Transmission Access Charge Options for Integrating New Participating Transmission Owners

Issue Paper

October 23, 2015

Market & Infrastructure Policy

Table of Contents

1. Introduction and Scope of Effort 3
2. Initiative Schedule 4
3. Transmission Cost Allocation Principles 4
4. Other ISOs and RTOs 6
5. Considerations 8
6. Options Being Considered 8
7. Examples 10
8. Observations 14
9. Appendix. Calculated TAC rates for the baseline scenarios and alternatives 15

Transmission Access Charge Options for Integrating New Participating Transmission Owners

1. Introduction and Scope of Effort

The ISO's current transmission access charge (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 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 PTO-specific rates charges to load within the PTO's service territory (low-voltage or "local" rates). The regional TAC is a formula rate that recovers the total TRRs for all participating transmission owners (PTOs), which the ISO then distributes to each individual PTO based on its TRR approved by the Federal Energy Regulatory Commission (FERC). Through the regional TAC 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 now believes it is prudent to consider whether the same structure would be appropriate if the ISO were to significantly expand its balancing authority area into a regional ISO by integrating a transmission owner outside the current boundaries as a new PTO, or whether some other structure would be more appropriate. This paper initiates a discussion of potential TAC structures the ISO could consider as alternatives to the current regional, high-voltage postage stamp rate,[1] when one or more new entities join a regional ISO as new PTOs with load-serving territories.[2] For this paper we assume 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.

---

[1] This paper assumes there could be justification for such an alternative and potential challenges to the current TAC structure, but notes that at this point there is no reason to think it would be unjust, unreasonable, or unduly discriminatory to apply the ISO's current TAC structure to all new PTOs.

[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 regional 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 low-voltage facilities only provide local, not regional, benefits, and therefore would likely approve PTO-specific rates for such facilities.

The next section of this paper provides a proposed schedule for this initiative. The subsequent two sections then provide a review of FERC orders and decisions regarding allocation of TRR and the practices of the other ISOs and Regional Transmission Organizations (RTOs). Sections 5 and 6 suggest important considerations for the design of a TAC structure and describe high-level conceptual design options. Section 7 then provides numerical projections of possible future TAC rates under illustrative, hypothetical TAC structures, using actual TRR data and forecasts for the current ISO footprint and PacifiCorp, assuming that PacifiCorp becomes a PTO in 2019. Section 8 offers some observations and Section 9 provides a table of the projected TAC rates under different hypothetical TAC structures illustrated in section 7.

2. Initiative Schedule

Date	Activity
October 23, 2015	Post issue paper
October 30	Stakeholder conference call
November 13	Submit written comments on issue paper
Various dates to be determined	ISO proposals, stakeholder meetings and written comments
June 2016	Submit any proposed tariff changes to TAC structure to ISO Board of Governors

3. Transmission Cost Allocation Principles

FERC precedent and order nos. 890 and 1000 provide the basis for considering possible alternatives. These precedents are based on two significant principles for FERC: (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 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.[4]

In Order No. 1000, FERC specified six principles of cost allocation for new transmission projects:[5]

1. Costs must be allocated in a way that is roughly commensurate with benefits.

[4] 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).

2. Costs may not be allocated involuntarily to those who do not benefit.
3. A benefit to cost threshold may not exceed 1.25.[6]
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.
6. A planning region may choose to use different allocation methods for different types of projects.[7]

Tellingly, half of the six principles (one, two, and four) are variations on a theme: costs can only be allocated to those who benefit, 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 its "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.'"[8] However, the same court in 2009 and again in 2013 rejected FERC's approval of a postage-stamp rate for PJM's 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."[9] 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."[10]

---

5 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).

6 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.

7 *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).

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

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

10 *Id*. at 566. The court summarized its criticism of FERC in stating that FERC had "an aversion to cost-benefit analysis." *Id*. at 563.

