California ISO

Transmission Access Charge Options for Integrating New Participating Transmission Owners

Second Revised Straw Proposal

September 30, 2016

Market & Infrastructure Policy

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Second Revised Straw Proposal

1. Executive Summary

In 2015 the ISO began considering how it would need to modify its tariff to integrate additional transmission-owning utilities with load-service territories into an expanded balancing authority area ("BAA"). The rationale for starting this effort was based on the operational and market efficiencies of larger BAAs that have been demonstrated in the eastern United States, plus the environmental and cost benefits of using geographic resource and load-shape diversity in the west to integrate renewable generation. At the same time, PacifiCorp, the first BAA to join the new energy imbalance market ("EIM") operated by the ISO, expressed interest in joining the ISO as a full participant.

A central policy element of expanding the ISO is the question of how to allocate the costs of owning, maintaining and operating the transmission assets[1] that would comprise the expanded ISO's controlled grid. This element is referred to as the Transmission Access Charge ("TAC"), which is the mechanism currently used by the ISO to recover these costs. To address this policy element the ISO opened the "TAC Options" stakeholder initiative with the release of its October 23, 2015 issue paper, to consider whether the ISO's existing TAC design would be suitable for a significantly expanded BAA, and if not, how to revise it to better align cost allocation with the benefits that different sub-regions of the expanded ISO would receive from the transmission facilities placed under ISO operational control. The ISO issued a TAC Options straw proposal on March 1, 2016, a revised straw proposal on May 20, and conducted several public meetings and received written comments on these proposals.[2]

The present second revised straw proposal modifies the May 20 revised straw proposal based on comments received from stakeholders on both the May 20 proposal and a working group discussion held on August 11, and on further consideration by the ISO of the pros and cons of the alternatives discussed over the course of this initiative.[3] As a second revised straw proposal,

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1 These costs are referred to as "transmission revenue requirements" or "TRR." The amount of money a PTO can recover as its TRR must be approved by the Federal Energy Regulatory Commission (FERC).

2 The ISO's web page for this initiative contains all prior documents issued by the ISO and all written comments submitted by stakeholders. See: http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionAccessChargeOptions.aspx

3 For brevity this paper omits most of the background discussion and comparison of other ISOs/RTOs, which was provided in prior ISO papers on this initiative. Readers of this paper should refer to the October 23, 2015 issue paper and March 1, 2016 straw proposal for these additional details.

this paper reflects the ISO's best thinking to date on the various TAC design elements and issues, but is not intended to be the final word. Section 2 below provides the proposed schedule of further activities the ISO has planned for working with stakeholders to arrive at the final proposal ISO management will present to its Board of Governors some time in 2017 for approval.

The major provisions of the second revised straw proposal are summarized as follows. Complete details are provided in section 3.

1. The proposal distinguishes between "existing" and "new" transmission facilities for cost allocation purposes. "Existing" facilities are defined here to mean transmission facilities that are in service or have been approved in separate planning processes for the current ISO BAA and the new PTO's area at the time the new PTO is fully integrated into the expanded BAA. In contrast, "new" facilities are defined here to mean facilities that are planned and approved under an integrated transmission planning process that will plan new transmission infrastructure for the entire expanded BAA and will commence upon integration of the first new PTO. Simply stated, all transmission facilities that are included in the controlled grid for the expanded BAA and are not "new" facilities will be considered "existing" facilities.

2. Upon integration of the first new PTO to form the expanded BAA, the expanded BAA will be considered a "region" in the terminology of FERC Order 1000, and the existing ISO BAA and the new PTO service territory will each be a "sub-region" for cost allocation purposes. Similarly, another transmission-owning utility with a load service territory that joins the expanded BAA as a new PTO at a later date will become another sub-region, unless that entity is embedded within or electrically integrated with an existing sub-region, in which case it will become part of that sub-region.

3. The costs of existing high-voltage (rated 200 kV and above) facilities will be recovered on a sub-regional basis, where the current ISO BAA is considered one sub-region and the new PTO is another. This means that each sub-region would continue to pay the same costs for existing facilities under an expanded ISO BAA that they would have paid if they remained separate. In the case of a new PTO that is embedded within or electrically integrated with an existing sub-region, the costs associated with its existing high voltage facilities will be combined with the existing high voltage facility costs of that sub-region for recovery through the common sub-regional TAC rate.

4. The costs of new facilities will be allocated to sub-regions of the expanded ISO depending on the classification of the facility and the economic benefits it provides to each sub-region.
    a. The cost of a reliability project within a sub-region that addresses a reliability need of that sub-region will be allocated entirely to that sub-region.
    b. The cost of a policy-driven project within a sub-region that supports policy mandates for that sub-region only will be allocated entirely to that sub-region.
    c. The cost of an economic project, for which its economic benefits must exceed its cost, will be allocated to sub-regions in proportion to each sub-region's benefits.

   d. For a reliability or policy-driven project that is enhanced or replaced by a more costly project that also provides economic benefits that exceed the incremental cost above the cost of the original reliability or policy-driven project, the avoided cost of the original project will be allocated to the sub-region with the original reliability or policy need, and the incremental cost will be allocated to sub-regions in proportion to each sub-region's benefits.

   e. For a policy-driven project that supports policy mandates of more than one sub-region, or that is built in one sub-region to meet the policy mandate of another sub-region, the ISO will calculate the economic benefits of the project and allocate costs to each sub-region in proportion to the sub-region's benefits, but only up to the point where each sub-region's cost share equals the sub-region's benefits. Any additional cost of the project will be allocated to the sub-region(s) whose policy mandate(s) are driving the need for the project.

