Transmission Access Charge Options for Integrating New Participating Transmission Owners

Straw Proposal

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Market & Infrastructure Policy

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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 US, plus the greenhouse gas reduction 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. PacifiCorp began its own assessment of the costs and benefits of becoming a full participating transmission owner ("PTO") and began working closely with the ISO to develop the details of the integration process.

A central policy element of expanding the ISO is the question of how to allocate the costs of the transmission assets that would comprise the expanded ISO's grid. This element is referred to as the Transmission Access Charge ("TAC"), which is the mechanism currently used by the ISO for this purpose. To address this policy element the ISO opened a 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 particular transmission facilities.[1]

In considering how best to address TAC structure for an expanded ISO, the ISO reviewed and provided information to stakeholders on the practices of other ISOs and RTOs, including the implications of various Federal Energy Regulatory Commission (FERC) orders and court decisions on this subject. One key principle these precedents reflect is the need to effectively align cost allocation with the benefits different geographic areas of the ISO/RTO receive from the transmission facilities in question. That said, FERC policy and court decisions also recognize that cost-benefit alignment is not an exact science, that different regions of the country should be allowed regional variation in how they approach transmission cost allocation, and that abrupt changes in rate impacts resulting from expanding ISOs/RTOs should be

[1] The ISO's web page for the TAC Options initiative contains the October 23, 2015 issue paper that opened the initiative, as well as written comments submitted by stakeholders and presentations the ISO used in public stakeholder meetings held to discuss the issue paper. See: http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionAccessChargeOptions.aspx

avoided. The ISO also recognizes the merits of the existing TAC structure and therefore the October 23 issue paper explained how it was originally designed, developed, and justified as compliant with these cost allocation principles.

The present straw proposal provides the ISO's initial thinking on TAC structure questions that were identified in the October 23 issue paper and to which stakeholders responded in their written comments. As a straw proposal it reflects the ISO's best thinking to date on these questions, but is not intended to be the final word. Section 3 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 in June for approval.

The ISO's straw proposal may be summarized as follows:

1. The costs associated with existing facilities – defined here to mean transmission facilities that are in service or have been approved by independent planning processes and are under development at the time a new PTO joins the ISO, i.e., any facilities that were not planned and approved under an integrated planning process for the expanded ISO BAA – 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 both sub-regions would continue to pay the same costs for existing facilities under an expanded ISO that they would have paid if they remained separate.
2. The costs associated with new regional facilities – defined here to mean facilities that are planned and approved under a comprehensive transmission planning process that would be established for planning transmission for the entire expanded ISO BAA, and that meet certain threshold criteria specified in this proposal – would be allocated to multiple sub-regions of the expanded ISO based on assessing the benefits each sub-region receives from each of the projects.
3. Methods for assessing the benefits for sub-regions are only initial proposals for discussion purposes, to be explored more thoroughly and compared with alternatives via stakeholder activities to occur over the coming months.

   On this item the ISO does, however, articulate an important basic principle: policy-driven regional transmission projects whose need may derive initially from one state's policy mandate will typically provide benefits across the entire region. The ISO does not support the approach, which some stakeholders have advocated, of allocating 100 percent of a policy-driven project's costs to the state whose policy first triggered the need for the project. To the contrary, the TAC structure and benefits methodology must consider a broad range of regional benefits and beneficiaries that result from policy-driven projects and allocate costs accordingly.

The next section of this paper introduces the subject and describes the scope of the initiative. Section 3 provides a proposed schedule for the initiative. Section 4 reviews key principles of transmission cost allocation that have been articulated in FERC orders and court decisions regarding other ISOs and RTOs. Section 5 provides a summary of the methods used by PJM, MISO and SPP to allocate the costs of new transmission facilities. Section 6 provides the details of the ISO's straw proposal. Finally, section 7 is a brief review of some of the major points raised by stakeholders in written comments submitted on this initiative. This is by no means an exhaustive compilation of stakeholder comments; interested readers may review all submitted comments on the initiative web page.

2. Introduction and Scope of Effort

The ISO's current TAC structure is a two-part rate charged to each MWh of internal load and exports for the purpose of recovering transmission revenue requirements (TRR) associated with owning, operating and maintaining ISO-controlled grid facilities. TRR associated with facilities rated 200 kV and above are recovered through a system-wide "postage stamp" rate (the high-voltage or "regional" rate), whereas TRR for facilities rated below 200 kV are recovered via specific rates charges to load within the service territory of each PTO; these are the PTO-specific low-voltage or "local" rates. The regional or high-voltage TAC is a formula rate that recovers the total TRR for all PTOs, which the ISO then distributes to each individual PTO based on its TRR approved by FERC. Through the regional and local TAC structure each PTO recovers its full FERC-approved cost of ownership, operation, and maintenance of all facilities under ISO operational control.

