Stakeholder Comments Template

Integration of Transmission Planning and Generation Interconnection Procedures (TPP-GIP Integration) Straw Proposal, July 21, 2011

Submitted by	Company	Date Submitted
Please fill in the name, e-mail address and contact number of the specific person who can respond to any questions about these comments. Keith White kwh@cpuc.ca.gov 415-355-5473	Please fill in here California Public Utilities Commission staff	Please fill in here August 9, 2011

This template is for submission of stakeholder comments on the topics listed below, covered in the TPP-GIP Integration Straw Proposal posted on July 21, 2011 and discussed during the stakeholder meeting on July 28, 2011.

Please submit your comments below where indicated. At the end of this template you may add your comments on any other aspect of this initiative not covered in the topics listed. If you express support for a preferred approach for a particular topic, your comments will be most useful if you explain the reasons and business case behind your support.

Please submit comments (in MS Word) to TPP-GIP@caiso.com no later than the close of business on Tuesday, August 9, 2011.

1. The ISO has laid out several objectives for this initiative. Please indicate whether you organization believes these objectives are appropriate and complete. If your organization believes the list to be incomplete, please specify what additional objectives the ISO should include.

First of all, the Staff of the California Public Utilities Commission (CPUC Staff) would like to congratulate and thank the CAISO for this constructive and strongly needed proposal to better integrate the Transmission Planning Process (TPP) and Generator Interconnection Procedures (GIP), while also promoting improved consistency and coordination with resource planning. Such planning reforms are essential to provide a more efficient, transparent and holistic process for planning and assigning costs for transmission additions as we face large and challenging energy infrastructure changes.

The objectives listed in Section 4 of the Straw Proposal are all appropriate and important. This includes the various sub-objectives within objective 7, “resolve several previously identified GIP issues”, although as discussed below some of these sub-objectives could be lower priority or less urgent. Additional objectives which may in part be implied but should be explicitly captured in the listed objectives should include:

- deployment of a more efficient and transparent TPP-GIP integration process in an *expeditious* manner in order to impact processing of the interconnection queue and planning of transmission as soon as reasonably possible;

- more effective removal of nonviable or inactive generation projects from the interconnection queue, in terms of speed and also in terms of financial and staff resources consumed, realizing there may be tradeoffs such as time versus resources;

- best use of credible up-to-date information on the viability of generation projects; and

- transparent disclosure and consideration of costs and cost-effectiveness for new transmission, along with opportunity for independent development, including independent development of location constrained resource interconnection (LCRI) transmission.

Furthermore, objectives 1, 2, 3, 4, 5, and 6 emphasize, respectively: approving new rate-based transmission based on a comprehensive planning approach addressing system needs holistically, relying more on the TPP as the venue to approve rate-based transmission, providing incentives for resource developers to select cost-effective locations, limiting exposure of ratepayers to costs of inefficient grid upgrades, providing greater support for subsequent siting of transmission, and providing greater transparency. All of these objectives would be best served if it was made clear as an objective of this initiative that the cost of new network transmission will not be rolled directly into the transmission access charge (TAC) unless that transmission is first approved via the TPP. Any transmission included in existing individual generator interconnection agreements would remain eligible for generator reimbursement (and thus ultimate TAC roll-in) under existing provisions consistent with FERC policy.

2. At the end of the Objectives section (section 4) of the straw proposal, the ISO lists seven previously identified GIP issues that may be addressed within the scope of this initiative.

    a. Please indicate whether your organization agrees with any or all of the identified topics as in scope. If not, please indicate why not.

    The seven previously identified issues “a” through “g” are all in scope. However, re-study, disposition of funds collected from drop-outs and additional opportunities to downsize, issues b, c and g respectively, may be better addressed or resolved *after* more basic issues are resolved, since these three issues appear unlikely to significantly drive selection of a basic design for TPP-GIP integration. In particular, if Option 1B is selected (move directly from GIP Phase 1 to TPP), re-study would be associated with the TPP not GIP, and opportunities to downsize would affect TPP process rather than GIP process. Furthermore, early consideration of issue "d" (substitution of development milestones for financial postings) could be illuminating, but ultimate resolution of this issue might have to follow resolution of some other issues, including selection of the fundamental TPP-GIP integration design and the method of allocating limited TAC-funded transmission among interconnection customers.

b. Please identify any other unresolved GIP issues not on this list that should be in scope, and explain why.