5. In discussions of governance for an expanded ISO BAA, which are in progress in parallel to this initiative, the ISO and stakeholders are exploring the formation of a Western States Committee (WSC) that would have primary authority with respect to some aspects of transmission cost allocation. (The WSC concept supersedes what the May 20 proposal in this initiative called a "body of state regulators.") With regard to cost allocation provisions just described, the ISO suggests that item (e) – cost allocation for policy-driven projects that involve more than one sub-region – would be an appropriate and valuable area for WSC to exercise primary authority. Resolution of WSC roles and authorities will, however, be determined as part of the governance initiative, not within the TAC Options initiative. Item (e) above should therefore be viewed as the ISO's default cost allocation provision for these types of projects.

6. New high-voltage transmission facilities will be subject to competitive solicitation to determine the entity that will build and own the facility, except, as stated in tariff section 24.5.1, where the facility involves "an upgrade or improvement to, addition on, or a replacement of a part of an existing Participating TO facility," in which case the Participating TO will construct and own such upgrade, improvement, addition or replacement facilities unless a Project Sponsor and the Participating TO agree to a different arrangement." This is consistent with FERC Order 1000 and the ISO's current provisions regarding competitive solicitation.

7. The ISO will charge a single region-wide "export access charge" ("EAC") to all export and wheel-through transactions from the expanded ISO BAA. The EAC will be calculated as the load-weighted average of the sub-regional TAC rates. The revenues collected via the EAC will be allocated to sub-regions in proportion to their high-voltage transmission revenue requirements.

2. Initiative Schedule

Date	Activity
September 30, 2016	Post 2nd revised straw proposal
October 7, 2016	Stakeholder meeting in Folsom
October 28, 2016	Submit written comments on 2nd revised straw proposal
December 2016 date TBD	Post draft final proposal
December 2016 date TBD	Stakeholder meeting in Folsom
December 2016 date TBD	Submit written comments on draft final proposal
2017 Date TBD	Board of Governors meeting

3. Second Revised Straw Proposal

This section provides the details of the ISO's second revised straw proposal.

Key terms, concepts and assumptions

a) This proposal applies only to transmission cost allocation for high-voltage (200 kV and above) transmission facilities. We assume that cost allocation for low voltage (<200 kV) facilities that become part of the expanded ISO controlled grid will be recovered on a PTO-specific basis, comparable to "local" facilities in the terminology of Order 1000 and the CAISO TAC structure today.

b) "CAISO" as used here refers to the existing ISO balancing authority area (BAA), including the ISO Controlled Grid and member PTOs as they are today, prior to integrating a new PTO with a load service territory.

c) "Expanded ISO" refers to the expanded BAA after a new PTO with a load service territory integrates with the CAISO.

d) "PTO#1" refers to the first new PTO with a load service territory to join the CAISO to form the expanded ISO.

e) "New facilities" or "new transmission facilities" are transmission elements that are planned and approved via an integrated transmission planning process (TPP) for the expanded ISO BAA. This straw proposal does not address the specifics of an integrated TPP for the expanded ISO BAA. Assuming the integrated TPP retains the same overall structure and schedule as today's CAISO TPP, the first integrated TPP would be started in January of the first full calendar year in which PTO#1 is integrated into the expanded ISO BAA.

   The "new facilities" category could include a project that was being considered prior to the new PTO joining the ISO as an "inter-regional" project under the FERC Order 1000 approved provisions for considering inter-regional transmission projects, and then is subsequently adopted and approved via the integrated TPP.

f) “Existing facilities” or “existing transmission facilities” are the high-voltage transmission assets of a PTO that are not “new facilities” as defined above.

g) Currently the CAISO is considered a “region” as that term is used for purposes of complying with FERC Order 1000. Once PTO#1 joins, the expanded ISO BAA will become the new “region” consistent with Order 1000. After that the current CAISO system would be considered a “sub-region,” as would PTO#1 and each subsequent new PTO with a load service territory that joins, unless the new PTO is embedded within or electrically integrated with an existing sub-region. In the latter case the new PTO would become part of the sub-region in which it is embedded or with which it is integrated.

