COMMENTS OF THE STAFF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION

ON THE 2016-2017 TRANSMISSION PLANNING PROCESS DRAFT STUDY PLAN FOLLOWING THE FEBRUARY 29, 2016 STAKEHOLDER MEETING

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March 15, 2016

Introduction

The Staff of the California Public Utilities Commission ("CPUC Staff") appreciates this opportunity to provide comments on the draft 2016-17 Transmission Planning Process ("TPP") Study Plan ("Draft Study Plan") posted February 22 and discussed at the February 29 stakeholder meeting.

Our comments address the following topics.

1) If the 2016-2017 TPP encounters situations where transmission projects foreseeably could require follow-on measures to achieve initial objectives, the CAISO should consider and discuss the reasons and implications.

2) The CAISO should clearly document key differences in assumptions among the varied reliability and LCR study cases, should describe which key assumptions drive modeled violations in particular cases, and also should explain how multiple cases individually and jointly contribute to findings of need for transmission investment.

3) The method for allocating customer (behind-the-meter, or BTM) PV to buses should be clearly described and the resulting allocations should be reported.

4) Methodologies used by PTOs to create bus-level load forecasts should be explained in greater detail.

5) The CAISO should be prepared to run reliability sensitivity cases with higher levels of AAEE than included in the 2015 IEPR load forecast.

6) The CAISO should assess need for new and previously approved reliability driven transmission upgrades in light of continued decline in load forecasts and growth of customer generation, and should explain how customer generation in Community Choice Aggregator (CCA) areas will be considered.

7) The CAISO and transmission developers should ensure that planned in-service dates for approved projects are consistent with realistic timelines particularly for permitting and siting – including the permitting timeline estimates provided in Appendix A**.**

8) The CAISO should assess, discuss with stakeholders and model as warranted - - the value of reactive controls at various categories of resources in helping manage overvoltage issues such as those driving approval of reactive controls at six PG&E substations in the draft 2015-2016 Transmission Plan.

9) The CAISO should clarify the methodology for modeling preferred resources in reliability assessment *and also LCR* studies.

10) In assessing preferred characteristics for "slow response" local capacity resources the CAISO should describe what types of resources are considered slow versus fast response, and how, quantitatively, total reliability and LCR needs can be met by combinations of these two categories of resources.

11) The CAISO should report the planning status of transmission projects falling within the planning horizon that support a state infrastructure project (such as the High Speed Rail project), and should begin more detailed studies when required by those projects' timelines.

12) CPUC staff reiterate our comments on the draft 2015-2016 Transmission Plan appreciating CAISO's initial informational 50% RPS study and looking forward to continuing studies, and we also look forward to future insights regarding out-of-state renewable resources identified as one area of focus in the Draft Study Plan.

13) CPUC Staff look forward to further assessments of frequency response issues particularly under high renewables futures, and with fine-tuning of modeled response from existing providers as emphasized in the Draft Study Plan.

14) The CAISO should explain how required frequency response capabilities will be modeled in both economic and operational flexibility studies.

15) CPUC staff look forward to additional detail and vetting for the CAISO's approach to assessing the potential for economically driven retirement of generation.

1. If the 2016-2017 TPP Encounters Situations Where Transmission Projects Foreseeably Could Require Follow-On Measures to Achieve Initial Objectives, the CAISO Should Consider and Discuss the Reasons and Implications.

As CPUC Staff commented regarding the draft 2015-2016 Transmission Plan, transmission planning can experience the "whack-a-mole" effect, where new infrastructure planned at one location to address a problem can be followed in short order by problems that consequently pop up (like moles) elsewhere. The Mesa loop-in project was cited as a current example. CPUC Staff asked that the CAISO provide deeper insight into these situations. Now, the CAISO is requested to provide such deeper insight in the 2016-2017 TPP cycle, such as regarding the following.

a. Whether need for follow-on measures is reasonably apparent and deserving of inclusion in the original assessment.

b. Whether need for follow-on measures could reasonably arise (or has arisen) from *changed information and forecasts*, and when it is appropriate to proactively examine (e.g., via sensitivities) alternative conditions that might produce such needs.

c. Whether need for follow-on measures could result (or has resulted) from differences among or changes within modeling methods (supporting different conclusions), and how the impacts of such changes or differences can be anticipated or managed.

2. The CAISO Should Clearly Document Key Differences in Assumptions Among the Varied Reliability and LCR Study Cases, Should Describe Which Key Assumptions Drive Modeled Violations in Particular Cases, and Also Should Explain How Multiple Cases Individually and Jointly Contribute to Findings of Need for Transmission Investment.

CPUC Staff made this request in commenting on the draft 2015-2016 Transmission Plan. Besides being valuable generally, the requested information is helpful to the CPUC in administering permitting and siting processes. In those processes, it is important to accurately identify project goals. CPUC Staff requests that the CAISO provide such deeper explanation and insights in the final 2016-2017 TPP Study Plan and in the 2016-2017 Transmission Plan.