The ISO can draw two important conclusions from these cases. First, ISOs must proffer an articulable, plausible cost-benefit analysis.[11] Second, distance and transfer capacity between service territories matter, 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. An objective of this initiative, then, is to consider what if any changes to the ISO's high voltage TAC might be considered consistent with existing orders and precedent, without suggesting it would be unjust and unreasonable to move forward with the current regional TAC structure as the ISO expands regionally by integrating new PTOs.

4. Other ISOs and RTOs

While most of the ISOs and RTOs employ license-plate rates for pre-existing or "legacy" transmission, they employ their regional flexibility and ability to use different allocation methods for new projects. As such, cost allocation practices for new projects vary among and within the various ISOs/RTOs, and their practices vary from the straightforward (SPP's highway/byway system) to the highly complex (PJM's DFAX methodology).

The table below provides a concise summary of some of the RTOs' cost allocation methods following Order No. 1000.[12]

---

[11] The court also faulted FERC for "ignor[ing] the need to discount future to present value in order to value a future benefit" with the limited data it provided. *Id*. at 563.

[12] ISO/RTO cost allocation methods are in somewhat constant flux, especially following Order No. 1000. This table is simplified for illustrative purposes only, and should not be used as a precise reference for what other ISOs/RTOs now have in place.

	PJM	MISO	SPP	ISO-NE
High-Voltage	<u>*Reliability Projects:*</u> 50% allocated on postage-stamp basis to pricing zones based on load ratio share. 50% allocated to identified beneficiaries using DFAX. <u>*Economic Projects:*</u> 50% allocated on postage-stamp basis to pricing zones based on load ratio share. 50% allocated to identified beneficiaries by analyzing expected decreased LMP payments for LSEs.	<u>*Reliability Projects:*</u> ◦ ≥ 345 kV: 20% allocated system-wide and 80% allocated to affected pricing zones based on Line Outage Distribution Factors. ◦ Multi-Value Projects: Regional, high-voltage transmission (≥ 100 kV) facilities designed to “address energy policy laws and/or provide widespread benefits across footprint.” Allocated via postage stamp. <u>*Economic Projects:*</u> ◦ Market Efficiency Project: ≥ 345 kV, cost $5 million or more, and meet certain benefit criteria. ◦ 20% of the costs are allocated on a system-wide basis and 80% of the costs are allocated to one of the 9 “local resource zones,” which generally is the local state. ◦ Market efficiency projects must reduce congestions and the benefits must be 1.25 times greater than the costs.	"Highway": Facilities ≥ 300 kV are allocated via postage stamp rate. "Byway": Facilities 100 kV to 300 kV: ◦ 1/3 allocated via postage stamp rate. ◦ 2/3 allocated via license plate rate. ◦ Ratios switch when serving designated wind resources across zones.	Facilities ≥ 115 kV are allocated via postage stamp rate based on monthly zonal coincident peak loads. “Market Efficiency Transmission Upgrades” not needed for reliability but with greater system benefits than costs are allocated the same as reliability upgrades. Also must be ≥ 115 kV.
Low-Voltage	Neither Regional Facilities nor Necessary Lower Voltage Facilities.[13] Based on identified beneficiaries using DFAX.[14]	Below 345 kV and non-MVP: license plate rate to zone where costs are incurred.	Below 100 kV: zonal/license plate rate to zone where costs are incurred.	Lower voltage and non-METU economic projects: license plate rate to zone where costs are incurred.

13 For economic and reliability projects, PJM distinguishes “Regional Facilities,” all facilities above 500 kV and double-circuit facilities above 345 kV, and “Necessary Lower Voltage Facilities,” which are below the regional voltage requirements but must be constructed to support Regional Facilities, from other transmission facilities

14 PJM’s DFAX methodology identifies beneficiaries using solution-based distribution factors, i.e., how much existing facilities benefit from the new facility.