   “Embedded” is defined to mean that the new PTO cannot import power into its service area without relying on the transmission facilities of an existing sub-region. “Integrated” is harder to define for purposes of establishing a sub-region under this proposal. At a minimum it means that the new PTO is not entirely dependent – perhaps not dependent at all – on another PTO’s transmission facilities to import energy prior to joining, but once it joins the expanded BAA it will benefit significantly from the transmission system of the sub-region with which it is integrated. Rather than establish a precise definition of “integrated,” the ISO proposes to make this determination on a case-by-case basis, subject in each case to the approval of the Board of Governors for the expanded ISO BAA, and considering specific criteria stated in the tariff such as the proportion of the new PTO’s annual and peak load served over the facilities of the existing sub-region. A potentially useful model could include some of the existing criteria in tariff section 27.5.3.8.1 to be considered for establishing a new Integrated Balancing Authority Area (IBAA), such as [italics and bracket substitutions added for illustrative purposes]:

   > (1) The number of Interties between the *potential or existing IBAA* [*new PTO*] and the *CAISO Balancing Authority Area* [*existing sub-region*] and the distance between them;
   >
   > (2) Whether the transmission system(s) within the *other Balancing Authority Area* [*new PTO*] runs in parallel to major parts of the *CAISO Controlled Grid* [*existing sub-region*];
   >
   > (3) The frequency and magnitude of unscheduled power flows at applicable Interties;
   >
   > (4) The number of hours where the actual direction of power flows was reversed from scheduled directions.

h) This proposal assumes that TAC will continue to be charged on a per-MWh basis to load and exports. It does not consider whether anyone other than load or exports should pay the TAC, nor does it consider alternative billing determinants such as demand-based charges.

   Some stakeholders have expressed concerns that the use of a volumetric basis for TAC charges (in contrast to a demand basis) in the ISO’s settlements process would inevitably translate into a purely volumetric basis for recovering a PTO’s transmission revenue requirement (TRR) from retail customers. They point out that if this occurs for a customer that has a high load factor and had been paying for transmission service based on demand, that customer will be allocated a larger cost share than before for the same TRR.

   The ISO clarifies that using a per-MWh TAC rate for wholesale market settlements does not necessarily mean that retail customers must also pay a purely volumetric charge. The ISO settlements process applies the per-MWh TAC to each utility distribution company (UDC) taking service from the ISO grid based on the total end-use metered load (called “Gross Load” as defined in the ISO tariff) served over that UDC’s system during each settlement period. The ISO’s settlement process does not prescribe how each UDC will recover its TAC payment to the ISO from its end-use customers. For example, the UDCs that are functional units within the investor-owned utilities who are CAISO PTOs today have retail rate structures for TRR recovery that are volumetric for residential and a combination of volumetric and demand-based for commercial and industrial customers. The question of how a UDC will recover TRR from its retail customers is not determined by the structure of the TAC.

Second revised straw proposal – existing facilities

1. TRR associated with existing facilities will be recovered on a sub-regional basis, where the CAISO is one sub-region and PTO#1 is the other sub-region. This is referred to as the “license plate” approach, where the “license plates” are sub-region specific even though a given sub-region may be comprised of multiple PTOs.

   The sub-regional license plate rate will be charged to internal load within each sub-region, including the load of what are known today as “non-PTOs” in the CAISO system and currently pay the CAISO’s wheeling access charge (WAC).[4] Exports out of the expanded BAA, including wheel-through transactions, will be charged a region-wide export access charge (EAC) described later in this document.

   Some stakeholders advocated blending costs of some existing facilities for cost recovery on a region-wide basis. The ISO considered alternative ways to carve out a subset of existing facilities for this purpose and ultimately concluded that the complexities and risks of such an approach would be counterproductive. In approving license plate rates for existing facilities in the context of other ISOs/RTOs, FERC has accepted the argument that the individual PTO areas had made decisions to build their existing systems for the benefit of their existing ratepayers without any anticipation of some other parties paying part of those costs. By coming together into a larger BAA all PTO areas benefit. Keeping the existing facility costs separate means that no area experiences a positive or negative rate impact that would occur if costs of some existing transmission facilities were merged and reallocated.

   An important feature of this approach is that all sub-regions have equal access to the benefits of the expanded ISO transmission system and BAA, and continue to pay the same TRR for existing facilities that they otherwise would have paid. FERC has agreed that this approach meets their standards for aligning costs and benefits.[5]

[4] The non-PTOs are listed in tables 3-4 of the following document: http://www.caiso.com/Documents/WheelingAccessRatesEffectiveJul6_2016_UpdatedJul12_2016.pdf

[5] Refer to the ISO’s October 23, 2015 issue paper and March 1, 2016 straw proposal for information on specific FERC and court decisions on this topic.

This approach also preserves the clear principle that any facilities eligible for region-wide cost allocation would have to be planned and approved under an integrated planning process that includes all member PTOs and their stakeholders. In particular, this approach mitigates the risk of incentivizing a potential new PTO to develop costly new high-voltage transmission for its area outside of the integrated TPP with the expectation that some of its costs can be transferred to other members of the expanded ISO upon its joining. With an approach that blends some costs of existing facilities the ISO would have to design and impose a rule that mitigates this incentive in a manner that would be transparently applicable to any subsequent new PTO. Again, the ISO has concluded that the complexities and risks of developing such rules would be counterproductive.

2. The existing facilities at the time PTO#1 joins the expanded ISO will be referred to as "Legacy Facilities" for purposes of integrating subsequent new PTOs (explained in the next step).