Although the current TAC structure was approved by FERC most recently in response to the ISO's filing of compliance with Order 1000, the ISO opened this initiative to consider whether the same structure would be appropriate if the ISO were to significantly expand its BAA by integrating a transmission owner outside the current boundaries as a new PTO, or whether some other structure would be more appropriate. The October 23, 2015 issue paper initiated a discussion of potential TAC structures the ISO could consider as alternatives to the current regional, high-voltage postage stamp rate, when one or more new entities join a regional ISO as new PTOs with load-serving territories.[2] This initiative focuses narrowly on recovery of the TRR associated with transmission facilities rated above 200 kV, with the assumption that each PTO would continue to recover its TRR for below 200 kV facilities from the load within its own service territory only, at a PTO-specific rate.[3] We also assume that we will retain the present TAC billing determinants, i.e., a per-MWh rate assessed to internal load and exports.

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2 This is in contrast to entities that become PTOs by building and then owning new transmission projects via the ISO's competitive procurement process, but do not have load service territories from which TRR would be recovered via the TAC.

3 The logic for limiting the inquiry to the regional TAC rate is the expectation that the desire for an alternative TAC structure would be driven mainly by a concern with how the regional rate might shift cost allocation between the load served by the ISO prior to a new PTO joining and the load that is served by the prospective new PTO once it becomes part of the ISO's expanded service territory. For example, if the new PTO places a large amount of costly high-voltage transmission under ISO operational control, the ISO's existing customers likely would be concerned about a significant increase in the regional TAC rate, whereas if the new PTO's system has relatively low high-voltage system costs and new infrastructure investment, its own existing customers would have the analogous concern. Moreover, FERC likely would find that lower-voltage facilities provide local benefits, and therefore would likely approve PTO-specific rates for such facilities.

Through this initiative the ISO intends to develop a TAC structure that will be applicable to any new transmission owning utility with a load-service territory that joins the ISO. At the same time, parties are well aware that PacifiCorp is actively considering such an action and may join the ISO in and expand the ISO BAA as early as the beginning of 2019.[4] This straw proposal therefore makes reference to PacifiCorp for illustrative purposes in numerous places. The reader should keep in mind, however, that the goal of the initiative is a broadly applicable TAC structure, not a TAC structure tailored to the specific circumstances of PacifiCorp.

Stakeholders asked several questions about the scope of this initiative in the comments they submitted on the October 23 issue paper and in the stakeholder meetings the ISO conducted in the subsequent months. The ISO clarifies here that the following topics are not within the scope of the present initiative.

1) A comprehensive assessment of the costs and benefits associated with expanding the ISO BAA. or of any particular entity joining such an expanded ISO;
2) Specific details of an expanded transmission planning process (TPP) and new resource interconnection process that would be created for an expanded ISO;
3) Possible changes to the allocation of TAC to exports;
4) Possible treatment of transmission service contracts that existed on the new PTO's system prior joining the ISO;
5) Review of the rules for determining load subject to TAC to reflect the effects of utility-side distributed generation;
6) Congestion revenue rights (CRRs).

Items 1), 2), 4), 5) and 6) will be addressed in separate activities during the coming year or early in 2017. Item 3) was raised last year in the context of possible market incentives to help relieve excess supply or over-generation the ISO expects to see under certain conditions due to the production of large amounts of solar energy on the grid. At this time item 3) is no longer being considered.

The ISO is discussing item 1) with stakeholders in the context of the studies being conducted over the next several months as directed by California Senate Bill 350.[5]

The ISO will address items 2) and 6) in an initiative on "implementation issues" beginning late in 2016 or early in 2017. Regarding item 2) several stakeholders have suggested that the TAC structure and the design of an expanded TPP are closely inter-related and should be addressed together. The ISO believes that it is appropriate and preferable to address the TAC structure first and the TPP later. As the reader will see in the straw proposal described in this paper, the TAC provisions will specify cost allocation rules and methods for assessing the benefits and

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[4] The Memorandum of Understanding between the ISO and PacifiCorp outlines the intent of the parties to negotiate and file a transition agreement with FERC that would establish a binding commitment to move towards integration; it is available at: http://www.caiso.com/Documents/NewParticipatingTransmissionOwnerMemorandum_Understanding.pdf

[5] For more information please see: http://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx

beneficiaries of transmission projects that the later TPP design effort will have to conform to. In other words, the TAC structure initiative will set the rules and the TPP design will provide the process for implementing the rules. In particular, this means that the TAC structure needs to be defined and approved by FERC in order for the TPP design effort to figure out how to structure the planning process and specific studies to produce results that satisfy the rules for cost allocation.[6]

PacifiCorp and the ISO are addressing item 4) collaboratively through a review of all existing contracts on PacifiCorp's system. A joint stakeholder meeting on this subject was held in Portland on January 27, 2016, and additional meetings will be held this year.

