, through backstop procurement by the ISO as needed. In contrast, if we assume for LCR study purposes that the WECC-established 1,000 MW path rating for Sunrise is nonbinding or that it can be eliminated between now and June 1, 2012, then the Greater San Diego-Imperial Valley LCR requirements become binding at 2,804 MW. In this case, units at Imperial Valley can be relied on as local units and their total is about 1,000 MW. However, under these study circumstances, if Sunrise's in-service date is delayed, the additional local resources that would be needed within the existing footprint of the San Diego area would be quite significant (up to potentially 1,000 MW and would pose a high burden on the LSEs or a high likelihood of backstop procurement by the ISO.

The impact of this new Greater San Diego-Imperial Valley local capacity area on the Sunrise reliability benefits was an issue addressed by the parties in the Sunrise proceeding, A.06-08-010. The testimony in that case reflected that both SDG&E and the ISO share the vision that Sunrise will carry a significant amount of renewable power to ISO ratepayers as soon as anticipated renewable resources and associated transmission are built. The CPUC agreed that the Greater Imperial Valley-San Diego

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http://www.caiso.com/20ad/20ad77d04d70.pdf for studies done in 2008, http://www.caiso.com/1cc2/1cc2dab86fd50.pdf for studies done in 2007 and at http://www.caiso.com/18d8/18d8ce1118390.pdf for studies done in 2006. Thus, this issue has not only been vetted in the Sunrise CPCN proceeding but also in five LCR stakeholder processes.

will provide grid benefits by allowing renewable generation in the Imperial Valley area to satisfy both RPS and LCR requirements.[7]

Furthermore, based on both the ISO's LCR studies conducted in the transmission planning process, it appears that most of the issues TURN has raised diminish or disappear over time, if all things proceed as assumed in the studies. In particular, the studies show that the LCR needs for the Greater Imperial Valley-San Diego area will decrease as additional transmission is constructed between the Imperial Irrigation District ("IID") and CFE systems and Imperial Valley, and more power is flowing in real-time from their areas into the ISO balancing authority area. The ISO 2010/2011 Transmission Plan included detailed transmission reliability studies of renewable development scenarios with 1500-2200 MW (nameplate capability) of renewable generation operating in the IID and ISO portion of Imperial County (see tables 5.1.1-5.1-8, http://www.caiso.com/2b4b/2b4bf09070b00.pdf). Table 5.4.5 shows that SDG&E generation dispatch requirements under 2020, 1 in 5 peak load conditions (5,533 MW) would range from 2000 to 2500 MW. Under these generation scenarios, the loss of the Imperial Valley-North Gila 500 kV line with the biggest resource in this area out of service did not overload the South of SONGS 230 kV path. The 2012 LCR study only had 4,844 MW of load in the San Diego area, but because of the absence of the 1500-2000 MW of renewable generation, 2804 MW of generation was required in the San Diego area to mitigate the South of SONGS 230 kV path constraint. Accounting for the approximately 700 MW of more load in San Diego, renewable

7 D. 08-12-058 (December 18, 2008), *Sunrise Powerlink Transmission Project* Docket A.06-08-010, at 125.

generation production and Sunrise together were able to reduce local conventional generation reliability needs by at least 1,000 MW.

The ISO will continue to discuss regularly these issues with CPUC, TURN and SDG&E through ongoing dialog as well as with stakeholders in public meetings such that any relevant changes to system conditions and assumptions are broadly introduced and discussed during the LCR process and associated stakeholder meetings.

III. SEASONAL LCR

In its comments, SDG&E again suggests that the ISO should establish seasonal LCR for summer and non-summer periods, rather than a single annual LCR. SDG&E has previously made this suggestion in RA proceedings and it has not been adopted by the CPUC.[8] The ISO continues to strongly object to a seasonal local RA requirement and urges the CPUC reject the suggestion in this proceeding for the following reasons.

First, SDG&E's proposal is based on an incorrect assumption that a monthly or seasonal local RA requirement will be lower than the August peak load currently used in setting the year-ahead obligation. In actuality, the ISO's experience is that local areas can be more constrained during the spring and fall months when many generating units are off-line for scheduled maintenance. By switching to a seasonal analysis, there is real potential that the RA requirement will increase for most of the local areas in the non-summer months, which is the opposite result SDG&E intended.

