Stakeholder Comments Template

# 2015-16 CAISO Draft Transmission Plan

***Please submit comments (in MS Word) to regionaltransmission@caiso.com.***

| Submitted by | Company | Date Submitted |
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Southern California Edison (SCE) appreciates the opportunity to provide comments to the CAISO. SCE has reviewed the draft 2015-16 Transmission Plan and participated in the February 18, 2016 stakeholder meeting. Below please find SCE's comments regarding specific sections of the draft 2015-16 Transmission Plan.

## 3.1.3 & 3.1.4 "Minor Transmission Upgrades"

CAISO identified a number of small-scale transmission upgrades which were evaluated for mitigating contingency overload concerns on the south of Mesa 230 kV lines resulting from an increased dispatch of renewable generation. Three options were highlighted as being more effective and potentially lower cost.

1. Opening the Mesa 500/230 kV Bank #2 under contingency conditions
2. Re-arranging the Mesa – Laguna Bell 230 kV lines and opening the Laguna Bell – La Fresa 230 kV line under contingency
3. Installing 10-Ohm series reactors on the Mesa – Laguna Bell #1 230 kV transmission line

As part of the evaluation of the Mesa 500 kV Substation project, SCE investigated Option 2, and determined that it is not feasible to re-arrange the Mesa – Laguna Bell lines due to constraints in line routing and substation arrangement. The other options may be feasible but will require further analysis. Given the scale of the upgrades, further analysis of these and other options can be performed in the 2016-17 TPP and still meet the 12/31/20 need date. Based on the uncertainty present in the assumptions, SCE agree that mitigation is not prudent at this time to address the potential deficit in the LA Basin/San Diego Area.

**3.1.3 & 3.1.4 – Sensitivity 2021 LCR Assessments for the LA Basin/San Diego Area**

As part of the 2013-14 Transmission Plan, the CAISO Board approved a group of projects to maintain reliability in Southern California to address the loss of Once Through Cooling units including San Onofre Nuclear Generating Station.[1] This group of projects included an additional 450 MVAR of dynamic reactive support at San Luis Rey, the Imperial Valley Phase Shifter, and the Mesa 500 kV "Loop-in" project (Mesa). In March 2015, SCE filed with the CPUC for a permit to construct Mesa with the intent to complete the Project by December 31, 2020.[2] In addition to these transmission projects there are several other components which contribute to meeting the reliability need in the combined San Diego and LA Basin area. This includes resource procurement authorized as part of the 2012 Long Term Procurement Plan (1,812 MW in SCE and 707 MW[3] in SDG&E), increasing Additional Achievable Energy Efficiency (1,568 MW in SCE by 2025[4]), and availability of fast acting Demand Response programs.

As part of the 2015-16 Transmission Plan, CAISO performed a sensitivity analysis to consider the possible impacts of a potential one-year delay in Mesa. The results of the CAISO analysis identified that a delay of Mesa would result in a 682 MW deficit. The CAISO states that this deficit could be met through an extension of the OTC compliance schedule of the Redondo Beach generating facility until Mesa is completed[5]. Avoiding such an impact to the OTC compliance schedule will require the CPUC and SCE to work expeditiously to ensure all regulatory approvals and project milestones are met.

The CAISO's sensitivity analysis also includes a new factor not present in the 2013-14 Transmission Plan; a higher dispatch of renewable resources (about 2,000 MW) to reflect CPUC NQC values[6]. If the location of these resources, or their anticipated output changes, the deficits identified in the sensitivity analysis would also change. The current draft identifies a deficit of 576 MW with Mesa and 682 MW if Mesa is delayed. At the February 18 stakeholder meeting, CAISO stated that with Mesa and a "minor transmission upgrade" located south of Mesa Substation there would be no deficit.

This type of sensitivity analysis may be meaningful in assessing the impact of a potential project delay but should not be used as an indicator of the overall value of a project. Mesa was approved as part of a large group of mitigations, and the order in which the projects are studied plays a significant role in the perceived value a particular project may display. Due to the interconnected nature of the transmission system, a

[1] 2013/14 ISO Transmission Plan at 108
[2] SCE believes it can complete Mesa by 12/31/2020, consistent with its proposal in A.15-02-003, if it obtains a CPUC Notice to Proceed (NTP) by 9/30/2016. Obtaining the CPUC NTP in time will depend upon timely CPUC issuance of CEQA documents, certification of the Final Environmental Impact Report, and a PTC decision far enough in advance to allow the NTP to be issued by 9/30/2016.
[3] Draft 2015/2016 ISO Transmission Plan at 49, Table 2.3-5
[4] *Id.* at 100, Table 2.6-5
[5] *Id. at 164*
[6] *Id.* at 154-155

large group of mitigations will interact with each other and impact the value of a project when a specific project is assessed incrementally.

