2010 CALIFORNIA ISO TRANSMISSION PLAN

COMMENTS OF THE STAFF OF THE

CALIFORNIA PUBLIC UTILITIES COMMISSION

FOLLOWING THE SECOND STAKEHOLDER MEETING OF OCTOBER 26-27, 2009

November 10, 2009

Introduction

Staff of the California Public Utilities Commission (CPUC staff) welcome the opportunity to comment on the California Independent System Operator's (CAISO's) development of the *2010 ISO Transmission Plan ("*2010 Plan*")* as updated for stakeholders via the second stakeholder meeting for the 2010 Plan cycle, on October 26 and 27. Besides seeking clarity and disclosure in several areas, the following comments emphasize the need for greater robustness in treatment of uncertain (but in some instances very likely and consequential) future developments, in both the reliability and economic assessments. Our comments especially emphasize the need to address how the 2010 Plan and associated actions and decisions anticipate and are coordinated with the proposed new 33% RPS renewable transmission planning process, as well as the proposed process for "enhanced" interconnection projects. CPUC staff recommend that the latter process be pursued on a faster track than the more expansive 33% RPS transmission planning initiative.

Generation Assumptions for Reliability Assessments

Reliability assessments and identified reliability solutions are influenced by projected temporal and locational patterns of not only loads, but also of generation. As described in the Study Plan for 2009 studies and the planning standards cited in that Study Plan (and also during the October 26 stakeholder meeting), the 5-year reliability assessment for 2014 includes only "Level 1" future generation which is

already under construction, and the 10-year reliability assessment for 2019 includes Level 1 generation plus "Level 2" generation that has received regulatory approvals. We assume that regulatory approvals refers to siting/environmental approvals such as CEC approvals for thermal power plants above 50 MW, but clarification here would be helpful. What is not clear is how, if all, LGIAs and progress toward LGIAs influence inclusion of future generation in the Reliability Assessment. Apparently a generation project having a PPA is *not* included in the Reliability Assessment unless it also meets the Level 1 or Level 2 criteria. It is unclear exactly what criteria were used for incorporating generator *retirements* into the Reliability Assessment, but apparently only those retirements that are now firmly committed are included.

As was briefly discussed in the October 26 stakeholder meeting, the Reliability Assessment's conservative criteria for including generator additions and retirements may no longer be sufficient for most usefully illuminating future circumstances and needs that will very likely reflect substantial and consequential generator additions and retirements. These generation changes, especially renewable generation additions and OTC generation retirements, can significantly impact power flows and reliability needs especially over the 10-year horizon but also over the 5-year horizon. A Reliability Assessment that does not take this situation into account could on the one hand overlook important reliability challenges and their needed solutions or, on the other hand, may identify solutions that are inefficient or unnecessary in light of likely generation changes. Subsequent planning cycles may have time to update the Reliability Assessment and identify efficient solutions before significant infrastructure commitments need to be made. However, when the Reliability Assessment essentially ignores substantial generation changes 5 and 10 years from now that are very likely even if imprecisely known, there appears to be a very real risk of risk of shortsighted reliability infrastructure planning and diminished opportunity to identify efficient overall solutions. The sooner a good overall picture is developed regarding inevitable reliability challenges from delivering and integrating large amounts of

variable renewable generation from new locations, and from retiring substantial historically relied upon generation in load centers, the sooner "big picture" solutions can begin. While this situation does *not* alter the need to address more urgent short-term needs, it does require considering a wider range of generation futures in the Reliability Assessment, drawing some guidance from futures reflected in the CAISO's Renewable Transmission Conceptual Plan, and in the CPUC 33% RPS implementation cases.

Even if the present planning cycle's Reliability Assessment is not modified to address the above concerns, the 2010 Plan should recognize and address the impact of these very likely generation changes on reliability challenges and solutions, both generally and with regard to specific reliability needs and solutions identified in the 2010 Plan.

Assessment of Uncertainties and Sensitivities in General

The study process for the 2010 Plan (and for individual major projects such as the C3ETP) must adequately address uncertainties in order for study results to be informative and plans to be robust. This clearly includes the uncertain but consequential generation changes discussed above, which impact not only the Reliability Assessment but also the economic studies. For example, discussion in conjunction with both the 2010 Plan and the new 33% RPS renewable transmission initiative suggests that it may be valuable to consider a robust range of futures when assessing the value of "foundation lines" that would support management of renewable generation from multiple resource areas.

We would expect to learn, in the upcoming draft 2010 Plan, how the studies, their interpretation, and the resulting 2010 Plan are made reasonably robust with regard to uncertainties concerning generator additions and retirements, loads (especially as we face various DSM, DG and electrification possibilities), hydro conditions, gas prices, and CO_2 constraints. While the reliability assessment may internalize some (not all) of these uncertainties simply by deliberately focusing on worst case or high stress situations, the economic assessment does need to address the range of major

uncertainties. (And, as noted above, future Reliability Assessments should more fully address generation uncertainties.)