5. Considerations

Based on FERC decisions for other ISOs and RTOs, there are a number of factors that would be appropriate to consider for allocating costs of any given transmission facility between current ISO PTOs and one or more new PTOs.

1. Is it a new or existing facility? (type)
2. What are the facility's electrical characteristics? (voltage)
3. What is the geographic scope of the project; e.g., system, regional, local? (scope)
4. What is the purpose of the project; e.g., reliability, economic, policy? (purpose)
5. Which zones or sub-regions benefit from the project? (benefit criteria)
6. When was the facility approved? (transition)
7. Under what planning process was the facility approved? (procedure)
8. What happens upon the new PTO's withdrawal? (exit)

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 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.[15] 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.[16]

6. Options Being Considered

Through this initiative the ISO intends to consider a broad range of options that could align with the principles and considerations described above, including the option of no change to the existing TAC structure. The options described in this section and illustrated with numerical examples in the following section are intended only as examples to stimulate discussion, not as ISO proposals. The ISO invites stakeholders to submit suggested approaches in their written

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

16 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).

comments in response to this issue paper. The ISO will consider stakeholder suggestions and any issues and concerns raised in the comments as we develop the initial straw proposal and subsequent proposals later in this initiative.

Baselines for comparison

For the purpose of examining the effects of alternative TAC structures, each option will be compared against two baselines, which represent the two simplest design options as well as the endpoints of the range between maintaining complete separation of TRR recovery and full integration of the new PTO into the current TAC structure. Within that range this initiative will consider several more customized options.

- Baseline 1: The potential new PTO either does not join the ISO, or joins the ISO and maintains completely separate TRR recovery for all existing and currently planned transmission facilities, at all voltage levels. The existing ISO PTOs remain under the current ISO TAC structure.
- Baseline 2: The potential new PTO joins the ISO and is immediately incorporated into the current TAC structure, with a single postage-stamp rate for all existing and planned facilities above 200 kV, and PTO-specific rates for all facilities below 200 kV.

Options with a phase-in period

In principle a phase-in period could be used for transitioning to any intended end-state TAC structure. The simplest example for purposes of discussion – though not necessarily the most desirable – is to use a phase-in or transition period to arrive at the current TAC structure. That is, apply a PTO-specific high voltage ("HV") rate for the new PTO initially, with a transition period to the postage stamp HV rate for all PTOs within the expanded ISO system. This would provide a transition period of several years to mitigate any rate-shock concerns that may arise from widely disparate TRRs at the time the new PTO first joins the ISO.

Other phase-in options are possible in combination with the next category of options.

Options with a breakdown of the HV category

One simple version of this would be to break down the HV category (> 200 kV) into sub-categories; for example, "HV-1" contains facilities between 200 kV and 300 kV, while "HV-2" contains facilities above 300 kV. We would then apply a postage stamp rate for the 345 kV and 500 kV facilities in the HV-2 category, and create "sub-regional" rates for facilities between 200 kV and 300 kV in the HV-1 category. This approach would reflect the rationale that 345-500 kV facilities benefit the entire expanded ISO system, whereas facilities in the 200-300 kV range would provide benefits primarily to sub-regional groups of PTOs. Under this approach the current ISO PTOs could form the initial sub-region when a new PTO joins, thereby maintaining the current structure for the present ISO footprint. This approach thus would create a three-tiered TAC structure. For example, customers in PG&E's territory would pay (a) the postage stamp rate for all 345-500 kV facilities in the newly expanded ISO balancing authority area, (b) the sub-regional rate for all 200-300 kV facilities in the combined PG&E-SCE-SDG&E area, and (c) the local rate for PG&E facilities below 200 kV.

A variation of this approach would be to break down the HV category by type of transmission project – reliability, policy or economic – and then assess which areas of the expanded ISO territory receive the benefits of each facility and allocate costs accordingly.