Item 5) was raised by some stakeholders who argued that the allocation of TAC to gross load on the system should be reconsidered to reflect the growth of distribution generation that serves some of the load locally with less reliance on the transmission system. The ISO will include this topic in the scope of phase 2 of the energy storage and distribution energy resources (ESDER 2) initiative, which will begin in the near future.

Simultaneous with this straw proposal the ISO is posting a spreadsheet model that enables stakeholders to estimate the impacts on TAC rates of additional new PTOs joining the ISO and new regional transmission facilities approved for cost allocation across the expanded ISO BAA. The spreadsheet provides projected cost data associated with "existing" transmission as defined above, as well as load projections on an annual basis through 2029 for the existing ISO BAA and for PacifiCorp. This is the same data used in the October 23 issue paper to generate illustrative TAC structure scenarios. The spreadsheet model enables stakeholders to add two additional new PTOs with hypothetical transmission cost and load data, and see how the TAC structure scenarios are affected. The model also allows stakeholders to identify hypothetical new regional transmission projects, specify their allocations of benefits across the sub-regions and see these impacts on TAC rates. The spreadsheet model and a detailed user guide are posted on the web page for this initiative.

3. Initiative Schedule

Date	Activity
October 23, 2015	Post issue paper
October 30	Stakeholder conference call
November 13	Submit written comments on issue paper
December 15	Stakeholder workshop in Salt Lake City

[6] The ISO expects that the start of an expanded TPP would occur at the same time as the effective integration date of the first new PTO. For example, if the first new PTO joins effective January 1, 2019, then the TPP that begins in the first quarter of 2019 would be the first implementation of the expanded TPP and would deliver its first comprehensive transmission plan in March 2020, assuming the 15-month time frame of today's ISO TPP remains the same.

January 11, 2016	Stakeholder workshop in Folsom
February 10	Post straw proposal
March 1	Stakeholder meeting in Folsom
March 10	Submit written comments on straw proposal
Tentative: March 21-23	Stakeholder working group on benefit assessment methodologies
April 7	Post draft final proposal
April 21	Stakeholder meeting
May 10	Submit written comments on draft final proposal
June 28-29, 2016	Submit final proposal to ISO Board of Governors for approval

4. Transmission Cost Allocation Principles

FERC precedent and Order Nos. 890 and 1000 provide the basis for considering possible alternatives. Through these precedents and orders FERC articulated two significant principles for allocating the costs of new transmission facilities: (1) rates should reasonably align cost allocation for any given transmission facility or group of facilities with the distribution of benefits from the facilities; and (2) cost allocation is not an exact science. FERC therefore recognizes the need for, and will allow, an ISO or RTO flexibility in allocating costs for new transmission facilities as long as there is reasonable cost-benefit alignment, adequate incentives to construct new transmission, and general support among the participants across the ISO or RTO territory.[7]

In Order No. 1000, FERC specified six principles of cost allocation for new transmission projects:[8]

1. Costs must be allocated in a way that is roughly commensurate with benefits.
2. Costs may not be allocated involuntarily to those who do not benefit.
3. A benefit to cost threshold may not exceed 1.25.[9]
4. Costs may not be allocated involuntarily to a region outside of the facility's location.
5. The process for determining benefits and beneficiaries must be transparent.

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7 See *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559; *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

8 See *Cal. Indep. System* Operator, 143 FERC ¶ 61,057, PP 297-305 (2013) (finding that the ISO's current regional access charge largely complies with the Commission's costs allocation principles).

9 This principle refers to the threshold criterion a transmission planning entity applies to approve an economic transmission project; in effect, it says that the threshold cannot be so high as to prevent approval of projects whose benefits are shown to exceed their costs.

