

# 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](mailto: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.*

TEAM does not currently calculate economic multiplier benefits that accrue to a region that produces energy, such as the creation of jobs and increased tax revenue. While calculation of such economic benefits to a region using TEAM makes sense in theory, their quantification may prove challenging. If economic benefits to a region could be reliably calculated, then they should be considered in the allocation of transmission costs to the sub-regional TAC. ORA understands the market simulation model deployed as part of TEAM provides the generator profits or producer benefit calculations. At a minimum, the sub-regional producer benefit in addition to the ratepayer benefit needs to be accounted for in transmission cost allocation purposes.

At one point, TEAM was used to estimate greenhouse gas emissions cost savings. Going forward, it would be useful to use TEAM for that function as well.

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.*

ORA supports the consideration of the avoided cost of the reliability project as a benefit for cost allocation purposes. Rather than including the avoided cost of the reliability project B as a benefit incremental to the production cost savings modelled by TEAM, and then allocating costs of the preferred project A based on total benefits that include the \$40 million cost of reliability project B, it would be better to first allocate the \$40 million cost of reliability project B to sub-region 1, and then allocate the remaining cost of the preferred project A to each of the sub-regions in proportion to the economic (production cost savings) benefits they receive as modelled by TEAM. This would recognize the \$40 million savings that accrued to sub-region 1 from avoiding the need to build reliability project B, as well as taking into account the economic benefits that all sub-regions received from project A.

Allocating the cost of project B first is more equitable because it requires sub-region 1 to pay the cost of the project it avoided, while at the same time requiring all sub-regions to pay for the economic benefits of project A without, in effect, paying for the reliability costs that should be borne by sub-region 1.

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 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?*

It is important to perform the detailed studies needed to develop reasonably accurate cost estimates of avoided projects. The studies of avoided projects should be at the same level of detail as the studies of projects expected to be built. Cost estimates generally increase as projects move from the planning stage to the execution stage, as more details of the requirements to implement the project are known. Allocating costs using the estimated cost of a project that was only in the initial planning stage and the more refined cost of a project that had been further developed with additional details could bias the cost allocation.

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 base on the avoided cost of the 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.*

ORA recommends first allocating costs based on reliability (as discussed in the response to question 2 above ) and policy needs, because the calculation of those costs should be easier to quantify, and less speculative, than potential benefits.

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?*

ORA supports the use of reasonable threshold criteria to determine which projects should undergo TEAM studies. For example, if power flow studies indicate that five percent or less of the energy that would flow on a proposed project would flow to another sub-region, it is unlikely that complete TEAM studies on the proposed project are necessary.

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?*

A uniform default set of parameters would enhance certainty and provide a uniform basis for comparing different projects. The assumptions, study process, and methodology for completing TEAM studies should be developed as part of a transparent stakeholder process.

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?*

Generally, if a sub-region would experience improved efficiency from economic dispatch, through the reduction of transmission line losses, and the reduction of resource adequacy capacity costs in a quantifiable amount exceeding a threshold percent of the project cost (for example 5 per cent) the sub region should pay for the benefits commensurate with their value of the benefits. However, if TEAM studies indicate that a sub-region would receive less than a threshold amount (accepted by stakeholders at large) of a project's benefits, it may not be necessary to allocate the costs of a reliability or policy project to that sub-region receiving such a small proportion of benefits. In those cases, however, it would be important to limit the project solely to what is needed to resolve the reliability or policy need.

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

ORA continues to recommend allocating the costs of existing transmission to all sub-regions in the expanded ISO based on the benefits received from existing facilities. Although the CAISO previously questioned the feasibility of analyzing the benefits of existing facilities to other sub-regions, at the August 11, 2016 workshop, Dr. Kristov acknowledged that such analysis would be possible, but would require significant resources. Given the potential impact to both existing CAISO ratepayers and ratepayers of the expanded ISO going forward, ORA recommends completing this analysis. Initially, the analysis would be for CAISO and PacifiCorp (PAC), but the analysis of benefits from existing transmission network should be repeated or updated anytime a new PTO with a substantial footprint joins the regional ISO.

The existing CAISO transmission network has the potential to benefit new PTO ratepayers. At the same time, PacifiCorp has indicated its interest in “[f]inding one or more partners to share in Energy Gateway project” in order to allow PacifiCorp’s ratepayers to benefit from a project that is otherwise not cost effective and also to provide regional benefits.<sup>1</sup> The potential for a project to provide regional benefits does not depend on whether it was constructed before or after regionalization, but on the analysis that examines potential benefits to other sub-regions.

While CAISO ratepayers have already funded extensive transmission projects and hence currently pay a high voltage (HV) TAC rate of \$11.22 per MWh for all internal load and exports, PacifiCorp ratepayers pay a high voltage TAC that is approximately \$4.50 per MWh.

