Stakeholder Comments Template

Integration of Transmission Planning and Generation Interconnection Procedures (TPP-GIP Integration) Second Revised Straw Proposal, posted January 12, 2012

Please submit comments (in MS Word) to TPP-GIP@caiso.com no later than the close of business on January 31, 2012.

Submitted by	Company	Date Submitted
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This template is for submission of stakeholder comments on the topics listed below, which were discussed in the TPP-GIP Integration Second Revised Straw Proposal posted on January 12, 2012, and during the stakeholder meeting on January 19, 2012.

Please use the list of topics and questions below to structure most of your comments. At the end of the document you may offer comments on any aspect of this initiative not covered by the topics listed. When you state a preference for a particular approach on a topic or issue, your response will be most helpful if you clearly explain the reasoning and business case for your preference.

Section 1. High-level structure of the TPP-GIP Integration proposal. (Please use section 2 below to comment on the details of each element.)

The ISO's TPP-GIP integration proposal is continuing to move toward what Ormat believes is the appropriate endgame, removing deliverability analysis completely from the GIP, and hopefully incorporating deliverability into the ISO's congestion management system.

RA deliverability was developed prior to the ISO's move to a nodal LMP market to provide a straightforward consistent mechanism for determining if generation capacity would be able to operate and serve load during system peaks. While deliverability does not provide any scheduling priority in actual operations, having full deliverability pretty much assures that there will be enough transmission capacity available to avoid congestion and potential curtailment. Because RA deliverability cannot be transferred (except to replacement generation of the same size or smaller at the same location), it is impossible to determine if it may be more cost-effective to allow one resource to transfer its deliverability to another than to build a major transmission upgrade. As has been demonstrated by the analysis of the Cluster 1&2 deliverability concerns, this inflexible, non-market-based mechanism could lead to overbuilding transmission and dramatically raise the transmission component of rates. It also provides no opportunity for buyers and sellers of renewable generation to obtain deliverability from alternative sources that may have a lower cost or provide valuable renewable integration services.

RA deliverability is a blunt tool that is being used to perform precise procedures. This is why Ormat strongly encourages the ISO to initiate a stakeholder process to develop alternatives to the current RA deliverability procedure that are better suited to the issues and initiatives that are currently driving the evolution of California's electricity industry.

1. The process as described in the January 12 paper and outlined below reflects the proposed process for projects in GIP cluster 5 and later. The process for existing queue projects (serial through cluster 4) will proceed according to the ISO's January 10, 2012 revised discussion paper.

2. After GIP Phase 1, each generation project advancing to GIP Phase 2 must elect either (A) – project requires TPP-based deliverability; or (B) – project is willing to pay for delivery network upgrades.

   It is very unlikely that any developer would choose Option B unless their intent was to deliver outside the CAISO.

3. The requirement for customer-funding of network upgrades (option (B)) would apply only to delivery network upgrades (DNU); posting and reimbursement for reliability network upgrades (RNU) for all projects would remain as today.

   Ormat supports this proposed change, as a start. The GIP should only consider RNUs.

4. The allocation of TPP-based deliverability to generation projects would occur after GIP Phase 2, rather than after Phase 1 as in the previous proposal.

   The entire deliverability concept should be subsumed into the ISO's congestion management process, which has the necessary mechanisms to get **cost-effective** transmission built to relieve congestion through the economic component of the TPP.

5. Allocation of TPP-based deliverability – and project's ability to retain allocation – will depend on the project's completion of significant development milestones that demonstrate high confidence in attaining COD. (Specification of appropriate milestones is covered in the next section.)

   Eliminating deliverability from GIP entirely eliminates the need for the ISO to take a position as to "confidence in attaining COD."

6. The allocation of TPP-based deliverability should achieve the following objectives as far as possible: (a) select projects with high probability of completion; (b) limit ability of non-viable projects to retain the allocation; (c) provide sufficient certainty to enable financing of viable projects; (d) objectivity and transparency.

Once again, removing deliverability from GIP would take the ISO out of the role of judging any interconnecting project's viability.

Section 2. Details of individual elements of the proposal.