3. When PTO#2 joins the expanded ISO and creates a new sub-region, the TRR for PTO#2's existing facilities will be recovered from the PTO#2 sub-region, and PTO#2 will have no cost responsibility for the Legacy Facilities. This is comparable to the treatment of the CAISO and PTO#1 existing facilities when the larger ISO BAA is first formed. PTO#2's existing facilities then become part of the Legacy Facilities for purposes of integrating PTO#3. Similarly, each subsequent new PTO for which a new sub-region is created for will be responsible for the costs of its own existing facilities at the time it joins, and will not be responsible for the costs of the Legacy Facilities.

4. Alternatively, if a new PTO joins and becomes part of an existing sub-region, that PTO's costs for existing facilities 200 kV and above will be combined with the corresponding costs of the sub-region it joins for recovery through the common sub-regional license plate rate.

Second revised straw proposal – new facilities

5. In the May 20 revised straw proposal the ISO stated: "Decisions to build and cost allocation for new regional economic and policy-driven facilities as defined here will be determined by a body of state regulators to be formed as part of a new ISO regional governance structure in conjunction with the integration of the new PTO into the expanded BAA." The ISO also noted, however, that "FERC Order 1000 requires the ISO to have back-stop provisions for approving and allocating the costs of economic and policy-driven transmission projects." Since the previous proposal was released, discussions around governance have proposed formation of a "western states committee" (WSC) that would assume some to-be-specified functions with regard to transmission cost allocation.[6] The present proposal offers some ideas about the role of a WSC regarding cost allocation for public policy-driven transmission

[6] *See* Principles for Governance of a Regional ISO, dated July 15, 2016 (stating that the WSC will have primary authority over certain regional ISO policy initiatives on specific topics within the subject area of transmission cost allocation). http://www.caiso.com/Documents/RevisedProposedPrinciples-RegionalISOGovernance.pdf

projects discussed below. But beyond that narrow topic, this proposal sets aside any further discussion of such a WSC and its possible functions and focuses instead on the default transmission cost allocations provisions the ISO would need to include in its tariff to satisfy FERC Order 1000.

Because the default provisions developed in the present initiative would become part of the ISO tariff upon approval by FERC, stakeholders should view these provisions as the rules that would apply to transmission cost allocation unless and until FERC approves any alternatives or exceptions. In other words, when a WSC is formed at some point in the future and assumes some functions with regard to transmission cost allocation, its actions can supersede the provisions established through the present initiative only with FERC's approval.

6. A "new" facility – i.e., a facility planned and approved through the integrated ISO TPP for the expanded BAA – will be considered for regional cost allocation if it is rated 200 kV or higher, regardless of whether the facility is categorized as a reliability, policy or economic project. Regional cost allocation means allocation of costs to more than one sub-region. "Consideration" for regional cost allocation does not mean automatic allocation of costs to multiple sub-regions; it just means the facility will be subject to further criteria or analysis, described below, to determine whether regional allocation is warranted based on benefits. A new facility could also be a project to upgrade an existing facility.

7. The ISO will use its existing Transmission Economic Assessment Methodology (TEAM) to estimate sub-regional economic benefits of certain categories of new transmission facilities rated 200 kV or above, as described in item 9 below, in addition to determining economic benefits to the expanded BAA as a whole.[7]

8. Although the scope of the present initiative does not include developing the details of an integrated TPP for the expanded BAA, the working assumption is that the integrated TPP will retain the overall process structure of the current CAISO TPP. It will begin with a Phase 1 to specify the unified planning assumptions and study plan for the current TPP cycle. Phase 1 includes identifying the federal, state or local public policy mandates or requirements driving needs for transmission that will be addressed in the current TPP cycle. Because a given sub-region could be affected by different state and local policy mandates within its territory, this proposal assumes there will be procedures in place for authorities whose policies may drive transmission needs to provide input to the integrated TPP, in a manner analogous to the CPUC's provision of renewable energy procurement portfolios to the ISO today for this purpose. Thus, public policy drivers of new transmission will either be national and thus applicable to the entire expanded BAA, or will be clearly associated with specific states or local jurisdictions within states.

[7] The ISO is in the process of updating the online documentation of TEAM; as several stakeholders noted in their comments, the existing documentation was prepared about ten years ago and needs to be updated.

The rest of this item summarizes features of the existing ISO TPP that we expect will carry over to an integrated TPP for the expanded BAA. Phase 2 of the current TPP identifies needed new transmission facilities or upgrades in three steps:

a. First, perform reliability studies and identify mitigations for anticipated future reliability problems such as criteria violations. Such mitigations are categorized as reliability projects.

b. Second, assume that the identified reliability mitigations are in place and determine the transmission projects that efficiently and effectively meet public policy requirements based on the criteria specified in the tariff. The projects identified in this step are categorized as policy projects. In some cases a policy project may offset the need for a reliability project identified in the first step. In this case the project will still be categorized as policy, and the cost of the avoided reliability project will be included in determining the cost allocation for the policy project.

c. Third, assume that the projects identified in the first and second steps are in place (removing any reliability projects that may have been superseded by policy projects), and consider whether any economic projects would be appropriate. In this step the ISO performs economic studies for specific areas of the grid that were identified in Phase 1 of the TPP as areas where new transmission might provide significant economic benefits. Projects identified in this step must be shown by the TEAM to have a benefit-to-cost ratio (BCR) greater than 1 in order to be proposed in the comprehensive transmission plan at the end of the TPP cycle, in which case they are categorized as economic projects.