Another issue for consideration is whether and how the method of calculating deliverability and delivery upgrades, including the system scenarios and generator injection levels utilized for this purpose would change if Option 1B is selected and study activity moves directly from GIP Phase 1 into the TPP. This would seem to offer the possibility of assessing deliverability in a more holistic ***and*** probabilistic manner considering multiple systemwide resource cases and total deliverability of resources system-wide.

A more general consideration is whether (and which of) the cited problematic GIP issues would disappear or be more readily resolved if effectively transferred into the TPP as part of the TPP-GIP integration design. This should be an explicit goal and benefit of TPP-GIP integration.

3. Stage 1 of the ISO's proposal offers two options for conducting the GIP cluster studies and transitioning the results into TPP.

a. Which option, Option 1A or Option 1B, best achieves the objectives of this initiative, and why? Are there other options the ISO should consider for structuring the GIP study process?

Option 1B, moving from GIP Phase 1 directly to the TPP, appears to offer the best opportunity for achieving the overall objectives. There would likely have to be more modifications to the GIP and TPP under Option 1B, but higher value should be placed on an improved outcome and streamlining rather than on minimizing changes, unless the changes seriously impair feasibility. Option 1A would be preferable only if there is convincing demonstration that Option 1B entails unmitigable problems. It would be helpful for the CAISO to explain why in Section 5.2 of the July 21 Straw Proposal Option 1B is estimated to provide an Interconnection Customer (IC) timeline from interconnection application to CAISO approval of a plan of service that is only 8-9 months shorter than provided under Option 1A, rather than something closer to a full year shorter.

Several reasons why Option 1B appears preferable are that it would:

- → achieve greater TPP-GIP integration and greater use of the TPP (versus GIP);
- → better accelerate the overall process for ICs;
- → provide greater transparency generally, because the TPP is more transparent than the GIP and Option 1B would provide a faster transition to the TPP arena;
- → provide a more efficient and transparent basis to deal with dropouts and re-studies because there would be fewer GIP stages where dropouts would occur and the dropouts could be dealt with in the broader context of system-wide scenarios and their assessment, as opposed to being more strongly driven and constrained by the sequencing and processing of individual connection requests and their status within clusters and study groups;
- → provide a more efficient basis for handling a large volume of interconnection requests, since a simplified Phase 1 (more efficiently producing cost signals that encourage less viable generation to drop out) could reasonably be developed as is currently being considered for Cluster 4 in a separate CAISO initiative, and then any large volume of interconnection requests still remaining would move right into the TPP where it would be more readily handled than if moving into Phase 2 studies; and
- → provide less potential for conflict or confusion between GIP-developed transmission needs or plans (which are more fully developed in Phase 2 than in Phase 1) versus TPP-developed plans.

There are certainly some advantages for Option 1A, such as giving generators additional decision points within the GIP, and potentially providing more detailed information to pass along to the TPP. However, CPUC Staff believe that Option 1A's advantages are outweighed by the advantages of Option 1B.

In selecting among Options 1A, 1B or other proposed fundamental options, it is important to respect the information needs and the financial (and other) commitments of generation developers. On the other hand, we should recognize that there will *inevitably* be some "picking of winners and losers". The only way to fully avoid this is to either design a "copper plate grid" where transmission access is so extensive as to not constrain or favor any generators, or on the other hand to require generators to "self-fund" all of the transmission upgrades that they need. TPP-GIP integration design should be chosen to give generation developers *reasonable* opportunity to control their fates.

If possible, generators that would have sufficiently limited impact on large grid upgrades or on the operations of other generators might be given some greater degree of certainty and reduced risk when planning moves into the TPP arena, but only if this can be done in a beneficial, efficient and fair manner.

b. What, if any, modifications to the GIP study process might be needed?

If Option 1B is selected there would be no GIP Phase 2. There will likely need to be a mechanism providing a "restricted" Phase 1 study process and associated cost assignments under either Option 1A or 1B, to deal with large volumes of interconnection requests greatly exceeding viable levels of generation additions, to avoid unrealistically studying every MW of requested generator interconnection. If Option 1A is selected, such a restriction option might need to be applied not only to Phase 1 studies but also to Phase 2 studies before moving to the TPP, depending on the rate of generator dropouts.

CPUC Staff offer no further discussion of GIP modifications at this time, but recognize that such modifications will need to be discussed once the desired fundamental direction of TPP-GIP integration is clarified. However, beyond elimination of GIP Phase 2 under Option 1B, and development of a "restricted" study methodology to deal with excessive cluster sizes under either Option, we believe that most changes or process refinements would involve the TPP, not the GIP.

