Stakeholder Comments Template

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

Submitted by	Company	Date Submitted
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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.

Key Take-A-ways of Wellhead's Comments

A. ***"Chosen Areas" in the TPP should be based on updated information, technology and cost trends (including environmental costs/issues that jeopardize project viability).***
B. ***"Tuck In" generation projects outside a "TPP chosen area" should be treated the same as projects in a "chosen area," i.e. if "Tuck In" projects do not trigger local upgrades, they should be treated the same as "chosen area" projects for upgrade cost reimbursement purposes.***
C. ***Deposit forfeiture rules need to be rationalized and changed from "CAISO will take your money if you drop out or change your project" to a process of "1st show your money to the CAISO to prove you are real," then, "CAISO will keep your money to the extent of actual damages incurred."***
D. ***A PPA should be the key indicator of whether or not an upgrade should be reimbursable, i.e. rely on the LSEs to include transmission costs in their procurement analysis and the CPUC review/approval of that procurement decision.***

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.

Wellhead agrees that cost-effective use of ratepayer funding for transmission investment is the top priority objective. This requires the transmission planning process to take significant consideration of competitive generation development. Generator interconnections are not the key; GIP should simply be a step in the least cost procurement process.

As such, the CAISO must be careful that that the TPP does NOT result in foreclosing development of previously unidentified competitive resource opportunities when it selects areas to be served with incremental TPP approved network upgrades. Current market information and technology trends must be routinely considered in the annual TPP. This is necessary to ensure that rate payers are benefitting (paying lower costs) as a result of competition and technology development.

For example, significant cost reductions in PV technology have made, or will make, many more geographic areas within California competitive with earlier identified areas. Only a few years ago, in the RETI process, areas of highest insolation were deemed necessary in order for solar PV projects to be regarded as economically competitive. Current and predicted PV costs place that earlier conclusion in question. The optimum mix of alternative technologies to achieve a least cost 33% renewable portfolio is likely different today compared to only a year or two ago. (See Exhibit A, attached to these comments, as a specific example of such updated information for the Westlands Water District area in the southern San Joaquin valley.)

In addition, Wellhead supports PG&E's recommendation that the TPP should include consideration of environmental issues/costs. Environmental costs are real and can significantly impact the cost and viability of a project; ignoring them in making significant capital expenditure decisions for transmission upgrades or additions would NOT be in the public interest. Westlands CREZ had the highest environmental ranking (lowest costs) of any identified CREZ in the RPS scenarios and that must be a significant consideration in the policy-driven TPP project elements.

To ensure the process is not limiting competition or ignoring new competitive opportunities, the TPP needs to be "forward-looking" and to take advantage of the latest competitive information, which information is clearly available in the LSE's procurement activities. Not doing this will result in higher costs to consumers. As such, there needs to be a high degree of reliance on the LSE's procurement information and decisions; in fact, an informed transmission planning and interconnection process seems to dictate this <u>requirement</u>.

Additionally, the TPP needs to have an objective to <u>fully support</u> the competitive marketplace so as to ensure consumers get the full benefit of competition. This means the TPP may have to plan to "overbuild" the transmission system to some extent in order to ensure that there is competition for all of the needed procurement of renewable resources.

For example, if only enough transmission is built to meet the 33% RPS, competition will be thwarted. Resources in the TPP's preferred area(s) will know they can price power higher because they must be selected to meet the 33% requirement. Or, in the circumstance where resources inside or outside of a TPP preferred area are able to interconnect for little or no cost, but are competing to use the same bulk system facilities that deliver generation to load, the preferred area competitors will be able to charge a higher price if the non-preferred area projects are assessed transmission upgrade charges. This latter result is nonsensical if the project outside the TPP area is priced below the project within the TPP area.

All of this points to the conclusion that utility procurement decisions need to have great weight in any decisions as to whether a project is assessed non-refundable network upgrade costs. Done the wrong way, prices to consumers will be higher.