Construction of reliability assessment and Local Capacity Requirements (LCR) study cases that are appropriately informative, stressful and at the same time reasonable appears to be becoming more challenging. This may reflect increasing penetration of resources that are variable and only partly predictable, as well as of distributed and behind-the-meter resources having varied operating characteristics and locations plus limited or uncertain visibility and responsiveness from a grid operation perspective. All of this makes it especially important that the CAISO clearly document, explain and differentiate the load and resource assumptions across various reliability assessment and LCR study cases, as well as how those cases individually and jointly drive conclusions regarding reliability risks and needed solutions.

For example, the CAISO indicates on page 11 of Draft Study Plan that reliability assessment base cases will use CEC peak and energy forecasts from the 2015 IEPR[1] without reflecting potential impact of increased PV penetration in pushing net peak load later into the day. The same page then states that "*these and other forecasting uncertainties will be taken into account in the sensitivity studies identified in section 4.11.2 as needed*." This illustrates the growing complexities of designing and interpreting reliability assessment and LCR studies, and underscores the need to specifically document, explain and differentiate the load and resource assumptions used for the different reliability assessment and LCR study cases.

Beyond clearly documenting, explaining and differentiating key generation and load assumptions in different cases, the CAISO should clearly identify

- *which* key assumptions drive significant modeled reliability problems or violations in particular cases,
- *which* reliability problems identified in the various reliability assessment and LCR study cases drive conclusions regarding needed transmission investments or other reliability solutions, and
- how the different cases and their results are interpreted both individually and *jointly* to arrive at conclusions.

This will help all parties understand and assess how evolving conditions, in both the real world and in modeling, especially regarding variable, distributed and behind-the-meter generation, are impacting determination of reliability needs.

Some specific types (this is not an exhaustive list) of information and insight that are valuable and are requested include the following.

a. <u>*The resource output levels modeled for each reliability assessment and LCR study case should be clearly and completely identified*</u>. Tables 4.7-1 through 4.7-4 of the Draft Study Plan show output levels to be assumed for different kinds of

[1] Page 11 of the Draft Study Plan cites the CEC's Revised Electricity Demand Forecast, (Volume 1, page 37, January 2016) as stating that this effect of BTM PV pushing the peak load hour later into the day has "not been incorporated into the demand forecast through CED 2015…", but is expected to be incorporated into demand forecasts for the 2017 IEPR

renewable generation (e.g., 25% NQC for solar, during peak hours, for the PG&E area), for different types of study cases. Tables 4.11-1 and 4.11-2 list the different reliability assessment base and sensitivity cases (off-peak with maximum PV output, etc.) to be run for different load areas, for different time horizons (e.g., 2026). The final Study Plan and also the ultimate 2016-2017 Transmission Plan should show explicitly, completely and in a readily understandable manner, what output levels were assumed for each generation type (including fossil and hydro where relevant) for each reliability study case.[2] Corresponding and *similarly formatted* (comparable) information should be provided for LCR study cases, since LCR studies are playing a complementary role in identifying reliability problems and solutions.

CPUC staff note that storage and its potential future reliability and economic[3] roles are increasingly factoring into electric system planning studies and their uncertainties. We also note that CAISO's documentation and interpretation of reliability assessment and LCR studies have apparently not to date provided detailed insights into how electric storage is being modeled in these different study cases. Going forward and starting with the 2016-2017 TPP Study Plan and Transmission Plan, the CAISO should document and explain *storage* operational assumptions used in reliability assessment and LCR studies, analogous to the way that the CAISO documents and explains, or is requested in these comments to document and explain, corresponding assumptions for other kinds of resources. We understand that modeling of storage is a growing challenge and will likely evolve. However, we look forward to seeing that evolution more explicitly documented in future studies and reports, including how modeling of storage is or should in the future be influenced by system interconnection level (transmission level, distribution level, customer/BTM level) and by storage durations (e.g., 2 hours, 4 hours, 6 hours, longer durations).

b. *What each reliability study and LCR study case represents, in terms of specific real world operational hours (thus, conditions) should be clearly identified.* For each reliability assessment and LCR study case, the operational time period(s) such as hours of the day, weekday vs holiday/weekend, and months/season being represented by the generation and load levels for that case should be clearly identified, such as via a separate table or via footnotes to other tables that list study cases and assumed generator output levels (see topic 2-a. above). If a particular case represents a composite or generalization across a range of hours or conditions, or if the load and generation levels assumed for a particular case are not typically coincident, then this should be clearly explained.

[2] If this is shown via separate tables for (1) cases run and (2) generator output levels assumed for different kinds of cases, then the "kinds of cases" shown in table (2) should clearly map onto the "cases run" in table (1).

[3] One economic (and also reliability) role of storage would be to help manage potential renewable generation driven over-generation including its costs.