GIP Phase 1

7. For extremely large cluster groups compared to the amount of "TP deliverability" (the amount supported by existing grid plus all approved upgrades to date), GIP phase 1 will study deliverability in each area up to the amount of TP deliverability plus a reasonable margin. The intent is to avoid excessive DNU costs that can result from extremely large clusters, while providing useful information on needed DNU and associated costs if generation development exceeds grid capacity.

   Take the next step – remove deliverability entirely from GIP. TP deliverability guesses are still guesses and depend on various forecasts rather than actual commercial interest. The ISO's congestion management process adapted for RA deliverability already has a mechanism to assure that cost-effective transmission is built to offset congestion.

8. Phase 1 will study RNU for all projects in the cluster.

   As it should.

9. As a result of Phase 1 each project will know its RNU and associated costs, and these results will establish cost caps for RNU as they do today.

10. The DNU and associated costs resulting from phase 1 will be advisory. The only formal use of Phase 1 DNU costs in the TPP-GIP process will be to establish posting requirements for projects advancing to phase 2 under option (B), as described below.

    If DNU estimates are only advisory, why even bother.

Project's Decision to Enter Phase 2 and Implications of Decision

11. After GIP Phase 1, each generation project advancing to GIP Phase 2 must elect either (A) – project requires TPP-based deliverability; or (B) – project is willing to pay for delivery network upgrades. Once a project chooses and the deadline for phase 2 is passed, the project cannot switch to the other option.

    Given the disadvantages that Option B projects face, it is difficult to conceive of situations where it would be chosen.

12. A project choosing (A) will have to post for its RNU under today's rules, but not for DNU.

13. A project choosing (B) will have to post for both RNU and DNU. Its DNU posting amount will use phase 1 results for the project's study area, converted to a DNU rate ($ per MW

of deliverability) = (cost of incremental DNU)/(deliverability MW studied above TP deliverability amount). The posting amount will = rate x (project MW), where project MW reflects how the project is modeled in the deliverability study depending on the resource type, would typically be less than nameplate for renewables.

14. A project choosing (B) will be eligible for TPP-based deliverability if available, but should expect very low probability of obtaining it and should plan to fully fund its needed DNU.

GIP Phase 2

15. ISO will perform a baseline re-study at the start of each phase 2 study process. The re-study will assess impacts of status changes – project drop-outs or revised COD, new transmission expansion approvals, etc. As a result, the RNU or DNU for some projects may be modified and their GIAs revised.

16. Phase 2 will study RNU for all projects in phase 2.

17. Phase 2 study will assume that all TP deliverability is used up by (A) projects and existing queue, and then will model (B) projects at requested deliverability status to assess their incremental DNU needs.

Allocation of TPP-based Deliverability

18. Once phase 2 results are completed and provided to the projects, the 120-day period for negotiating and executing the GIA begins. Option (A) projects that demonstrate completion of certain milestones within this period will be able to execute GIAs at their requested deliverability status, with no cost responsibility for DNU. Option (B) projects that complete the same milestones would be eligible for TPP-based deliverability, but would receive an allocation only if capacity is available.

19. The proposed milestones required are (a) completion of all permitting required to begin project construction, and (b) either a PPA approved by buyer's regulatory authority or demonstration of committed project financing. PLEASE COMMENT on whether these milestones are appropriate, or if not, what milestones would be preferable and explain why. Please keep in mind the objective that milestones must provide a high confidence that the project will meet its planned COD.

    Even with permitting and a PPA in hand, there is ample evidence of proposed projects failing due to different criteria. Having the ISO choose winners and losers is not a particularly good idea, regardless of the milestones. Removing DNUs from GIP eliminates this issue entirely.

20. PLEASE COMMENT on what could constitute evidence of committed project financing as an alternative to regulator-approved PPA for item (b) above.

    See response to #19 above.

21. All option (A) projects that meet the milestones by the time required would be able to execute FC GIAs at this time, even if the total amount exceeds the TP deliverability available. In that case, the ISO would expand the TPP planning portfolio in that area for the next TPP cycle, to provide sufficient deliverability.