6. A planning region may choose to use different allocation methods for different types of projects.[10]

Tellingly, half of the six principles (one, two, and four) are variations on a theme: costs can only be allocated to those who benefit from the new transmission facilities, and they should be allocated in proportion to benefit. This standard can be difficult to meet because it requires more precise specification, particularly in a large region. The common adages of "high-voltage transmission benefits everyone," "enhanced reliability," and "more access to renewables" may not be sufficient justifications for FERC, and especially, reviewing courts.

For example, in a 2013 court decision, MISO was able to prevail in justifying a postage-stamp rate for new transmission facilities that meet the criteria to be "multi-value projects" by providing detailed data showing that "there would be cost savings of some $297 million to $423 million annually because western wind power is cheaper than power from existing sources, and that these savings would be 'spread almost evenly across all Midwest ISO Planning Regions.'"[11] However, the same court in 2009 and again in 2014 rejected FERC's approval of a postage-stamp rate for PJM's new high-voltage facilities across all of PJM based on load ratio. The court found that FERC and PJM had failed to justify its cost allocation with commensurate benefits: "[S]ome of the benefits of the new high-voltage transmission facilities will indeed 'radiate' to the western utilities, as the Commission said, but 'some' is not a number and does not enable even a ballpark estimate of the benefits of the new transmission lines to the western utilities."[12] The court went on to state: "[T]he lines at issue in this case are part of a regional grid that includes the western utilities. But the lines at issue are all located in PJM's eastern region, primarily benefit that region, and should not be allowed to shift a grossly disproportionate share of their costs to western utilities on which the eastern projects will confer only future, speculative, and limited benefits."

With respect to the costs of *existing* transmission facilities, FERC has found that a license plate rate design is reasonable because it reflects the prior investment decisions of the individual transmission owners to support load within the zones of those individual transmission owners. FERC has found that replacing a license plate rate design for existing transmission facilities could result in abrupt and unjustified cost shifts and dislocations. In 2009, the same federal court that rejected FERC's approval of a postage-stamp rate for PJM's new high-voltage facilities affirmed FERC's decision to allow PJM to retain license plate rates for existing transmission facilities, citing favorably FERC's rationale that, even for those existing transmission facilities that had not yet been fully paid for, "there would be no economic basis for shifting any part of their costs to other [PJM] members, because [the PJM transmission owner]

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10 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 612 *et seq.* (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

11 *Illinois Commerce Commission v. FERC*, 721 F.3d 764, 774 (7th Cir. 2013).

12 *Illinois Commerce Commission v. FERC*, 756 F.3d 556, 560 (7th Cir. 2014).

did not expect when it built the facilities that any part of their cost would be defrayed by anyone besides its customers."[13]

The ISO can draw a number of important conclusions from these cases. First, policy considerations, including the expectation of utilities when making investment decisions and the need to avoid unjustified cost shifts associated with the formation or expansion of ISOs or RTOs support the retention of license plate rates for existing transmission facilities. Second, ISOs must proffer a defensible assessment of the distribution of benefits from new transmission facilities. Third, geographic distance of load from a transmission facility may reduce the benefits that load receives from the facility, even in the realm of high-voltage transmission. In particular, ISOs and transmission owners must be able to demonstrate commensurate benefits across a region when justifying any new postage-stamp rate.

In some cases – generally for new transmission facilities – FERC has approved the use of phase-in periods in some cases for moving to a new TAC structure. That is, the new PTO joins in year X with a specified "end-state" TAC structure to be applied in year X+Y, and with specified incremental annual adjustments that move gradually from the year X rate structure to the year X+Y rate structure. In the ISO's history, there was such a phase-in period for existing facilities with Y = 10 years when the ISO was first established.

Most recently, FERC approved Entergy's integration into MISO with a five-year transition period for the allocation of the costs of new transmission facilities.[14] During this time, MISO would apply its existing transmission planning process to the Entergy region to identify network upgrades, but the cost of network upgrades approved *before or during* the transition period would not be shared between MISO and Entergy. However, after the transition period, the costs of any Multi-Value Project that had been approved during the transition period would be allocated system-wide incrementally over eight years (increasing 12.5% per annum) until a system-wide rate is achieved.[15] After Entergy's integration into MISO, the costs of Entergy's existing facilities will be paid by load in the Entergy zones.[16]

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13 *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 474 (7th Cir. 2009).

14 *Midwest Independent Transmission System Operator, Inc.*, 139 FERC ¶ 61,056 (2012).

15 MISO originally proposed a four-year phase-in, but FERC rejected that period as unfounded. *Midwest Independent Transmission System Operator, Inc.*, 137 FERC ¶ 61,074 (2011).

