Stakeholder Comments Template

Transmission Access Charge Options

August 11, 2016 Stakeholder Working Group Meeting

Submitted by	Company	Date Submitted
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The ISO provides this template for submission of stakeholder comments on the August 11, 2016 stakeholder working group meeting. Topic 1 of the template is for comments on the default cost allocation provisions for new regional transmission facilities, the topic of the morning session of the working group. Topic 2 is for comments on the region-wide TAC rate for exports, which the presentation referred to as the "export access charge" (EAC) and was the topic of the afternoon session of the working group. The ISO invites stakeholders to offer their suggestions for how to improve upon the ideas discussed in the working group meeting.

The presentation for the August 11 meeting and other information related to this initiative may be found at: http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionAccessChargeOptions.aspx

Upon completion of this template please submit it to initiativecomments@caiso.com. Submissions are requested by close of business on **August 25, 2016.**

Topic 1. Default Cost Allocation Provisions for New Regional Transmission Facilities

Context

For purposes the working group discussion the ISO assumed that the current structure of the transmission planning process (TPP) would be retained for the expanded BAA. That is, the TPP would consist of a first phase for specifying and adopting planning assumptions including public policy directives that would drive transmission needs, as well as a study plan. The second phase would consist of a sequential process for performing planning studies and identifying reliability projects, followed by policy-driven projects, and finally economic projects. With each successive project category, the ISO may identify a project that serves the need of a project identified in a prior category, in which case the project would be labeled by the last category in which it was identified, but its cost allocation would reflect the benefits in all categories.

By design these two TPP phases take 15 months, at the end of which the ISO would present the comprehensive transmission plan for approval to the governing board for the expanded BAA. At the working group meeting the ISO also pointed out that while the concept of a "body of state regulators" or "Western States Committee" is still under discussion in the context of governance for the expanded BAA, no details have been developed or proposed regarding this entity's role with regard to transmission planning and cost allocation. Moreover, once the default provisions being discussed in the working group are finalized, filed and have been approved by FERC for inclusion in the ISO tariff, any variations or deviations from those provisions would also have to be filed and approved by FERC. Stakeholders should therefore view the current effort to develop default cost allocation provisions as determining the rules that would govern transmission cost allocation for the expanded BAA.

Stakeholders should assume for purposes of their comments that the current ISO TPP structure would be followed in an expanded TPP performed for the expanded BAA. Parties wishing to comment on or suggest alternatives to these assumptions may add any additional comments at the end of this topic.

Questions

1. The working group presentation assumed we would use the current Transmission Economic Assessment Methodology (TEAM) to calculate a project's economic benefits to the BAA as a whole and to each of the sub-regions. Currently TEAM calculates the following types of benefits: efficiency of the economic dispatch, reduction of transmission line losses, and reduction of resource adequacy capacity costs. Are these economic benefit types sufficient for purposes of cost allocation, or should other types of benefits be included? Please describe any additional benefit types you would include in the benefits assessment and suggest how they could be quantified.

   At a high level, the benefit types listed above capture the most directly-quantifiable benefits. It should be understood that the "benefits" of the prospective transmission upgrade that is being evaluated are relative to a "reference case" ("project alternative") that meets the need identified in the expanded ISO's TPP.

   The "efficiency of the economic dispatch" captures several important sub-categories of benefits, namely the change in gross consumer costs (i.e., end-use consumption multiplied by applicable Locational Marginal Prices (LMPs)), plus the sum of:

      (i) the change in producer surplus (the difference between gross generator revenues (i.e., output multiplied by applicable LMPs) and variable operating costs) for those generators that are owned by or contracted to Load Serving Entities (LSEs),[1]

[1] The change in producer surplus for sub-regions within the CAISO can be either positive or negative depending on the location of generators, the least cost dispatch and the resulting LMPs.

