Review Transmission Access Charge Structure

Revised Straw Proposal

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Market & Infrastructure Policy

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1. Executive summary

The ISO has focused on potential Transmission Access Charge (TAC) modifications over the past several years. In 2015, the ISO launched its TAC Options initiative where the ISO considered potential modifications to its TAC structure to support the possible expansion of the ISO balancing authority area. Following that initiative, in June 2016, the ISO opened its Review TAC Wholesale Billing Determinant initiative to consider the Clean Coalition's proposal to modify the point of measurement for assessing TAC charges.

Stakeholders that support changing the point of measurement for assessing TAC charges seek to move away from utilizing hourly gross load at the end-use customer meters to a measurement of hourly net load metered at each transmission-distribution (T-D) interface. Their objective is to reduce TAC charges by lowering the energy down flow from the transmission grid required to serve load where distribution-connected generation serves part of the load in an area. Rather than proposing modifications focused more narrowly on the point of measurement as originally contemplated, other stakeholders urged the ISO to broaden the initiative's scope and holistically look at the overall TAC structure given today's transforming grid. In response, the ISO launched this Review TAC Structure initiative to consider a more holistic review of the ISO's high voltage TAC structure.

There are two basic issues the ISO addresses in this proposal: (1) how to measure transmission usage; and (2) where to measure transmission usage. The ISO explores modifications to address how to measure transmission usage in this initiative. A volumetric approach has been used since 2001. Since the ISO implemented the volumetric-only approach, there have been significant changes in resource mix and usage patterns that have accompanied the evolution of the electric industry in California. The ISO believes that the current volumetric-only approach may no longer best reflect the cost causation, utilization, and benefits of the existing transmission system. Therefore, the ISO is proposing to modify the current volumetric billing determinant to better reflect customer usage and the cost causation and benefits of the transmission system.

The ISO believes that a hybrid approach, utilizing both peak demand and volumetric measurements of customer use to assess TAC charges, is preferable because the transmission system provides both energy and capacity functions, and other reliability benefits and a two-part hybrid approach captures both peak demand and volumetric use and better accounts for these functions. For instance, the hybrid approach would preserve a volumetric measurement as part of the billing determinant; it would not limit TAC cost recovery to only peak demand periods as a simple peak demand TAC charge approach would. Restricting TAC charges to only recover transmission system costs through peak demand charges may not capture all benefits provided since policy projects and other energy delivery functions of the transmission system provide benefits that accrue throughout all hours of the day and year, not just during peak demand periods. Thus, the ISO believes preserving a volumetric charge component is appropriate and reflects cost causation given the benefits policy projects and the energy delivery capability of the system. Coincident peak demand TAC charges have been used in other regions and can be appropriate for assigning costs reflecting benefits for the transmission system's use during system peak demand periods. Peak demand and reliability needs have been a significant reason for investment in the existing transmission system and are a cost driver that should be appropriately assessed to users of the grid. The existing volumetric-only approach is indifferent to when consumption occurs, which may not accurately reflect cost causation or benefits received during certain periods. Therefore, the ISO believes that the hybrid approach, which incorporates both a peak demand and volumetric measurement, better reflects cost causation and the benefits users of the transmission receive from the existing transmission system.

The ISO also considered the issue of where to measure transmission usage, *i.e.*, the "point of measurement" and received considerable stakeholder feedback. A majority of stakeholders are opposed to moving the current point of measurement away from the end-use customer and to the T-D interface. Stakeholders express concerns over the resulting cost shift that would occur if the point of measurement were to move up to the T-D interface. Specifically, the stakeholders' major concerns with moving the point of measurement to the T-D interface is that the embedded costs of the existing transmission grid would simply shift to those areas that do not have distributed generation to serve a comparable portion of their load. Furthermore, significant retail rate design changes would be needed to fully effectuate the intended purpose of changing the point of measurement and there is currently no state policy supporting such changes. Due to these concerns, the ISO proposes to maintain its existing practice of measuring customer use at the end-use customer as the point of measurement.

The ISO is willing to revisit the point of measurement issue– for purposes of prospectively allocating the costs of future transmission facilities– if state policy makers adopt retail rate changes that provide a transmission cost credit (*i.e.*, relief from retail rate charges for certain new transmission facilities) to load-serving entities (LSEs) that have procured distributed generation (DG) resources. Such retail rate design changes are outside of the purview of the ISO and this stakeholder initiative. The ISO discusses stakeholder feedback received on the point of measurement issue in Appendix A of this proposal.

2. Introduction

The current TAC framework was placed in service in 2001 and the structure has remained relatively stable through the intervening years. In late 2015, the ISO started its Transmission Access Charge Options initiative in the context of potential expansion of the ISO balancing authority area (BAA) to integrate a large external BAA such as that of PacifiCorp. The focus of that initiative was limited to matters of transmission cost allocation over a larger BAA, including the costs of both existing transmission facilities that each member service area or "sub-region" would bring into the expanded BAA and new facilities jointly planned through an integrated transmission planning process for the expanded BAA. That effort culminated in the Draft Regional Framework Proposal posted to the ISO web site on December 6, 2016.[1]

During the Transmission Access Charge Options initiative, the Clean Coalition suggested potential modifications to the procedure for collecting the Transmission Access Charge (TAC) to use the hourly net load at each transmission-distribution (T-D) interface substation as the billing determinant instead of the current Gross Load billing determinant, which sums the end-use metered load in each hour. The suggested change to the point of measurement was focused on the potential need to reduce TAC charges where distribution-connected generation (DG) could serve part of the load in an area, and presumably lower use of the transmission grid.

The ISO determined that the Clean Coalition's proposed modifications were outside the scope of the Transmission Access Charge Options initiative and proposed to address it through a separate initiative. In June 2016, the ISO opened the Review Transmission Access Charge Wholesale Billing Determinant initiative specifically to consider the Clean Coalition proposal. In the first round of stakeholder discussion and comments in that initiative several stakeholders argued against the narrow focus on the Clean Coalition proposal and urged the ISO to undertake a broader review of the structure of the TAC charge. Some stakeholders argued that the ISO should reconsider whether it is appropriate to maintain the current volumetric TAC charge or adopt a demand-based charge to align better with the cost drivers of transmission upgrades. The ISO agreed that a broader, holistic examination of the TAC structure would be preferable to a narrow change to the TAC billing determinant. The ISO could not reasonably re-direct its resources already committed to other initiatives to such an effort at that time but committed to re-open the topic in 2017.

The present initiative is taking up where the summer 2016 initiative left off and broadening the scope to a wider consideration of the TAC structure. While the ISO intends to explore the TAC structure under this initiative, it must stipulate this effort is limited to the ISO High Voltage-Transmission Revenue Requirement (HV-TRR) allocation process, and not any other aspects of transmission cost recovery, which also includes Participating Transmission Owner (PTO) collection of Low Voltage-Transmission Revenue Requirements (LV-TRR), PTO FERC proceedings, and the transmission component of retail rates. In April 2017, the ISO published a background white paper titled "How transmission cost recovery through the transmission access charges works today" to provide a common understanding among stakeholders about how transmission cost allocation and recovery within the ISO works.[2]

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[1] See TAC Options Draft Regional Framework Proposal: http://www.caiso.com/Documents/DraftRegionalFrameworkProposal-TransmissionAccessChargeOptions.pdf

[2] See Review TAC Structure Background White Paper: http://www.caiso.com/Documents/BackgroundWhitePaper-ReviewTransmissionAccessChargeStructure.pdf

In June 2017, the ISO published an issue paper outlining the fundamental principles and key considerations it has identified and sought stakeholder feedback. The ISO has also held two stakeholder working group meetings to assist in parties understanding of the current TAC structure and settlements process, and also, to review the Clean Coalition's suggested modifications and allow for other interested stakeholders to present questions for the Clean Coalition representatives to consider. The ISO published its initial straw proposal in January 2018 and received stakeholder feedback that has been incorporated in the development of this revised straw proposal. The following sections reflect the ISO's current positions on this initiative.

