How Transmission Cost Recovery Through the Transmission Access Charge Works Today

Background White Paper

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Market & Infrastructure Policy

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1. Introduction

Within the broad subject of transmission cost recovery, ISO initiatives over the past year have focused on two matters. First, the "Transmission Access Charge Options" initiative developed a proposal for allocating transmission costs over an expanded regional balancing authority area, to be applied if the ISO expanded its current area by integrating one or more new participating transmission owners (PTOs) with load service areas. That initiative concluded with the posting of the ISO's "Draft Regional Framework Proposal" on December 6, 2016, which proposed resolutions to several cost allocation elements and identified a number of issues and details for further discussion with stakeholders if and when this and other regional expansion initiatives are reopened.

Second, the "Review TAC Wholesale Billing Determinant" initiative considered whether it would be appropriate to revise the current method of billing transmission costs in the ISO's wholesale settlement process—specifically the use of end-use customer metered load (*i.e.*, Gross Load[1] as defined in the ISO tariff) in PTO service areas to bill the volumetric transmission access charge (TAC)—to reflect potential benefits from distribution-connected generation in reducing or avoiding some transmission costs. The ISO settlement process also uses another volumetric rate, the wheeling access charge (WAC), to bill transmission charges for wheeling power to loads off the ISO controlled grid, including Non-PTO[2] loads and exports, but consideration of billing to these entities was not within the scope of the 2016 review. The June 2, 2016 issue paper and written stakeholder comments received in that initiative revealed a number of complex and controversial issues that would require more in-depth consideration and allocation of resources than the ISO could dedicate or most stakeholders would support at that time. The ISO therefore closed that initiative in September 2016 without reaching a conclusion and

1 The term "Gross Load" may be somewhat confusing because some parties understand gross load to be the physical end-use consumption before its measurement at the meter is reduced by any behind-the-meter supply. Thus, in more common understanding one might say "metered load" or "net load" equals "gross load" minus "behind-the-meter supply." To be consistent with the ISO tariff definition, however, in this paper "Gross Load" means metered load. See ISO Tariff Appendix A for the exact definition.

2 Non-PTOs are load-serving entities (LSEs) that receive power from the ISO grid but are not PTOs. All of these entities were electric utilities or other wholesale entities operating in the ISO footprint prior to the establishment of the ISO. Non-PTOs may own or have contractual entitlements to transmission facilities, but have chosen not to execute the Transmission Control Agreement and become PTOs. See the detailed discussion in section 3.5.

promised to open a more comprehensive assessment of TAC structure in 2017. The new initiative, called “Review TAC Structure,” will begin in the summer of 2017 and include the full scope of issues identified in the 2016 effort. The ISO will propose a detailed scope for that initiative when it posts an issue paper to kick off the initiative.

One observation resulting from these prior initiatives, particularly the second one, was the need for a clear and complete understanding of how transmission cost allocation and recovery within the ISO works today, including the role and function of the ISO’s wholesale TAC and WAC settlement. The purpose of this background white paper is to provide that background for the upcoming “Review TAC Structure” initiative. Through this paper the ISO intends to provide a detailed explanation of how transmission cost recovery works today, from the filing of transmission revenue requirements (TRRs) at FERC by the PTOs to the collection of the TRRs through the TAC and WAC charges and the remission of those revenues to the PTOs, and to the collection of retail transmission rates from end-use customers.

Section 2 of this paper provides a general overview of the transmission cost recovery process. Section 3 then looks at each of the PTO TRR filings and retail rate setting approaches in more detail and explains how their processes differ. Section 4 then provides some observations and conclusions. The ISO tariff sections relevant to this subject are Section 26 and Appendix F Schedule 3.

2. Overview of Transmission Cost Recovery

AB1890 directed the creation of the ISO and required the ISO to develop within two years a transmission rate methodology based on principles including an equitable balance of costs and benefits. The ISO also had to define those transmission facility costs, if any, to be rolled into the transmission service rate and spread equally among all ISO transmission users, and those transmission facility costs, if any, which should be specifically assigned to a specific utility’s service area. Those AB 1890 requirements form the basis of the cost recovery provisions described in this background paper.