(ii) the change in congestion rents,[2] and
(iii) the change in the amount of surplus transmission loss revenues rebated to consumers (i.e., the difference between the amount of money collected by the expanded ISO at full marginal losses and the actual cost to the expanded ISO of accommodating transmission losses (i.e., average losses)).[3]

SDG&E notes that by calling out "reduction of transmission line losses" as a distinct category of economic benefits, the presumption is that the economic grid simulation modeling ignores transmission losses (i.e., assumes a lossless transmission system) such that a separate calculation of transmission losses for the transmission upgrade being evaluated and for the reference case, is required.

SDG&E also notes that the differences in other fixed costs for the transmission upgrade being evaluated and for the reference case needs to be accounted for (e.g., the difference in capital costs and fixed O&M).

2. The ISO's presentation suggested that a sub-region's avoided cost for a needed transmission project could be included among the benefits of a project with region-wide benefits. For example if project A with region-wide economic benefits enables sub-region 1 to avoid a reliability project B that would have cost $40 m, then the $40 m avoided cost should be included in the total benefits of project A for purposes of cost allocation to the sub-regions. Please comment on whether such avoided costs should be included in the benefits for cost allocation purposes.

   Costs which can reasonably be expected to be avoided by the prospective transmission upgrade should be included in the benefits for cost allocation purposes. Also, the avoided facility should be modeled in the reference case so that the facility's impacts on grid operations are captured in the economic grid simulation of the reference case (and thereby reflected in the "efficiency of the economic dispatch").

3. In the example of Question 2 a specific project B was identified to meet a reliability need, and so its avoided cost could be viewed as a realistic estimate of the cost to sub-region 1 of mitigating its reliability need. In many instances in practice, however, cost-effective projects may be identified that provide economic, policy and reliability benefits without the planners ever identifying less costly but narrowly-scoped hypothetical alternative projects that could serve to provide concrete avoided cost estimates. Do you think it is important to perform additional studies to determine meaningful avoided cost estimates to use in cost allocation, perhaps by identifying hypothetical alternatives that would not ordinarily be considered in

[2] The change in congestion rents will usually be negative since the prospective transmission upgrade will usually result in less grid congestion within the sub-regions of the expanded ISO.
[3] The change in the amount of surplus transmission loss revenues can be either positive or negative depending on how the amount of transmission losses changes and on how the loss components of the LMPs change.

the TPP? Are there other approaches you would favor for estimating avoided costs to use in cost allocation? What other methods should the ISO consider for allocating reliability or policy "benefits" to a sub-region absent a well-defined project that can be avoided?

Question 2 points to the significance of defining a reference case that represents a realistic view of what would be done in the expanded ISO to meet all applicable reliability[4] and public policy requirements if the prospective transmission upgrade were not built. Absent such a reference case, there is no way to determine whether the prospective transmission upgrade is the most economic option for customers. Also, once a reference case is defined, it is possible to compare multiple alternatives against the reference case, not just the prospective transmission upgrade. This allows for an apples-to-apples comparison of a broader range of options for meeting the applicable reliability and public policy requirements.

SDG&E recognizes that there are practical limits to how many different alternatives can be evaluated using the comprehensive TEAM. SDG&E believes that the degree of analytic rigor, and the number of alternatives considered, should be in rough proportion to the magnitude of the costs that consumers would be obligated to were the prospective transmission upgrade built.

Because most transmission assets have very long life-cycles, the degree of uncertainty inherent in the estimated benefits of a prospective transmission upgrade for the different sub-regions of the expanded ISO can be very high. This is one reason why transmission cost allocation is often considered as much art as science. Nevertheless, an objective estimation of sub-regional benefits will provide the expanded ISO's Board an important reference point for reaching agreement on which sub-regions should be allocated what amount of costs. The reference case and alternatives must therefore include "well-defined project[s];" otherwise, an objective estimation of sub-regional benefits is impossible.