Clarification of the Renewable Transmission Conceptual Plan

The Renewable Transmission Conceptual Plan (Conceptual Plan) developed in the 2010 Plan process is described as providing full deliverability for renewable generation additions sufficient to meet an assumed 69,000 GWh/year net short position in renewable generation (going forward from approximately 2008), based on analyzing high-stress spring and summer power flow scenarios. Slide 4 from the October 26 presentation of this Conceptual Plan indicates that over the various renewable resource locations and two power flow scenarios (August 3-4 pm, April at noon) considered, the assumed renewable generation output levels relative to maximum capacity were roughly 35% for wind and 65-85% (depending strongly on hour of the day) for solar. In response to a question regarding whether designing transmission to accommodate these, and not higher, levels of output could lead to curtailment in hours when solar or wind output approaches full potential, it was stated that higher levels of renewable output were assumed for assessing *individual* resource zones.

This leaves ambiguity as to what was actually done in developing the Conceptual Plan based on simulated renewable generation output and resulting power flows. Perhaps closer to full capacity wind and solar output levels were assumed in conceptually sizing "collector lines" accessing individual resource zones, or other parts of the network, to produce the "augmented" study results referred to on page 13 of the 2020 Renewable Transmission Conceptual Plan study results document released on September 15. However, this process needs to be clarified.

Another area of needed clarification concerns what kind of solar output profiles were used for the different resource zones, and the implications. During discussion of the Conceptual Plan at the October 26 stakeholder meeting it was stated that only one type of solar technology was assumed for

modeling purposes. It would be helpful to know what this technology was, as well as what might be the consequences of more diverse assumptions, such as contrasting PV versus CSP output profiles. Also, we may now be at a useful starting point for going forward in the future, and examining the transmission implications of different kinds of solar generation, of solar generation with thermal storage, and of wind and solar generation with other kinds of storage.

Overall, the Conceptual Plan and other renewable generation and transmission scenarios and plans such as those developed in conjunction with RETI and with the CPUC's 33% RPS Implementation Analysis will provide an important basis for future transmission plans and approvals, such as under the CAISO's new 33% RPS transmission planning initiative, and for assessing "enhanced" (elsewhere known as "right-sized") LGIP-driven transmission expansions within the framework of the existing Order 890 compliant Transmission Planning Process.

Interaction with the Proposed New33% RPS Transmission Planning Process

The 2010 Plan and its associated activities and decisions will clearly address some renewable generation-related transmission. At the same time, how the newly proposed 33% RPS transmission planning process will interact and coordinate with the existing Order 890 compliant planning process remains to be worked out, both in preparation for a tariff filing with FERC and also on a longer term basis when lessons are inevitably learned.

Key fundamental requirements for coordinating the two processes include consistency, transparency, fairness to diverse stakeholders, efficiency/streamlining, and also the ability to gain FERC approval. It is clear that 2010 Plan developments will inform development of conceptual and final renewable transmission plans under the proposed new 33% RPS transmission planning process. Conversely, developments and products under the new process will inform future cycles of the CAISO's overall transmission planning process. However, this still leaves unanswered the more *immediate*

question of how, in the next few months, final development of the 2010 Plan and associated decisions should anticipate the nascent 33% RPS renewable transmission process. Two issues in particular stand out.

The first issue concerns LGIP-related project approvals. We note that

1. the LGIP and LGIAs provide the magnitude and timing of transmission upgrades that interconnecting generators may expect under the CAISO's FERC-approved tariff, but that

2. more expedited and/or proactively over-sized transmission upgrades might in some instances be planned either via the existing TPP with proposed tariff amendments to facilitate "enhanced" (e.g., upwardly sized) interconnection-related transmission projects, or via the proposed new 33% RPS renewable transmission planning process.

The immediate question is when, in connection with the present planning cycle, should renewable generation interconnection-related transmission projects, particularly in an "enhanced" (upwardly sized) form, be approved in advance of the schedule for approvals under the proposed new 33% RPS transmission planning process?

Under the proposed new process, initial project approvals would occur in early 2011, whereas some approvals in conjunction with the current planning cycle, such as for LGIP-related projects submitted in the Request Window, could occur in early 2010. For perspective, the large amount of renewable generation projects in the transition cluster will very shortly have to decide whether to post initial security deposits and enter Phase 2 studies, and those studies are scheduled to conclude with plans of service and LGIAs towards the end of 2010.

The second issue concerns whether any renewable generation-supporting transmission projects that support multiple resource zones and are found to be needed across a wide range of possible futures should be approved in conjunction with the present planning cycle or at least ahead of the early 2011 timing of approvals under the proposed new 33% RPS renewable transmission planning process. For example, such projects may include, or be analogous to, foundation and delivery lines identified in RETI Phase 2.

However, regarding the above issues, potential approval of either interconnection-related (perhaps "enhanced') transmission projects or "robustly needed" transmission projects ahead of the approval schedule envisioned for the newly proposed 33% RPS transmission planning process, two important complications are as follows.