Wellhead is also not certain that "to manage or filter" the number of MWs contained in active interconnection requests is a proper objective. This says the CAISO wants to limit competition. Why is it unrealistic that there are many more projects that want to compete than are needed? The focus should be on ensuring that projects selected for development (an outcome of the utilities procurement process) are viable, and such projects should be held tightly accountable to the commercial deal negotiated and approved by regulators. The interconnection process is not the end game, it is only a step in the development of a project that is part of the RPS future. The CAISO's interconnection process must recognize this reality and remove all of its process hurdles that make it difficult or expensive for viable competitive projects to be successful.

Wellhead agrees that new resources should be incentivized to locate at cost effective interconnection locations that limit/avoid transmission additions or upgrades, It is good public policy to require that existing transmission capacity be used before significant new transmission is built to accommodate RPS requirements. However, the straw proposal will make it very difficult for viable competitive projects with PPAs, which can "tuck into" an area with available capacity, to obtain financing if there is a risk that they will be required to pay for non-reimbursable upgrades require only because of IRs by projects without PPAs.

The inability to obtain reimbursement for these upgrade costs very likely will make such projects uneconomic compared with projects in TPP-favored areas to the extent the latter projects are not charged for such costs or have them reimbursed. Where competitive projects outside TPP-favored areas are able to utilize existing capacity with little or no local system upgrade costs, they should not be saddled with the costs/risks of unreimbursed network upgrades; doing so will simply lead to higher cost projects in other areas being selected. That result is completely inconsistent with the primary objective of ensuring cost effective use of ratepayer funding.

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.

If there is proper consideration of commercial realities in the transmission planning process (i.e. utilities procure resources in a way that is least cost after consideration of transmission costs), many of the existing GIP issues in this initiative will be resolved.

For example, if a developer were allowed the option in the interconnection process of checking a box that said the project would only proceed if it received a PPA, then there would be a mechanism to ensure that any upgrades triggered by the project would be properly considered in a utility's procurement decisions to meet the RPS goals . Hence, the ratepayers' interests would be protected with the added protection of a CPUC review/decision that the resultant costs to ratepayers were reasonable.

This of course is not intended to suggest that planning should not be forward looking. Planning is only effective when it looks forward in consideration of all the relevant information available at the time. The comment is an acknowledgement that planning is based on uncertain assumptions and any adopted plans need to have appropriate flexibility and the TPP should also revisit prior decisions to ensure that least cost plans are being implemented (abandoning early-stage costs can be the least regrets decision when it avoids higher further expenditures on a project that is no longer a cost effective use of ratepayer funds; abandoned cost recovery can be a least regrets decision). Procurement decisions are one of the basis upon which prior plans may appropriately be changed and they provide a significant body of information about where the future may go.

With regard to the "disposition of funds from projects that drop out," the fact that this is a CAISO concern indicates that the requirements are excessive. Security deposits are intended to ensure that developers are serious and have necessary access to capital and other resources needed to bring the project to a successful completion. The fact that the funds currently collected are "far beyond expectations" should be interpreted by the CAISO as a clear message that there are lots of qualified developers that want to compete to meet the limited RPS needs.

The CAISO needs to revisit their deposit forfeiture requirements to better align them with the actual costs, damages, or stranded costs that the deposits are intended to prevent the ratepayers from incurring. Punitive penalties have no place here and should not be used simply to generate funds to subsidize other activities or interests. Indeed, notwithstanding the overwhelming number of interconnection requests, our experience is that a number of strong and sophisticated renewable generation project investors with proven local, national and international generation-industry experience are balking at new California investment opportunities. In other words, the process is driving some strong successful long-term players to the sidelines or to other markets

because the deposit forfeiture exposure of the interconnection process is not justified by the renewable investment opportunity; exactly the opposite of what the CAISO wants to be promoting/causing.

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

We agree that the 7 issues are in scope.

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

As noted above, the amount of forfeiture risk is an issue that the CAISO needs to address to ensure desirable competitors are not driven from California.