4. The cost allocation approach presented at the working group for projects with benefit-cost ratio BCR < 1) started by first allocating cost shares equal to economic benefits, and only after that allocating remaining costs to the sub-region(s) driving the reliability or policy need. In the discussion, some parties suggested reversing this order, i.e., to start by allocating a cost share to the sub-region with the reliability or policy driver based on the avoided cost of the

[4] *In SDG&E's experience, it is always the case that there are multiple ways ("project alternatives") to satisfy an identified "reliability need." For example, because of load growth at a particular substation, an N-1-1 contingency condition under extreme weather conditions could result in thermal overloading of a transmission line. This overload could be mitigated by reconductoring the transmission line. Alternatively, a storage device could be added at the substation to defer the reconductoring for a year or two. Or, if the substation is located outside a "dense urban area," a controlled load-drop scheme could be implemented that is armed in the event the extreme weather condition overlaps with the first N-1 contingency. Each of these alternatives has its own unique set of costs and impacts on the system.*

reliability or policy project it would have had to build, and only then allocating remaining costs based on economic benefit shares. Please state your views on these two approaches, or describe any other approach you would prefer and explain your reasons.

As a threshold matter, SDG&E wonders why the expanded ISO's TPP would approve a prospective transmission upgrade with a BCR of less than one. In effect, approving a prospective transmission upgrade with a BCR of less than one means that the reference case -- against which benefits of the prospective transmission upgrade were estimated -- is actually the more cost-effective means of meeting the applicable reliability and public policy requirements

However, assuming there are other factors in play that could lead to such an approval (e.g., environmental licensing concerns associated with the reliability upgrade included in the reference case may be so significant that a more costly alternative with fewer environmental challenges is actually preferred), a method needs to be devised to figure out each sub-region's share of the cost of the prospective transmission upgrade.

A simple example helps illustrate the issue. Assume the prospective transmission project costs $100 million to build and, if built, allows sub-region 1consumers to avoid the cost of a $50 million reliability project, and allows sub-region 2 consumers to reduce their energy costs by $40 million. The prospective transmission project would have a BCR of 0.9 ($90 million in gross benefits/$100 million cost of prospective transmission project). In this example, sub-region 1 consumers have 56% of the benefits ($50 million/$90 million) and sub-region 2 consumers have 44% of the benefits ($40 million/$90 million).

If the costs of the prospective transmission project were first allocated to the two sub-regions at the level of each sub-region's benefit, sub-region 1 would be allocated $50 million and sub-region 2 would be allocated $40 million. The remaining $10 million would be allocated to the sub-region 1since sub-region 1 is "driving the reliability or policy need." So sub-region 1's total allocated cost would be $60 million. The result is that sub-region 1 consumers have 60% of the costs ($60 million/$100 million) and sub-region 2 consumers have 40% of the costs ($40 million/$100 million).

Alternatively, if the costs of the prospective transmission project were first allocated "to the sub-region with the reliability or policy driver based on the avoided cost of the reliability or policy project it would have had to build," sub-region 1 would be allocated $50 million. The remaining $50 million would be allocated "based on economic benefit shares."[5] Sub-region 1's energy benefit share is 0% ($0 million/$40 million) so it would not pick up any additional cost (0% x $50 million). Sub-region 2's energy benefit share is 100% ($40 million/$40 million) so it would pick-up $50 million in costs (100% x $50 million). Sub-region 1's total allocated costs would therefore be $50 million and sub-region 2's total allocated costs would be $50 million. The result is that sub-region 1 consumers have 50% of the costs ($50 million/$100 million) and sub-region 2 consumers have 50% of the costs ($50 million/$100 million).

[5] *SDG&E understands the CAISO's term "economic benefit" to be equal to the "energy" benefits in SDG&E's example.*

What the above example demonstrates is that both cost allocation approaches result in both sub-regions receiving cost allocations that are disproportionate to each region's relative benefits. SDG&E believes the simpler and more equitable approach is to allocate the costs of the prospective transmission project on the basis of relative benefit shares: 56% for sub-region 1 and 44% for sub-region 2. It is not obvious to SDG&E why either sub-region should be required to pick up more or less than a proportional share of the costs of approving a prospective transmission project in the expanded ISO's TPP.

5. The presentation at the working group suggested that all facilities > 200 kV planned through the expanded TPP would be assessed for potential region-wide economic benefits. Some parties suggested the ISO should apply threshold criteria to eliminate projects that clearly would not have region-wide benefits, rather than perform TEAM studies for all > 200 kV. Do you support the use of threshold criteria? If so, what criteria would you apply and why?