3. Changes from straw proposal

Significant changes from the straw proposal are summarized below:

- As described in section 7.1.1.1, the revised proposal for splitting the HV-TRR for a hybrid billing determinant is to utilize a system load factor calculation. The ISO provides it's rational and explains the proposed calculation to split the HV-TRR into components to be collected under the volumetric and coincident peak demand billing determinants.
- As described in section 7.1.1.4, the ISO has included proposed changes to the rate structure and billing determinant for Non-PTO and Metered Sub System entities to align with the proposed TAC structure modifications for a hybrid billing determinant. The ISO received feedback from stakeholders that indicated support for this proposed alignment of treatment of these entities.
- The ISO also notes that it is willing to revisit the TAC point of measurement issue– for purposes of prospectively allocating the costs of future transmission facilities– if state policy makers adopt retail rate changes that provide a transmission cost credit (i.e., relief from retail rate charges for certain new transmission facilities) to LSEs that have procured DG resources. Such retail rate design changes are outside of the purview of the ISO and this stakeholder initiative. Section 7.3 describes the ISO proposal on the point of measurement issue.

4. Initiative scope and schedule

Through this initiative the ISO proposes to address the following major HV-TAC structure items:

1. Consider whether to modify the TAC billing determinant to better reflect customer utilization and benefits. The ISO proposes to explore modifying the billing determinant to accomplish objectives such as reducing TAC charges for load offset by distributed generation output as described above and, if so, to determine what modifications would be most appropriate.
2. Consider whether to modify the current volumetric billing determinant of the TAC structure to better reflect cost causation and customer benefits. The ISO proposes to explore the potential benefits and impacts of using a demand-based charge, a time-of-use pricing structure, a volumetric charge, or a hybrid combination thereof.

The ISO continues to propose excluding the following topics from the scope of this initiative to avoid overly complicating the efforts of this TAC structure review:

- The current allocation of regional and local transmission charges. The current approach uses a "postage-stamp" rate (*i.e.*, a common rate across the ISO BAA) to recover the costs associated with regional or high-voltage transmission facilities under ISO operational control (*i.e.*, facilities rated at or above 200 kV), and utility-specific rates in each of the investor-owned utility (IOU) service areas to recover the costs of local or low-voltage facilities (*i.e.*, facilities rated less than 200 kV) under ISO operational control. The ISO proposes not to consider changing this aspect of TAC structure in this initiative, even if the ISO revises the TAC structure from the current volumetric framework to some other approach
- The ISO's role in collecting the TAC. Each of the UDCs collect from retail customers the rates to recover the TRRs approved by FERC for both regional and local facilities. The ISO collects from UDCs through its settlement system only the TAC charges associated with regional transmission facilities. The ISO's settlement system only bills or pays each UDC an amount needed to adjust between regional TRR revenues charged to its retail ratepayers and the UDC's share of the regional postage-stamp TAC structure. The ISO proposes not to consider changes to this aspect of TAC structure in this initiative.
- Regional cost allocation issues for an expanded BAA as discussed in the TAC Options initiative.[3] The two issues identified above for the present initiative can be addressed whether an expanded ISO BAA is created in the future, and can logically be treated separately from regional cost allocation issues. The ISO believes that policy changes that result from the present initiative should apply in an expanded BAA that may be created in the future.
- Alternative types of transmission service. The ISO has reviewed the approaches used by other ISOs and RTOs to recover transmission costs.[4] Some of the other regions offer different transmission service options compared to the ISO (*e.g.*, point-to-point versus network integration service). The ISO offers only one form of transmission service through its day-ahead and real-time markets. This initiative will not consider expanding or modifying the types of transmission service offered by the ISO.
- The current treatment of TAC for exports, also known as "wheeling out charges". The ISO believes this initiative should be focused on the internal TAC structure and potential modifications for recovering the HV TRR from internal loads that the existing ISO transmission system was built to serve. Based on the input of some stakeholders, considering revisions to export charges in this initiative will lead into the complex question of whether the ISO should offer alternative forms of transmission service, to allow a different rate structure that may be more desirable for parties that export from or

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[3] See TAC Options Draft Regional Framework Proposal: http://www.caiso.com/Documents/DraftRegionalFrameworkProposal-TransmissionAccessChargeOptions.pdf

[4] See Review TAC Structure Issue Paper: http://www.caiso.com/Documents/IssuePaper-ReviewTransmissionAccessChargeStructure.pdf

wheel through the ISO BAA. The ISO believes that considering while not without some support, would substantially expand the already ambitious scope of and effort anticipated for this initiative.

Initiative schedule with major milestones:

The updated schedule for this stakeholder initiative is provided in Table 1 below. The ISO plans to present its proposal to the ISO Board of Governors for their approval in September of 2018. This proposed decision date is based on the ISO's assessment of how much additional work is needed to develop a final proposal.

Table 1 – Stakeholder Initiative Schedule

Step	Date	Milestone
Kick-off	Feb 6, 2017	Publish market notice announcing initiative beginning mid-year 2017
White Paper	Apr 12	Post background white paper
Issue Paper	Jun 30	Post issue paper
	Jul 12	Hold stakeholder meeting
	Jul 26	Stakeholder written comments due
Working Groups	Aug 29	Hold stakeholder working group meeting to review and assess options
	Sep 25	Hold stakeholder working group to review stakeholder proposals and allow additional Q&A
	Oct 13	Stakeholder written comments due
	Dec 1	Discuss TAC initiative with Market Surveillance Committee (MSC) members and stakeholders
Straw Proposal	Jan 11, 2018	Post straw proposal
	Jan 18	Hold stakeholder meeting or call
	Feb 15	Stakeholder written comments due
Revised Straw Proposal	Apr 4	Post revised straw proposal
	Apr 11	Hold stakeholder meeting or call
	Apr 25	Stakeholder written comments due
Draft Final Proposal	June 21	Post draft final proposal
	June 28	Hold stakeholder meeting or call
	July 12	Stakeholder written comments due
Final Proposal	Sept 5,6	Present final proposal at CAISO Board meeting

5. EIM classification

For this initiative the ISO plans to seek approval from the ISO Board only. The ISO believes this initiative falls outside the scope of the EIM Governing Body's advisory role, because the initiative does not propose changes to either real-time market rules or rules that govern all ISO markets. This initiative proposes to change only one component of the TAC structure– *i.e.*, the volumetric component of the TAC billing determinant, which is based on gross load of end use customers in the ISO's balancing authority area, and does not depend on market bids or other inputs, or on market outcomes. This initiative does not propose to change any part of the TAC structure that could be paid by participants outside of the ISO's balancing authority area.

Stakeholders that opined on the ISO's initial EIM classification generally agreed with the ISO that this initiative falls outside of the scope of EIM Governing Body's advisory role. The ISO plans to seek approval from the ISO Board only for this initiative. The ISO seeks stakeholder feedback on the EIM classification of the initiative.

6. Stakeholder feedback on straw proposal

The ISO received feedback from stakeholders on the Review TAC Structure straw proposal. The stakeholder comments are available in their entirety on the initiative webpage here: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=5C786A65-1F2F-43BF-B761-77242DD8D690. The ISO provides a summary of this feedback and the ISO's responses in Appendix A.

7. TAC structure revised straw proposal

This initiative considers potential modifications to the HV-TAC structure. The ISO provides some relevant objectives and describes the issues that must be considered for any TAC structure modifications. The ISO proposes modifying the billing determinants for measuring customer use. The current approach is a volumetric measurement. The ISO believes that a hybrid approach, utilizing both peak demand and a volumetric measurement is more appropriate and better reflects cost causation.

The ISO also has received considerable stakeholder feedback on the point of measurement issue that has been discussed during stakeholder working groups. A significant majority of stakeholders oppose modifying the current point of measurement. They cite numerous concerns, including the potential for the unjustified shifting of embedded costs. Also, effectuating the primary objective of a point of measurement change requires a related change in retail rate design. Given the significant stakeholder opposition to a point of measurement change and that changing the ISO's TAC design alone cannot resolve the issue, the ISO believes there is no basis to pursue a TAC design change at this time.

The ISO is, however, willing to revisit the TAC point of measurement issue– for purposes of prospectively allocating the costs of future transmission facilities– if state policy makers adopt retail rate changes that provide a transmission cost credit (*i.e.*, relief from retail rate charges for certain new transmission facilities) to LSEs that have procured DG resources. Such retail rate design changes are outside of the purview of the ISO and this stakeholder initiative. The ISO has also described numerous challenges that would be faced with any future reconsideration of the point of measurement issue for future transmission costs.

TAC structure rate design objectives

The ISO believes that any modifications to the HV-TAC structure should meet the objectives of FERC ratemaking principles and ISO cost allocation principles described in the ISO's June Issue Paper.[5] The major objectives that the ISO intends to reflect in its proposed TAC structure modifications include two overarching concepts. First, TAC should be charged based on cost causation and cost drivers when decisions to invest in transmission infrastructure were made. *i.e.*, load for which the facilities were built should continue to pay for transmission built to serve them, regardless if their usage patterns have changed. This means that the ISO should attempt to identify various cost drivers of the existing system to the extent possible. Second, TAC should be charged based on benefits, which may be different than cost causation. To accomplish this second objective the ISO must decide how to best measure benefits. The ISO supports a rate structure that fairly links the billing determinants to the benefits accruing to users of the grid.

