CAISO Draft 2013-2014 Transmission Plan

Submitted by	Company	Date Submitted
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EnerNOC appreciates the opportunity to provide these comments on the February 3, 2014 *Draft 2013-2014 Transmission Plan* (Transmission Plan). We commend the California Independent System Operator (CAISO) for proposing a methodology to support California's policy emphasis on the use of preferred resources—specifically demand response and energy efficiency, which are at the top of the state's loading order. EnerNOC supports CAISO's consideration of how such resources can provide "non-conventional" solutions to meet local area needs that would otherwise require new transmission or conventional generation is commendable.[1] It is critical to incorporate these preferred resources into the planning assumptions to meet local reliability needs in order to appropriately represent the current and future potential of these resources. EnerNOC understands that the methodology applied in the 2013-2014 transmission planning cycle is a new approach due to unique circumstances in the LA Basin and San Diego and that a more generic application of this methodology will be applied in future transmission planning process cycles. We will be participating in the 2014-2015 Transmission Planning process just getting underway to support the inclusion of demand side resources in the assumptions and scenarios.

EnerNOC's overarching concern is that the planning assumptions and scenarios being used by the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and CAISO do not adequately represent the demand potential. For example, they fail to incorporate any growth over current levels of demand response; do not include modifications to the load forecast to reflect

[1] *Consideration of alternative to transmission or conventional generation to address local needs in the transmission planning process,"* September 4, 2013, p.3.

increasing customer exposure to time-variant rates; do not include any demand response resources for local reliability purposes; and fail to define the attributes that would allow preferred resources to be included for local reliability going forward.

In Track 1 (Local Reliability) Decision of the 2012 Long Term Procurement Proceeding (LTPP), the CPUC provided explicit direction to Southern California Edison Company (SCE) regarding the amount and type of procurement they were authorized to pursue, with as much as 800 MW of the maximum 1,800 MW procurement authorization to come from preferred resources.[2] This direction on preferred resource procurement has been confirmed in the CPUC's new Demand Response Rulemaking, with the stated goal to "increase the penetration of demand response programs,"[3] as well as the CEC's 2013 Integrated Energy Policy Report (IEPR), which recommends "taking full advantage of the contribution of low-carbon renewable generation."[4] All of this was captured in the Preliminary Reliability Plan for LA Basin and San Diego, prepared by Staff of the CPUC, CEC, and CAISO on August 30, 2013, in relation to the permanent retirement of the San Onofre Nuclear Generating Station (SONGS), which identifies its first key action to be development of 3,250 MW of preferred resources to meet 50 percent of the identified resource needs resulting from the SONGS closure.[5]

Demand response is one of the preferred resources being promoted in the state's policy context; however, it is being virtually ignored for planning purposes. This apparent lack of coordination among the agencies and their staffs conducting the studies is leading to an untenable situation. Parties, including EnerNOC, have to devote significant time and resources to continually advocate for the inclusion of preferred resources into planning scenarios, when they should be included automatically, consistent with state policy.

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[2] D.13-02-015 , at pp. 10-11.
[3] R.13.09-011, Order Instituting Rulemaking (September 25, 2013), at p. 15.
[4] CEC 2013 IEPR, at p. 40
[5] Preliminary Reliability Plan, at p. 2.

We include this background to support our position that the scenario analysis must accurately reflect the demand potential. EnerNOC strongly encourages the use of scenario analysis for supply-side and for non-dispatchable demand response in the load forecast. It is unreasonable to continue to rely on a forecast that assumes *no* growth in supply-side demand response over the planning period. It is also unreasonable to fail to consider demand resources for local capacity. Several supply-side demand response resources, including Aggregator-Managed Contracts, the Capacity Bidding Program, the Demand Bidding Program, and the Base Interruptible Program, are dispatchable by either local capacity area or sub-load aggregation point. However, this capability does not appear to be captured in the Transmission Plan's scenarios. Of the 2000 MW of demand response in California, a modest 200 MW is assumed to be in the LA Basin.[6] However, CAISO does not include any demand response for local reliability.

It is unclear what rationale CAISO is using for excluding demand response from the local reliability scenarios in the Transmission Plan. However, there is reference in the "Demand Response" section of the Plan to a requirement that demand response resources must be fast response curtailment (20 minutes) in addition to meeting the resource adequacy requirement for four hour duration.[7] Presumably this requirement is related to CAISO's need to stabilize the system within 30 minutes after a contingency event. CAISO interprets that requirement to suggest that demand response resources would need to be dispatched in advance of that 30 minute timeframe. To our knowledge this is not a requirement in other markets, however. The reality is that with 30 minute notification of an event, customers do start to drop load, so there is some amount of load drop that would definitely occur within the 20 minute window. However, resources that come on line within the 20-30 minute window still have some value for restoring the system, especially considering that most generation in a local

[6] 2012-2013 LTPP Track 1 Decision.
[7] Draft 2013-2014 Transmission Plan, at p. 92.

capacity area cannot respond to a 30 minute dispatch signal and yet still counts toward meeting local reliability. The value for the 30 minute demand response is certainly not zero!

The Transmission Plan also includes several scenario data tables, but it is unclear what the performance characteristics are for each of the resources. While the September 4 white paper describing the proposed new methodology for including preferred resources listed a number of characteristics, such as response time, availability and duration,[8] the Transmission Plan only appears to include duration in the LA Basin Preferred Resource Scenario Data.[9] EnerNOC recommends that the catalog of local preferred resources, which is the first step in the September 4 proposal, includes the essential performance characteristics of each resource.

It would be helpful to have a better understanding of how this September 4 proposal fits into the next iteration of transmission plans, as it has not been explored through the working group process or the CPUC process, to EnerNOC's knowledge. Therefore, this proposal that is the foundation for the 2013-2014 studies plans, has not been adopted and is conceptual at this point.

EnerNOC appreciates the opportunity to provide these comments and respectfully requests CAISO's consideration.

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[8] *Consideration of alternative to transmission or conventional generation to address local needs in the transmission planning process,"* September 4, 2013, pp. 8-10.

[9] Draft 2013-2014 Transmission Plan, Table 2.6-4: Summary of Non-Conventional Alternative Assessment