To demonstrate the potential impact of not analyzing the benefits of existing transmission facilities to another sub-region and then allocating costs as appropriate, ORA used the CAISO’s Impact Assessment Tool to calculate potential future TAC rates using different assumptions. The separate TAC rates assume that each sub-region pays for its own existing facilities. The single merged TAC rates assume that each sub-region pays for the existing facilities of the other sub-region without an assessment of the benefits each sub-region would receive from the existing facilities of the other sub-region.<sup>2</sup> The analysis below uses the load ratio share of existing CAISO customers as a proxy for a benefits analysis that might be calculated for new facilities in the PacifiCorp sub-region. The analysis demonstrates that if the CAISO ratepayers paid their load ratio share, i.e., approximately 75% of PacifiCorp Gateway segments D, E, and F with an estimated capital cost of \$6 billion,<sup>3</sup> the CAISO ratepayers would pay a high voltage TAC rate of \$16.35 per MWh in 2026, while PacifiCorp

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<sup>1</sup> PacifiCorp’s 2015 Integrated Resource Plan Volume I, March 31, 2015, p. 200.

<sup>2</sup> Though the single merged TAC reflects the current HV TAC methodology in the CAISO BAA, it does not reflect the CAISO’s current proposal under regionalization. The single merged TAC is shown to illustrate the result if the current HV TAC method were maintained under regionalization.

<sup>3</sup> Gateway Segments D, E and F combined capital cost is assumed to be approximately \$6 billion in 2022 based upon the application of the TEPPC per unit costs (Developed by Black and Veatch) and the PG&E and SCE per unit cost guide.

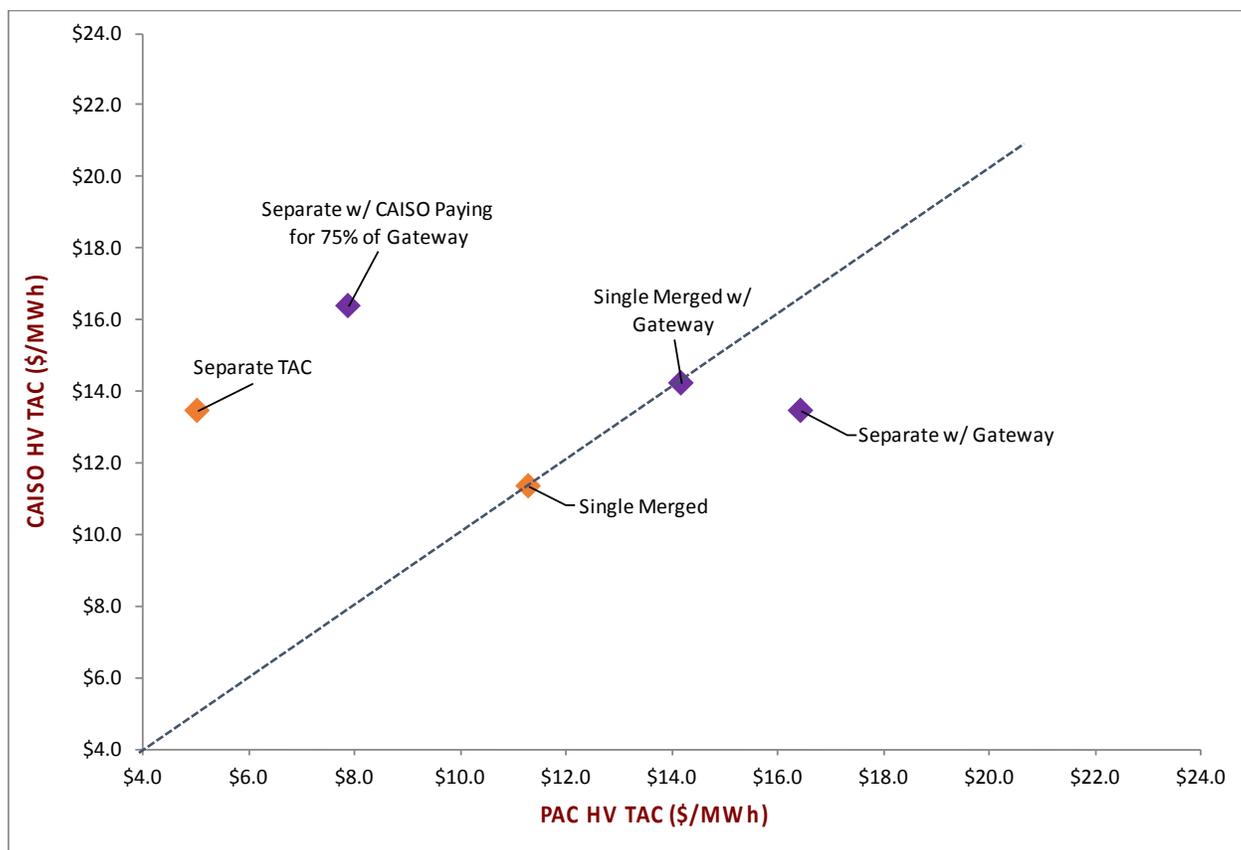
ratepayers would pay only \$7.89 per MWh.<sup>4</sup> Without Gateway segments D, E and F, the CAISO HV TAC is projected to be \$13.44/MWh in 2026. In other words, under the CAISO's Revised Straw Proposal, where the sub-regions pay license-plate rates for their existing transmission facilities and pay postage-stamp rate for the new transmission approved under the expanded ISO, such as potentially Gateway Segments D, E and F, the HV TAC of CAISO ratepayers could increase as much as \$3/MWh (from \$13.44 to \$16.35).