The ISO also recognizes that any TAC rate design can potentially modify future behavior, supporting specific policy goals. However, the ISO does not believe this should be a major driver for revising the TAC rate design for a number of reasons. First, transmission cost allocation is complicated by the multifaceted ratemaking layers currently present in California. The ISO allocates transmission costs to UDCs that have their own retail rates. This additional layer of rates can mute the price signals the ISO TAC rate design might otherwise provide to end use customers, unless the individual UDC rates are closely aligned with the ISO's HV-TAC structure.

Second, the ISO bills UDCs for TAC, not LSEs, which are the entities that make generation procurement decisions. The CPUC and local regulatory authorities regulate LSEs, not the ISO or FERC. To incentivize DG procurement, an additional ratemaking mechanism must be developed to properly assign any costs and benefits associated with DG procurement to individual LSEs. The ISO discusses these concepts in section 7.3.

7.1. Proposed modifications to TAC structure

There are two major TAC structure issues addressed in this initiative: (1) how to measure transmission usage; and (2) where to measure transmission usage. These aspects of the TAC structure are referred to as the billing determinant and the point of measurement, respectively. The billing determinant is the basis for measuring the consumption used to calculate a customer's bill or to determine the aggregate revenue from rates from all customers, *e.g.*, volumetric (total MWhs). The point of measurement is the point from where the billing determinant is measured and reported, which is currently taken from the end use customer meter.

[5] See Review TAC Structure Issue Paper: http://www.caiso.com/Documents/IssuePaper-ReviewTransmissionAccessChargeStructure.pdf

The ISO proposes to modify the billing determinant to utilize a hybrid approach, that reflects both peak demand (MW) and volumetric measurements of customer use. The ISO considered modifying the point of measurement to the T-D interface, but determined it is appropriate to maintain the current end-use-customer point of measurement. The ISO considered the level of stakeholder opposition and the main objectives of this TAC structure review described above in determining not to pursue this concept further at this time.

7.1.1. Billing determinant proposal

The ISO proposes to modify the approach for measuring customer usage to better align transmission cost recovery with cost causation and the benefits provided by the transmission system. Considerable stakeholder feedback supports exploring a hybrid billing determinant.

Aligning transmission system cost drivers with customer use is a vital aspect of a well-designed transmission cost recovery mechanism and a foundational element of the ISO's proposed modification. The current volumetric approach may no longer optimally align with the cost drivers and functional benefits being delivered by the transmission system. This change is due to the transformation of the use of the transmission system driven by an evolving resource mix in California. The transmission system today provides services beyond simply energy delivery.[6] The ISO has explained that its high voltage regional transmission facilities provide a backbone function that supports regional flows, reduces congestion, facilitates reserve sharing, and facilitates import and export of power, thus benefitting all users of the grid. In addition, high voltage lines increase the system's ability to avoid curtailments, allow supply diversity, withstand extreme disturbances, mitigate reliability issues, absorb unexpected changes in frequency, and support adequate voltage levels throughout the system. These are key functions that deliver additional benefits to customers that may not be fully reflected in the current volumetric billing determinant that is focused primarily on the energy delivery function of the system.

Because a volumetric measurement approach primarily reflects the energy delivery function of the system, there is a potential for the capacity function and other reliability benefits to be ignored if only a volumetric bulling determinant is used. A hybrid billing determinant approach would measure a portion of customer use through a volumetric measurement and a portion through a peak demand measurement. This approach would capture both the volumetric and peak demand benefits and uses of the system and mitigates some of their shortcomings if used alone. Some stakeholders have advocated for this hybrid approach because they believe it will more closely reflect the different cost drivers associated with the energy and capacity functions and the related benefits provided by the transmission system.

The ISO believes that a hybrid approach has an advantage over other billing determinant approaches because it can reflect the use and benefits of the system more accurately than either a wholly volumetric or peak demand billing determinant. The transmission system

[6] See Review TAC Structure Straw Proposal: http://www.caiso.com/Documents/StrawProposal-ReviewTransmissionAccessChargeStructure.pdf

provides both energy and capacity functions and several reliability benefits.[7] A two-part hybrid approach can measure each of these functions. A hybrid approach would not limit TAC cost recovery to only peak demand periods, which may be appropriate because the benefits of policy projects and other energy delivery functions would accrue throughout all hours of the year, not just during peak demand periods.

Adding a peak demand usage measure will also allow the costs and benefits of serving customers with low load factors and high peak demands to be reflected in the costs recovery more appropriately than a volumetric approach alone. A hybrid rate design could also help mitigate the potential rate burdens placed on certain customers, while retaining the proposed usage charge's sensitivity to seasonal changes and encouragement of energy conservation efforts. These reasons support the ISO's proposed modifications to the current volumetric billing determinant.

The hybrid billing determinant proposal will recover a portion of the HV-TRR through a coincident peak demand charge. The other portion of the HV-TRR would continue to be recovered through a volumetric charge. To utilize a hybrid approach for the TAC billing determinant, the ISO has previously indicated that it must determine how to split the portion of the HV-TRR to be collected through a volumetric billing determinant and a peak demand billing determinant. There are various potential options for splitting the HV-TRR that have been mentioned in the previous proposal. The ISO examines these options below.

7.1.1.1. HV-TRR cost split proposal for hybrid billing determinant approach

There are various ways to determine the percentage of the HV-TRR that should be collected through the separate components of a hybrid rate design. The ISO sought feedback from stakeholders and explored the potential variations that it might use for cost recovery under the proposed hybrid approach for the HV-TRR.

Any preferred approach for splitting transmission costs between volumetric and peak demand that meets the previously mentioned rate design objectives should allocate the costs of the existing system in a manner that reflects the functions and benefits provided. Specifically, any split should allocate costs associated with energy delivery-related functions through the volumetric component of the hybrid approach and allocate the costs of the system that can be associated with capacity and reliability functions through the peak demand component.

To accomplish this objective, the ISO proposed to analyze the costs of historically approved categories of transmission projects and to categorize such costs by the above mentioned functions. Some stakeholders agreed that this approach could be useful. In response, the ISO attempted to categorize historically approved TPP projects costs associated with the functions of energy delivery or capacity/reliability to inform the potential HV-TRR split that would be needed under the hybrid billing determinant approach.

[7] See Review TAC Structure Straw Proposal.

In attempting to categorize historically approved TPP costs, the ISO determined such an approach may lead to false precision and could result in extended disagreement among parties because the analysis could be seen as subjective. Despite the ISO's best attempts to determine the cost drivers of the existing system, the ISO realized such approach was overly complex and problematic to accurately determine what costs are linked to specific energy delivery and capacity/reliability functions, respectively. Thus, ISO has reviewed the stakeholder input and discussed additional potential options for determining the appropriate approach to the HV-TRR cost split.

After reviewing potential options, the ISO believes that there is a more accurate and less speculative method for splitting the HV-TRR under a hybrid approach. The ISO proposes to utilize a system load factor calculation as the preferred method for determining the HV-TRR split. The ISO explains this proposed approach in detail below.

System load factor calculation for hybrid HV-TRR split

One metric that can be used to assess system efficiency is the system load factor (load factor), or the ratio of the annual average system load (average load) and the annual peak system load (peak load). The ratio of the average load and the peak load is a good indicator of the capacity utilization of the transmission system. A higher system load factor indicates a higher degree of capacity utilization. The CPUC's System Efficiency Report provides some helpful background on the relationship between peak loads and load factors: As utility peak loads rise, utility load factors and system capacity utilization decreases. Conversely, as average load increases, load factors and system capacity utilization increase.[8] This relationship can be explained through the following load factor equation:

$$Load\ factor \uparrow = \frac{Average\ load \uparrow}{Peak\ load \downarrow}$$

In line with the above explanation, the ISO believes that the California historical system load factor can provide a useful and relatively simple analytical basis for splitting the HV-TRR. The ISO believes the system load factor also reflects the degree that the system is being utilized for peak capacity delivery versus energy delivery functions. The ISO proposes to utilize a system load factor calculation to split the HV-TRR for each year because a system load factor calculation can reflect the primary functions that should make up the basis for splitting the HV-TRR under a hybrid billing determinant approach. This will allow the ISO to calculate a HV-TRR split that reflects the utilization of the transmission system. The ISO believes this approach is preferable to other previously proposed concepts for splitting the HV-TRR described above. Moreover, FERC and the federal courts have stressed the need for analytic data to drive cost allocation (rather than arbitrary divisions). The system load factor proposal is data-driven and yet relatively comprehensible, thus making it more likely to withstand scrutiny.