The transmission system operated by the ISO, referred to as the ISO Controlled Grid, is comprised of transmission facilities owned, and contractual transmission entitlements held, by PTOs and for which the PTOs have turned over operational control of those facilities and entitlements to the ISO through the Transmission Control Agreement. These PTOs recover the costs associated with owning, maintaining, and physically operating these facilities and paying for the entitlements, reduced by the transmission revenue balancing account, non-volumetric standby demand charges and revenue from existing contracts that pre-date ISO operations, from ISO load and exports (*i.e.*, ratepayers). The amount of costs each PTO is authorized to recover annually is referred to as its transmission revenue requirement (TRR), which must be approved by FERC.

Most of the PTOs—the investor-owned utilities (IOUs) and those municipal utilities that have turned over their transmission facilities and entitlements to ISO operational control—have transmission and distribution service areas,[3] which means they have end-use transmission and distribution service customers who pay their share of the costs through retail transmission charges. For such load serving PTOs, FERC also approves a Gross Load figure that is used in determining the TAC rates, as described below. PTOs that do not have a service area are typically (but not exclusively) independent or non-utility transmission developers whom the ISO selected in its competitive solicitation process to build specific transmission facilities approved in the ISO's transmission planning process (TPP). The TRRs of these PTOs become part of the total amount of costs that must be recovered, but these entities do not have their own retail customers who pay a share of the costs.

Each PTO's TRR for ISO Controlled Grid facilities and entitlements is divided into a "Regional" or high-voltage revenue requirement (R-TRR) associated with transmission facilities rated 200 kV and higher, and a "Local" or low-voltage portion (L-TRR) for transmission facilities rated below 200 kV.[4] Currently, the ISO combines the R-TRRs of all PTOs into a total sum and divides by the total Gross Loads of all load-serving PTOs to produce a uniform "postage stamp" regional TAC rate (R-TAC) charged to all utility distribution companies (UDCs) and metered subsystems (MSS) serving customers in the ISO area and exports from the ISO area. The regional WAC rate (R-WAC) is calculated the same way to be equal to the R-TAC rate. The ISO then remits the appropriate amount of TAC and WAS revenues to each PTO in accordance with ISO Tariff Appendix F. In contrast, each of the PTOs with Local facilities[5] collects its own L-TRR from customers served over its Local facilities.[6] Customers using an IOU's Local facilities can include customers of municipal utilities that are PTOs or Non-PTOs located within the IOU's PTO service area.

The general process for transmission cost recovery is as shown in Figure 1. The process will differ somewhat for the following types of PTOs.

A. IOU PTOs (PG&E, SCE, SDG&E). These entities provide the majority of transmission facilities that comprise the ISO Controlled Grid. Their distribution service areas may also contain several municipal utilities, some of which are PTOs and some non-PTOs. If an embedded entity is a PTO, it pays the R-TAC and, if applicable, the L-TAC, as well as costs for any existing transmission contracts (ETCs) with the IOU in whose area it is

3 The fact that a PTO and its affiliated utility distribution company (UDC) are responsible, respectively, for providing transmission and distribution service in a specific service area does not mean that the utility is responsible for retail energy supply to all end-use customers. Many end-use customers may receive retail energy from non-utility retail suppliers while receiving transmission and distribution services from the utility.

4 The "Local" transmission facilities discussed in this paper are facilities rated below 200 kV that are under the Operational Control of the ISO. These are different from lower-voltage distribution system facilities that IOUs and municipal utilities use to deliver electricity to retail end-use customers. This paper does not address the recovery of costs for such distribution-level facilities.

5 The three investor-owned utilities (IOUs), Trans Bay Cable, and the Valley Electric Authority all have low-voltage or local transmission facilities in the ISO controlled grid.