   In some cases an economic project may offset the need for, or may be specified as an expansion of, a reliability or policy project identified in step 1 or 2. In such a case the BCR requirement for the project is only that its economic benefits be greater than the incremental cost of the project beyond the cost of the original project it offsets or expands. In such a case the project will still be categorized as economic, and the cost of the original reliability or policy project will be included in determining cost allocation for the economic project.

9. The ISO proposes that costs for new transmission projects be allocated as follows.

   a. To begin with, we emphasize that the cost allocation discussed here is only to the granularity of the sub-regions. Some parties have asserted that cost allocation by the ISO should be more geographically granular, particularly in the case of policy-driven projects for which the policy driver would likely originate at the level of a state or a local regulatory authority that comprises only a portion of a sub-region. The ISO recognizes that this argument may have some appeal, but for purposes of this proposal is focusing on cost allocation only to sub-regions for two reasons. First, allocation to sub-regions is a necessary first step to be resolved before allocating costs more granularly to entities or areas within a sub-region. Second, with regard to policy-driven projects for which this point is most relevant, the proposed WSC may be a preferable venue in which to address such matters. Depending on how the

WSC's authority is ultimately specified, the default cost allocation for policy-driven projects discussed here may be superseded by action of the WSC. Therefore, for purposes of the present proposal, the ISO is limiting the cost allocation discussion to the sub-regional granularity level.

b. For a reliability project that is narrowly specified as the more efficient or cost-effective solution to a reliability need within a sub-region, and has not been expanded or enhanced in any way to achieve additional benefits, we propose to allocate the project cost entirely to the sub-region with the driving reliability need, regardless of any incidental benefits that may accrue to other sub-regions. "Incidental" benefits are any unintended (by the planners) economic, policy or reliability benefits that may result from the proposed reliability project. These benefits are excluded from the cost allocation because the reliability project in question was identified as the preferred solution to the reliability need based solely on meeting that need, without the planners trying to obtain any additional benefits.

c. For a policy-driven project that is connected entirely within the same sub-region in which the policy driver originated, we propose to allocate the project cost entirely to the sub-region with the driving policy need, regardless of any incidental benefits that may accrue to other sub-regions.

d. For a purely economic project with BCR > 1, cost shares will be allocated to sub-regions in proportion to their benefits, and because BCR > 1 this completely covers the costs. A purely economic project is one that is selected on the basis of the TPP economic studies following the selection of reliability and policy projects, and is therefore is a distinct new project, not an enhancement of a previously selected reliability or policy project.

e. For an economic project that is so categorized as a result of enhancing a reliability or policy project,[8] and as a result has higher cost than the original reliability or policy project, a cost share equal to the avoided cost of the original project will be allocated to the sub-region with the reliability or policy need, and the balance of the cost will be allocated to sub-regions in proportion to their benefits as calculated by TEAM.

   Note that in this situation, the economic benefits of the project must only exceed the incremental cost beyond the cost of the original reliability or policy project for the new project to be deemed "economic." Also, the present approach adopts the proposal made in several stakeholder comments that for such projects the ISO should allocate the avoided cost of the original reliability or policy project first, and only then recover

[8] The ISO notes that it may be appropriate to define a new transmission project category for cost allocation purposes for such projects. Strictly speaking an economic project must have BCR greater than or equal to 1, which may not be true if a reliability or policy project is enhanced for economic benefits. The idea here is similar to MISO's "multi-value projects" (MVPs).

any residual project cost based on economic benefits.[9] The approach recognizes the fact that the primary driver of the project is the reliability or policy need, and if not for that driver the project may not need to be built at all.

f. For more complicated policy projects – for example if the same project meets the policy needs of more than one sub-region, or if a policy project is built in the system of one sub-region to meet the policy need of another sub-region – the allocation of costs becomes more challenging. As a matter of principle it may appear desirable and logical to follow the "driver first" method described in the previous bullet. The problem in practice, however, is that a credible avoided cost for an alternative pure policy project may not be achievable.

   Case 1. Consider a policy driver originating in sub-region A for which the policy project proposed is within sub-region B. The ISO expects that such a project would likely have significant benefits to sub-region B, so that allocation of the full costs to A would not be appropriate. But how to estimate the avoided cost of an alternative project (or alternative procurement approach) that A might take to meet the policy mandate instead of building the project within sub-region B?