[8] See CPUC 2017 Report: System Efficiency of California's Electric Grid: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPD_Work_Products_(2014_forward)/System_Efficiency_Report%20PPD_May_24_Final.pdf

Calculation steps and example figures for system load factor hybrid HV-TRR split:

The following steps describe the proposed calculations that would be conducted annually to set the amounts of HV-TRR to be recovered through the demand charge and volumetric portions of the TAC billing determinant. The ISO has included numerical figures from the 2017 year to demonstrate the proposed calculation.

1. The ISO will start with approved annual HV-TRR ($2,165,294,596 from the HV Access Charge Rates effective Jan 1, 2017)

2. The ISO will divide this amount by the year's annual system peak multiplied by 8760 hours in a year to determine the amount of MWh's that would reflect system utilization at 100% load factor
   - Reported system coincident peak used for settlement purposes (49,900 MW for 2017) multiplied by annual hours (8760): **49,900 MW x 8760 hours = 437,124,000 MWh**

3. The ISO will divide the annual HV-TRR ($ 2,165,294,596) by the 100% load factor MWHs calculated above (437,124,000 MWh) to calculate the volumetric rate: **$2,165,294,596 ÷ 437,124,000 MWh = $4.9535/MWh**
   - This volumetric rate ($4.9535/MWh for 2017) reflects the rate that would collect the full HV-TRR cost of the transmission system if all UDCs were 100% load factor utilities

4. Using the PTO filed annual Gross Load (209,260,146 MWh for 2017), the ISO will multiply this value by the volumetric rate determined above: **$4.9535/MWh x 209,260,146 MWh = $1,036,570,546**
   - This is the amount of revenue expected to be collected by the volumetric component
   - For this example year (2017) the volumetric component would comprise ~**48%** of overall HV-TRR

5. The ISO will subtract the revenue determined for recovery through the volumetric component above from the total TRR to determine the remaining HV-TRR: **$2,165,249,596 - $1,036,570,546 = $1,128,724,050**
   - This the remaining HV-TRR value expected to be collected through the peak demand component
   - For this example year (2017) the peak demand component would comprise ~**52%** of overall HV-TRR

The ISO believes that the system load factor approach described above is an appropriate solution to the issue of determining how to split the HV-TRR to allocate the costs through each part of a proposed hybrid billing determinant. To determine actual TAC rates in the future, the ISO will utilize the forecasted annual system coincident peak with the target year's filed and approved TRR to determine this system load factor calculation for splitting the HV-TRR under the proposed hybrid approach. This process will be utilized to set the volumetric and peak demand charge TAC rates for each annual period. The ISO is open to refining the concepts further as it develops its' draft final proposal. The ISO seeks stakeholder feedback on this proposed system load factor approach to splitting the costs for a hybrid billing determinant approach.

Comparing current rate vs hybrid approach with proposed HV-TRR split approach

The following table compares the historical volumetric ($/MWh) TAC rates and the proposed hybrid approach volumetric rate, as well as the potential HV-TRR split that would have occurred under the proposed system load factor calculation for hybrid HV-TRR split.

Table 4 - Historic volumetric HV-TRR rates

Year	Filed Annual HV-TRR ($)	Filed Annual Gross Load (MWh)	Volumetric TAC Rate ($/MWh)	ISO Annual Peak Load (MW)
2012	1,331,131,427	208,203,435	$ 6.3934	46,846
2013	1,718,985,660	209,747,674	$ 8.1955	45,097
2014	1,695,601,699	211,699,031	$ 8.0095	45,089
2015	1,999,620,213	212,120,690	$ 9.4268	46,519
2016	2,195,146,895	211,289,953	$ 10.3893	46,232
2017	2,165,294,596	209,260,146	$ 10.3474	49,900

Table 5 - Proposed hybrid HV-TRR split formulation applied to prior annual historic data

Year	ISO Annual Coincident Peak Load (MW)	Filed Annual HV-TRR ($)	Filed Annual Gross Load (MWh)	Volumetric component TAC Rate ($/MWh)
2012	46,846	1,331,131,427	208,203,435	$ 3.2437
2013	45,097	1,718,985,660	209,747,674	$ 4.3513
2014	45,089	1,695,601,699	211,699,031	$ 4.2929
2015	46,519	1,999,620,213	212,120,690	$ 4.9070
2016	46,232	2,195,146,895	211,289,953	$ 5.4202
2017	49,900	2,165,294,596	209,260,146	$ 4.9535
Year	**TRR amount collected under volumetric component ($)**	**Volumetric HV-TRR portion (%)**	**TRR amount to be collected through peak demand charge ($)**	**Peak Demand HV-TRR portion (%)**
2012	675,355,136	51%	655,776,291	49%
2013	912,678,140	53%	806,307,520	47%
2014	908,799,341	54%	786,802,358	46%
2015	1,040,868,997	52%	958,751,216	48%
2016	1,145,237,728	52%	1,049,909,167	48%
2017	1,036,570,546	48%	1,128,724,050	52%

7.1.1.2. Implementation details for hybrid billing determinant approach

The ISO provides the following implementation details for stakeholders to consider and address in their comments.

Coincident peak demand measurement frequency

For a hybrid billing determinant's peak demand measurement component, a key consideration is what peak definition to use for the peak demand measurement. As discussed in the ISO straw proposal, a variety of options can be used to employ demand based billing determinant measurements. One option is the frequency of peak demand measurements, *e.g.*, annual peak (1), seasonal peaks (4), monthly peaks (12), or daily peaks (365). Different regions have employed these various methods, and they all can measure customer usage of the transmission system.

The ISO believes that the choice of peak demand measurement frequency should reflect the way the transmission system has been planned and the way that customers use transmission service and receive benefits. It is also reasonable to align the way customers use and benefit from the services provided through access to the transmission system with the frequency of the peak demand measurement. To accomplish this alignment, the ISO proposes to utilize a 12 monthly coincident peak (12CP) approach for recovery of the peak demand component of the HV-TRR. The ISO previously noted that most other ISO/RTOs rely on coincident peak demand measurements for billing transmission costs.[9] FERC settled on demand as the *pro forma* billing determinant in Order No. 888, and indicated a general preference for using a 12 monthly coincident peak (12 CP) allocation method.[10] The ISO believes that a 12CP approach strikes an appropriate balance in reflecting the way the system has been planned and is used to maintain reliability and benefit and serve loads.

The ISO plans its system through its Transmission Planning Process (TPP) not only based on meeting the annual system peak, but also to meet identified reliability issues that can occur in numerous off-peak scenarios. Given the unique circumstances on the ISO grid, the transmission system must meet important reliability needs during both peak and off-peak periods. The ISO believes that a 12CP approach reflects both the capacity function and reliability benefits provided to system users on a monthly basis. Additionally, the ISO and CPUC's System resource adequacy (RA) capacity requirements are based on monthly peak loads, as determined by the CEC's Integrated Energy Policy Report (IPER) load forecast. Because the system is utilized to deliver monthly peak capacity needs of loads, the ISO believes the proposed 12CP approach reflects the benefits associated with delivery of capacity on a monthly basis.

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[9] See ISO Review TAC Structure Issue Paper.

[10] *Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities*, 61 F.R. 21540-01 at 21599, Order No. 888 (1996).

The ISO also believes that the proposed 12CP approach provides advantages over other coincident peak demand measurements, such as 1CP or 4CP. The ISO believes that a 12CP frequency of peak demand measurements will mitigate the potential for certain UDC areas to avoid some of the potential costs that should be allocated to the area due to peak demand anomalies, such as an abnormally high or low peak demand observation that might occur for one UDC area during the single annual system coincident peak hour (1CP). A lower frequency of CP demand measurements will result in the demand charge component of the rate to be relatively higher rate per MW ($/MW). The aforementioned potential for abnormal observations in particular UDC areas combined with a low frequency of CP demand measurements could result in costs being incurred, or avoided, by particular UDC areas in a manner that is inconsistent with the cost causation and overall benefits provided to particular UDCs. In other words, a higher frequency of CP demand measurements can avoid some potential for anomalous outcomes that could shift costs unreasonably, because including higher frequency of measurements can provide a less volatile overall reflection of UDC's coincident peak demands that also produces a more appropriate allocation of the peak demand charge TRR component among UDC areas.