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

Either of these options will work, but it seems the deciding factor should be determined by which one will have the shorter time requirement to get to the end of a study with <u>reasonable</u> results (identification of required upgrades <u>and</u> associated cost estimates). Assuming that the CAISO reforms the process to incorporate the reality that most, if not all, renewable projects will only make it to commercial operation if they have a power sales contract, the interconnection studies will be refocused on the basic interconnection requirements; network upgrades needed so that the generation will be used and useful will be addressed by proper integration of the transmission planning process with the results of competitive procurement decisions.

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?

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

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.

Feedback between the interconnection process and the transmission planning process is needed because the interconnection process is one of the major

ways that the market tells the CAISO where competitive projects can be located. However, that needs to happen during the consideration of "policy driven" facilities. As discussed above, the annual TPP must consider the latest market and technology information in updating RPS areas for upgrade cost reimbursement benefits.

It seems the only time the CAISO will need to look beyond the TPP approved projects is when there is a merchant generator that is prepared to take on the costs and risks associated with the needed transmission upgrades (in addition to the costs and risks associated with the generation project). For projects in this category, additional requirements will be needed to ensure that ratepayers do not bear the costs for transmission facilities that are not beneficial. It may well be that many of the current process requirements are appropriate for these projects; provided, that the merchant project is compensated for any benefits the ratepayers receive (i.e. there are no windfall profits/benefits to ratepayers due to the merchant transmission facility).

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

It seems that a most rational interconnection process will take account of the fact that a utility will NOT contract for resources that trigger transmission upgrades unless the total cost resulting from the decision is a least cost use of the ratepayers funding. Again, the CPUC will review the LSE's procurement decision, and agree with or reject it. With a properly designed process, and rational utility procurement, it is unclear why an allocation process will be required. However, to the extent allocation is an issue, there should be priority consideration given to the "first in time priority" that was a fundamental basis of the current interconnection process (under which projects made the financial commitments/expenditures of getting into the queue). Priority projects which have PPAs that make use of available local system capacity should not be required to fund future local system upgrade costs. To the extent a project with a PPA does not fit onto existing (or TPP approved) transmission system capability, it should share in the upgrade costs, as described in Option 3A of the straw proposal, UNLESS it elects to downsize its IR to avoid such costs.

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

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

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

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?

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.

For transmission facilities that are not needed for reliability, economic, or policy reasons (i.e. are approved in the TPP), a merchant transmission mechanism is needed. However, as previously indicated, the interconnection process requirements for a project that wants to proceed on a merchant basis are appropriately different than for a project that will only proceed if it is selected in a utility procurement process. Those different requirements are properly focused on ensuring that ratepayer funding is not used for payment of any benefits not received by the ratepayers. With some adjustment, many of the existing GIP process requirements may fit this need.

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?

NO, simply providing CRR's does not provide just and reasonable compensation to the merchant facility and will result in windfall profits/benefits to other parties. CRR's are a power supply <u>locational price signal</u> which do not reflect all of the value an incremental merchant transmission facility brings to the system.

For example, a merchant transmission facility may be found in the TPP to be uneconomic because the annual benefits (such as reduced losses or avoided reliability upgrades) total less than 100% of the annual costs. The merchant facility should receive payments for those benefits (i.e. leave the ratepayers indifferent) plus receive payments whenever the facility is used by another project (i.e. get a reasonable rate for the incremental service provided). Anything else would seem to be a confiscation of the merchant's investment.

There also needs to be further consideration of tax implications and how operations and maintenance costs will be handled <u>if</u> the merchant funded facility is "turned over" to a PTO. The electric transmission system is highly integrated and keeping track of all the interactions is

not a simple matter. An interconnection process that creates/requires using the merchant model must address all of the essential elements.

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

Yes, provisions for later ICs to compensate earlier ICs who paid for network upgrades must be included. Later ICs should not be allowed to free ride on such upgrades. There should also be no time limit on when a user of the merchant facility has to pay a fair and reasonable cost to the party that was financially responsible for the facility.

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.