   In an interconnected network, every prospective network upgrade, regardless of voltage or location, will have some economic effect on the customers within all sub-regions. It is not possible to know whether the magnitudes of these effects are significant without actually doing the analysis. However, as noted in SDG&E's response to Question 3, the rigor of analysis should be proportional to the cost of the prospective transmission upgrade under consideration. The larger the cost the more rigorous the analysis should be.

   Rather than using a voltage threshold for deciding when to apply the full TEAM, SDG&E suggests using a cost threshold. For example, the full TEAM could always be applied for prospective transmission upgrades with estimated capital costs exceeding $300 million. A simpler evaluation process, perhaps using limited power flow studies in combination with spreadsheet-level analysis, could be used for prospective transmission upgrades with estimated capital costs at or below $300 million.

6. Do the details of TEAM, e.g., financial parameters, period over which present values are determined, etc., need to be pre-determined to maximize consistency of methodology and criteria across all projects, or should case-by-case considerations be taken into account?

   See SDG&E's responses to Questions 3 and 5. In general, SDG&E believes an equitable cost allocation method needs to be based on life-cycle analysis. This is especially true where the benefits of prospective transmission projects are being determined in comparison to a reference case (or other project alternatives) which include infrastructure additions (transmission upgrades, generation additions, incremental energy efficiency, incremental demand response) with widely varying economic lives and with differing in-service dates.

7. Should incidental benefits to a sub-region cause a cost allocation share for that sub-region even though the project would not have been built but for a reliability or policy need in

another sub-region?

Yes. A "benefit" is a "benefit," whether "incidental" or not.

8. Please offer any additional comments, suggestions or proposals that were not covered in the previous questions.

In the "context" section for "Topic 1 above,*" the CAISO states as follows:*

> At the working group meeting the ISO also pointed out that while the concept of a "body of state regulators" or "Western States Committee" is still under discussion in the context of governance for the expanded BAA, no details have been developed or proposed regarding this entity's role with regard to transmission planning and cost allocation. Moreover, once the default provisions being discussed in the working group are finalized, filed and have been approved by FERC for inclusion in the ISO tariff, any variations or deviations from those provisions would also have to be filed and approved by FERC. Stakeholders should therefore view the current effort to develop default cost allocation provisions as determining the rules that would govern transmission cost allocation for the expanded BAA.

According to the CAISO's July 15, 2016 "Revised Proposal, Principles for Governance of a Regional ISO" *a "Western States Committee will be incorporated as a non-profit entity separate from the ISO, with a budget funded through the ISO." Once a regional governance plan becomes effective The Western States Committee "will have primary authority over…the subject area[] of transmission cost allocation…as defined in more detail by the transitional committee in consultation with state regulators and the ISO." The CAISO explains that "primary authority means the committee will play the lead role for its defined areas of authority, and policy approval by the committee would be a prerequisite to any ISO Section 205 filing with FERC in those areas."*

SDG&E and other stakeholders have previously complained that giving the Western States Committee primary authority over transmission cost allocation without any details as to how such cost allocation would occur, puts stakeholders in an untenable position.[6] *If the Western States Committee will have "primary authority," it is essential that stakeholders know how this authority would be exercised. As it stands, stakeholders have no basis for assessing whether the Western States Committee's transmission cost allocation processes will result in equitable outcomes.*

SDG&E requests that the CAISO explain how the "default cost allocation provisions" that are the subject of the instant comments, relate to the transmission cost allocation provisions that the Western States Committee will presumably promulgate. Which transmission cost allocation provisions will apply and in what circumstances? SDG&E believes the "default

[6] SDG&E has separately expressed concern with giving the Western States Committee primary authority over transmission cost allocation in the first instance. Transmission cost allocation should be the responsibility of the expanded ISO Board and the Western States Committee should have a strictly advisory role in this regard.

cost allocation provisions" that are the subject of the instant comments are pointing in the right direction. SDG&E would be concerned if there were significant deviations from these provisions.