Second, SDG&E has overlooked the fact that most planned maintenance on transmission facilities is performed during the non-summer months. Under a seasonal approach, the ISO would need to include in its studies for the non-summer months some level of transmission maintenance beyond the existing criteria for local capacity

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8 SDG&E's Comments, pp. 1 – 7.

requirements. This will increase the need for RA resources during the non-summer months, otherwise there will not be sufficient RA capacity in local areas to support the planned transmission maintenance activities.

Third, the "2013 SDG&E Non-Summer/Maintenance Season Local Capacity Area Study", attached to SDG&E's comments, contains significant flaws. For example, it is difficult to ascertain what criteria SDG&E used in its study or is proposing to account for "planned maintenance" in the non-summer months. It appears to the ISO that SDG&E's intention may have been to use one transmission maintenance outage and two to four resource maintenance outages. The reasonableness of the outage level is directly related to the reliability of the study results and SDG&E has not demonstrated that the outage level used in its study has any relationship to the actual level of planned maintenance during the non-summer months.

In addition, the ISO believes that SDG&E's study does not account for the most limiting single "transmission maintenance" condition, which is a necessary modeling scenario. Based on SDG&E's example, the most limiting maintenance would be one of the five 230 kV lines that form the South of SONGS path, since this path rating will decrease to around 1650 MW with one element out of service. This "single maintenance condition" will then be considered "normal system condition" and the worst contingency would become the Imperial Valley-North Gila 500 kV line with Otay Mesa unit out of service (both of these on forced outage). This would result in a LCR need of about 2453-2653 MW depending on assumption of available imports from IID and CFE [3700 MW load - 1650 MW south of SONGS + 603 MW biggest forced outage resource - (0-200) MW of imports]. In SDG&E's study, the amount of the San Diego area LCR reduction in the non-summer months would be estimated at about 200-400 MW, not 1,000 MW as claimed by SDG&E.

Fourth, increasing the local RA requirement on a monthly or seasonal basis will affect all load serving entities and will likely increase their cost of RA procurement, without providing any corresponding or necessary enhancement of system reliability. In these circumstances, the increased cost may help insulate SDG&E from non-availability charges under the standard capacity product, but it would do so unfairly at the expense of other load serving entities.

Fifth, SDG&E claims that a seasonal LCR will result in ratepayer savings is unsupported and incorrect. The ISO believes that if the seasonal LCR were implemented AND the subsequent LCR studies show a decreased local RA capacity need in the non-summer months, then resource owners, as they have stated at numerous CPUC and ISO open stakeholder meetings, will shape the capacity charges heavily towards the summer season leaving small amounts for the off-peak such that they can become competitive with off-peak system capacity prices. This would basically make procurement of local area RA capacity more expensive for all LSEs in the peak periods. The savings SDG&E anticipates under a seasonal approach may also not materialize because demand response MW values may be reduced during certain seasons, which would necessitate additional procurement of RA capacity and erode the procurement savings SDG&E claims will result from a seasonal LCR. In addition, the unavailability of local resources in the non-summer months may increase the likelihood that the ISO will need to engage in backstop procurement in these periods, which will increase the costs to ratepayers beyond the cost of today’s local capacity.

Sixth, a seasonal local RA requirement can be implemented without significant burden to the ISO. Such a change would require the ISO to perform many more deliverability studies than it does today. Since only deliverable resources should count for RA purposes, especially local capacity, a change to a seasonal local requirement would oblige the ISO to conduct deliverability studies to assure that such resources are actually deliverable in each month or each season. Today, it takes about six months for ISO to perform its studies and complete the stakeholder process for the following year's local capacity requirements. Performing seasonal studies would substantially increase the time and effort required by the ISO and would be unduly burdensome. If the CPUC is interested in a seasonal study, there must be an appropriate balance between the granularity of LCR study and the workload required of the ISO.

IV. CONCLUSION

The ISO respectfully request that the CPUC issue an order consistent with the ISO's proposal and reply comments in this matter.

Respectfully submitted,

/s/ Beth Ann Burns

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Dated May 13, 2011

CERTIFICATE OF SERVICE

I hereby certify that on May 13, 2011, I served, by electronic and United States mail, a copy of the foregoing REPLY COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO COMMENTS ON 2012 LOCAL CAPACITY REQUIREMENTS to each party in Docket No. R.09-10-032.

Executed on May 13, 2011
at Folsom, California

/s/ Susan L. Montana//

Susan L. Montana
An Employee of the California
Independent System Operator