Another variation would be to break down the HV category by the date and/or the process by which the project was approved. For example, we might use different cost allocation for (i) pre-existing facilities and new facilities approved prior to opening negotiations to join the ISO, (ii) new facilities approved while in negotiations but before the formation of a joint comprehensive planning process, and (iii) new facilities approved via the new joint TPP.

Finally, a TAC structure could combine two or more of these structural ideas into a proposed approach. For example, the TAC structure could break down the HV category into sub-categories, and then apply a phase-in period for combining TRR for certain sub-categories and no phase-in for other sub-categories – either combining them immediately upon joining or keeping them separate forever. The examples in the next section illustrate both approaches.

7. Examples

This section provides two examples of possible TAC structures for the scenario in which Pacificorp (PAC) is integrated as a new PTO in the ISO effective at the beginning of 2019. Example 1 applies a breakdown of the HV category into two sub-categories, the HV-1 (< 300 kV) and HV-2 (> 300 kV) structure described above, effective immediately upon integration in 2019. Example 2 uses the same breakdown and adds a five-year phase-in period from 2019 to 2023. The impacts are illustrated with graphs; the numerical TAC values are provided in a table at the end of this paper.

For developing these examples, the annual regional (greater than 200 kV) transmission revenue requirements for the current ISO area were estimated based on the methodologies employed in the transmission revenue requirement model employed in the 2014-2015 Transmission Plan and more fully documented in that plan. This model includes the impacts of all ISO-approved transmission capital projects, with an annual minimum of $250 million in new capital established for reliability projects. Further, capital maintenance costs are estimated at 2 percent of gross plant, and escalations are projected for operations and maintenance. No further public policy-driven or economic transmission projects are assumed beyond those already approved.

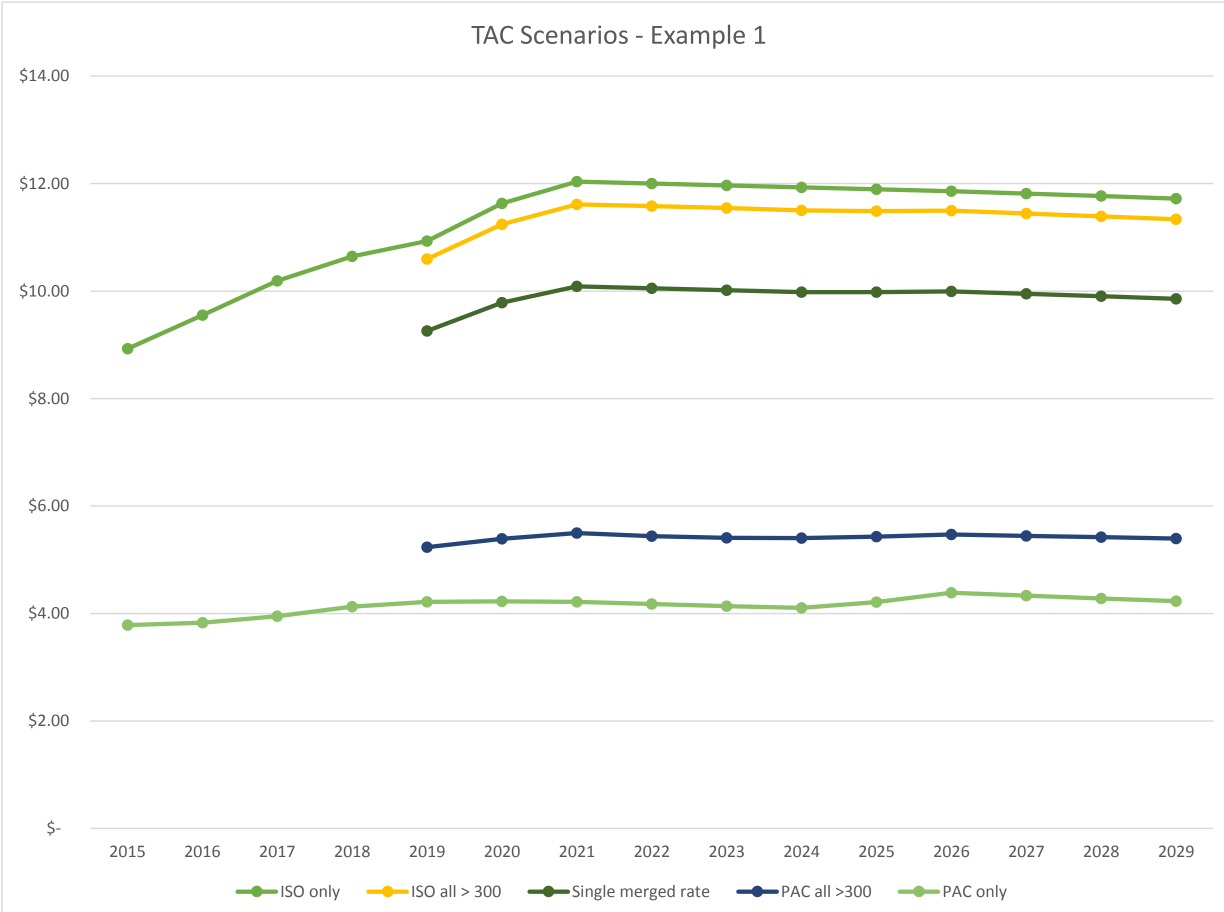
The PacifiCorp annual transmission revenue requirement was similarly projected utilizing the ISO's model and incorporating PacifiCorp initial year annual revenue requirement information and projected capital costs supplied by PacifiCorp. This includes a projection of capital expenditures over the study period, including capital maintenance and all capital projects identified thus far by PacifiCorp, with the exception of two segments of the Gateway project. Specifically, Segment D (Windstar to Populus) and Segment F (extending approximately 400 miles from the planned Aeolus substation in southeastern Wyoming into the Clover substation near Mona, Utah) were not included in the revenue requirement projections. These segments are designed to access Wyoming wind generation. As the ISO has not developed or included additional transmission reinforcements to complement these additions, and the need for new upgrades to access additional renewable generation will be the subject of future planning decisions, it would be inconsistent to include the Gateway D and F costs in this comparative analysis at this time.