6 There is an exception to the direct collection of L-TRRs by the PTOs: the ISO collects the WAC on all exports from the ISO system, including exports that utilize local facilities, and remits the revenues to the appropriate PTOs.

embedded. If the embedded entity is a Non-PTO, it pays the WAC or, if applicable, any ETC-related costs. Thus, the IOU PTOs recover a portion of their TRRs from their internal municipal utilities, in addition to the distribution service customers of their affiliated distribution companies, and exports that utilize their intertie facilities.

B. Municipal PTOs (Anaheim, Azusa, Banning, Colton, Pasadena, Riverside, Vernon) and a rural electric association (VEA). These entities' R-TRRs are included in the total ISO system R-TRR and recovered by the ISO via the postage-stamp R-TAC and R-WAC rates. Except for VEA, these entities do not have Local transmission facilities in the ISO Controlled Grid. In addition, the municipal PTOs are electrically connected to SCE, so if they were connected to SCE's Local transmission they would be subject to SCE's L-TAC (as well as the R-TAC collected by the ISO). However, none of these entities is connected to Local facilities.

C. Non-utility or non-load-serving PTOs. (DATC Path 15, Startrans IO, Trans Bay Cable, Citizens Sunrise).[7] These entities do not have load service areas. They are companies that have built and are currently responsible for maintaining and physically operating transmission facilities in the ISO Controlled Grid. Therefore, the costs associated with their Regional transmission facilities comprise a portion of the total R-TRR for the system. In addition, a non-utility PTO can have an L-TRR that is combined and collected with the L-TRR of the IOU in whose service area the facilities are located.

D. In addition to the above types of PTOs, there are several "Non-PTOs" within the ISO balancing area. These entities either do not have transmission facilities or have not turned over operational control of their transmission facilities to the ISO Controlled Grid. Therefore they do not recover their own transmission costs, if any, through the TAC or WAC, and they pay the WAC for their use of the ISO system rather than the TAC. See section 3.5 for details regarding Non-PTOs.

The process shown in Figure 1 is summarized in the following steps:[8]

1) Each of the PTOs (groups A, B, C above) files its proposed TO Tariff and TRR with FERC. The TRR is usually specified in an appendix to the PTO's TO Tariff, and can include forecasted O&M and A&G expenses, as well as forecasted capital additions. A

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[7] Prior to changes in the ISO tariff associated with FERC Order 1000, the ISO tariff allowed entities that were not PTOs with load service areas inside the ISO area to build transmission and receive cost recovery through the TAC. Following the ISO's reform of its TPP in 2010 and the tariff changes to implement FERC Order 1000, the ISO tariff now defines an "Approved Project Sponsor" to be the entity that has been selected through the ISO's competitive solicitation process to build and own transmission facilities approved in the TPP to become part of the ISO controlled grid. An approved project sponsor that is not a PTO with a load service area will also be considered a non-utility PTO for the purposes of this background paper; although, at this time none of these projects has yet been completed and included in TAC or WAC rates. Thus, the term "non-utility PTOs" is used here to refer to all PTOs that do not have load service areas from which transmission charges are collected, without regard to whether that PTO's project was authorized prior to Order 1000 or through the competitive solicitation process adopted in 2010.

[8] Complete up-to-date TAC rates are posted here: http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffectiveMar1_2017.pdf

FERC ruling determines the TRR amount each PTO may collect in rates. The rate cases and the FERC rulings for the load-serving PTOs also address the forecasted Gross Load quantities from which the TRRs will be recovered. For the IOU PTOs, FERC also approves each PTO's retail transmission rate structure for the various customer classes and the exact amounts of its retail transmission rates. That said, the IOUs generally align the retail transmission rate structures they file at FERC with the CPUC's overall retail rate policies prior to making their FERC filings. For the municipal PTOs, FERC rules on the TRR amounts and Gross Load, and the municipal utility's governing authority determines its retail transmission rates.