As a separate point, SDG&E notes that the CAISO's SB-350 studies demonstrated that reducing electric costs for consumers provides indirect benefits. When the prospective transmission upgrade being evaluated results in direct economic savings for specific sub-regions of the expanded ISO as compared to the reference case, there is an associated up-tick in economic activity and a resulting increase in employment. While these indirect benefits may be difficult to quantify, especially for prospective transmission upgrades of relatively small scope, they are nonetheless real and should be acknowledged in the evaluation—at least qualitatively.

Topic 2. Region-wide "Export Access Charge" (EAC) Rate for Exports and Wheel-throughs

Context

For the working group discussion, the ISO's presentation assumed a scenario where the current ISO BAA is expanded by the integration of a large external PTO such as PacifiCorp, and that the current ISO footprint and the new PTO would each be a "sub-region" with its own separate sub-regional TAC rate for load internal to the sub-region. The ISO further assumed that in this future scenario, only exports and wheel-throughs would pay the new EAC rate, while the "non-PTO" entities internal to the ISO BAA who currently pay the WAC would pay the sub-regional TAC rate. **Please assume the same in responding to the questions below.** If you wish to comment on or propose alternatives to these assumptions you can add any additional comments at the end of this section.

Questions

1. For an expanded BAA do you agree that a single region-wide access charge rate for exports and wheel-throughs is appropriate? Please explain your reasons. NOTE: This question is only about whether a single rate is appropriate, not about how that rate should be determined; the latter is covered in question 3 below.

   SDG&E believes a single rate is appropriate for wheels out of the ISO. This rate should be $0/MWh as that is the incremental cost of the transmission that is needed to support the export of power out of the expanded ISO. SDG&E notes that a $0/MWh import charge is currently imposed since that is the incremental cost of the transmission that is needed to support the import of power.

2. If you answered YES to question 1, do you favor the load-weighted average rate the ISO presented at the meeting, or another method for determining the single rate? Please explain the reasons for your preference.

   A load-weighted average of $0/MWh is still $0/MWh.

3. To distribute the revenues collected via the EAC, the ISO's presentation suggested giving each sub-region an amount of money equal to the MWh volume of exports and wheels from the sub-region times the sub-regional TAC rate. Please indicate whether you would support this approach or would prefer a different approach for distributing EAC revenues to the sub-regions.

   Since the sub regions will fare as well with the wheeling uses of the grid as they will with non-wheeling, no sub region will suffer relative disadvantage. SDG&E would support this suggestion.

4. The working group presentation illustrated how the method of distributing EAC revenues to sub-regions would most likely produce "unadjusted" sub-regional shares that do not add up exactly to the amount of EAC revenues collected from exports and wheels. The presentation offered one approach for distributing any **excess EAC revenues** to the sub-regions. Do you support that approach, or would you prefer a different approach? Please explain.

   The method suggested in the meeting is reasonable since the relationship of the final distribution among the sub regions isn't changed. It's therefore no less fair than the method of computing the unadjusted results.

5. Suppose that in a given year the EAC revenues are not sufficient to cover a distribution to sub-regions that aligns with sub-regional TAC rates, as described in question 3. How would you propose the ISO deal with that situation? I.e., should the ISO ensure that each sub-region receives export revenues equal to its sub-regional internal TAC rate times the volume of exports from its facilities, drawing upon other TAC revenues if necessary, or should the ISO only return EAC revenues to sub-regions until the EAC revenues are used up?

   Certainly the latter. No transfer of monies from other expanded ISO activities should be allowed. The actual revenues allocated should be in the same proportion as the use of the export volumes times the TAC rates, however.

6. If you answered NO to question 1, please explain what rules or principles you would prefer be applied to exports and wheel-throughs. Please discuss both (a) how you would propose to charge exports and wheel-throughs, and (b) how you would distribute the revenues collected to the sub-regions.

7. Please offer any additional comments, suggestions or proposals that were not covered in the previous questions.

   In efficient markets transactional signals should be based on the incremental cost of engaging in the transaction. Since exporting an additional megawatthour of energy from the expanded ISO balancing authority creates no incremental transmission cost (other than the impact on energy prices, losses and congestion which are already captured in LMPs), the export fee should be $0/MWh.