A specific situation where CPUC Staff request clarification regarding what hours and conditions certain cases represent is the following. CAISO staff's response at the February 18 stakeholder meeting indicated that for certain study cases BTM PV output would be modeled for the specific hour (or set of hours?) represented by that study case whereas front-of-meter solar (and wind?) generator output would be modeled at a certain percentile level achieved over a wider range of hours. While helpful and appreciated, this information requires further clarification. Does it refer only to LCR studies, to on-peak reliability studies, or to other (which?) studies? Is the BTM PV output assumed for the hour or set of hours represented by such a study case based on 8760-hour PV output profiles, or on some other (which?) information? (How) is this different than the derivation of output levels in different cases, for utility scale and other front-of-meter wind and solar resources?

c. *Specifically for the reliability assessment case "summer peak with no BTM PV" the CAISO should explain what load and resource output levels were used, and the rationale*. What hour(s) of the day does this case represent in *each* load area? Is it meant to represent an hour in which there would normally be BTM PV output but there is complete cloud cover for all BTM PV in an area, simultaneously? In contrast, how will front-of-the-meter PV be modeled for this case, and what is the rationale? Is there a similar LCR study case also having high loads and no or extremely low BTM PV output, and if so, how and why does it differ from the "summer peak with no BTM PV" reliability assessment sensitivity case?

d. *Page 15 of the Draft Study Plan states "In 2016-2017 TPP base cases, the PV component of self-generation will be modeled as discrete element"[sic] and CPUC Staff requests that that CAISO clarify what this means for each kind of study case (e.g., reliability assessment versus LCR, on-peak versus other).*

- The CAISO should clarify if modeling BTM PV as a "discrete element" means allocating aggregate BTM PV amounts among different individual buses in each service area using PTO allocation methodologies discussed in CPUC Staff comment topic 3 below. If it means something more or different, the CAISO should explain.

- In reliability assessment and LCR study cases, is BTM PV modeled as *supply*, discretely at each bus, or in some other manner? How (using what profiles, or via some other manner) is BTM PV removed from the basic load forecast at each bus, and then added back as discrete supply (or otherwise)? We understand that three output "data points" for BTM PV amounts in the aggregate and at any bus may be: zero, the on-peak MW BTM PV impact given for each area in the 2015 IEPR load forecasts, and nameplate MW levels identified on page 16 of the Draft Study Plan as coming from a CEC-provided spreadsheet. The CAISO should explain if the different BTM PV output levels assumed for the different reliability assessment and LCR study cases are derived based on the above three output levels, or if any (which?) study cases incorporate BTM PV output levels based on 8760-hour or other *multi-hour profiles*, and what is the source of the profiles. This explanation should also clarify the statement on page 16 of the Draft Study Plan that "*Output of the self-generation PV will be selected based on the time of day of the study using the end-use load and PV shapes for the day selected*."

- Are the output profiles[4] modeled for BTM PV the same across all of the different buses among which the BTM PV is distributed[5] within any given study area (e.g., SCE metro or Los Angeles Basin)? In other words, do BTM PV at the *different* buses all have the *same* output level as a fraction of their nameplate capacity, for each hour studied? How is this rationalized as a reasonable representation of output levels that likely do not fluctuate in unison across all buses? The CAISO is requested to provide similar clarification regarding diversity or uniformity of output profiles modeled for front-of-meter wind and solar resources, including the number of different profiles modeled.

3. *The <u>Method</u> for Allocating Customer (BTM) PV to Buses Should be Clearly Described and the Resulting <u>Allocations</u> Should be Reported.*

Slide 10 of the February 18 presentation on the Reliability Assessment indicates that modeled BTM PV locations "*will be identified based on location of existing behind-the-meter PV and information from PTO on future growth.*" Given the growing importance of BTM PV in reliability and other studies, the CAISO and PTOs should describe in more detail how and based on what information BTM PV locations will be modeled, and what key uncertainties and assumptions this involves. Discussion at the February 18 meeting indicated that Distribution Resource Plans recently submitted by PTOs to the CPUC may play a role in establishing these locational assumptions, and this should be explained more fully.

Additionally, understanding (e.g., via maps or tables) where the BTM PV are actually being placed on buses or groups of buses for the 2016-2017 TPP would be very useful for

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[4] "Output profiles" refers to the time series (e.g., hourly) of modeled output levels for a given unit or increment of PV capacity, which may be stated as a time-varying fraction of the nameplate capacity for that PV unit or increment.

[5] This refers to BTM PV amounts allocated among the different buses in an area, using methodologies discussed in CPUC Staff comment topic 3 below.

understanding reliability and LCR study assumptions and results, as well as for understanding implications for future planning needs and methods.

4. *Methodologies Used by PTOs to Create Bus-level Load Forecasts Should be Explained in Greater Detail.*

Pages 11-14 of the draft Study Program describe at a high level how the PTOs convert 2015 IEPR load forecasts into bus-specific load forecasts. More detail should be provided, including whether the methodology for allocating aggregate forecast load to buses only applies to *peak* loads (including 1-in-2, 1-in-5, 1-in-10, weather-adjusted), and whether the 8760-hour load shapes for the different buses are then calculated based on a single 8760-hour load shape for an entire load area, allocated to buses *in the same proportions as peak loads* - - or whether some other method is used. Also, it should be clarified if peak loads modeled for different buses are coincident peak loads, so that a situation cannot occur, for example, in which bus X has a modeled peak load occurring at a different hour than the modeled (coincident) peak load for the overall load area (such as SDG&E).