4. Stage 2 of the straw proposal adds a step to the end of the TPP cycle, in which the ISO identifies and estimates the costs of additional network upgrades to meet the interconnection needs of the cluster. Please offer comments and suggestions for how to make this step produce the most accurate and useful results.

The most accurate and useful results would arise from identification and use in the TPP of resource scenarios that are sufficiently realistic, current and wide ranging (but not overly wide ranging). Thus the scenarios and studies should be informed by activity, plans and scenarios in the resource procurement process, such as scenarios being provided by the CPUC for the present TPP cycle. The TPP studies should also make use of reliable information passed from the preceding GIP, such as regarding generator locations and dropouts. Even if previously included in a Plan, a transmission project should not be included in study base cases if it has been rejected or is shown to have high likelihood of rejection, in the permitting process.

Besides studying the amount of new transmission needed in a "least regrets" manner across adopted resource planning scenarios, the TPP will likely have to consider the value, economic efficiency and driving contingencies for a certain amount of additional transmission that would not be ready for approval in the Transmission Plan. This might be necessary to (1) help identify what level of new transmission *is* cost-effective for inclusion in the Plan, (2) what potentially valuable transmission should be identified for possible future consideration perhaps as "Category 2" policy-driven transmission, and (3) inform ICs of their likely funding needs should they seek to self-fund transmission beyond that level of transmission identified for funding via the TAC. More generally, with TPP-GIP integration, the TPP will likely have to do a number of things not within its current scope, which will need to be explored in this initiative.

If generator interconnection costs calculated towards the end of the TPP are much different from what was previously assigned in the GIP (such as via Phase 1), this difference may not impact costs for generators making use of TAC-funded transmission. It could be consequential for generators who elect to self-fund transmission above the TAC-funded level, but we offer three considerations regarding that situation. (1) It is unclear if significant self-funding would occur. (2) A self-funding situation already exists with regard to the direct interconnection component of interconnection costs, and generators electing to self-fund may undertake their own studies and/or contracting to control the development and cost of transmission that they self-fund. (3) Because of the potential magnitude and uncertainty of generators' exposure to costs if they self-fund transmission above the TPP-identified TAC-funded level, generators should not be exposed to excessive financial risks for "dropping out" when they do not obtain TAC-funded transmission at the end of the TPP. This raises the question of what level of deposits or commitment should be required from generators to remain in the process as the interconnection study arena moves from the GIP to the TPP.

5. Stage 3 of the straw proposal identifies three options for allocating ratepayer funded upgrades to interconnection customers in over-subscribed areas.

    a. Please identify which option, Option 3A, 3B, or 3C, your organization prefers and why. Are there other options the ISO should consider?

        CPUC Staff believe that "critical milestones" beyond financial payments/deposits could be applied towards the end of the TPP cycle to remove from the studies and queue those generators showing strong evidence of non-viability, before allocating TAC-funded transmission to remaining generators. However, such project removals should be conservative and eliminate only generators showing strong evidence of non-viability, to avoid being, or being perceived as being, overly arbitrary or unpredictable. This would be unlikely to remove enough ICs to reliably reach the level accommodated by TAC-funded transmission, as would be needed under Option 3A. Thus CPUC Staff recommend appropriate conservative project removals prior to allocating TAC-funded transmission, but not reliance on Option 3A to ultimately allocate TAC-funded transmission.

If utilized, the pro rata approach, Option 3B should if possible be based on different generators' calculated impact on the transmission constraint(s) being alleviated by transmission upgrades whose TAC-funded capacity is being allocated among the generators, as discussed under question 5c below.

However, CPUC Staff are concerned that the pro rata approach might not adequately manage the risk of having generators remain in the process to sell their pro rata allocations to other generators, so that the former drop out while the latter, more viable generators remain but transfer significant funds to the less viable "speculators." To manage this risk, generators could be required to post substantial deposits before studies move to the TPP, with these deposits not being refunded if the generators drop out, regardless of how much added transmission capacity is ultimately TAC-funded. However, the desirability of placing this risk of deposit loss on generators dropping out as the only alternative to self-funding transmission needs to be evaluated, as noted at the end of the CPUC Staff response to Question 4.