16 *ITC Holdings Corp., et al.*, 143 FERC ¶ 61,257 at PP 122-27 (2013) (approving the use of license plate pricing for existing transmission facilities within Entergy Operating Companies' proposed transmission pricing zones upon Entergy's integration into MISO).

5. Other ISO/RTO Practices for New Facilities

PJM, MISO and SPP – which would be the best analogs for an expanded ISO – all employ PTO-specific or "license-plate" rates for allocating costs of pre-existing or "legacy" transmission.[17] For new projects, however, they employ the regional flexibility FERC has afforded and use different allocation methods. As such, cost allocation practices for new projects vary among and within the various ISOs/RTOs, and their practices vary from the simple and straightforward (SPP's highway/byway system) to the highly complex (PJM's DFAX methodology). Below we describe three main approaches based on these entities' compliance with FERC Order 1000.

PJM

PJM employs two cost allocation methodologies for new reliability and economic extra high-voltage facilities.[18] These are facilities planned to operate at 500 kV and above, double-circuit 345 kV facilities, equivalent HVDC facilities, and lower voltage facilities required in connection with any of the foregoing. For economic projects, 50 percent of project costs are allocated to its pricing zones using a postage-stamp rate, and the other 50 percent of costs are allocated to load zones that benefit based on their expected share of decreased LMP payments.

For reliability projects, PJM allocates 50 percent of costs to its pricing zones on a postage-stamp rate, and the other 50 percent of costs are allocated based on PJM's solution-based distribution factor allocation methodology, known as DFAX. The intent of DFAX is to calculate how much each load zone benefits from a new transmission facility based on the flow across the facility caused by serving additional load in the load zone. On this approach PJM has faced years of litigation, including the two federal court cases discussed above: the choice between postage-stamp cost allocation and the DFAX-based "beneficiary pays" methodology has been continually challenged at FERC and in the courts, including an ongoing FERC proceeding where parties are challenging the application of the DFAX methodology to reliability projects.[19] The 50/50 hybrid discussed above was established in PJM's Order 1000 compliance filing for projects approved after 2012. Allocation for older projects is still subject to litigation.

For lower voltage facilities, 100 percent of the projects' costs are allocated according to these methods: economic projects are allocated entirely in accordance with LMP benefits, and reliability projects to the zones that are projected to use the new facilities, as determined through DFAX analysis.

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[17] NYISO also employs a license plate transmission rate design for existing facilities.

[18] PJM does not have a separate public policy category of transmission facilities.

[19] *See Delaware Public Service Comm'n v. PJM Interconnection LLC*, Docket Nos. EL15-95-000, ER15-2563-000 (not consolidated).

MISO

MISO employs three cost allocation methodologies for new high-voltage facilities. The costs of Baseline Reliability projects are allocated to the local pricing zone.[20] For "market efficiency projects" (MEPs), i.e., economic projects, MISO allocates 20 percent of costs on a postage-stamp basis, and 80 percent to the affected "local resource zone," which is generally a MISO state, based on MISO's calculation of how future adjusted production cost savings resulting from the MEP will be distributed across these local resource zones.

MISO employs a third cost allocation methodology for "multi-value projects" ("MVPs"), which are facilities at or above 100 kV designed to "address energy policy laws and/or provide widespread benefits across the MISO footprint." In nearly every case, these are transmission lines designed to reach previously untapped wind pockets. MISO allocates MVPs on a postage-stamp basis. Although MISO has faced legal challenges to a postage-stamp rate for MVPs, it prevailed in a 2013 court decision as explained in section 4 above.

SPP

SPP employs what is arguably the simplest cost allocation scheme, and one that has resulted in less litigation than certain cost allocation issues in PJM and MISO. SPP uses what it calls the highway/byway method for new high-voltage facilities. All "highway" facilities—above 300 kV—are allocated via postage-stamp rate. "Byway" facilities—between 100 kV and 300 kV—are allocated 1/3 via postage-stamp rate and 2/3 via license plate rates; however, these ratios switch where the byway facilities serve designated wind resources across multiple pricing zones (i.e., 2/3 postage-stamp and 1/3 license plate).

6. ISO Straw Proposal

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

Key terms and concepts

The ISO introduces the terms listed below solely to help make this straw proposal as clear as possible. The ISO does not intend to suggest formal definitions for purposes of new tariff provisions. If necessary, such terms will be developed at a later time with stakeholder review and input.

a) "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.

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

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[20] Before Order No. 1000, for reliability projects MISO allocated 20 percent of costs on a postage stamp basis and 80 percent of costs to affected pricing zones based on line outage distribution factors.