Additionally, it should be clarified if and how the loads allocated to buses using the PTOs' methodologies represent loads without accounting for either AAEE or BTM PV, such that both AAEE and BTM PV are added (to each bus for each hour) separately, according to whatever bus allocations and 8760-hour or other shapes are attributed to the AAEE and to the BTM PV.

5. *The CAISO Should be Prepared to Run Reliability Sensitivity Cases with Higher Levels of AAEE than Included in the 2015 IEPR Load Forecast.*

Senate Bill 350 calls for doubling of AAEE by 2030. SB 350 and its planning implications were not known in time to inform the CEC's development of the 2015 IEPR load forecast. However, if an appropriate planning scenario reflecting a higher AAEE goal is developed it would be valuable for this scenario to be analyzed as a sensitivity case(s) in the 2016-2017 TPP. Thus CPUC Staff request that the CAISO be prepared to run such a case(s), should it be developed in a timely manner.

6. *The CAISO Should Assess Need for New and Previously Approved Reliability Driven Transmission Upgrades in Light of Continued Decline in Load Forecasts and Growth of Customer Generation, and Should Explain How Customer Generation in Community Choice Aggregator (CCA) Areas will be Considered.*

CPUC Staff appreciated CAISO's effort in the last TPP cycle to assess previously approved transmission projects, resulting in cancellation of 13 projects that are no longer needed apparently due largely to declining load forecasts. As we stated in comments on the draft 2015-2016 Transmission Plan, the CAISO should continue such assessment for all load areas. Results should be reported in the 2016-2017 Transmission Plan. Load forecasts continue to decline and distributed (including behind-the-meter) resources continue to grow.

As one example, the CAISO should evaluate the continued need for the Vaca-Dixon/Lakeville reconductoring project, and should indicate the year (if any) in which absence of this upgrade produces modeled reliability violations. If modeling does produce violations, the final reporting of this study and its conclusions should clearly describe whether continued operation (past assumed retirement dates) of Pittsburg generators, or other (which?) measures, were modeled as mitigations. We note that status of PG&E's application to the CPUC regarding this project is currently uncertain.

Finally, CPUC Staff note that resource developments and planning by Community Choice Aggregators (CCAs) can impact reliability needs in some areas, including the North Bay/North Coast area affected by the above mentioned reconductoring project. It is unclear to what extent this information is reflected in the IEPR load forecasts and in the CAISO's studies. Any clarification here would be valuable. In particular, CPUC Staff have received information regarding Marin Clean Energy[6] and Sonoma Clean Power,[7] indicating that load served by

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[6] Marin Clean Energy began providing power in 2010. Greg Brehm, Director of Power Resources, expects the amount of load served by demand-side resources to increase from roughly 38 MW to 130 MW in the next 10 years. Marin Clean Energy's demand-side resources estimates include about 30 MW of behind-the-meter (customer-owned) solar and include the following pending wholesale energy projects: 10.5 MW from their Solar One project, additional Feed-in Tariff projects, 1 MW from the Buck Institute solar project, and 2 MW from the College of Marin and Tesla storage project. (Marin Clean Energy communication to CPUC staff, September 2015)

[7] Sonoma Clean Power, which began providing power in 2014, currently serves roughly 100 MW of load from demand-side resources. Geof Syphers, Chief Executive Officer, expects to more than double that amount in the

behind-the-meter resources in these two areas exceeds 100 MW and could roughly double in 10 years, while slightly smaller but significant amounts of local distributed wholesale renewables are being contracted or planned.

7. *The CAISO and Transmission Developers Should Ensure That Planned In-Service Dates for Approved Projects Are Consistent with Realistic Timelines Particularly for Permitting and Siting - - Including the Permitting Timeline Estimates Provided in Appendix A.*

CPUC Staff comments on the draft 2015-2016 Transmission Plan emphasized this point, citing as an example a project for which the planned in-service date may be unachievable given a realistic timeline. CPUC Staff have reviewed the status of several major transmission projects recently approved by the CAISO that are now before the CPUC for permitting. Updated information relevant to the timelines for those projects are listed in Appendix A,[8] and these timelines should be considered by the CAISO and project developers.

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next 10 years. The output from demand-side resources in Sonoma Clean Power's service area consists of roughly 85 MW from behind-the-meter (customer-owned) solar and an additional 15 MW from behind-the-meter wind power, combined heat and power, and fuel cells. Sonoma Clean Power has signed contracts to build 14 MW of additional local wholesale solar and intends to add more local wholesale capacity of about 80 MW over the next 10 years from a mix of resources. An estimated 50 MW of additional customer-owned solar and wind is expected over the next 10 years. Sonoma Clean Power is beta-testing a customer demand response tool today, and they intend to have roughly 10 MW of dispatchable demand-response within 10 years. They are planning to exceed the battery storage mandate, meaning that at least 4 MW of peak demand would be met by storage within 4 years. Sonoma Clean Power obtains wholesale geothermal baseload energy from the Calpine Geysers facility in Sonoma County with current output about 650 MW, but with potential for future increases. (Sonoma Clean Power communication to CPUC staff, September 2015)

[8] The current CPUC permitting applications all require development of an environmental document as a precursor to the Commission's full consideration of a proposed decision on the permit application itself. Noted in Appendix A are the currently available CPUC Expected Draft and Final EIR timelines, which are subject to change based on a variety of factors, including the timeline of the Draft EIR, the extensiveness of the comments on the Draft EIR, and the responsiveness of the Project Applicant to requests for information in support of the development of the environmental document. In cases where the Draft or Final document has already been released, the item is noted in Appendix A as "issued". If the document is not yet released, it is listed as "expected" with the current timeline for issuance provided.