1. The projects in question may require their own stakeholder process if reaching the $200 million cost level. However it is unclear if this requirement applies to projects that are strictly interconnection-related. Furthermore, a tariff amendment (which CPUC staff recommend be pursued on a separate and faster track than the broader 33% RPS planning process initiative) might provide for an expedited process for "enhancement" of interconnection projects.
2. There is a possibility that even if prudent project approvals guard against risk of stranded investment, transmission projects that are approved expeditiously in conjunction with the present planning cycle might ultimately prove to be undersized or otherwise inefficient within the broader renewable transmission plan to be ultimately developed at the end of 2010 under the proposed new 33% RPS transmission planning process.

CPUC staff believe that the solution to the two above complications is to tread cautiously regarding any renewable transmission approvals in the near future, but recognizing that such approvals may be warranted in some instances and should be evaluated on a case-specific basis, balancing benefits and risks. Where a transmission project in question requires a substantial stakeholder process, then a head start within the present planning cycle might conceivably not provide much expediting

relative to addressing the project within the proposed 33% RPS transmission planning process. However, this should not be taken for granted, since the head start might allow various planning, analysis, stakeholder interaction, and permitting steps to proceed faster than otherwise.

Relationship between C3ETP and Needs Identified in the Reliability Assessment for the 2010 Plan

The 2010 Plan should clarify the relationship between the objectives and potential configuration of the C3ETP, versus the short-term, 5-year and 10-year reliability needs and solutions identified in the Reliability Assessment for the 2010 Plan. In particular, what needs and solutions identified in the Reliability Assessment...

- are needed before the C3ETP could be implemented (i.e., are urgent),
- would be needed (or would likely be needed depending on future developments) in *addition to* a reasonably likely C3ETP design, or
- would be displaced by, or subsumed within, a reasonably likely C3ETP design to meet Fresno area reliability needs ?

Economic Studies for 2010 Transmission Plan and for the C3ETP

Similar to what CPUC staff has previously recommended regarding economic studies of the C3ETP, it is important that economic studies for the 2010 Plan clearly identify how economic benefits are being measured, including clearly distinguishing benefits that represent *means* to ultimate ends (e.g., reduced MWh of congestion, increased Helms operability, increased transfer capability) versus benefits that represent ultimate ends such as regarding energy and ancillary services costs, reliability, renewable energy goals, and CO_2 emissions. Operability of Helms and possibly other pumped storage plants appears to potentially have substantial benefits for integrating renewable generation, maintaining reliability, and reducing energy and/or ancillary services costs. There should be as clear and informative a description as possible regarding

- how pumped storage plant operations are modeled, including key assumptions, simplifications and analytic limitations, and also
- how enhanced pumped storage operations support ultimate benefits such as regarding energy and ancillary services costs, reliability, management of renewable generation, and reduction of CO_2 emissions.

Also regarding the economic studies, there should be as full a description as possible regarding how renewable generation-related benefits (such as improved management of renewable generation) are being *measured*. For example, are renewable generation benefits apart from benefits already captured via energy/ancillary services costs and reliability, being based on ability to avoid simulated curtailment of renewable generation? To what extent are the modeling tools and methods adequate to capture renewable generation-related benefits beyond what is already captured via measured energy, ancillary services and reliability benefits?

Finally, regarding the economic study

- with what temporal granularity are the transfer capabilities of transmission paths being varied? Seasonally (in each direction), or more finely? Does simulating security-constrained commitment and dispatch based on a large number of contingency and monitored lines impact the conservatism with which explicit path limits should be modeled?
- It was noted that San Diego County results were skipped or otherwise not emphasized due to data inadequacy. What is the data inadequacy and how will it be rectified?

Status of Last Year's Request Window Submittals

In 2008, eleven Request Window proposals for "economic" transmission projects were moved forward to the 2009 studies for the 2010 Plan, to be treated as requests for Economic Planning Studies. [1] What is the significance of treating these proposals as requests for economic studies rather than as economic project proposals? How were these eleven 2008 requests dealt with in 2010 Plan process?

It appears that several of these eleven proposals from 2008 represent independent developer proposals for transmission projects that would access or otherwise support new renewable generation. What is the relationship of these proposals to the Renewable Transmission Conceptual Plan? Do or could any of these proposals meet new infrastructure needs reflected in that Conceptual Plan? Are these proposals displaced by, or do they compete with, other proposals? How will these proposals and their disposition be addressed in the final 2010 Plan? Can any of these proposals be treated within the existing Transmission Planning Process as "enhanced interconnection projects" that meet LGIP-driven needs on a proactively enhanced scale as described under the CAISO's October 30 33% RPS renewable transmission planning proposal and the subsequent November 6 stakeholder call?

On the other hand, looking forward, which of these eleven 2008 Request Window proposals would have to be re-submitted or otherwise re-evaluated relative to the renewable transmission plan proposed to be developed and approved by the end of 2010 under the CAISO's 33% RPS renewable transmission planning proposal?

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[1] 2009 California ISO Transmission Plan, page 16.