Figure 1 on the next page shows the potential CAISO and PacifiCorp HV TAC rates expressed in \$/MWh in year 2026 under multiple scenarios using the assumptions explained below.

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<sup>4</sup> Based upon the CAISO's *Impact Assessment Tool - Transmission Access Charge Options*, dated February 9, 2016.

**Figure 1: Potential Impact of Regionalization on TAC: CAISO & PAC HV TAC (\$/MWh) in 2026\***



\* **Data:** The CAISO's *Impact Assessment Tool - Transmission Access Charge Options*, dated February 9, 2016. ORA has adjusted the 2015 and 2016 CAISO's TRRs/Loads to reflect the actual TRRs/Loads, which results in an HV TAC increase of ~\$1/MWh.

#### Scenario Descriptions:

**Separate TAC:** Assumes separate HV TAC rates for each sub-region within the expanded BAA, i.e., CAISO and PAC.

**Single Merged:** Assumes a single merged rate for the expanded BAA. That is, the cost of existing TRR in each of the two sub-regions/BAA's is spread over the entire expanded BAA load.

**Single Merged w/ Gateway:** Single Merged TAC scenario with Gateway Segments D, E and F (qualified as new regional transmission).

**Separate w/ Gateway:** Separate TAC scenario with Gateway Segments D, E and F rolled into the PAC TAC only.

**Separate w/ CAISO Paying for 75 % of Gateway:** Separate TAC with the CAISO ratepayers paying for Gateway Segments D, E and F (qualified as new regional transmission).

Allocation of the TAC rates of each sub-region's existing facilities entirely to that sub-region fails to acknowledge the benefits that a sub-region's existing facilities may provide to another sub-region. This approach has the potential to provide benefits at no cost to customers of the first new PTO to join an expanded ISO. It would be inconsistent with FERC Order 1000's requirement that costs must be allocated "roughly commensurate" with benefits. It is therefore necessary to develop a methodology for evaluating the benefits and costs from existing facilities.

While there are likely benefits to CAISO ratepayer associated with future regional transmission upgrades,<sup>5</sup> there are also likely to be benefits to each sub-region from the existing transmission system. Therefore, ORA recommends that the CAISO allocate the cost of existing transmission facilities to each of the sub-regions based on an analysis of the benefits, similar to its proposal for new facilities.

## 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.*

Yes, the CAISO is correct that a single EAC would prevent gaming. It would also offer additional revenue streams to the PacifiCorp and CAISO regions if they become net exporters. ORA notes that the CAISO's proposal treats exports on a postage stamp basis, while deliveries to load within the expanded ISO are treated on a license-plate basis.

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<sup>5</sup> For example, new transmission infrastructure could allow ratepayers to access the benefits of high quality wind resources in other states, which could offset overall costs.

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.*

Load weighting would assign costs proportionate to benefit consistent with FERC Order 1000 transmission cost allocation principles.

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.*

If the blended rate approach is adopted, the distribution of revenue collected via the EAC would most closely track how it works today, even though a "true up" would likely be required to avoid the potential shortfall described in question 5. This approach needs to ensure that post regionalization no sub-region is worse off in terms of collecting adequate revenues towards the relevant PTO TRRs within those sub-regions.

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.*

ORA supports the proposed approach, because it reflects the volumetric use of the transmission infrastructure.

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?*

Yes, again consistent with the approach for the redistribution of excess revenues and consistent with the volumetric use of the transmission infrastructure.

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.*

Not applicable.

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

The uncertainty about how the market will respond to the new EAC (higher or lower than the current Wheeling Access Charge (WAC), depending on the sub-region from which the power is exported), makes it challenging to design an EAC at the outset that best fits the trading patterns that will occur. It may be necessary to refine the EAC in light of actual market conditions.