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

d) "Existing facilities" means an entity's transmission assets that are either in service at the time of joining the ISO or have been approved in the entity's separate planning process and have scheduled in-service dates.

e) "New facilities" means transmission elements that are planned and approved via an integrated TPP for the expanded ISO BAA. This category could include a project that was being considered as an "inter-regional" project prior to the new PTO joining the ISO, and that is subsequently adopted and approved via the expanded TPP.

f) Currently the CAISO is considered a "region" in the terminology of FERC Order 1000. Once PTO#1 joins, the expanded ISO BAA will become the new "region" for Order 1000 purposes. After that the current CAISO system, as well as PTO#1 and each subsequent new PTO with a load service territory that joins, would be considered a "sub-region" under this proposal.

g) This proposal applies only to high-voltage (>200 kV) transmission facilities. We assume that TRR for low voltage (<200 kV) expanded ISO controlled grid facilities will be recovered on a PTO-specific basis, comparable to "local" facilities in the CAISO TAC structure today.[21]

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 peak-demand based charges.

Straw proposal overview

The logic of this straw proposal can be described in terms of a sequence of key questions and the answers to them.

First, should we retain the existing CAISO TAC structure when PTO#1 joins? That is, should we merge the TRR for all facilities rated > 200 kV across the entire expanded ISO BAA and collect the total revenues via a postage-stamp "regional" rate charged to all loads and exports? This straw proposal answers this question in the negative. FERC's acceptance of the existing CAISO TAC was based on its agreement that the regional postage-stamp rate effectively aligned cost allocation with benefits in the existing ISO footprint, in accordance with FERC's cost allocation principles. The ISO believes that although the benefit-cost alignment is accurate for the existing CAISO BAA, the simple 200 kV criterion would improperly allocate costs if applied to merge the TRR for all existing facilities in a significantly larger geographic area.

Second, could we simply change the voltage level threshold for the regional rate to a higher value and thereby retain a structure similar to the existing CAISO TAC with minimal revision? This idea was illustrated as "Alternative 1" in the October 23, 2015 issue paper for this initiative.

21 In some instances a lower voltage facility placed under ISO operational control may qualify for regional cost allocation; see the definition of "new regional facilities" below.

Here again the ISO believes that this would not be appropriate, for reasons explained in the discussion of the next question.

Third, in specifying a new TAC structure, should the TRR for “existing facilities” as defined above be collected in the same manner as the TRR for “new facilities”? The ISO believes that TRR for these two classes of facilities should be recovered differently in an expanded ISO BAA. Specifically, the ISO proposes that TRR for existing facilities be collected on a sub-regional basis, using sub-regions as defined above (CAISO, PTO#1, PTO#2, etc.). The main argument for this approach is that both areas – the current CAISO and PTO#1 – have 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 both areas benefit, while keeping the existing facility costs separate means that neither area experiences a positive or negative impact that would occur if some costs of existing transmission were merged and reallocated.

Once we answer the third question in this way, costs would be allocated on a regional basis across the entire expanded ISO BAA only for new regional facilities (as defined below) that are planned and approved through an integrated TPP for the expanded ISO BAA. In the cases of other ISOs/RTOs FERC has agreed that this approach meets their standards for aligning costs and benefits.

Fourth, how should the ISO specify criteria for deciding which new facilities are eligible for regional cost allocation and assess the distribution of benefits on which to base cost allocation for the new regional facilities? This question is answered below.

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, though here the “license plates” would be sub-region specific; not PTO-territory specific.

   The rationale for this provision is three-fold. First, both areas have 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 both areas benefit, while keeping the existing facility costs separate means that neither area experiences a positive or negative impact that would occur if some costs of existing transmission 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 costs for existing facilities that they otherwise would have paid. FERC has agreed that this approach meets their standards for aligning costs and benefits.

   Second, there is no consistent voltage-only bright-line criterion for allocating cost across a geographically large BAA. For example, it would be difficult to show that a facility in San

Diego area provides load ratio share benefits to customers in Utah based solely on its voltage level, even if the facility is rated at 500 kV, without further demonstration of benefits.

Third, this approach mitigates the risk of incentivizing a potential new PTO to develop costly new high-voltage transmission for its area with the expectation that some of its costs can be transferred to other members of the expanded ISO upon its joining.