8. ***The CAISO Should Assess, Discuss with Stakeholders and Model as Warranted - - the Value of Reactive Controls at Various Categories of Resources in Helping Manage Overvoltage Issues Such as Those Driving Approval of Reactive Controls at Six PG&E Substations in the Draft 2015-2016 Transmission Plan.***

In identifying need for investment in reactive controls at six PG&E substations, the CAISO cited growing overvoltage issues in both modeling and real-world monitoring. In discussion at the February 18 stakeholder meeting, the CAISO cited as a significant cause the changing generation mix including growth of renewable generation. The CAISO should explain which generators or types and locations of generators are responsible, and whether these issues would be detected or addressed in transmission or distribution-level interconnection studies.

CPUC Staff also previously asked whether periodic investment in reactive controls on the transmission system is the best or only solution. We repeat and expand that request. We ask the CAISO to consider and model the ability of reactive controls at distributed and customer resources to significantly contribute to mitigating this problem. CPUC Staff note that CAISO has a market reform initiative in place to require reactive controls on asynchronous generators, and that one of many thrusts of the CPUC's Rule 21 (distribution level interconnection) reforms is achieving reactive control capabilities at distribution-level resources. Periodic investment in centralized transmission level reactive controls may be the most cost-effective solution or part of that solution, but there should be a proactive assessment of the mix of potential solutions.

9. ***The CAISO Should Clarify the Methodology for Modeling Preferred Resources in Reliability and Also LCR Studies.***

CPUC Staff understand that at least for the Los Angeles Basin and San Diego areas, the CAISO will initially model (in reliability assessment base cases) most preferred resources offline. Then, if this results in identified reliability problems, the CAISO will add preferred resources up to specific limits, at the most effective locations, to test ability of those resources to mitigate the reliability problems. Here, we use the term preferred resources broadly to include energy efficiency, demand response, storage, and local distributed renewable generation.

Below, we request clarification regarding (1) what preferred resources will be included in the reliability assessment base cases, and (2) what will be the upper limits on amounts of preferred resources subsequently modeled to test ability to mitigate problems. These clarifications should be included as specifically as possible in the final Study Plan, with full clarification in the 2016-2017 Transmission Plan. Further, CPUC Staff request that the same information regarding modeling of preferred resources, as elaborated below, *also be provided for LCR studies*.

First, the amounts and types of preferred resources *included in reliability assessment base cases* should be explicitly defined. CPUC Staff understand the bottom of page 26 and top of page 27 of the Draft Study Plan as indicating that energy efficiency, demand response ("DR") and behind-the-meter ("BTM") generation - - as "*embedded in the CEC load forecast*" will be included in base cases. CPUC Staff assume and request confirmation that this means that BTM generation amounts specified in the load forecast, even if ultimately modeled as supply, will be included in reliability base cases. The CAISO should clarify if the statement that modeling BTM PV as "*a discrete element*" as described on page 15 of the Draft Study Plan means that BTM PV will be modeled as supply allocated to individual buses and if not, what it does mean. CPUC Staff also request clarification regarding what types and amounts (by location) of DR are being included in the base cases, and specifically whether this means only that certain amounts of DR are assumed to already be reflected be in the load forecast (based on the above-cited statement from page 27 of the Draft Study Plan) thus not needing to be modeled explicitly, or whether it means something else and if so, what it means.

The next paragraph on page 27 of the Draft Study Plan states that "*assessments will be initially performed using preferred resources other than DR to identify reliability concerns …and if reliability concerns are identified….. additional rounds of assessment will be performed using potentially available demand response and energy storage*…" Page 28 states that "*The DR capacity amounts* [having been described in preceding table and text] *will be modeled offline in the initial reliability study cases*…." and later states that "*These storage capacity amounts* [1404 MW shown in Table 4.8-3] *will not be included in the initial reliability analysis*." On the other hand, slide 17 of the Reliability Assessment presentation on February 29 states that energy storage amounts [apparently referring to amounts in Draft Study Plan Table 4.8-3] are "*not* *included in starting cases (no location data available),* <u>unless</u> [emphasis added] *already procured by LSEs as part of the LTPP process*."