   Case 2. Consider similar policy drivers originating in two sub-regions A and B such that the preferred project meets the policy mandates of both sub-regions. Here also the "driver first" method would say to allocate cost shares to A and B equal to the avoided costs of the alternative policy projects each would have had to build to meet their own policy needs. Presumably the preferred project should be less costly than the total cost of the two avoided projects. But again, the ability to apply this method depends entirely on being able to identify credible, concrete alternatives targeted narrowly to meet the policy mandate of only one sub-region, that would have been

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[9] In contrast to the "driver first" approach proposed here, the ISO had previously presented a similar but not identical approach in which the avoided cost of the original reliability or policy project is included as a benefit with the economic benefits for calculating sub-regional cost shares based on benefits ("total benefits" method). A simple example illustrates how the proposed "driver first" method will allocate a larger cost share to the sub-region with the reliability or policy driver than the "total benefits" method would do.

Consider a preferred or enhanced) project with cost = $100 million

Sub-region A benefits

- $30 million production cost savings (from TEAM)
- Meets sub-region A reliability need, where sub-regional reliability alternative would cost $60 million but with no economic benefit

Sub-region B benefits

- $40 million production cost savings (from TEAM)

- Cost responsibilities under "driver first" method:
  - Sub-region A = $60M + $40M*$30M/$70M = $77M
  - Sub-region B = $40M * $40M/$70M = $23M
- Cost responsibilities under "total benefits" method:
  - Sub-region A = $100M ($30M+$60M)/($30+$40M+$60M) = $69M
  - Sub-region B = $100M ($40M)/($30+$40M+$60M) = $31M

built absent the preferred project. This simply may not be possible in many if not most situations.

Given the above considerations, and the recognition that the ISO's proposal in this initiative is intended as a default cost allocation that may be superseded by action of the proposed WSC, the ISO proposes to apply the "total benefits" method as the general default approach for policy-driven projects. This means that the ISO will estimate economic benefits for each sub-region, allocate cost shares to each sub-region equal to the sub-regional economic benefits, and then allocate the residual cost to the sub-region(s) driving the policy need.

If the policy mandate(s) driving the need for the project original entirely within one sub-region, then allocation of the residual cost is straightforward. If the mandates come from more than one sub-region, the ISO proposes to allocate the residual cost to sub-regions in proportion to their internal load projection for the year in which the project will be energized.

10. The ISO previously proposed that new regional facilities whose costs are allocated to multiple sub-regions will be subject to competitive solicitation to build and own the facility. Some stakeholders commented this scope is too narrow, that limiting competitive solicitation to such projects would create a disparity between how competitive solicitation is applied within the CAISO today and how it would be applied in a new sub-region that is the territory of a single PTO. In particular, because costs of all 200 kV and above facilities within the CAISO today are allocated to the entire BAA on a postage stamp basis, all such facilities are subject to competitive solicitation except, as stated in tariff section 24.5.1, where the facility involves "an upgrade or improvement to, addition on, or a replacement of a part of an existing Participating TO facility," in which case "the Participating TO will construct and own such upgrade, improvement, addition or replacement facilities unless a Project Sponsor and the Participating TO agree to a different arrangement." The ISO proposes to retain the same provision for the expanded ISO BAA, as it complies with the requirements of FERC Order 1000 and would create a level playing field for competitive solicitation across the expanded ISO. This means that new transmission facilities at or above 200 kV in the expanded ISO that do not qualify for the exemption under section 24.5.1 would be subject to competitive solicitation, regardless of whether they would be eligible for regional cost allocation.
11. The ISO proposes to drop its prior proposal to recalculate sub-regional cost/benefit shares of new regional facilities periodically to adjust for impacts of any changes to the network. Although patterns of flow can change when there are changes to grid topology or the supply fleet or when a new PTO joins the expanded ISO, which could in turn modify the benefit shares for a given facility, several stakeholders commented that such recalculations would create serious uncertainty regarding future cost exposure for transmission upgrades. The ISO now proposes, therefore, that the cost allocation initially determined and agreed to should be maintained without later recalculation to reflect system changes.

12. The ISO also proposes to drop its prior proposal that PTO#2 and subsequent PTOs joining the expanded ISO should be allocated cost shares for new regional facilities that were approved prior to PTO#2 or the subsequent PTOs joining. Thus any regional facilities whose costs are allocated to the CAISO and PTO#1 when they were the only two sub-regions in the expanded BAA would essentially be treated similarly to “existing” facilities from the perspective of PTO#2 and others joining at a later date.

    There are mixed incentives with this approach, however. On the one hand, it removes a concern with the previous proposal that it could create a deterrent for PTO#2 to join the expanded BAA if it stands to be allocated a cost share for a project in whose planning and approval it had no involvement. On the other hand, if PTO#2 could avoid costs for projects approved through the regional TPP from which it receives substantial benefits, it would be PTO#2’s best strategy to stay out of the expanded ISO until after significant projects were approved, and then join after such approval. In this way PTO#2 could avoid paying a fair share for projects from which it actually receives significant benefits.

13. As a point of summary and clarification, as a result of the provisions above regarding cost recovery for existing and new facilities rated 200 kV and above, each sub-region would have a high-voltage sub-regional license plate TAC rate that recovers its TRR for all existing facilities plus its cost shares of any new facilities.