2) In its TRR filing to FERC, each PTO with both Regional and Local facilities proposes a breakdown of its TRR into Regional and Local amounts (R-TRR and L-TRR) based on voltage level and ISO tariff Appendix F, Schedule 3, Section 12. The FERC ruling determines the approved R-TRR and L-TRR amounts.
3) The R-TRR amounts for all PTOs are combined to comprise the R-TRR amount for the ISO system, which is divided by the total Gross Load for the ISO area to produce the R-TAC and R-WAC rates the ISO collects through its settlement process in the form of the postage-stamp R-TAC and R-WAC. The ISO settlement process collects the R-TAC from utility distribution companies (UDCs) and metered subsystems (MSS) within the IOU and Municipal PTOs (groups A and B above), and the R-WAC from the Non-PTOs (group D). The ISO remits revenues from both the R-TAC and R-WAC to the PTOs, including the non-load-serving PTOs (groups A, B, and C, above). As noted earlier, the ISO also collects the L-WAC from Non-PTOs that use local take-out points and exports that use local intertie facilities, but this detail is not shown in Figure 1.
4) Except for the L-WAC amounts just mentioned that the ISO collects, each of the load-serving PTOs collects its L-TRR amount through its own process. The three IOU PTOs collect their L-TRR from the distribution service customers that use their local facilities, and for which the IOU PTOs have transmission cost billing responsibilities.[9] Among the Municipal PTOs (group B, above) only VEA has Local facilities, and it collects its L-TRR from its distribution service customers. The ISO collects all L-TRR for exports and Non-PTOs that use local take-out points and remits the revenues to the appropriate PTOs.
5) Each IOU PTO UDC or other distribution utility or LSE then recovers the transmission charges from its retail end-use customers that use its distribution facilities (and for which the UDC has transmission cost billing responsibilities). Each entity has its own retail transmission rate structure that is determined per the process described in section 3.[10]

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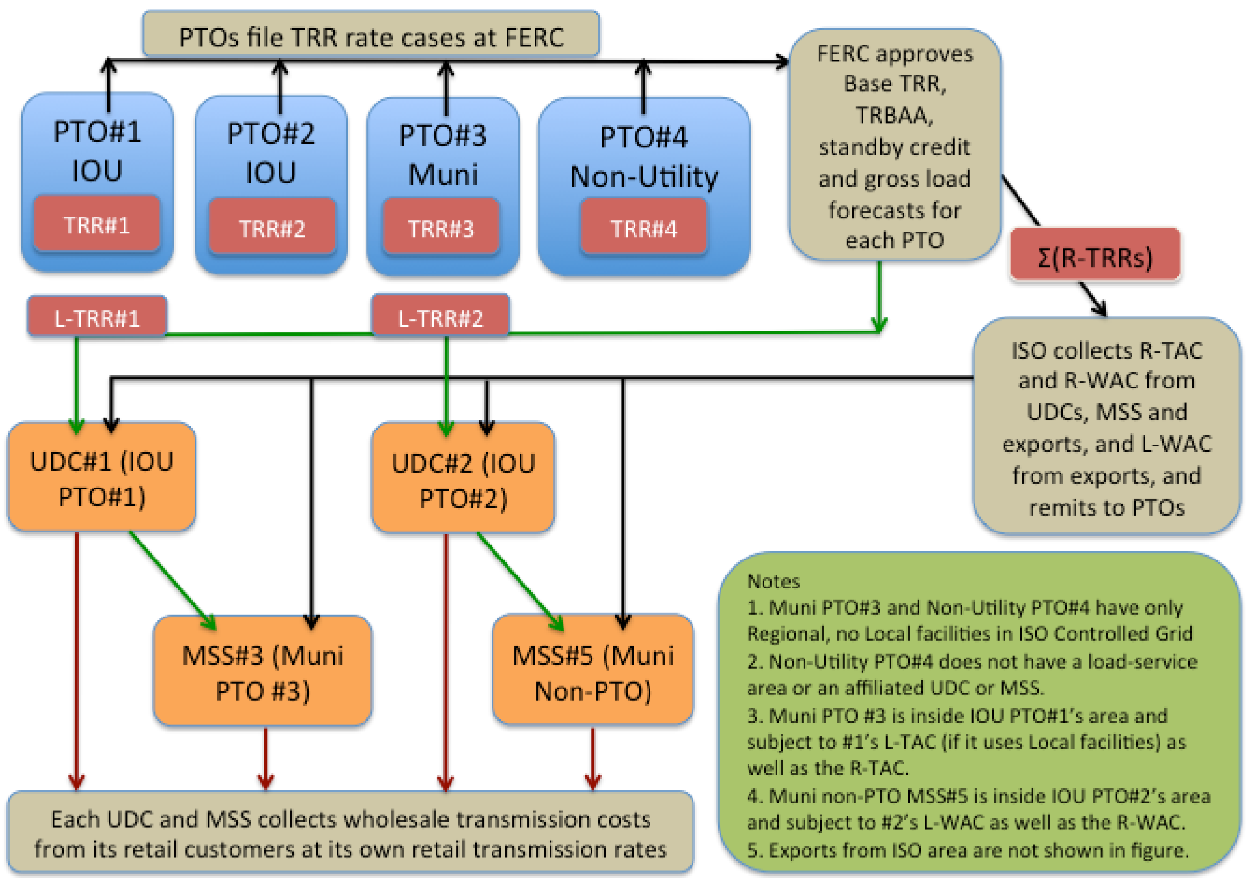
[9] In the IOU service areas, a non-utility retail supplier (direct access electric service provider (ESP) or community choice aggregator) may elect to do its own billing, in which case it will collect the transmission charges from its retail customers and remit the funds to the PTO. To date, however, these non-utility suppliers all use the PTO/UDCs' billing services.