All of the above leaves ambiguity regarding what preferred resources are included in base cases. CPUC Staff's interpretation, which CAISO is requested to confirm or correct, is that:

> *No DR amounts not already embedded in the load forecast (if any) will be included in base cases. Otherwise, preferred resources falling within CPUC Track 1 and 4 authorizations will be included in bases cases only if (1) they have already been procured with CPUC approval, and (2) the locations of such procured preferred resources are well defined. CPUC Staff request clarification of what types and amounts of preferred resources procured pursuant to Track 1 & 4 authorizations, beyond storage amounts described on pages 30 and 31 of the Draft Study Plan, thus qualify for inclusion in reliability assessment base cases.*

Second, CPUC Staff request clarification of what will be the *<u>upper limits</u>* on total amounts of preferred resources that may be added as potential mitigation measures, where initial modeling has identified reliability problems. Our understanding, which the CAISO is requested to confirm or correct, is that the following limits apply.

a. Local Additional Achievable Energy Efficiency (AAEE) will be added up to bus-specific amounts consistent with the aggregate LSE amounts in the low AAEE forecast in the 2015 IEPR.

b. Local EE procured via Track 1 & 4 authorizations will be considered additive to (i.e., will increase) the AAEE modeling limit given by a. above.

c. Local DR amounts assumed to meet a 30-minute total response time[9] (for N-1-1 contingencies) will be added as specified in Table 4.8-1 of the Draft Study Plan, and there will also be a separate sensitivity case(s) in which the SCE amounts in Table 4.8-1 are replaced by amounts provided by SCE. The DR procured under Track 1 & 4 authorizations such as indicated in Table 4.7-7 of the Draft Study Plan is additive to the above amounts, as an upper limit on total amounts added for mitigation tests.

d. Local renewable resources procured through Track 1 & 4 authorizations will be added for mitigation, and are assumed to be additive to any local distributed renewables included in the TPP base case RPS portfolio.

[9] This refers to a 30-minute overall response time based on NERC Standard TOP-004-02 as noted, for example, on pages 27 and 51 of the Draft Study Plan.

e. Local storage procured via the CPUC storage mandate (or in the case of SCE, exceeding the mandate) will be added if not already included in the base cases.

CPUC staff assume and request confirmation or correction that upper limits on aggregate preferred resource additions for mitigation modeling in the Los Angeles Basin and San Diego areas will be set at the maximum of (i) the Track 1 & 4 maximum authorizations and (ii) amounts actually procured. We request clarification as to how maximum preferred resource additions above amounts already procured in these areas will be allocated among the *different* types of preferred resources, for modeling purposes.

The CAISO is also requested to describe

a. how the specific aspects of preferred resource modeling for reliability studies as discussed above are treated for *LCR studies*, clearly indicating the similarities and differences (reiterating a request stated above);

b. which kinds of preferred resources described above, and which kinds of other resources, are considered to be "fast response" (e.g., within 30 minutes total response time) for reliability study and LCR purposes;

c. how, including types and MW limits, preferred resources will be modeled and assessed for ability to mitigate reliability problems in *other areas* besides the south coastal load centers, noting that page 26 of the Draft Study Plan states that in previous planning cycles, CAISO "…*made further progress in integrating preferred resources into its reliability analysis focusing on other areas where reliability issues were identified*."

10. In Assessing Preferred Characteristics for "Slow Response" Local Capacity Resources the CAISO Should Describe What Types of Resources are Considered Slow Versus Fast Response, and How, Quantitatively, Total Reliability and LCR Needs Can be Met by Combinations of These Two Categories of Resources.

In summarizing its planned special study "*to identify the characteristics of the 'slower' response* [resources] *that are to be considered for local capacity resources*" the CAISO notes on page 51 of the Draft Study Plan that slow response resources unable to respond within 30 minutes of an initial contingency may if having certain [to be identified] characteristics provide local capacity value by being able to be dispatched or "positioned" in advance of an actual contingency. The CAISO also states that "*The number of dispatches in the latter* [slow response, pre-positioning] *case is anticipated to be orders of magnitude higher than the former* [fast post-contingency response]. This appears to CPUC Staff to offer the possibility of slow-response resources making a substantial contribution to meeting overall local capacity and local reliability requirements particularly under certain important scenarios and, as the CAISO indicated in the February 18 meeting, perhaps more so in certain parts of the grid than in others.

Thus, CPUC Staff request that the CAISO identify (starting with the final Study Plan to the extent possible) what kinds of resources are categorized as slow versus fast response. Beyond this, it will be important to learn (and we look forward to learning) what relative and absolute amounts of fast versus slow response resources, or perhaps even amounts of different *types* of fast versus slow response resources, are needed *in combination* to meet reliability and local capacity requirements in different load areas, and certainly in the Los Angeles Basin and San Diego areas.

11. The CAISO Should Report the Planning Status of Transmission Projects Falling Within the Planning Horizon that Support a State Infrastructure Project (Such as the High Speed Rail Project), and Should Begin More Detailed Studies When Required by Those Projects' Timelines.

In comments on the Draft Study Plan for the 2015-2016 TPP, PG&E requested a large load interconnection sensitivity study be performed on the Greater Fresno area during the summer peak period, significantly driven by planned interconnection of the California High Speed Rail Project (HSR). The CPUC supports this request for the 2016-2017 TPP, as the 2025 initial operating date for the San Jose - North of Bakersfield segment of the HSR project falls within the CAISO's planning horizon. The CPUC believes it is important for stakeholders to be able to <u>*track the status and progress*</u> of transmission projects for which objectives significantly involve electrical support of a state infrastructure project.