Note that a change of $1 per MWh in the TAC rate translates to approximately $235 million per year for existing ISO customers and $70 million per year for PAC customers.

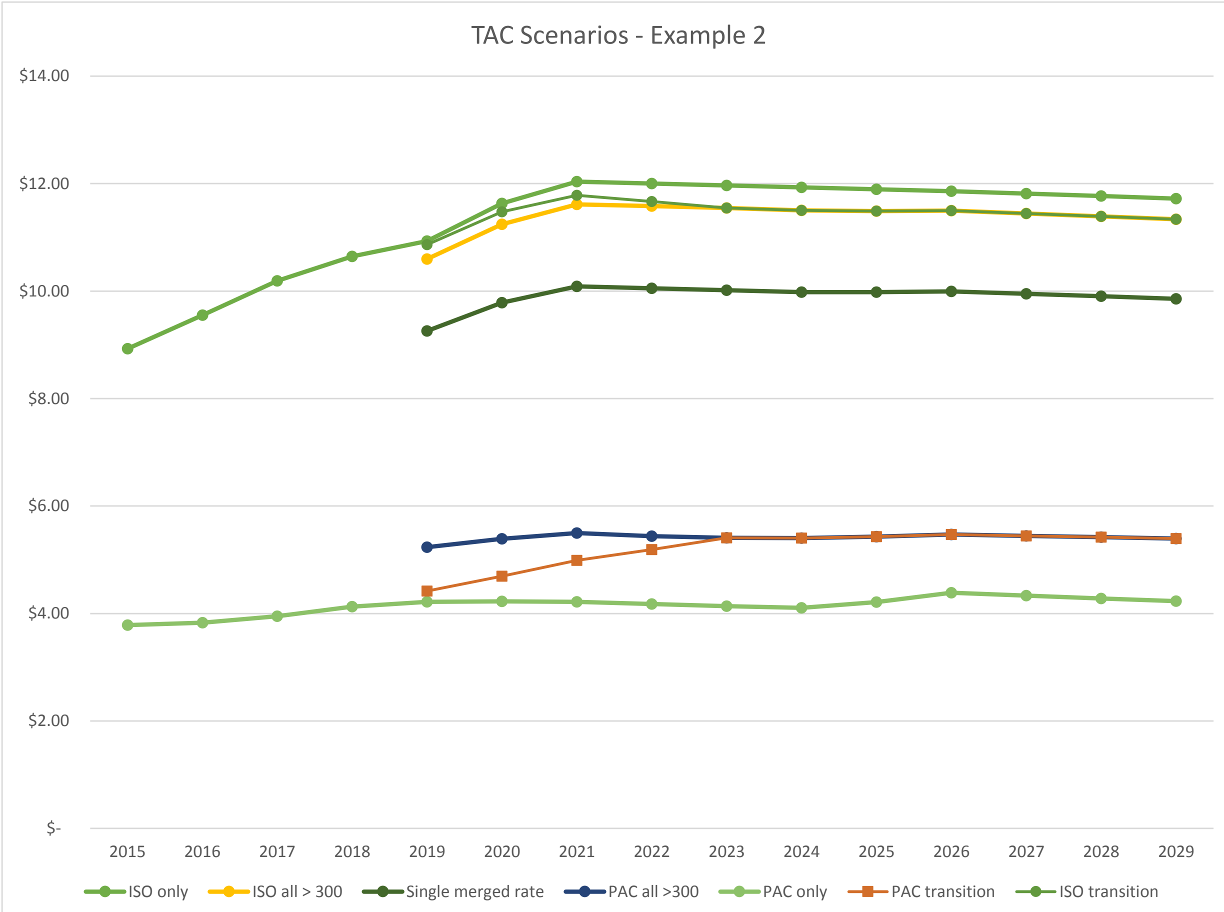
Example 1. The graph below illustrates a simple breakdown of HV into two categories – below 300 kV and above 300 kV – with no use of a phase-in period. The below 300 kV facilities are kept separate for cost recovery – i.e., one rate for all existing ISO PTOs, and a separate rate for PAC – while the above 300 kV are combined into a single postage stamp rate. The lines on the chart represent, from top to bottom (in $ per MWh of demand):

- TAC rates for the existing ISO footprint, with no combining of facility costs with PAC (baseline 1)
- TAC rates for the existing ISO footprint, with costs of > 300 kV facilities combined
- Common TAC rates for the entire expanded ISO footprint, with costs of all HV facilities > 200 kV combined (baseline 2)
- TAC rates for PAC, with costs of > 300 kV facilities combined
- TAC rates for PAC, with no combining of facility costs with the existing ISO PTOs (baseline 1).

This example illustrates the substantial transmission rate shock PAC customers would experience if we were to immediately incorporate PAC into the existing ISO TAC structure (baseline 2, combining all costs for > 200 kV facilities). It also shows that the rate shock is dramatically reduced by limiting the merger of costs to only those facilities rated > 300 kV, in this case the 345 kV and 500 kV facilities. In this case the existing ISO customers get a relatively small TAC reduction, while the increase to PAC customers is still significant but less dramatic than under baseline 2.



Example 2. This example uses the same breakdown of the HV category and adds a five-year phase in, so that 20 percent of the > 300 kV costs are combined into a postage stamp rate in 2019, and another 20 percent each year until 100 percent of the > 300 kV costs are combined in 2023 and thereafter. The results are shown in the graph below, which retains all the lines in the previous graph and adds two new lines for the phase-in scenario.