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, 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 qualified PTO will be considered a new sub-region for TRR allocation purposes, and 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. This proposal contemplates that each new PTO would be considered a new sub-region, without regard to size or geographic location. The ISO nonetheless appreciates that circumstances, both general and specific, may be relevant to the applicability of this rule. Therefore, the ISO welcomes comments on whether a one-size fits all definition of sub-region is appropriate for this proposal, potential criteria for considering exceptions to this principle, and methods for treating the exceptional cases.

Straw proposal – new facilities

5. A "new" facility – i.e., a facility planned and approved through the expanded ISO TPP – will be considered for regional cost allocation if it: (a) is rated > 300 kV, or (b) interconnects two or more sub-regions or upgrades an existing interconnection, regardless of voltage level, or (c) creates a new or upgrades an existing intertie with a BAA adjacent to the expanded ISO BAA, regardless of voltage level. A facility that meets at least one of these criteria will be referred to as a "new regional facility." New regional facilities that are eligible for regional cost allocation would be open for competitive solicitation under this proposal, subject to any exception that may be accepted by FERC. Costs of new facilities on the expanded ISO controlled grid that do not meet any of these criteria will be recovered entirely from the sub-region in which they are connected.
6. The TRR for a new regional facility will be allocated to each sub-region based on the benefits that sub-region receives from the facility.
7. Methods for calculating benefits to sub-regions are still under consideration. Thus, the methods suggested here are intended as a starting point for discussion. The ISO will review these and other possible methods carefully between now and the stakeholder meeting on

March 1, and is considering holding a full-day stakeholder working group to discuss methods for determining benefits from a new regional transmission facility.

The ISO's initial proposals are to use a power-flow approach similar to the PJM DFAX method for reliability projects, and an economic production cost approach for economic projects. Both methods involve technical studies currently used by ISO planners in the context of the TPP and GIDAP. This follows what FERC approved for PJM, which uses the DFAX method for reliability projects. The CAISO recognizes that there are pending issues at FERC regarding whether DFAX would be applied to all types of reliability projects. For economic projects PJM bases benefits on projected reduction in LMPs for each grid area.

For evaluating the distribution of benefits resulting from public policy projects the ISO proposes a basic principle at this time but does not offer a specific method of analysis. The basic principle is that the method adopted should assess benefits to each sub-region irrespective of the particular state whose policy mandate was the originating motivation for the project. Some stakeholders have argued that a state whose policy drives the original need for a project should be allocated 100 percent of the cost of the project. Stakeholders may have taken this position with respect to existing facilities or all facilities, but in any case, the ISO does not agree with this approach for new facilities. Rather, if the project meets the criteria stated above for a "new regional facility" it has the potential to provide benefits to all sub-regions of the expanded ISO. The ISO believes that the method we adopt should fairly and transparently assess such benefits, and costs should be allocated accordingly. That said, the ISO is not yet ready to address questions of which benefits to consider and how to measure them, and requests stakeholders to engage in these questions and offer their ideas and suggestions.

8. The ISO would recalculate cost/benefit shares for the sub-regions annually to adjust for impacts of any changes to network topology.

   This is important because patterns of flow can change when there are changes to grid topology or the supply fleet, in which case the distribution of benefits for the facility in question could change as well.[22]

9. PTO#2 and subsequent PTOs joining the RISO will be allocated cost shares for new facilities according to the above methodologies, even if those new facilities were approved prior to PTO#2 or the subsequent PTO joining the RISO. This essentially means that all new regional facilities approved under the expanded ISO TPP from the time the expanded TPP begins with the joining of PTO#1 will potentially become the cost responsibility of all members, regardless of when they join, based on the assessment of benefits they receive from the facilities.

   There are two important justifications for this approach. First, if PTO#2 or a subsequent new PTO could avoid costs for projects approved through the expanded ISO TPP, it would be PTO#2's best strategy to stay out of the ISO until after significant projects were approved,

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22 For this reason, PJM annually refreshes its DFAX analyses for reliability projects.

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. Second, the use of a transparent benefits assessment methodology means that PTO#2 will not pay a portion of the costs of the facility if PTO#2 does not receive benefits.

Note that the above proposal for allocating costs of new regional facilities is designed to allocate 100 percent of costs based on a benefits assessment and would not apply postage-stamp rates automatically for certain project types, as the other ISOs/RTOs do in many cases. The ISO clarifies here that it is not opposed to using postage stamp rates if these are determined to be appropriate based on their reasonable alignment with the distribution of benefits. Indeed, postage stamp rates could greatly simplify cost allocation for certain types of new facilities. Postage stamp rates by design automatically allocate costs on a load-ratio-share basis, which in many cases could be reflective of the share of benefits a sub-region receives. Moreover, we may find as we pursue potential methodologies that the costs of applying more complex approaches outweigh the incremental increase in accuracy. The ISO will therefore try to assess whether and for which types of new facilities a postage stamp rate could reflect the distribution of benefits as well or nearly as well as a more complex method, and will remain open to such TAC structures.