Furthermore, the CPUC suggests that, when studies are conducted for each transmission project of this type, the CAISO indicate the extent to which the cost, electrical configuration and approximate geographic location of the transmission project are affected by the needs of the state infrastructure project.

12. CPUC Staff Reiterate Our Comments on the Draft 2015-2016 Transmission Plan Appreciating the CAISO's Initial Informational 50% RPS Study and Looking Forward to Continuing Studies, and We Also Look Forward to Future Insights Regarding Out-of-state Renewable Resources as an Identified Area of Focus in the Draft Study Plan.

CPUC Staff appreciate the CAISO's initial informational study of implications and feasibility of pursuing the legislatively established 50% renewable energy goal. We look forward to future refinements of both CAISO studies and the CPUC's planning tools informed by those studies. This includes further insights regarding the following.

- Benefits (e.g., reliability, reduced curtailments, perhaps even limited RA deliverability) of different levels of transmission upgrades well below upgrade magnitudes needed for full capacity deliverability.
- How conditions at the distribution level such as expansion of distributed energy resources and various kinds of controls and services for/from such resources - - impact feasibility and costs for pursuing a 50% RPS in different ways.
- The important but still uncertain role of *ability to export* surplus renewable generation - - in affecting feasibility and costs for pursuing a 50% RPS in different ways.
- The extent to which potential problems revealed in power flow studies do or do not resolve themselves via reasonable fine tuning of assumptions regarding how/where future renewable resource additions will be deployed.

We look forward to further exploration of options and implications for pursuing out-of-state renewable energy as indicated in the Draft Study Plan. We expect that resulting insights will partly fall under the topics identified above, along with additional insights such as regarding source and delivery options for out-of-state renewables, and perhaps how westwide developments and uncertainties may impact these options.

13. CPUC Staff Look Forward to Further Assessments of Frequency Response Issues Particularly Under High Renewables Futures, and with Fine-Tuning of Modeled Response From Existing Providers as Emphasized in the Draft Study Plan.

For future frequency response studies in 2016 CPUC Staff request that the CAISO:

- provide context relative to other studies (such as 50% RPS studies and 2016-2017 TPP study cases) by describing in sufficient detail both CAISO area and westwide renewables portfolios and dispatch levels assumed for frequency response studies;

- provide greater quantitative insight into how commitment of resources to meet frequency response needs interacts with flexible reserves commitment to manage load/wind/solar variations and uncertainties, including the extent to which flexible reserves versus frequency response needs are fully additive, overlapping, or somewhere in-between;

- assess the potential (and modeling requirements) for additional sources of primary frequency response not modeled in recent studies especially looking out 10-15 years with high renewables penetration, such as storage, demand response, other preferred resources, and frequency response obligation contracts with other BAs; and

- complementary to the CAISO's stated intent to focus on understanding the discrepancy between modeled versus historically experienced frequency responsiveness from conventional providers - - assess and clarify the extent to which current assumed (conventional) frequency response providers could and should be expected or incentivized to provide greater frequency responsiveness, and the extent to which this impacts differences between modeled versus observed system frequency responsiveness.

14. The CAISO Should Explain How Required Frequency Response Capabilities will be Modeled in Both Economic and Operational Flexibility Studies.

In production simulation studies, the CAISO formerly modeled regional minimum generation constraints as proxies for a mixture of more complicated reliability requirements not inherently captured in direct current (DC) flow production simulations. Subsequently the CAISO has transitioned to instead modeling commitment constraints as production simulation proxies for *frequency response capability requirements*. CPUC Staff comments on the draft 2015-2016 Transmission Plan requested that the CAISO describe how this frequency response capability modeling was conducted in production simulations for 2015-2016 TPP economic studies.

The CAISO should describe to the extent possible now, and if necessary more fully when possible, what production simulation methodology or constraints will be used to model (serve as proxies for) frequency response capability requirements, in 2016-2017 TPP studies. This should include description of requirements or constraints regarding commitment and/or headroom levels for different specific kinds of generation. Also, the CAISO should clarify if different methodologies may be used (and may of necessity have to be used) for GridView simulations such as for TPP economic studies, versus for PLEXOS simulations such as for operational flexibility studies.

Besides being important in the context of the CAISO's own planning processes, methods of modeling production simulation operational constraints as proxies for frequency response capability requirements will be important when the CAISO's modeling studies are presented and discussed in the CPUC's Long Term Procurement Plan (LTPP) proceeding. In the recent cycle of that proceeding parties have already expressed strong interest in understanding and discussing the rationale and implications of production simulation constraints as proxies for reliability needs. Thus, information requested here regarding modeling of frequency response-based constraints the 2016-2017 TPP should supplement and/or update characterization of such modeling constraints as described in the *Assumptions and Scenarios* documentation for the new cycle of CPUC's Long Term Procurement Plan proceeding.

15. CPUC Staff Look Forward to Additional Detail and Vetting for the CAISO's Approach to Assessing the Potential for Economically Driven Retirement of Generation.