22. Any project that obtains TPP-based deliverability would have additional milestones in its GIA which track progress toward COD. Failure to meet one of these milestones would cause the project to lose its deliverability allocation, but would not necessarily terminate its GIA if the project wishes to continue as EO.

23. An option (A) project that does not meet the milestones by the time required would have an opportunity again in the next GIP phase 2 cycle, one year later. If it does not qualify by the end of the next year's 120-day GIA period, it must either withdraw from the queue or continue under an Energy Only (EO) GIA.

24. An option (B) project that does not obtain TPP-based deliverability in the current cluster cycle (120 days from phase 2 results to GIA execution) will no longer be eligible for TPP-based deliverability and must proceed to GIA that includes full self-funding of its DNU.

25. If a (B) project drops out after phase 2 instead of executing a GIA that includes self-funding of its DNU, it loses a portion of its posting. PLEASE COMMENT on how much of the posting should be forfeited, and explain your logic.

<u>Other Proposal Elements</u>

26. DNU paid for by an interconnection customer would fall under the merchant transmission provisions of the ISO tariff and would be eligible for allocation of congestion revenue rights commensurate with the capacity added to the ISO grid. The customer would be able to select a non-incumbent PTO to build the project, provided it is a "green field" project and the builder meets qualifications specified in the ISO tariff.

    Converting deliverability to CRRs would provide added benefit to self-funding and be more likely to encourage self-funded transmission.

27. If a (B) project funds DNU that provide more capacity for deliverability than the project needs, the funding party or parties would need to fully pay for the DNU, but would receive reimbursement for the excess deliverability from later projects that are able to use it.

    See answer to #26.

28. Some projects that go forward under these new provisions could be subject to reduction in annual net qualifying capacity (NQC) for one or more years. This could occur if transmission capacity in an area must be expanded through the TPP to accommodate the amount of deliverable capacity that achieves COD in that area. Consistent with the ISO's January 10 discussion paper on cluster 1-2 approach, "existing" projects would not be subject to the reduction, but "new" projects would be. "New" would include all cluster 5 and later projects that elect option (A).

29. It was suggested by some stakeholders at the January 19 meeting that as an alternative to applying NQC reductions if the need arises, the ISO should allow the new projects to count fully for resource adequacy without any NQC reduction so that the projects and the LSE buyers are insulated from any direct impacts, and then make up for any resulting shortfall in resource adequacy capacity via ISO backstop capacity purchases. PLEASE COMMENT on this proposal.

    These proposals do not include a mechanism for determining if upgrades (or CRM purchases) are cost-effective options. Incorporating deliverability into congestion management incorporates an economic test.

30. Please use the space below to offer comments on any other aspect of the proposal not covered above.

    Ormat appreciates the ISO's valiant attempts to make a legacy mechanism such as RA deliverability fit into what is becoming a transforming industry. It is now time to bite the bullet and conform resource adequacy to the ISO's market design. Unlike attempts to implement a centralized capacity market, subsuming deliverability into congestion management will not require total restructuring of the CPUC's RA program and should be relatively easy to implement. A short analysis of the issue is included below.

Deciphering the Distressing Deliverability Dilemma

California is in the midst of attempting to transform its electricity production, distribution and consumption industry. The Golden State has:

- established an aggressive schedule for generate a third of its electricity from renewable sources,
- provided substantial incentives for roof-top solar photovoltaic generation and combined heat and power in hopes of seeing 12,000 MW of distributed generation,
- required installation of millions of advanced "smart meters" to give consumers more information and opportunities to be more energy efficient,
- begun to plan a transition to a self-healing more robust Smart Grid, and
- even established special rates and rules to encourage the use of plug-in electric vehicles.

While the political (and hence policy) winds can change rapidly, California appears to have made an all-in bet on a different energy future. Getting there will require a transformation in the operation of the grid at all levels. That is the challenge considered here.

Resource Adequacy (RA) deliverability has been at the heart of many of the challenges currently faced in achieving California's transformative goals. Deliverability is creating challenges in the generator interconnection process, transmission planning process, renewable resource integration, and even demand response. In order to transform the industry, some reform or modification of the RA mechanisms and deliverability requirements will probably need to be made.