Coincident vs non-coincident peak measurement approaches

The ISO also has explored utilizing either a coincident peak demand measurement and non-coincident peak demand measurements (or both). For a coincident peak demand measurement, usage is measured for each customer based upon the customer's contribution to the overall coincident system peak. Coincident peak demand is the most commonly used for transmission cost recovery at the wholesale level. For non-coincident peak demand measurement, usage is measured for each customer based upon that customer's own non-coincident peak demand, regardless of the overall system peak. Non-coincident peak demand charges are more commonly used by utilities for retail rates for commercial and industrial customers.

The ISO has received stakeholder feedback supporting both approaches, but most stakeholders support utilizing only a coincident peak demand component. The ISO agrees with these stakeholders and proposes to use a 12CP demand measurement in the proposed hybrid billing determinant design. The ISO believes this approach for implementation of a hybrid billing determinant more closely reflects the ISO's objectives for TAC structure modifications, while balancing the tradeoffs of utilizing higher or lower frequency of peak demand measurements and of coincident versus non-coincident peak demand measurements.

Potential need for phase-in for hybrid billing determinant approach

Some stakeholders believe that it may be necessary to include a phase-in to reduce possible billing impacts, should the cost allocations among PTO/UDCs change significantly. Phase-ins for new rate designs are frequently used in retail ratemaking to mitigate bill impacts resulting from dramatic changes in allocation among customers and a phase-in was also used to establish the current postage stamp TAC rate. The ISO agrees with stakeholders that a phase-in to the hybrid billing determinant approach may be warranted and should be explored. The ISO notes that the impact analysis for the proposed hybrid approach included in this proposal has shown relatively small impacts to most UDC areas. This does not mean that a phase-in is not needed however, as the impact analysis is based on forecast peak and volumetric use data and does not reflect actual outcomes that could vary widely from the modeling results. The ISO believes this suggestion for a phase-in is worthy of additional consideration and requests additional feedback from stakeholders on this issue.

Mechanism for avoiding stranded transmission costs

The ISO has received stakeholder feedback indicating that it should try to address the potential risk for stranded costs under the proposed modifications to the billing determinant. The ISO recognizes stakeholder concerns that any changes to the TAC billing determinant should not affect the ability of PTOs to recover their TRRs and the ISO agrees with this concept generally, but notes that particular outcomes will also be impacted by the rate structure of each PTO as described further here.

The ISO proposes to continue to utilize the current transmission revenue balancing account (TRBA) mechanism, which tracks revenues received by the PTO outside of the TAC that reduce the amount of TRR that must be recovered through the TAC. 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 TRBA and the standby charge revenues then apply as offsets to the TRR to be collected starting January 1 of the coming year. 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. This lack of adjustment mechanism would still occur for PTOs with stated rates that do not utilize the TRBA mechanism under their rate design. Recognizing that this may still be an issue for some PTOs under the proposed modifications, the ISO is open to feedback on additional methods that could be utilized to address any further concerns with the potential for over/under-collection of HV-TRR costs.

Setting HV-TAC rates and updating for approved TRR changes

The ISO proposes to set the HV-TAC rates according to the proposed hybrid billing determinant for each year. The ISO will follow the steps provided above for the proposed system load factor calculation to split the HV-TRR and determine the volumetric rate ($/MWh) and 12CP demand charge rate ($/MW) each year. The ISO will continue to utilize the approved TRR values for each PTO to determine the overall HV-TRR to be recovered for each year. The annual system peak demand utilized to the set the HV-TRR split components for volumetric and demand recovery will be taken from the forecasted annual peak and 12CP average system peak demand that can be provided through the CEC demand forecast, which is also utilized for the ISO's TPP process. The ISO will continue to provide updates to the HV-TAC rates when PTO's inform the ISO of updates to their approved HV-TRR amounts as new assets are included or facilities are withdrawn from in the HV-TRR rate base by PTOs that have received approval under FERC transmission rate proceedings. When PTOs provided updated HV-TRR figures the

ISO will recalculate the resulting HV-TAC volumetric and 12CP demand charge rates accordingly based on the effective date approved by FERC.

Example Hybrid Billing Determinant Rate Formulation

The following example describes the formula and data that will be used to set the HV-TAC rates under the proposed hybrid billing determinant. The values that have been included here are for illustrative purposes only and actual resulting HV-TAC rates will vary.

- **Assume HV-TRR (HV-Transmission Revenue Requirement) = $2,366,000,000**
- Assume 50-50 (%) split of HV-TRR for this example:
    - HV-TRR to be collected under volumetric rate: $2,366,000,000 x 50% = **$1,183,000,000**
    - HV-TRR to be collected under 12CP demand charge rate: $2,366,000,000 x 50% = **$1,183,000,000**
- Volumetric billing unit: annual gross load (MWh) = **210,000,00 MWh**
- **Volumetric rate ($/MWh)** = HV-TRR to be collected under volumetric rate / volumetric billing unit: $1,183,000,000/ 210,000,000 MWh **= $5.63/MWh**
- 12CP peak demand billing unit: system average 12CP peak demand (MW) = 31,800 MW[11]
- 1CP demand charge rate ($/MW) = HV-TRR to be collected under CP demand charge rate / CP demand billing unit: $1,183,000,000 / 31,800 MW = $37,201.25/MW
- **12CP demand charge rate ($/MW)** = 1CP demand charge rate / 12CP: $37,201.25 / 12 = **$3100.10/MW**

Billing determinant data utilized for settlements under hybrid billing determinant approach

The ISO will continue to utilize gross load settlement data to determine each UDC areas volumetric usage and associated HV-TAC volumetric charges. The ISO proposes to use hourly average peak data provided through UDCs gross load settlement data. The ISO will use each UDC's hourly average peak demand coinciding with each monthly system coincident peak hour to determine the 12CP monthly demand usage and associated HV-TAC 12CP demand charges. Because the ISO will set the 12CP demand charge rate using the forecast annual system peak, the ISO will use the hourly average peak data provided through UDCs gross load settlement data that is also currently used for the volumetric TAC billing determinant approach.

The ISO seeks stakeholder feedback on these implementation details and welcomes input on potential issues or concerns, as well as suggestions for improving these proposed implementation items.

[11] The data used to derive the system average 12CP peak demand will be taken from the CEC demand forecast. The forecast peak demand for PTO/UDC areas each month will be averaged to calculate the average system peak demand that will be utilized under the proposed 12CP rate.

7.1.1.3. Analyzing hybrid billing determinant cost impacts to current UDCs

The ISO provides the following analysis of the potential cost impacts to UDCs due to the proposed hybrid billing determinant modifications. These figures were produced with the TAC cost impact model previously described in the ISO straw proposal. The ISO stresses that the future year's cost impact figures are only forecasts; they do not reflect firm outcomes. TAC cost allocations for future years will be based on the real usage measurements, which may differ from these forecasts due to differences in a number of potential variables including the projected overall HV-TRR, the resulting calculated volumetric and peak demand charge TAC rates, and the monthly peak demand and monthly volumetric usage for each utility that may vary from the forecasts.

Table 6 - Existing TAC Charge ($ million)

	2016	2017	2018	2019	2020
PG&E	$1,021.4	$1,084.5	$1,009.6	$1,063.1	$1,143.5
SCE	$1,028.5	$1,092.1	$1,016.7	$1,070.5	$1,151.4
SDG&E	$223.4	$237.2	$220.8	$232.5	$250.0
Anaheim	$27.5	$29.2	$27.2	$28.7	$30.8
Azusa	$3.0	$3.1	$2.9	$3.1	$3.3
Banning	$1.7	$1.8	$1.7	$1.7	$1.9
Pasadena	$12.6	$13.3	$12.4	$13.1	$14.1
Riverside	$25.8	$27.4	$25.5	$26.9	$28.9
Vernon	$13.0	$13.8	$12.8	$13.5	$14.5
Colton	$4.1	$4.4	$4.1	$4.3	$4.6
VEA	$5.4	$5.7	$5.3	$5.6	$6.0
CAISO Total	$2,366	$2,513	$2,339	$2,463	$2,649
Existing Rate ($/MWh)	$11.25	$11.96	$11.11	$11.63	$12.42

Table 7 - Proposed TAC Charge for Hybrid Approach: 50/50 TRR Split & 12CP ($ million)