There is no logic or fairness in requiring projects in the current clusters to make business decisions on yet to be written rules that will be retroactively applied to them. Wellhead supports the need to make significant modifications to the current process requirements and <u>not</u> stop everything while the new process/rules are being developed. However, it is essential that project developers caught in the transition have the ability to revisit any significant decisions that are impacted by the changes. Projects have entered the interconnection process and are making, or have made, business decisions and incurred substantial costs based on the current process rules. It is patently unfair to expect developers to make binding business and financial decisions that will be significantly impacted by, as yet, unwritten rules and processes.

As a result, ICs should be allowed an election, to be made within 30 days after the new rules are approved by the FERC, either to drop out of the process or to exercise the option of being covered by the current rules or the new rules, Their IFS postings should be fully refundable upon making an election to drop out of the process. In addition, as compensation for the time (in some cases, several years of effort) and money spent prior to dropping out, withdrawing ICs should receive a full refund of their interconnection study deposit (in addition to the site control deposit that is already fully refundable). The substantial business disruption caused to the ICs by modifying the rules

applicable to Cluster 3 and 4 projects, at this stage of the process, must be fixed.

Wellhead would also note that in its comments on the Cluster 4 Phase 1 study methodology comments, it suggested that receiving this option to revisit the business decisions could reasonably require a higher level of security deposit (i.e. must be cash possibly in an escrow account). Wellhead renews that suggestion here and notes that it supports the CAISO objective of ensuring ICs do not remain in the queue unless they demonstrate the financial strength essential to capital intensive generation projects.

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.

Yes, deposits made in accordance with the current process/rules which are impacted by the changes in this initiative must be fully refundable as more fully described in the preceding item.

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 restudies should be conducted, in the context of the proposed new TPP-GIP framework.

For projects that are only going to proceed with development if they have a PPA, it is difficult to envision why TPP restudies would be required outside of the normally recurring TPP cycle. However, restudies may be needed to for merchant projects, to ensure that upgrades actually built are properly sized for the project(s) actually built. In this case, the impacted merchant project(s) should have significant say in the restudy decision as well as be the recipient of appropriate portions of the security deposits the withdrawing merchant project posted to protect other parties from its failure to follow through.

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?

As discussed above, the transmission planning and generation development processes must be complementary and iterative. And by aligning the interconnection process with the realities of when generation projects will get developed (i.e. after they get a power sales agreement), the linkage between TPP and GIP should be automatic. In any event, the entire process is

improved to the extent that transparency is maximized. In this regard, the ISO should make readily available to the IC community local system available-capacity information that would encourage "tuck-in" projects that, by definition, do not require network upgrades.

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

After several efforts that addressed certain interconnection process issues, it is time to bite the bullet and make the significant changes that will align the interconnection process with development of highly modular generating project realities in a competitive environment. There are many current realities that were not present when the current interconnection process was first implemented. California needs to have a process that does not have inappropriate and unneeded hurdles for developers. To leave ill-functioning processes in place simply increases costs to consumers in the end.

It is clear to Wellhead that TPP-GIP changes will be ineffective if they do not bring rational business realities to the process. Identifying a project in the TPP will simply result in projects migrating to the new area served with the resulting "need" to build more transmission facilities. In other words, the TPP process will simply result in the "existing system" including more facilities which will still NOT serve all of the strong, capable developers. If the interconnection process continues to ignore the fact that not all projects entering the queue will be completed (achieve commercial operation), the problems we have today will be continued. Financially strong and experienced generation project developers will be pushed to other markets because of unfairness and excessive risk. And California consumers will not be the beneficiary of the competition such players can bring to the marketplace.

EXHIBIT A

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July 15, 2011

Wellhead Renewable Energy, LLC's Comments in Response to the CPUC's July 8, 2011 Presentation of Proposed 33% Renewable Portfolio Assumptions for Inclusion in the 2011-12 CAISO Transmission Planning Process

Wellhead Renewable Energy, LLC appreciates this opportunity to provide comments on the proposed 33% Renewable Portfolio Standard assumptions presented by the CPUC to the CAISO on July 8, 2011, pursuant to the CAISO 2011-12 Transmission Planning Process.