[10] An exception is CDWR, which does not have retail or end-use electric customers and does not set retail electric rates. CDWR recovers the costs of serving its pumping loads from water users.

At this point certain differences arise among the entities described above. The next section describes the differences in more detail, but we emphasize one important point here. For most municipal utilities, both PTO and Non-PTO, the utility is still vertically integrated and therefore is the only retail electric service provider (*i.e.*, the load-serving entity or LSE) in its service area and is also the distribution service provider. In contrast, the IOUs and some municipal utilities allow multiple LSE types, in addition to themselves, to provide retail electric service to end-use customers, including retail direct access providers (electric service providers or ESPs) and community choice aggregators (CCAs). All end-use customers served by a given IOU's or municipal utility's distribution facilities (within the same rate class) currently pay the same retail transmission rate, irrespective of the customer's choice of its preferred retail supplier.

Figure 1. Simplified Overview of Transmission Cost Recovery

Direction of arrows indicates flow of charges from origination of costs for each PTO to FERC approval to assessment of TAC charges by ISO (Regional) and PTOs (Local) to billing of retail charges to end-use customers by UDCs and MSS. The diagram is intentionally simplified and leaves out many details that are explained in the text.



3. Detailed Descriptions of the Cost Recovery Process

This section explains in greater detail how the process for determining TRRs, TAC, and WAC rates, and retail rates works for the various PTO types.

3.1. IOU PTO with Stated Rates: PG&E

PG&E has historically sought FERC approval of its TRR and gross load in a “stated rates” filing (rather than “formula rates,” discussed below). This means that PG&E’s TRR rate case at FERC includes the complete cost information and supporting analysis along with the estimated Gross Load for the R-TRR and L-TRR amounts PG&E wants FERC to approve. In essence, every time PG&E seeks to adjust its rates through a rate case, it must demonstrate that every cost within its TRR is just and reasonable. PG&E’s TRR (and therefore its rates) remain the same until PG&E files a new rate case.