Dramatic evolution of electricity resource mixes and markets can produce economic pressures on some resources, including resources having important reliability roles. The CAISO's planned assessment of potential for economically driven retirements thus confronts an important topic which is already on many minds and agendas. However, constructing a credible and robust methodology for such an assessment is challenging and potentially controversial, and the CAISO should carefully describe and vet this methodology before proceeding to conclusions. This should include consideration of revenue implications of increased needs for various reserve and ancillary services, combined with new patterns of generator operation.

Contacts:

Keith White kwh@cpuc.ca.gov

Appendix A.

CPUC Staff Comments on the CAISO's Draft Study Plan for the 2016-2017 TPP

Timelines for Selected Projects Approved by CAISO and Under CPUC Application and CEQA Review

Utility / Company	Project Description/Application #	Date Filed at CPUC	Date Deemed Complete for CEQA Adequacy	Draft MND/EIR/Joint MND-EA, EIR-EIS Potential Release Date	MND/EIR/Joint MND-EA, EIR-EIS Potential Release Date
SDG&E	**South Orange County Reliability Project & Capistrano Sub. Upgrades & new 230 kV line/A12-05-020**	5/18/2012	1/7/2013	**DEIR issued Feb 23, 2015; Recirculation August 10, 2015**	**Expected April 2016**
PG&E	**Sanger 115 kV substation expansion-reconfigure incoming power lines partial demo of substation A.15-09-012**	9/30/2015	1/26/2016	**DMND issued May 2016**	**Expected July 2016**
SCE	**West of Devers 220 kv Upgrades/A13-10-020**	10/25/2013	9/11/2014	**Joint Draft EIR/EIS issued August 7, 2015**	**FEIR issued 12/11/2015 - FEIS expected early/mid 2016**
SDG&E	**Sycamore-Penasquitos 230 kv line/A14-04-011**	4/7/2014	7/24/2014	**DEIR issued Sept.2015**	**FEIR issued Mar. 7, 2016**
SCE	**Circle City Substation 66kv & Mira Loma Jefferson 66kV line A15-12-007**	12/4/2015	1/4/2016	TBD	TBD

Utility / Company	Project Description/Application #	Date Filed at CPUC	Date Deemed Complete for CEQA	Draft MND/EIR/Joint MND-EA, EIR-EIS Potential Release Date	MND/EIR/Joint MND-EA, EIR-EIS Potential Release Date
SDG&E	**TL649 wood to steel 7 miles and 116 pole replacements/A.15-08-006**	8/10/2015	1/25/2016	TBD	TBD
SDG&E	**Salt Creek 69 kV Substation/A13-09-014**	9/25/2013	5/19/2014	**DEIR issued May 2015**	**FEIR issued Sept. 2015**
SCE	**Valley-South 115 kV - Valley to Triton 15 mile line/ A.14-12-013**	Dec. 15, 2014	4/2/2015	**DEIR issued Jan 2016**	**FEIR issued April 2016**
SDG&E	**Vine 69/12 kV Substation/A.14-05-021**	5/27/2014	5/4/2015	**DMND issued September 2015**	**FMND issued Jan 2016**
SCE	**Mesa Substation Loop-In 230/66/16kv to 500 kV service & other line routing & rework/A15-03-003**	3/13/2015	5/15/2015	**DEIR expected April 2016**	**FEIR expected September 2016**
PG&E	**Fulton-Fitch Mtn. 60 kV reconductor 9 miles A1512005**	12/3/2015	not yet	TBD	TBD
SDG&E	**Cleveland NF Wood to Steel poles 69kV/A12-10-009**	10/17/2012	8/7/2013	**Joint DEIR/EIS issued September 5, 2014**	**Joint FEIR/EIS issued July 2015**
NextEra (NEET West)	**Suncrest 230 kV 300 MVAR Dynamic Reactive Power support Project-1 mile line into Suncrest A15-08-027**	8/31/2015	12/11/2015	**DEIR expected July 2016**	**FEIR expected Oct. 2016** Note: Assuming 9 months to construct and given that the required CPCN Formal

Utility / Company	Project Description/Application #	Date Filed at CPUC	Date Deemed Complete for CEQA	Draft MND/EIR/Joint MND-EA, EIR-EIS Potential Release Date	MND/EIR/Joint MND-EA, EIR-EIS Potential Release Date
					Proceeding at the CPUC will be complex, CAISO's expected June 2017 operational date is likely to be delayed by about a year if the project is approved for construction.
SCE	**Moorpark-Newbury 66 kV line-A.13-10-021**	10/28/2013	11/27/2013	**DEIR issued June 2015**	**FEIR issued Nov. 2015**
SCE	**Alberhill System/A09-09-022**	9/30/2009	5/26/2011 Am ended PEA	**A joint project (Alberhill, Fogarty, Valley-Ivyglen components) DEIR/SEIR expected Mar. 2016**	**FEIR expected July 2016**
SCE	**Riverside Transmission Reliability Project/A15-04-013**	4/15/2015	not yet	**Subsequent EIR TBD**	TBD