As a general statement, we observe that many of the assumptions used to date could easily lead to a result of overlooking a major solar resource (specifically the Westlands Water District in Fresno County but more generally the Central Valley). This has the potential to result in unnecessary and large costs to ratepayers. We ask that you reconsider and be open to new information.

We make the following summary points and would appreciate the opportunity to provide additional information as the process evolves.

1. The Westlands CREZ is too small. The Westlands CREZ WAS considered in the last model update. However, easily 75,000 acres of Westlands Water District lands most suitable for solar development were not included in that CREZ boundary. A potential of over 10,000 MW of prime solar development area is being "left out." It seems the process should allow for reconsideration in the event new information such as this becomes available. .

2. The Environmental Features of Westlands Are Very Strong And Deserve More Weight. The Westlands area has the best environmental score of all of the CREZ areas that were ranked; this is understandable since disturbed, non-prime, non-irrigated, non-Williamson Act, retired farmland is an example of the resource type where state policy encourages development. Given the difficulties that many projects are encountering in more environmentally sensitive areas, it seems the selected portfolios should put more than a "zero weighting" on environmental considerations, from environmental, cost and project viability points of view.

3. The Westlands Solar Resource Is Strong Enough/Overall Costs Can Be Demonstrated To Be Low. The Westlands area has been described in the modeling to date as having a less attractive solar resource which resulted in relatively high costs when compared to other solar development areas. However, there are many other costs that go into the total LCOE for a development that are enough lower for projects in the Central Valley to more than make up for this solar resource difference (which is quite small after consideration of Time Of Day pricing in PPAs). It seems that recent responses to the utility RFOs should be reviewed to either validate or deny this point. Further, given the magnitude of the decisions and costs that are likely to evolve from this modeling

EXHIBIT A

exercise and process we would ask for reconsideration of the cost assumptions, which are inconsistent with our many years of development experience.

4. PV Costs Are Declining Rapidly. As we have learned to expect of new technologies that are, at least in part, based on the "laws" of technology development and associated pricing, solar PV project costs have dropped dramatically since the assumptions in the last model were assembled. For example, publically available information suggests that PV module prices will soon drop to the range of $.75 to $1.00 per watt. Balance of Plant costs are also declining to the point where "all in" solar PV project costs are likely to soon be approaching $2.00 per watt. This price is roughly 50% of the price used in the modeling assumptions. We ask that the model be updated to reflect these trends.

5. PV Has Gained Dramatically Relative To The Cost Of Other Generation Technologies Which Helps Projects In The Central Valley. Past evaluations of the Central Valley and the Westland CREZ assumed high PV costs. Since PV costs have declined so dramatically, this will have the effect of significantly improving the relative position of Westlands Water District and Central Valley "PV centric" projects. We ask that the modeling assumptions be changed to take this fact into account.

6. The Westlands CREZ Transmission Assumptions Are Too Narrow. The transmission cost evaluations of the current Westland CREZ do not appear to adequately take into account the fact that other nearby areas of the Westlands Water District still have zero to very low cost transmission capacity available. For example, it appears that the Panoche and Helm substations were not included in the previous Westlands CREZ evaluation. Modeling and the Transmission Ranking Cost Report suggest SOME low cost transmission capacity is available. We ask that more specific evaluation be done of the expected transmission costs of projects in both the Westlands Water District and elsewhere in the Central Valley. .

7. Development Where There Is "Tuck In" Transmission Capacity Should Be Encouraged. The CREZ process places heavy weight on assembly of large land areas to be studied "en mass" and, by its very nature, tends to not take into account that there are many opportunities for projects, some of a significant size, to be "tucked in" to the current transmission system. We ask that the process be flexible enough so that projects that do not fit into a selected RPS Portfolio area be given full and adequate consideration equivalent to CREZ projects. Everyone agrees that taking advantage of the present transmission system investment is highly desirable.

In summary, we ask that you be open to additional information as part of your on-going planning and modeling process.

Respectfully submitted,

Harold E Dittmer

Harold E. Dittmer
President