Second revised straw proposal – region-wide export charge

14. The ISO proposes to create a single region-wide export access charge (EAC) that would apply to all exports and wheel-through transactions out of the expanded ISO using high-voltage facilities. The rationale for the EAC is that having a different export rate for each sub-region would create incentives for parties who export from and wheel through the expanded ISO to distort their normal scheduling patterns and thereby cause inefficient grid congestion by seeking to export from the sub-region where the export rate is lowest. This is consistent with the practices of other multi-state ISOs and RTOs.

15. The new EAC would differ from today’s “wheeling access charge” (“WAC”) in that it would not apply to the non-PTOs within the CAISO system as the WAC does today, or to similarly situated entities within the service territories of the new PTO. Rather, the non-PTO entities would pay the sub-regional TAC for the sub-region in which they are located.

16. The ISO proposes to calculate the EAC as the load-weighted average of the sub-regional TAC rates. Thus if there are only two sub-regions and if TRR1 and TRR2 are the TRRs for sub-regions 1 and 2 respectively, and L1 and L2 are the corresponding internal loads, then the EAC rate would be:

    $$EAC = [TRR1 + TRR2] / [L1 + L2]$$

    This is the same formula the ISO presented in the August 11 working group meeting. Some stakeholders argued that the EAC should be higher, e.g., set at the maximum sub-regional TAC rate, while others said it should be lower, e.g., set at the minimum sub-regional TAC rate, or even zero. The intermediate approach of setting the EAC at the weighted average of the sub-regional TAC rates is consistent with the practice of other multi-state ISOs/RTOs.

17. The relationship between EAC revenues and TAC revenues and how they figure into the calculation of rates requires some explanation. For purposes of this proposal the ISO assumes that today's accounting approach will be retained for the expanded ISO. Today in the CAISO the WAC revenues in a given year are accumulated in a balancing account and applied as an offset to the TRR to be collected the following year.[10] For example, suppose EACrev1/1 = sub-region 1's share of EAC revenues in year 1, TRR1/2 = the total revenue requirements associated with sub-region 1's existing assets and its shares of new facilities for year 2, and L1/2 is sub-region 1's projected internal load for year 2, then its sub-regional TAC rate for year 2 would be:

    $$TAC1/2 = [TRR1/2 – EACrev1/1] / (L1/2)$$

    Similarly for sub-region 2, for year 2:

    $$TAC2/2 = [TRR2/2 – EACrev2/1] / (L2/2).$$

    In the formulations that follow and the numerical example below, we assume these "net" TRR values after subtracting the previous year's EAC revenues, and the TAC rates that result from these net TRR values, as reflected in the above formulas.

18. The ISO proposes that the EAC revenues be allocated to sub-regions in proportion to their TRRs. This is a departure from the approach presented at the August 11 working group meeting, where revenue shares were based on each sub-region's export volumes and sub-regional TAC rates. The two approaches are compared below using 2015 data. Under the present proposal, each sub-region's share would be:

    Sub-region 1 share = (total EAC revenues) * TRR1 / (TRR1 + TRR2)

    Sub-region 2 share = (total EAC revenues) * TRR2 / (TRR1 + TRR2).

19. In contrast, the approach presented at the August 11 working group meeting allocated EAC revenue shares in proportion to each sub-region's MWh volume of exports times its sub-regional TAC rate. This leads to the following shares:

    Sub-region 1 share = (total EAC revenues) * E1*TAC1 / (E1*TAC1 + E2*TAC2)

    Sub-region 2 share = (total EAC revenues) * E2*TAC2 / (E1*TAC1 + E2*TAC2).

Region-wide export charge example

The following example uses 2015 data for CAISO and PacifiCorp (PAC) because all the elements needed for the above calculations are available.

- CAISO is sub-region 1 (from ISO TAC rates, 10/19/15, on ISO web site)

[10] The following link to the CAISO web site shows how this works today. The item labeled "TRBAA" stands for "transmission revenue balancing account adjustment" and includes WAC revenues the PTO received in the previous year. See: http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffectiveJun1_2016.pdf

TRR1 = $2,071,851,575

L1 = 211,786,041 MWh

TAC1 = $9.78

- PAC is sub-region 2 (from Feb. 2016 TAC Options model posted for this initiative)

TRR2 = $291,318,198

L2 = 70,675,826 MWh

TAC2 = $4.12

- Weighted average EAC rate = $8.37
- Ezed = quantity of exports from CAISO to PAC = 1136 MWh
- E1 = quantity of exports on other CAISO ties = 1,854,995 MWh
- E2 = quantity of exports on other PAC ties = 34,996,078 MWh
- For comparison to the current system prior to forming an expanded BAA, based on the above numbers the CAISO export WAC revenues for 2015 were $18,158,079 which is (Ezed+E1) * TAC1.