7. Major Themes Raised in Stakeholder Comments

The purpose of this section is to identify the major themes and issues stakeholders raised in their written comments in response to the October 23 issue paper and in discussions at stakeholder meetings thereafter. This section does not provide an exhaustive summary of stakeholder comments; readers interested in more details can find all the submitted comments on the ISO web page for this initiative.

Alignment of cost allocation with benefits. Stakeholders generally agreed that alignment of costs with benefits is necessary, and that it is important to focus on measurable benefits and capture them accurately and completely. They had varying views, however, on how best to achieve alignment. With regard to existing facilities there were two main stakeholder positions. One group argued that the costs of all existing facilities above 200 kV should be combined and recovered through a postage-stamp rate for the expanded BAA. This would be a straightforward application of the ISO's existing TAC structure, and was illustrated using ISO and PacifiCorp data as "Baseline 2" in the issue paper. Some parties favored this approach based on their assessment that there has not been a demonstrated need to change the existing TAC structure. Another group argued that the costs of existing facilities should be kept completely separate and recovered via separate "sub-regional" rates for the current ISO BAA and for the new PTO. This approach was illustrated using ISO and PacifiCorp data as "Baseline 1" in the issue paper.

Factors to consider in TAC structure. The issue paper listed several factors that could be considered in designing the TAC structure: new versus existing facilities; electrical characteristics; geographic scope; purpose of the project; which sub-regions benefit; when and under what planning process the facility was approved. All factors were identified as important by at least some stakeholders. Other factors mentioned were whether the project increases the transfer capacity between sub-regions, and concern about potential "rate shock" an area might experience upon joining the expanded ISO. To address the last point several stakeholders suggested using a multi-year phase-in period for merging the costs of existing facilities. This approach was illustrated using ISO and PacifiCorp data as "Alternative 2" in the issue paper.

Voltage criterion for cost allocation. Many stakeholders supported the use of a voltage-level criterion for determining cost allocation, comparable to the ISO's existing TAC structure. One appealing attribute mentioned was the simplicity of this approach. However, many parties said that voltage level by itself may not accurately align costs and benefits over the entire expanded BAA. Several parties who favored the simple voltage criterion also favored merging the costs of all high-voltage facilities and simply applying the ISO's existing TAC structure to both existing and new transmission facilities.

Type of transmission facility. Parties expressed varying views on the appropriateness of the facility type as a cost allocation criterion. Those who favored using it seemed to suggest that it would be a simple proxy for determining the distribution of benefits. Some of those opposing it said that determining the benefits and beneficiaries of a facility should be paramount, and that type of facility is too coarse a criterion to capture the distribution of benefits. Others opposed it as part of their broader opposition to any change to the ISO's existing TAC structure.

In-service date and planning process. Many, though not all, stakeholders favored differential cost allocation treatment of transmission facilities based on either their in-service date (i.e., before or after the integration of the new PTO into the expanded ISO), or the planning process under which they were approved (i.e., under separate pre-integration planning processes or under a new integrated planning process). Several of those in favor of such a distinction made the point that the separate planning processes had approved certain facilities with the expectation that their costs would be recovered from their own BAAs or planning regions, so maintaining this cost allocation would be appropriate. In addition, some parties expressed concern that a potential new PTO would approve costly new transmission facilities in its separate planning process with the expectation of shifting some of the costs to the current ISO participants, and stated that such situations should be precluded. Some parties supported a requirement that all new facilities be approved under an integrated TPP comparable to the ISO's current TPP and, at the same time, supported rolling all costs of existing facilities into a postage-stamp rate for the expanded BAA. Most parties who opposed in-service date or planning process as a criterion did so as part of their broader opposition to departing from the ISO's existing TAC structure.

Sub-regional rates. The ISO introduced the idea of sub-regional rates in the issue paper, and illustrated it using ISO and PacifiCorp transmission revenue requirements and load data, treating the current ISO BAA and PacifiCorp as separate sub-regions. Many parties voiced support for sub-regional rates specifically with regard to allocating the costs of existing facilities. Parties opposed to sub-regional rates, particularly for existing facilities, stated that there needs to be demonstration that this approach fairly aligns cost allocation with benefits.