The rate case filing also includes a forecast of Gross Load in MWh that is used in the denominator of the R-TAC calculation as well as for purposes of calculating the retail rates for all customer classes. One key distinction between the stated rates used by PG&E and the formula rates used by SCE and SDG&E is that under stated rates, the utility bears the risk and potential benefit associated with Gross Load forecast inaccuracy and fluctuating costs. For example, once the TRRs and Gross Load are approved by FERC order, if the actual load turns out to be less than the forecast, the utility will under-collect its TRR; whereas, if the actual load turns out to be greater than the forecast, the utility will over-collect. The same is true if PG&E’s costs go up or down: the TRRs and rates remain the same as what PG&E filed and FERC approved; with stated rates there is no adjustment after the fact to compensate for any over/under-collection. In contrast, formula rates incorporate an adjustment mechanism, as explained in the next subsection, so that any inaccuracy of the Gross Load forecast does not have a financial impact on the PTO.

Prior to filing its TRR rate case, PG&E develops its retail transmission rate structures to align with the retail rate structure adopted by the CPUC for the other components of retail rates, which principally are the energy and distribution components.

Under the ISO and transmission owner (TO) tariffs, each PTO’s transmission cost recovery mechanism also includes a transmission revenue balancing account (TRBA), which tracks revenues received by the PTO outside of the TAC that reduce the amount of TRR that must be recovered through the TAC. The main components of the TRBA are the WAC revenues. Standby demand charges also offset some of the TRR in calculating the TAC and WAC rates, but are forecasted as a separate amount from the TRBA. In the case of stated rates there is no adjustment mechanism, either through the TRBA or some other mechanism, for over/under-collection due to differences between the actual and forecasted gross load. Under the ISO tariff, the PTO must file at FERC its proposed TRBA adjustment (TRBAA) for approval annually based on revenue received between October 1 of the prior year and September 30 of the current year. The approved TRBAA and the standby charge revenues then apply as offsets to the TRR to be collected starting January 1 of the coming year.

3.2. IOU PTOs with Formula Rates: SCE and SDG&E

SCE and SDG&E are IOU PTOs that have “formula rates.” A formula rate means that the PTO files for FERC approval of a formula for calculating the PTO’s TRR that will apply until the PTO files a proposed new formula rate with FERC. Once FERC approves the formula, the PTO files annually the data that comprise the required inputs for the formula, namely, the costs and Gross Load. Once FERC accepts the data, the formula produces the R-TRR and L-TRR amounts. Thus, the PTO’s typical filing is only an update to the formula inputs. During the term of the formula rate (as set forth in the SCE and SDG&E rate case settlements), the PTO is not obligated to file a new rate case to modify the actual formula. However, most of the PTOs with formula rates have “sunset” provisions in their rates, meaning they must file a new formula rate (or a stated rate) after three to six years.

As in the case of PG&E, these PTOs structure their retail transmission rates to align with CPUC retail rate structure policy before filing their annual proposed costs and gross load at FERC. Stated rates and formula rates principally differ in their treatment of any under/over-collection. For example, with formula rates, a subsequent year’s TRR is adjusted to account for and offset any over/under-collection of revenues that resulted from actual Gross Load being higher or lower than the FERC-approved forecast or from any actual cost being different from the previously-forecasted cost. Apart from this one key difference between stated rates and formula rates, all three IOU PTOs use the TRBAA mechanism and the other appropriate adjustments to their TRRs, and these adjustment amounts are filed with FERC for approval.

3.3. Municipal PTOs

Anaheim, Azusa, Banning, Colton, Pasadena, Riverside and Vernon are municipal PTOs, and Valley Electric Authority (VEA) is a rural electric association PTO. These entities are not generally subject to FERC jurisdiction with respect to their rates, but file their TO Tariffs and TRRs with FERC pursuant to their status as PTOs, FERC approves their TRRs and their forecasts of Gross Load, but the municipal utility’s or association’s governing authority establishes the retail transmission rates. For the California municipal utilities, these rates must, under state law, be based on cost of service principles. Each entity has the option of choosing stated rates or formula rates for its FERC-approved TRR. Anaheim and Pasadena have stated rates; whereas, Azusa, Banning, Colton, Riverside, and Vernon have partial formula rates, whereby a portion of the TRR is stated and a portion of the TRR tracks the rates charged by SCE through “pass-through” provisions for the Cities’ respective contractual entitlements on SCE’s system that are under the ISO’s Operational Control. The PTOs with such pass-through provisions submit updates to the costs charged to them by SCE each year. Similar to the IOU PTOs, the municipal PTOs annually file the TRBAA with FERC, which includes the same components that the IOUs include in their filings.