	2016	2017	2018	2019	2020
PG&E	$991.3	$1,052.5	$979.9	$1,031.7	$1,109.8
SCE	$1,044.2	$1,108.7	$1,032.2	$1,086.8	$1,169.0
SDG&E	$236.5	$251.1	$233.7	$246.1	$264.7
Anaheim	$28.3	$30.0	$28.0	$29.5	$31.7
Azusa	$3.1	$3.2	$3.0	$3.2	$3.4
Banning	$1.7	$1.8	$1.6	$1.7	$1.9
Pasadena	$12.8	$13.6	$12.6	$13.3	$14.3

Riverside	$26.2	$27.8	$25.9	$27.3	$29.3
Vernon	$13.3	$14.1	$13.1	$13.8	$14.9
Colton	$4.2	$4.4	$4.1	$4.3	$4.7
VEA	$4.9	$5.2	$4.9	$5.1	$5.5
CAISO Total	$2,366	$2,513	$2,339	$2,463	$2,649
Volumetric - Gross Load ($/MWh)	$5.62	$5.98	$5.56	$5.82	$6.21
Coincident Peak 12 Periods - Gross Load ($/MW)	$37,312.09	$39,667.80	$36,858.30	$38,583.01	$41,187.69

Table 8 - Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2016	2017	2018	2019	2020
PG&E	(30,127,162)	(31,988,972)	(29,779,795)	(31,356,864)	(33,727,689)
SCE	15,690,287	16,659,921	15,509,378	16,330,718	17,565,448
SDG&E	13,100,272	13,909,848	12,949,226	13,634,986	14,665,898
Anaheim	769,564	817,122	760,691	800,976	861,536
Azusa	94,063	99,876	92,978	97,902	105,304
Banning	(1,623)	(1,724)	(1,605)	(1,690)	(1,817)
Pasadena	206,724	219,500	204,341	215,162	231,430
Riverside	348,042	369,550	344,029	362,248	389,637
Vernon	314,694	334,142	311,066	327,539	352,304
Colton	58,262	61,862	57,590	60,640	65,224
VEA	(453,123)	(481,125)	(447,898)	(471,618)	(507,276)
CAISO Total	0	0	0	0	0

Table 9 - Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2016	2017	2018	2019	2020
PG&E	-2.950%	-2.950%	-2.950%	-2.950%	-2.950%
SCE	1.526%	1.526%	1.526%	1.526%	1.526%
SDG&E	5.865%	5.865%	5.865%	5.865%	5.865%
Anaheim	2.796%	2.796%	2.796%	2.796%	2.796%
Azusa	3.180%	3.180%	3.180%	3.180%	3.180%
Banning	-0.097%	-0.097%	-0.097%	-0.097%	-0.097%
Pasadena	1.647%	1.647%	1.647%	1.647%	1.647%
Riverside	1.347%	1.347%	1.347%	1.347%	1.347%
Vernon	2.423%	2.423%	2.423%	2.423%	2.423%
Colton	1.422%	1.422%	1.422%	1.422%	1.422%
VEA	-8.420%	-8.420%	-8.420%	-8.420%	-8.420%

7.1.1.4. Treating Non-PTO and Metered Sub System entities comparably under hybrid billing determinant approach

Because the ISO is proposing a hybrid approach for the measurement of customer use, there may be an opportunity to align the billing determinants of the Non-PTO and Metered Sub Systems (MSS) with the proposed billing determinants for other PTOs/UDCs. Non-PTO and MSS entities are currently billed for their use of the HV transmission system through the Wheeling Access Charge (WAC).[12] The ISO has received feedback from stakeholders mostly supportive of evaluating the need for this alignment in treatment of these entities.

The ISO proposes to align the WAC billing determinant approach for these entities with the other TAC structure modifications under the proposed hybrid billing determinant measurement approach. These entities are treated similar to internal loads in some important ways that support the ISO's proposal. Similarities include that these entities' loads are planned for and served by the transmission system similarly to other internal loads. These entities' use of the HV transmission system currently is measured volumetrically, although charged WAC instead of TAC. This approach for measuring their usage is similar to the way other traditional customers charged TAC are measured, using a volumetric billing determinant. Because the ISO is proposing a hybrid billing determinant approach for traditional PTO/UDCs, the ISO believes it is appropriate to modify the billing determinant approach used to recover transmission costs from these Non-PTO and MSS entities.

The ISO will adopt a hybrid billing determinant approach including peak demand and a volumetric measurement for the for these Non-PTO and MSS entities to align with the approach for measuring use of other traditional PTO/UDCs customers. To accomplish this change, the ISO will modify the WAC rates for transmission cost recovery from these customers. The ISO will calculate both the volumetric WAC rate and the peak demand WAC rate components in a manner consistent with the proposed hybrid billing determinant approach modifications described under section 7.1.1. This also will require a separate calculation of each entity's monthly peak demand TAC charge and monthly volumetric TAC charge for settlements purposes.

This proposal will result in three separate and distinct WAC rates: 1) volumetric rate as current practice for traditional exports and wheeling, 2) hybrid billing determinant volumetric rate for Non-PTO and MSS entities, and 3) hybrid billing determinant 12CP rate for Non-PTO and MSS entities. The ISO will continue to calculate the standard volumetric WAC rate used for normal exports and wheeling purposes in the same manner as currently done today. The ISO notes that this will be different from the proposed billing determinant for the Non-PTO and MSS entities being considered for modified treatment under this proposal (these entities will be charged under the hybrid billing determinant approach rates described in this section above).

[12] See Review TAC Structure Background Whitepaper.

The ISO requests feedback from stakeholders on this proposal to apply a similar hybrid billing determinant approach for Non-PTO and MSS entities.

7.2. Point of measurement proposal

The point of measurement is the point that the billing determinant is measured and reported from. This is currently performed at the end use customer meter. The ISO has received stakeholder feedback suggesting that the ISO consider modifying the point of measurement used for the billing of TAC. Some stakeholders strongly advocate for using the T-D interfaces for the point of measurement as an alternative to the current end use customer metered demand point of measurement. The ISO has discussed this issue in depth with stakeholders during multiple stakeholder meetings and working groups and has solicited written comments on this topic. There was significant stakeholder feedback opposing changes to the point of measurement.

Based on substantial stakeholder feedback and the ISO's analysis, a change of the ISO's point of measurement for assessing TAC charges from the end use customer meters to the T-D interface would not create an appropriate or effective incentive for load serving entities to procure additional DG resources. Additionally, allocating the embedded costs of the existing transmission system (which is what TAC is designed to recover) in this manner would produce several inappropriate outcomes. Stakeholders have identified several fundamental reasons for this, and the ISO previously discussed them in its straw proposal.

Also, most stakeholders expressed concern that this change would inappropriately shift costs among UDC areas, and it ignores the full benefits provided by the transmission system to particular customers. The ISO agrees with stakeholders' concerns about potential inappropriate cost shifts for existing transmission and the recommendations against changing the point of measurement to the T-D interface. Changing the point of measurement simply would move responsibility for the embedded costs of the existing system among UDC areas, shifting cost responsibility for costs incurred to meet customer needs to others customers in UDC areas that have not procured comparable amounts of DG resources, regardless of their actual transmission use or dependence on the transmission system.

Numerous stakeholders noted that <u>future</u> transmission costs potentially can be avoided by DG where the ISO identifies a need through the TPP, and non-wires alternatives, such as DG, demand response, or energy efficiency, constitute a more efficient or cost effective solution. The ISO recognizes that the TPP and current procurement processes already account for DG and other non-wire alternatives to avoid future transmission costs. Based on its review and consideration of stakeholder input, the ISO agrees that changing the point of measurement will not produce transmission cost savings benefits. Because the existing transmission system costs are embedded (sunk) costs, these costs cannot be reduced. Thus, the ISO believes that modifying the point of measurement will not improve efficiency or reduce these embedded transmission costs. Because the ISO TPP already accounts for DG and other load reducing resources in the planning process, the potential reduction in future transmission costs due to these DG resources and other load reduction efforts is already largely being captured from a planning standpoint on whether to approve new transmission. However, from a cost allocation standpoint there is some merit to the notion that LSEs that would not benefit (or would have relatively less benefit) from any approved new transmission due to choosing to serve some or all of their load from local distributed resources, should bear less of the associated costs of the new transmission.

However, to provide any useful incentive or credit for DG resource procurement and production, changes beyond the ISO's purview would be needed. Because the ISO bills UDCs for TAC– not the LSEs who make generation procurement decisions– to effectuate the goals of any TAC point of measurement change changes in retail rate design would be needed to assign the DG related costs and benefits to individuals LSEs, as opposed to accruing to the UDC and all LSEs with loads in the area. This necessary change would require action by state regulatory authorities and is outside of the ISO's purview.