Partly because of the above concern, and partly because of the fundamental attractiveness of a market-based approach, CPUC Staff believe that the Option 3C "auction" approach could be most useful. It would need to be assessed and vetted for logistical feasibility and risks such as gaming or high auction prices forcing otherwise attractive generators out of the market. However, this approach appears to offer the advantage of transferring funds from the winning bidders to the ISO, to ultimately be reimbursed or credited to ratepayers, whereas the pro rata approach has the potential to *permanently* transfer funds from viable generators to more speculative generators that sell their pro rata shares.

In summary, if milestones are conservatively applied to remove clearly nonviable projects but are inadequate to reliably allocate TAC-funded transmission capacity, and if the Option 3C auction approach tentatively favored by CPUC Staff is found to have fatal flaws, then the fallback would be reliance on pro rata allocation (Option 3B) to allocate TAC-funded transmission. In the latter case, the potential problem summarized above regarding speculative projects selling their pro rata shares to more viable projects would need to be addressed.

b. If Option 3A is selected, what are appropriate milestones to determine which projects are the "first comers?"

CPUC Staff recommend use of conservative milestones (likely to be violated only by clearly nonviable projects) to provide some potential removals of nonviable generation projects from the study process towards the end of the TPP cycle, but not as the ultimate mechanism to allocate TAC-funded transmission. What the milestones would consist of requires consideration. Preliminarily, we believe they could involve site control, permitting problems, uncertain equipment selection/design, or lack of meaningful procurement/sales prospects. Financial milestones should be addressed separately, via payment/deposit requirements, whose "violations" would be self-evident.

c. If Option 3B is selected, what is the appropriate methodology for determining pro rata cost shares?

Pro rata cost shares should be based on generators' impacts on the limiting transmission elements that would be added or expanded. For example, if two generators A and B each have the same capacity, but generator A has a higher impact on flows over the constraint to be alleviated by a transmission addition, then generator A would have a greater portion of its total MW *not* be covered by (deliverable over) the limited TAC-funded transmission, and thus would have a higher responsibility to self-fund additional transmission to make its output fully deliverable, relative to generator B.

The above impact-based approach might face complications including the need to consider multiple resource cases in the TPP, and lack of clarity regarding which combination of generators in each area or study group will ultimately proceed. This may in turn require some compromises in the allocation methodology, and if the problems are excessive, the fall-back would be a simpler per-MW pro rata allocation. However, as discussed above, CPUC Staff believe that the pro rata approach may have problems regarding potential to reward speculative projects and perhaps other problems, so that the auction approach is tentatively preferred, subject to further assessment and vetting.

d. If Option 3C is selected, how should such an auction be conducted and what should be done with the auction proceeds from the winning bidders?

Option 3C (auction) combined with conservative milestone-based removal of clearly nonviable generation projects appears desirable if assessment and vetting show that risks and unintended consequences are limited and manageable. Such an auction could be conducted as an adjunct to (or part of) the deposits that might be required of generators to remain in the process into the TPP stage. In other words, generators could "bid" above their minimum deposit requirements to express their high interest in obtaining TAC-funded transmission capacity.

However, it appears more useful to conduct an auction at the end of TPP studies because generators would then have a better idea of their situation, including the extent of TAC-funded transmission capacity as well as updated information on the generator's own viability such as regarding permitting, financing, power sales or other developments. (On the other hand, if "auction" bidding information is available earlier in the TPP process, it could conceivably inform TPP studies.)

Thought and discussion need to applied to the issue of how bidding-related deposits relate to or interact with any other deposits that might be required to keep generators active in the process as studies move to the TPP arena. In effect, auction bidding might represent a second, upped ante to not only remain active in the interconnection process but to also have high priority for TAC-funded transmission. One possibility that should be considered is to make auction bids non-refundable. This means that generators would effectively bid to fund a share of their "TAC-funded" transmission, reducing the TAC burden to ratepayers systemwide. Clearly a generator would not bid so high as to virtually self-fund the transmission anyway, but would submit a bid reflecting the generator's viability and business prospects, and how much the generation developer valued the added transmission.

At this time, CPUC Staff offer no further specifics regarding how an auction might be conducted, or what might be done with resulting funds, other than that customers who would ultimately bear TAC charges should benefit from any deposits that are not refunded.

6. The straw proposal describes how the merchant transmission model in the current ISO tariff could apply to network upgrades that are paid for by an interconnection customer and not reimbursed by transmission ratepayers. Do you agree that the merchant transmission model is the appropriate tariff treatment of such upgrades, or should other approaches be considered? If you propose another approach, please describe the business case for why such approach is preferable.