3.4. Non-Utility PTOs

Prior to implementing competitive solicitations, certain transmission developers built transmission (or acquired transmission facilities) and now receive revenue recovery through the

TAC process. These non-utility or non-load-serving PTOs include DATC Path 15, StarTrans IO, Trans Bay Cable, and Citizens Sunrise. These entities have built and continue to be responsible for maintaining and physically operating transmission facilities that are part of the ISO Controlled Grid but do not serve any load that is responsible for paying a share of the transmission system costs. Each of these entities has stated rates on file with FERC that were established pursuant to settlements; because their assets are depreciating and their TRRs are generally decreasing, most have provisions in their settlements requiring them to refile their rates every three years.

More recently the ISO's competitive solicitation process has approved certain non-utility "Approved Project Sponsors" (DCR Transmission, NextEra Energy Transmission West, and DesertLink) who will become non-utility PTOs once their projects are completed and placed in service as ISO controlled grid facilities.[11] To the extent these entities have both Regional and Local facilities in the ISO grid, when FERC approves their TRRs they become part of the R-TRR for the ISO system and the L-TRR of the utility PTO in whose service area the facility is located. Each of these entities has filed a formula rate with FERC.

Like the PTOs with formula rates, these non-utility PTOs have true-up mechanisms to correct for any over- or under-collection of their TRRs, so that the PTOs recover the correct amounts of their annual TRRs. These entities therefore make TRBAA filings with FERC to account for the over/under-collection and any WAC revenue they may receive.

3.5. Non-PTOs

Non-PTOs operating within the ISO balancing area are the City and County of San Francisco, the City of Santa Clara d/b/a Silicon Valley Power, California Department of Water Resources, the Metropolitan Water District of Southern California, and the Northern California Power Agency (NCPA) MSS Aggregation. All of these entities were electric utilities or other wholesale entities operating in the ISO footprint prior to the establishment of the ISO. Non-PTOs own transmission facilities or contractual entitlements to transmission facilities, but have chosen not to become PTOs. Therefore they do not contribute transmission costs to be recovered through the TAC or WAC, and they pay the WAC when using the ISO system rather than the TAC. These entities have assumed various forms, including MSS Operators. These entities' loads are outside the service territories of current PTOs, and under the ISO tariff they pay for using the ISO Controlled Grid through the WAC rather than the TAC.

These entities pay the WAC based on the amount of their load served by supply sources (generation and imports) that use the ISO Controlled Grid, *i.e.*, the net load measured at their point of interconnection with the ISO grid. For some, 100 percent of their load is served by ISO Controlled Grid facilities because all their supply is remote from their load, and therefore they

[11] The ISO tariff also provides for another category of PTO, the Merchant PTO, which is not relevant to the subject of this paper because the entity does not have a load service area and does not recover any of the costs of its project through the TAC. Instead of cost recovery through the TAC, a Merchant PTO that turns its facilities over to ISO control will receive merchant congestion revenue rights for the amount of capacity added to the system by its transmission addition or upgrade.

pay the R-WAC and appropriate L-WAC based on their Gross Load. For others, some of their supply is internal to their service area or delivered over non-ISO transmission and some of their supply uses the ISO Controlled Grid, so they pay the R-WAC and (as appropriate) the L-WAC for the net load served over the ISO Controlled Grid. In one case, the entity has transmission connecting its generation directly to its load and therefore does not pay any R-WAC or L-WAC. Beyond this distinction between how the TAC and WAC charges are applied, however, the actual dollar amounts of the WAC rates are set to equal the corresponding TAC rates.