Formulas for the baselines and alternatives

The formulas for the above examples are expressed in terms of the following component quantities, calculated annually from 2019 through 2029:

- TRR[ISO-HV] = TRR for all facilities >200 kV for current ISO BAA
- TRR[ISO-200] = TRR for facilities between 200 kV and 300 kV for current ISO BAA
- TRR[ISO-300] = TRR for facilities >300 kV for current ISO BAA
- Load[ISO] = Forecast of total MWh of internal load and exports for current ISO BAA
- TRR[PAC-HV] = TRR for all facilities >200 kV for PAC BAA
- TRR[PAC-200] = TRR for facilities between 200 kV and 300 kV for PAC BAA
- TRR[PAC-300] = TRR for facilities >300 kV for PAC BAA
- Load[PAC] = Forecast of total MWh of internal load and exports for current PAC BAA

Baseline 1

Regional TAC rate for current ISO BAA = TRR[ISO-HV] / Load[ISO]

Regional TAC rate for PAC = TRR[PAC-HV] / Load[PAC]

Baseline 2

Regional TAC rate for current ISO BAA = Regional TAC rate for PAC

= (TRR[ISO-HV]+TRR[PAC-HV]) / (Load[ISO]+Load[PAC])

Alternative 1

Regional TAC rate for current ISO BAA

= TRR[ISO-200] / Load[ISO] + (TRR[ISO-300]+TRR[PAC-300) / (Load[ISO]+Load[PAC])

Regional TAC rate for PAC

= TRR[PAC-200] / Load[PAC] + (TRR[ISO-300]+TRR[PAC-300) / (Load[ISO]+Load[PAC])

Alternative 2

Regional TAC rate = X * (Alternative 1 rate) + (1-X) * (Baseline 1 rate)

Where X = 0.2, 0.4, 0.6, or 0.8 for 2019, 2020, 2021 or 2022 respectively, and X = 1.0 for 2023 and beyond.

8. Observations

There are many variations on the above examples that are potentially viable. In the case of PAC, it is clear that bringing PAC immediately into the existing TAC structure would impose significant rate shock on PAC customers (the “merge all >200 kV” line in both examples, representing baseline 2). The variation used in example 1 mitigates some rate shock by using relatively simple voltage-based sub-categories of the HV transmission category. Further variations, such as using a phase-in period as in example 2, may result in TAC rates that are somewhere in between the stand-alone rates of baseline 1 and those of example 1.

9. Appendix. Calculated TAC rates for the baseline scenarios and alternatives

The annual TAC rates used to develop the above graphs are contained in the following table, in the same order as the lines in example 2, top to bottom.

Units are $/MWh	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
ISO Separate Rate	$8.93	$9.55	$10.19	$10.65	$10.93	$11.63	$12.04	$12.00	$11.97	$11.93	$11.90	$11.86	$11.82	$11.77	$11.72
ISO rate - transition to >300 kV merge					$10.87	$11.48	$11.78	$11.67	$11.55	$11.50	$11.49	$11.50	$11.45	$11.39	$11.34
ISO rate - merge >300 kV					$10.60	$11.25	$11.61	$11.58	$11.55	$11.50	$11.49	$11.50	$11.45	$11.39	$11.34
Merge all >200 kV					$9.26	$9.79	$10.09	$10.05	$10.01	$9.98	$9.98	$9.99	$9.95	$9.90	$9.85
PAC rate - merge >300 kV					$5.23	$5.39	$5.50	$5.44	$5.41	$5.40	$5.43	$5.47	$5.45	$5.42	$5.40
PAC rate - transition to >300 kV merge					$4.42	$4.69	$4.99	$5.19	$5.41	$5.40	$5.43	$5.47	$5.45	$5.42	$5.40
PAC Separate Rate	$3.79	$3.83	$3.95	$4.13	$4.22	$4.23	$4.22	$4.18	$4.14	$4.11	$4.21	$4.39	$4.33	$4.28	$4.23