For example, the sensitivity analysis implies a potential value for Mesa of 106 MW (682 – 576). Furthermore, if we assume the projects behave independently from each other, an alternative to fill the deficit without Mesa would be 106 MW of resources and the "minor transmission upgrade". Neither of these possible interpretations can be conclusively drawn from these sensitivity results. The "minor transmission upgrade" is dependent upon the presence of Mesa and would not significantly alter the deficit independently. A deficit would remain for the LA Basin/San Diego area if Mesa was replaced by 106 MW and the "minor transmission upgrade". This interdependency among projects demonstrates that the value provided by each project in a large package of mitigations cannot be calculated simply based on an incremental analysis.

### 2.7.1 Tehachapi and Big Creek Corridor

The generation assumptions for the low hydro sensitivity study that the CAISO performed for this area is not stated in the report. The maximum generation level available north of Magunden Substation during low hydro conditions is a key variable driving results and this assumption should be documented.

The CAISO lists modifying the existing RAS as a mitigation for low hydro conditions. The RAS was modified in early 2015 to add various P1 (N-1) contingencies to the existing Big Creek/San Joaquin Valley (BC/SJV) RAS. The current TPL-001-4 standard only allows for non-consequential load loss of up to 75 MW. A forecast of hydro capacity over a decade or more is not available and as the drought in California continues there is the potential that the 75 MW limit may be exceeded. Historical data of the last forty-one years has shown two significant low hydro capacity events occurring during droughts; 2015 summer (630 GWH) was the lowest hydro capacity followed by 1977 as the second worst (764 GWH).

The CAISO also lists managing hydro generation during peak hours as a mitigation. While this may be possible during normal conditions, it may not be an option during droughts. SCE did manage water supplies in 2015 to meet peak load demands, but this required cooperation from down-stream farmers. The water is not owned by SCE and SCE has a contractual obligation to deliver the water to owners down-stream. It is uncertain whether the water management practices used in 2015 will be able to be utilized in future years.

Under low Big Creek hydro conditions (Southern California was in its fourth year of drought), SCE's 2015 Annual Transmission Reliability Assessment (ATRA) identified seven (7) category P1 thermal overloads for the years 2017, 2020 and 2025. The maximum load drop required was 366 MW in 2020 for the loss of either Magunden-

Vestal No. 1 or No. 2 230 kV lines. NERC's current TPL 001-4 standard does not allow planned non-consequential load loss to exceed 75 MW for a category P1 contingency.

Based on the best transmission alternatives considered and in order to be compliant with TPL 001-4 at the earliest possible date, in September 2015 SCE proposed to install four (4) thyristor controlled series capacitors (TCSC) on the Big Creek 230 kV lines. SCE continued to study the issue and in January 2016, SCE developed a more cost effective alternative with three (3) TCSC's on the Big Creek 230 kV lines. By installing TCSC's on three of its 230 kV transmission lines and rapidly adjusting impedances post-contingency to control the power flow, the BC/SJV transmission system can reduce its local generation need to as low as 260 MW as well as limit load shed for a P1 contingency to below 75 MW in the year 2025. In conjunction with Distributed Energy Resources (DER) in the Big Creek area, the TCSC's will delay the need for large-scale transmission and generation projects in the area beyond 2025 by optimally utilizing existing transmission capacity and can be implemented with a short lead time at an estimated cost of $69 million.

To ensure reliability without the Big Creek TCSC in 2017, 476 MW of existing local generation north of Magunden Substation will be required to mitigate the worst P1 contingency. This generation requirement will grow to 574 MW by 2025. Due to the on-going drought conditions, ensuring an adequate amount of hydro generation may not be possible. SCE continues to believe the Big Creek TCSC project is needed to meet reliability criteria and requests the CAISO to approve the project as part of the 2015-16 Transmission Plan.