In the expanded ISO consisting of CAISO and PAC, the quantity Ezed goes away because transactions between CAISO and PAC become internal transactions and will not be subject to the EAC. In addition, it is expected that a substantial portion of E2 will also go away because transactions that are currently exports and imports between PAC East and PAC West will become transactions internal to the expanded BAA and not subject to the EAC. At this time the ISO is not able to estimate the amount by which E2 will be reduced, so for illustration we look at three scenarios of zero, 25 percent and 50 percent reduction to the value of E2. Clearly these numbers are not intended to be an accurate prediction of export revenues under the future expanded BAA, but are offered to illustrate how the proposal would work and how the different allocation methods would distribute EAC revenues given the relative magnitudes of the key variables for CAISO and PAC. The table below shows the distribution of EAC revenues according to the two methods described above.

	100% E2	75% E2	50% E2
PAC export MWh	34,996,078	26,247,058	17,498,039
EAC revenues	$308,308,311	$235,111,110	$161,913,908
Export-weighted CAISO share	$34,451,739	$33,771,872	$32,548,809
Export-weighted PAC share	$273,856,572	$201,339,238	$129,365,099
TRR-weighted CAISO share	$270,301,807	$206,127,942	$141,954,078
TRR-weighted PAC share	$38,006,504	$28,983,167	$19,959,830
CAISO 2015 export revenues	$18,158,079	$18,158,079	$18,158,079

Other issues

GIDNUCR[11] or "generator interconnection driven network upgrade cost recovery" is an initiative currently in progress that deals with a narrow issue within transmission cost allocation. In the discussions on that initiative some stakeholders asked about the linkage between that initiative and the TAC Options initiative. The ISO's most recent straw proposal on GIDNUCR proposes that costs of network upgrades on a PTO's low-voltage system that come out of the generator interconnection and deliverability allocation procedures (GIDAP) be allocated in the same manner as high-voltage transmission facilities, i.e., through the high-voltage TAC rather than exclusively to the load within the interconnecting PTO's territory.

At present the outcome of the GIDNUCR initiative is still uncertain, as the ISO has not yet issued a draft final proposal. That said, if the current straw proposal is eventually filed by the ISO and approved by FERC, the same principle would apply throughout the expanded ISO BAA when it is formed. In terms of the TAC provisions proposed in the present initiative, the ISO expects that the costs of such an upgrade would be included in the sub-regional TAC rate for the sub-region in which the network upgrade is built.

11 See this page on the ISO web site for details: http://www.caiso.com/informed/Pages/StakeholderProcesses/GeneratorInterconnectionDrivenNetworkUpgradeCostRecovery.aspx

4. Responses to some stakeholder comments

A more complete summary of stakeholder comments and ISO responses is being prepared in parallel to this paper and will be issued as a separate document a few days after this paper is posted. This section identifies some specific ways in which this second revised straw proposal has considered and adopted stakeholder comments and suggestions.

Key terms, items (a), (e) and (f)

The ISO's May 20 previous proposal identified certain cases where a low-voltage facility (below 200 kV) could qualify for regional cost allocation. It also contained additional criteria for defining new and existing facility categories. Several stakeholders commented that those provisions were too complicated and contained ambiguities. The ISO believes the present provisions simplify the definitions and remove the ambiguities.

Key terms, item (g)

This provision responds to stakeholder comments to the effect that not every new PTO should be its own sub-region if it is already embedded within or substantially integrated with an existing sub-region. Also in response to stakeholder comments the ISO proposes to drop its previous proposal to allow the new embedded/integrated PTO a one-time choice to join the existing sub-region or form a new sub-region. The May 20 proposal allowed the possibility that an existing embedded transmission-owning utility (e.g., one of today's non-PTOs within the CAISO that later becomes a PTO) could become its own sub-region and thereby avoid paying its fair share of costs of the transmission system with which it is embedded/integrated. The present proposal addresses that concern.

Key terms, item (h)

This paragraph addresses a concern raised by some stakeholders that the ISO's use of a purely volumetric billing determinant for charging TAC would adversely affect customer classes with high load factors who have been paying for transmission at least partially if not entirely on a demand basis. The ISO explains that its use of a volumetric TAC rate in its settlement process does not constrain or predetermine the structure of transmission rates for end-use customers.

2nd Revised Straw Proposal, item 1

The point about non-PTOs partially addresses a stakeholder concern regarding the May 20 straw proposal for a single region-wide export charge (EAC), that a non-PTO would pay an export rate lower than the CAISO WAC rate it currently pays, resulting in a loss of export revenues and a shifting of costs. The present proposal closes off that possibility by subjecting non-PTOs to the sub-regional TAC rate. This addresses the concerns only partially, however. Some stakeholders noted that having an EAC rate that is lower than one or more of the sub-regional TAC rates would create an incentive for these non-PTOs to form or join a separate BAA rather than join the ISO, in order to pay the lower EAC rate on energy procurement from within the ISO rather than the higher sub-regional TAC rate it would pay as internal load. These two concerns seem to require opposite solutions, however, such that trying to improve on one makes the other worse.

Proposal, item 9(b)

This provision agrees with the comments of several stakeholders in favor of the “drivers first” cost allocation approach for reliability and policy projects. It also clarifies the meaning of “unintended benefits” as some stakeholders requested.