Due to significant stakeholder opposition to changing the point of measurement, and because changes to the TAC point of measurement alone would not produce the outcome desired by stakeholders supporting such change absent a corresponding change in retail rate design, the ISO proposes to maintain the current point of measurement of end use customer at this time.

Future consideration of point of measurement

The ISO is willing to revisit the point of measurement issue– for purposes of prospectively allocating the costs of future transmission facilities– if state policy makers adopt retail rate changes that provide a transmission cost credit (*i.e.*, relief from retail rate charges for certain new transmission facilities) to LSEs that have procured DG resources. Such changes are outside the purview of the ISO and this stakeholder initiative. The ISO has previously requested stakeholder feedback on the potential need to make a change to the point of measurement for only future transmission costs in response to its straw proposal. Most stakeholders that provided feedback on this issue thus far have opposed the concept, citing numerous concerns.

First, there are cost and implementation challenges related to installing and managing revenue quality metering infrastructure at all of the T-D interfaces on the ISO system, which are not insubstantial. The ISO has not been able to determine an accurate cost estimate for even the initial installation of the infrastructure that would be needed because of the sheer number of unknown variables, including the potential needs to upgrade additional substation and transmission components to allow for revenue quality metering on current transformers and potential transformers. Also, the ability to fit the equipment into existing substations is currently unknown and would require detailed analysis to determine feasibility. The large number of substations on the grid could present significant challenges, in particular for certain T-D interface substations located in densely populated urban areas with substations limited to existing footprints.

A second concern is the ability to differentiate between future TRR cost additions when considering new investments versus non-ISO approved costs incurred for PTO's normal refurbishment and replacement of existing assets, as well as the treatment of other TRR costs such as future operations and maintenance costs (O&M). Third, stakeholders stated that it would be difficult to develop a method to differentiate use of the system for particular subsets of investments, even if subsets of TRR costs were developed by splitting the existing embedded costs and future investment costs. The ISO likely would need to develop an accurate method to measure of the usage of the particular system components that were included in each category of TRR costs. In other words, the ISO and stakeholders may struggle to differentiate the level of usage of various components of the transmission system if subsets of TRR costs for future investments versus existing investments were measured at different points, especially to the level of scrutiny required by regulators and courts for cost allocation decisions. This issue presents a potential barrier to effectively designing a potential split point of measurement concept.

Next Steps

The ISO will discuss this straw proposal with stakeholders during a meeting on April 11, 2018. Stakeholders are asked to submit written comments by April 25, 2018 to initiativecomments@caiso.com. Please use the template available at the following link to submit your comments:
http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx

Appendix A – Stakeholder comment summary and ISO responses

The ISO received feedback from stakeholders on the Review TAC Structure straw proposal. The stakeholder comments are available in their entirety on the initiative webpage here: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=5C786A65-1F2F-43BF-B761-77242DD8D690. The ISO provides summaries of this feedback and the ISO's responses below.

Stakeholders supporting the hybrid billing determinant proposal:

The ISO has received feedback from 20 stakeholders generally supporting the ISO's hybrid billing determinant proposal on various levels. These entities include: Alliance for Retail Energy Markets (AReM), Bay Area Municipal Transmission Group/City and County of San Francisco (BAMx/CCSF), CAISO Department of Market Monitoring (DMM), California Department of Water Resources (CDWR), City of Vernon, California Large Energy Consumers Association (CLECA), California Public Utilities Commission (CPUC), Clean Coalition, Independent Energy Consumers Association (IEP), International Transmission Company (ITC), Northern California Power Agency (NCPA), NRG Energy Inc. (NRG), Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Six Cities, Silicon Valley Power (SVP), State Water Contractors (SWC), and Transmission Agency of Northern California (TANC).

Discussion of stakeholder feedback supporting the proposed hybrid billing determinant:

- PG&E, SCE, City of Vernon, IEP, and Clean Coalition are generally supportive of considering the concept of a two-part hybrid approach that has the potential to provide a better assessment of TAC costs than the current volumetric billing determinant. These stakeholders also indicate that additional details and data-driven analysis are needed to enable parties to independently evaluate the merit and the impacts of the CAISO's proposal. These stakeholders support an approach that better reflects customer usage and the cost causation and benefits of the transmission system. Stakeholders also note the design of the HV-TRR split under a hybrid billing determinant is of key importance.

The ISO appreciates stakeholder's requests for additional detail and analysis to better understand the proposed modifications. The ISO has provided additional information on the potential impacts of the proposed hybrid billing determinant. The ISO has also evaluated the approach proposed for splitting the HV-TRR in light of stakeholder comments and provides an alternative approach in this revised proposal.

- BAMx/CCSF, CDWR, CLECA, CPUC, ITC, NCPA, SDG&E, SVP, SWC, and TANC generally support the concept of the proposed hybrid billing determinant approach. These stakeholders have expressed support for including a peak demand component in the TAC billing determinant because it can reflect the role of coincident peak demand in cost causation for transmission investment and use of the transmission system during system peaks. They made references to issues that the ISO has identified in prior background sections of its proposals; stating that the transmission system provides a variety of benefits that go beyond simply transporting energy and note that a hybrid billing determinant would more appropriately reflect the multiple drivers and functions of transmission facilities.

The ISO appreciates these stakeholders supporting the concept of a hybrid billing determinant approach. The ISO believes the proposed modifications will better reflect the role of coincident peak demand in cost causation and the benefits provided by the transmission system. The ISO has provided additional details on its proposal for a hybrid billing determinant in the revised straw proposal.

Stakeholders opposing the hybrid billing determinant proposal:

The ISO has received feedback from 3 stakeholders generally opposing the ISO's hybrid billing determinant proposal on various levels. These entities include: 350 Bay Area, Bonneville Power Administration (BPA), and California Office of Ratepayer Advocates (ORA).

Discussion of stakeholder feedback opposing the proposed hybrid billing determinant:

- 350 Bay Area and Clean Coalition assert that demand charge component of the proposed hybrid billing determinant proposal should carefully consider how its impact would provide signals or incentives for customers to modify behavior. 350 Bay Area states that residential demand charges have been shown to be unnecessary to smooth load and are difficult for residential customers to understand. Clean Coalition also states that it appears the ISO is attempting to influence UDC and wheeling customers' behavior, and that the ISO must be clear about what behavior it is hoping to incentivize with the demand charge component of the proposed billing determinant. Clean Coalition states its belief that if CAISO is seeking to reduce peak flows on the transmission system, then CAISO should focus demand charges on peak transmission flows.

The ISO has previously stated that the primary objectives of this proposal for a hybrid billing determinant approach is focused on better reflecting both cost causation and benefits provided to customers through their use of the transmission system. The ISO explains how these primary objectives can be reflected by a proposal to include a peak demand charge component under a hybrid billing determinant in its revised proposal. The ISO believes that recovering the embedded costs of the existing system correctly is the primary goal of this modification and the ISO does not intend that a specific incentive or influencing customer behavior would be a primary focus of the proposed demand charge component so the issues raised by stakeholders are not as impactful to the overall goal of the proposed modifications. Instead, the ISO believes that the proposed hybrid billing determinant will more accurately reflect cost causation because a primary cost driver of the system is the need to meet system peaks reliably. This proposal will also better reflect the benefits delivered to end use customers, because the current volumetric approach may not always provide as accurate of a reflection of the benefits associated with delivery of capacity and reliability services during peak periods.

- BPA does not support the ISO's hybrid billing determinant proposal because they believe the proposed change to the TAC formula would cause a cost shift resulting in loads that have higher demand in the typical heavy load or peak hours receiving most of the cost shift. BPA states that flat loads would see some increase in cost, while loads with DG that are able to reduce peak load would notice a reduction in TAC cost. BPA asks why there is a need to move to a hybrid approach, unless the ISO feels that specific types of loads are not paying their fair share of the TRR. ORA supports maintaining the existing volumetric TAC structure and does not recommend considering a peak demand or time of use approach for the TAC structure at this time. ORA believes that this approach would not more accurately reflect cost causation and would not result in equitable treatment of ratepayers because some ratepayers would likely pay more than their fair share of transmission costs.