The merchant transmission model should be applicable, but awarding CRRs to generators that self-fund all or part of their needed transmission upgrades may, by itself, be inadequate compensation for such generator funding. Optimal amounts of generation and transmission development might result if generators that self-fund transmission receive additional compensation (and incentive to self-fund) beyond CRRs. This is further discussed in response to question 7.

7. Stage 3 of the proposal also addresses the situation where an IC pays for a network upgrade and later ICs benefit from these network upgrades.

   a. Should the ISO's role in this case be limited to allocating option CRRs to the IC that paid for the upgrades?

   As stated in response to question 6, CPUC Staff believe that if a suitable mechanism can be worked out it would be desirable and likely economically efficient for self-funding generators to receive additional compensation, probably but not necessarily through a CAISO-managed mechanism.

b. Should the ISO include provisions for later ICs that benefit from network upgrades to compensate the earlier ICs that paid for the upgrades?

First, if additional viable generators show up to use transmission initially self-funded by earlier generators, this situation should be considered in the contemporaneous TPP planning cycle and may provide justification for making the transmission TAC-funded, in which case the initial self-funding generators would be reimbursed. If such TAC funding is not approved but additional generators show up to use the "self-funded" transmission, it is preferable that some mechanism be developed whereby these later generators pay for a share of the transmission in question, and that this payment mechanism be as transparent and predictable as practicable.

8. In order to transition from the current framework to the new framework, the ISO proposes Clusters 1 and 2 proceed under the original structure, Cluster 5 would proceed using the new rules, and Clusters 3 and 4 would be given an option to continue under the new rules after they receive the results their GIP Phase 1 studies.

a. Please indicate whether you agree with this transition plan or would prefer a different approach. If you propose an alternative, please describe fully the reasons why your approach is preferable.

At this time, CPUC Staff agree with the above approach.

b. If the straw proposal for the transition treatment of clusters 3 and 4 is adopted and a project in cluster 3 or 4 drops out instead of proceeding under the new rules, should the ISO provide any refunds or other compensation to such projects? If so, please indicate what compensation should be provided and why.

Any security deposits and site exclusivity deposits should be refunded. Study deposits in excess of actual study costs should be refunded. If found to be workable, generators should have the option of crediting non-refunded deposits towards a subsequent interconnection request for the *same* project.

9. Some stakeholders have expressed a need for the ISO to restudy the need for and costs of network upgrades when projects drop out of the queue. The ISO seeks comment on when and restudies should be conducted, in the context of the proposed new TPP-GIP framework.

If Option 1B is selected, then this issue would be less problematic or may disappear, since dropouts potentially driving re-studies would generally occur after planning has moved into the TPP. Then, such dropouts could be considered in the context of (and as part of) the broader set of factors being updated and assessed when holistically studying system-wide transmission needs under different resource cases. This appears to be one important reason for favoring Option 1B.

If dropouts occur during GIP Phase 1 the consequences would appear to cause limited problems due to the more limited role of Phase 1 in providing approximate cost estimates and signals motivating nonviable generators to exit the process, and in any event would need to be addressed without violating the timeline under which GIP Phase 1 results are moved into the TPP. If Option 1A is selected and dropouts occur during Phase 2, the consequences may be more consequential but would not be as severe as under the present process because the ultimate planning and cost assessment for transmission needed by interconnecting generators would be moved into the TPP.

The main arena for planning adjustments due to dropouts under a reformed TPP-GIP integration appears to be the TPP. This is a benefit of better integrating the TPP and GIP and giving the TPP a greater role, because the TPP appears to be better suited to making adjustments based on generator dropouts, and to be less sensitive to such dropouts in that it focuses on the "big picture" cost-effectiveness of potential transmission additions system-wide.

10. Some stakeholders have suggested that there may be benefits of conducting TPP first and then have developers submit their projects to the GIP based on the TPP results. Does your organization believe that conducting the process in such a manner is useful and reasonable?

This will be an iterative process involving ...TPP-GIP-TPP-GIP....etc. Developers may choose to step in at the time of their choosing. In terms of the long run "end state", which comes "first" thus appears to be essentially a semantic question. The issue may only be meaningful when considering the <u>*transition*</u> from the present process. For transition, what comes "first" depends on when the new process is implemented and what strategies market participants adopt. If implementation timing is such that the next step is a GIP application window, then generators have the option of entering that window or else waiting until after the next TPP cycle.

11. Please comment below on any other aspects of this initiative that were not covered in the questions above.

This has been a constructive and helpful comments template.