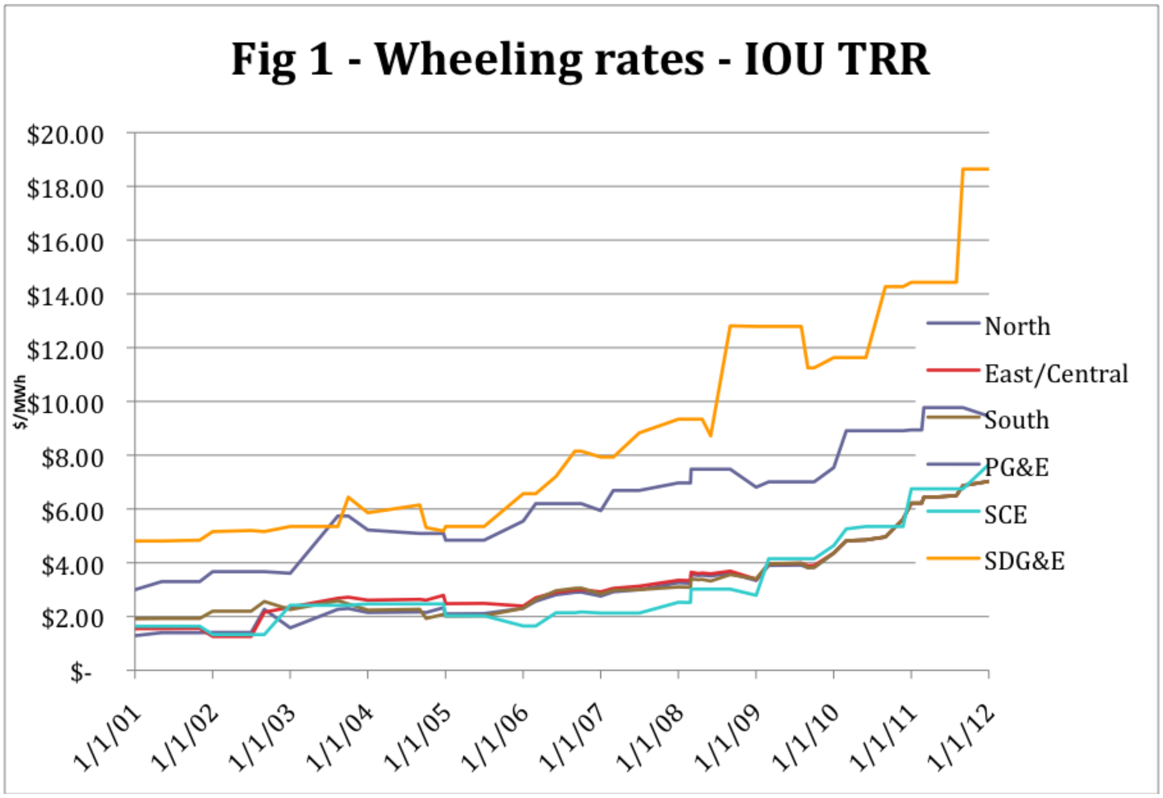
Background

After California's poorly designed electric industry restructuring initiative lost its gleam in the millennial market meltdown of 2000-2001, the regulators decided that a resource adequacy program was needed to make sure physical generating resources would be available and committed to serve California load in the future to minimize future prospects of rolling blackouts and mind-boggling prices. The RA program required Load Serving Entities (LSEs) to annually demonstrate that they had sufficient resources (generation and demand response) under contract to meet their share of 115% the forecasted system peak. Local capacity requirements (LCR) were added in later years, but a centralized forward capacity market, such as is used in other organized markets, was rejected; primarily due to discomfort with the idea of paying existing resources based on the cost of building new ones.