The ISO tariff has long distinguished between PTOs and LSEs that chose not to become PTOs. Non-PTOs either own their own transmission or have entitlement rights to use transmission that is not part of the ISO Controlled Grid. As such, they are already paying transmission costs for delivery over that transmission to serve load that is not served over the ISO grid, and therefore charging them TAC on Gross Load would constitute double payment.

Under ISO Tariff Section 26.1.2, the ISO charges TAC to UDCs and MSS Operators "serving Gross Load in a PTO Service Territory." The WAC is charged to Wheeling Transactions under Section 26.1.4 of the tariff. Wheeling Transactions (either Wheeling Out or Wheeling Through) consist of use of the ISO Controlled Grid for delivery to a point "outside the transmission and Distribution System of a Participating TO." This is sometimes referred to as "net load billing."

As Existing Transmission Contract entitlements have expired, the affected entities have paid greater amounts of R-WAC reflecting their increased use of the ISO Controlled Grid, while the billing determinant allocation respects the value of their continuing pre-existing resource arrangements. In some cases, all or almost all of these loads now pay WAC.

Although MSS Operators that are not PTOs do use WAC net billing, it is not exclusive to MSS Operators. The ISO created the MSS to allow vertically integrated governmental utilities to operate in the ISO tariff framework.

The ISO tariff recognizes different types of MSS Operators and some of the different options are explained in Section 4.9 of the ISO tariff. MSS Operators that are also PTOs pay the R-TAC (and L-TAC where applicable), consistent with the requirements discussed above. The tariff allows MSSs to form aggregations under the control of a single MSS Aggregator. Currently, NCPA serves as the MSS Aggregator for a number of its members, including Silicon Valley Power, and they are a Load-Following MSS Aggregation, giving them the ability to follow MSS Aggregation loads with MSS Aggregation resources in real-time. This structure accommodates the net billing construct discussed above (see definition of Gross Load at 3).

3.6. Exports

For exports to entities completely external to the ISO footprint, the WAC works the same way. The ISO charges the export based on voltage level of the relevant scheduling point. The ISO charges the export the R-WAC if the scheduling point is rated 200 kV or above. If the scheduling point is below 200 kV the ISO charges the export both the L-WAC and the R-WAC. The ISO remits export revenues collected at each scheduling point to the PTO or PTOs that own the scheduling point facilities and those revenues are included in the PTOs' TRBA.

4. Observations and Conclusions

Several key observations can be drawn from the above explanations.

1. Recovery of the costs associated with building, owning, maintaining, and physically operating transmission facilities in the ISO Controlled Grid is a complex process with many steps, including PTOs filing TRRs with FERC, the ISO collecting a portion of the TRRs through the R-TAC and R-WAC, and UDCs and other utilities collecting retail transmission charges from end-use customers.
2. The processes are somewhat different for each of the entities that has FERC-approved costs to recover; *i.e.*, the various PTOs in the ISO system.
3. The parties that receive shares of the revenues collected through the TAC and WAC (*i.e.*, the PTOs) are not always the same parties whose end-use customers pay these charges. There are some PTOs that do not have service areas and customers who pay transmission costs, and there are some UDCs and MSS whose customers pay transmission costs but do not contribute to the transmission costs collected for the ISO controlled grid.
4. The ISO's role in calculating and billing TAC and WAC charges and remitting the revenues to PTOs applies only to:
    a. The Regional or high-voltage facilities in the ISO Controlled Grid used by wholesale customers in the ISO's markets; and
    b. The Regional and Local facilities in the ISO Controlled Grid used for wholesale exports.
5. The original structure based on a volumetric $/MWh rate was established to reflect the fact that the ISO market, through which use of the transmission system is allocated and scheduled, is an energy market, not a capacity market. In other words, use of the ISO controlled grid is scheduled based on the hourly MWh energy volumes for which market participants need transmission service, and the current volumetric TAC and WAC rate structure aligns with this market structure.