The CAISO determined the amount of net qualifying capacity (NQC) that each resource could provide for RA purposes. It revised its generator interconnection process so that applicants could choose an "energy only" interconnection with no RA deliverability or "full capacity" interconnection with 100% deliverability of NQC. Network upgrades were differentiated between reliability network upgrades (RNU) needed to safely connect the resource to the grid without degrading reliability, and deliverability network upgrades (DNU) needed to make sure there is sufficient transmission system capacity available to deliver the NQC to the aggregate of load during annual peak load hours. As long as only the occasional new generator was interconnected to deal with load growth and resource retirement, this approach worked fairly well. However, when California established its 20% Renewable Portfolio Standard (RPS) in

2006, the number of interconnection requests went through the roof. The ability to interconnect became a sign of project viability, and full deliverability (the ability to provide RA capacity) became a standard requirement. As of January 13, 2012, there are 452 projects, totaling over 68,000 MW, of active projects in the interconnection queue, virtually all of which have requested full capacity interconnection. Since this is over 130% of the CAISO historic peak demand and several times the amount of renewable generation needed to meet the 33% RPS requirement for 2020, there is a high probability that a majority of this generation will not actually get built. That would not necessarily be a problem, except for the issue of deliverability. Under current procedures, the CAISO assumes that all generation within a cluster, as well as all earlier "full capacity" projects in the queue, will be in operation and trying to provide RA capacity. As a result, it identifies the need for massive amounts of new transmission capacity that will be needed to provide this deliverability, which results in equally massive advance payments for DNU that applicants must make or commit to in order to move forward in the interconnection process. While DNUs are (currently) fully refundable within five years after the resource comes on line, the up-front obligation – in some cases a significant percentage of the total development cost – can strain the finances of even the deepest pocketed developer. Even worse from the ISO's perspective, however, project attrition can trigger a series of restudies and ongoing changes in upgrade requirements to meet the ever-changing level of anticipated generation. It thus becomes virtually impossible to know how much the generation developer must pay, which transmission projects to approve and which to postpone in anticipation of the need for them going away.

The IOU's, purchasers of most proposed renewable generation under long-term contracts, are also in a bind. They prefer that renewable resources, for which they are paying significant premiums, provide full RA deliverability. Besides counting towards RA, full deliverability also assures that there will be minimal congestion (and associated congestion management expenses) and little chance that the IOUs will be paying for renewable generation that has to be curtailed because of congestion. However, because the ISO does not account for RA deliverability in its daily scheduling process, fully deliverable resources receive no scheduling priority. IOUs have to hope potential congestion problems are solved by building enough wires to make sure there isn't any congestion. From the IOUs' perspective this is not necessarily bad, since they get to build, own and ratebase all those new transmission lines. From the customers' perspective, this is less of a good idea. As the chart below shows, transmission wheeling rates and IOU Transmission Revenue Requirements (TRR) rates have more than tripled since 2001, even though few major transmission projects have come on line.



Another challenge is how to treat the smaller distributed generation projects that interconnect at the distribution level. These projects, typically under 3 MW, interconnect to IOU facilities and are not involved in the CAISO RA deliverability assessments. There is effectively no way to know how deliverable these resources may be absent entering into the CAISO's costly, and seemingly never-ending interconnection process.

The current RA process is also poorly suited to deal with the intermittency of much of the new renewable (primarily wind and solar PV) generation coming on line, and the need to have dispatchable capacity available to ramp up when the wind suddenly dies down or large clouds roll through an area. The CAISO is proposing a special category of RA to assure that a sufficient amount of flexible, fast ramping generation is available to meet renewable integration needs. A recent example is the CAISO's response to the proposed retirement of Calpine's Sutter Center, a 500 MW combined cycle plant that first came on line in 2001. Calpine informed the CAISO that the plant, which is not contracted to provide RA in 2012, would shut down if not designated as needed under the CAISO's Capacity Procurement Mechanism (CPM). The CAISO proposes to contract with Sutter, at an RA price of $67.50/kW year, on the basis that it will be needed for reliability in the 2017-2018 period. CAISO is considering a new stakeholder process to investigate the prospects for limited long-term RA procurement of Sutter and other resources like it. The CPUC is proposing to require the IOUs to negotiate RA contracts with Sutter at a price not to exceed $67.50/kW year, apparently to sidestep and avoid CAISO procurement. While Sutter is fully deliverable, the current RA program is not designed to deal with this issue.