The ISO recognizes that the proposed billing determinant modifications will result in some cost shifts among the cost allocation of the HV-TRR and believes the resulting charges are justified and the impacts are reasonable. The ISO provides an estimated impact of the proposed hybrid approach in the proposal and also notes that one of the justifications for the proposal is that the current volumetric rate may allow for some loads to avoid paying their fair share of the HV-TRR costs in some situations. The ISO believes that this potential for cost avoidance by some areas is addressed to a greater extent through the peak demand charge component of the proposed hybrid approach. The ISO believes this proposal will better reflect customer's contributions to cost causation and the benefits they receive from these transmission investments. The ISO also believes the resulting rate design will only shift costs in a manner that more appropriately reflects customer utilization of the transmission system, better reflecting the benefits received during system peak conditions.

Discussion of stakeholder feedback on proposal to split the HV-TRR under hybrid billing determinant approach

- AReM, BAMx/CCSF, CDWR, CLECA, Clean Coalition, CPUC, ITC, NRG, ORA, PG&E, SCE, SDG&E, Six Cities, SVP, TANC, and VEA have provided feedback expressing support on various levels for the ISO's proposed historical cost categorization for split of the HV-TRR under a hybrid billing determinant. Some of these stakeholders have also raised concerns and numerous issues for consideration, with suggestions for potential improvements to the HV-TRR split approach. A common theme that has been noted is the need for additional detailed data and analysis to support such a categorization effort for the proposed split. Some have pointed out that it will be difficult to determine the purpose of all of the transmission projects for which costs are currently being recovered through the TRR it to divide the projects (and their associated costs) into those designed for energy flows and those needed to meet peak demand. Stakeholders also state that the proposed categorization method will still be somewhat arbitrary, even with further analysis, and may not be able to precisely reflect transmission functions because transmission facilities generally serve all of the identified functions when they become part of the embedded system. Stakeholders also stress that relative simplicity and the ability to readily implement should be key considerations.

The ISO agrees with various concerns that have been expressed over the previously proposed historical TRR cost categorization. The ISO has attempted to categorize historically approved TPP costs as previously proposed and determined that such an approach may lead to false precision that could result in extended disagreement among parties, because the analysis could be seen as subjective due to the inability to precisely reflect the functions of the cost categories of the transmission system. Despite the ISO's best attempts to determine the cost drivers of the existing system, the ISO realized such approach was overly complex and problematic to accurately determine what costs are linked to specific energy delivery and capacity/reliability function. Thus, ISO has reviewed the stakeholder input and discussed additional potential options for determining the appropriate approach to the HV-TRR cost split. The ISO has proposed to use a system load factor calculation to split the HV-TRR and describes this change in further detail in this revised straw proposal.

Discussion of stakeholder feedback on proposal to apply a monthly coincident peak (12CP) demand charge frequency of measurement under hybrid billing determinant approach

- BAMx/CCSF, Clean Coalition, and SVP have provided feedback generally opposing the proposed monthly (12CP) demand charge measurement frequency for various reasons. These stakeholders have expressed various points reflecting their concerns with the proposed 12CP frequency. They believe that since the CAISO does not have a relatively flat load profile throughout the year (it peaks in the summer), their expectation would be that demand-based costs would be allocated during a smaller number of months (as opposed to on a 12 CP basis). Clean Coalition states that cost allocation should be aligned with actual use (benefit), not simply planned use. BAMX/CCSF states that a demand-based billing determinant that focuses on the summer peak loading condition best follows the way the transmission system is planned and is the best method to appropriately allocate cost. BAMX/CCSF and SVP provided feedback that any adopted methodology for allocating transmission costs should be more aligned with the CAISO transmission planning methodology that is focused on the summer peak load condition. These stakeholders also argue that CPUC's monthly Resource Adequacy program assessment approach does not directly impact the CAISO transmission planning base case scenarios. BAMx/CCSF believe a 1CP methodology is appropriate, they also state that the ISO could consider using a 3CP methodology to capture the three highest monthly peaks if considering more data points around the summer peak is more desirable.

The ISO believes that a 12CP approach strikes an appropriate balance in reflecting the way the system has been planned and is used to maintain reliability and benefit and serve loads. The ISO plans the system through its TPP not only based on meeting the annual system peak, but also to meet identified reliability issues that can occur in numerous off-peak scenarios. Given the unique circumstances on the ISO grid, the transmission system must meet important reliability needs during both peak and off-peak periods. The ISO believes that a 12CP approach reflects both the capacity function and reliability benefits provided to system users on a monthly basis. Additionally, the ISO and CPUC's System resource adequacy (RA) capacity requirements are based on monthly peak loads and because the system is utilized to deliver monthly peak capacity needs of loads, the ISO believes the proposed 12CP approach also reflects the benefits associated with delivery of capacity on a monthly basis. The ISO also believes that the proposed 12CP approach provides advantages over other coincident peak demand measurements, such as 1CP or 4CP. The ISO believes that a 12CP frequency of peak demand measurements will mitigate the potential for certain UDC areas to avoid some of the potential costs that should be allocated to the area due to peak demand anomalies, such as an abnormally high or low peak demand observation that might occur for one UDC area during the single annual system coincident peak hour (1CP). The potential for abnormal observations in particular UDC areas combined with a low frequency of CP demand measurements could result in costs being incurred, or avoided, by particular UDC areas in a manner that is inconsistent with the cost causation and overall benefits provided to particular UDCs. In other words, a higher frequency of CP demand measurements can avoid some potential for anomalous outcomes that could shift costs unreasonably, because including higher frequency of measurements can provide a less volatile overall reflection of UDC's coincident peak demands that also produces a more appropriate allocation of the peak demand charge TRR component among UDC areas.

- CLECA, DMM, and ITC have expressed general support for the proposed monthly (12CP) demand charge measurement frequency. NCPA expressed a need for additional information on how the assumptions used in the ISO TPP align with the proposed approach. PG&E explains that the frequency of demand charge measurements is very important to the overall rate design and should be carefully considered. DMM has stated that 12CP approach seems to strike a reasonable balance between capturing peak demand intervals and allocating across enough intervals to prevent disruptive shifts in spot market consumption. DMM also recognizes that as more intervals are incorporated into the demand-based TAC calculation, the concept begins to depart from how the transmission system is planned. However, these types of approaches could mitigate significant shifts in consumer behavior in the spot market driven by avoidance of TAC. PG&E also notes that the ISO should also consider the impact of the peak shifting over time and plan to update the basis for the demand component frequently.

The ISO believes that a 12CP approach strikes an appropriate balance in reflecting the way the system has been planned and is used to maintain reliability and benefit and serve loads. The ISO believes that a 12CP approach reflects both the capacity function and reliability benefits provided to system users on a monthly basis. The ISO appreciates DMM support for a 12CP approach that provides a reasonable balance between capturing peak demand intervals and allocating across enough intervals to avoid unwanted outcomes. The ISO appreciates PG&E's recommendation to reevaluate the impact of peak shifting over time and believes the proposed system load factor approach for splitting the HV-TRR and the 12CP demand charge measurement frequency will reflect changing peak impacts accordingly.

Discussion of stakeholder feedback on coincident versus non-coincident peak demand measurement approaches

- BAMx/CCSF, City of Vernon, CDWR, CPUC, SVP, and SWC provide general support for use of a coincident demand charge over any non-coincident peak demand charge measurements for the TAC billing determinant. These stakeholders explain their understanding that ISO's high-voltage transmission facilities are designed on an ISO-system-wide basis to accommodate coincident peak demands, and believe that non-coincident demands may not reflect cost causation as accurately for these investments. CLECA, SCE and SDG&E believe that consideration could be given to alternative methods to ensure all customers appropriately contribute to the recovery of peak-related reliability costs, perhaps through use of a non-coincident demand charge. SCE would like to see additional data to see if there is a potential benefit to inclusion of NCP as a billing determinant. SDG&E believes there is merit in using a non-coincident demand charge because a demand-based TAC component that is determined on the basis of each utility's non-coincident monthly peak load recognizes that high voltage transmission projects built primarily for reliability are usually identified to accommodate each utility's maximum load, whenever that may occur. These projects are usually not identified on the basis of each utility's load during the coincident peak for the ISO Balancing Authority area as a whole.

The ISO appreciates stakeholder feedback on the issue of coincident versus non-coincident peak demand measurement approaches. The ISO has explored utilizing either a coincident peak demand measurement or non-coincident peak demand measurements (or both). The ISO has received stakeholder feedback supporting both approaches, but most stakeholders support utilizing only a coincident peak demand component. The ISO agrees with those stakeholders that believe the ISO's high-voltage transmission facilities are designed on an ISO-system-wide basis to accommodate coincident peak demands, and believe that non-coincident demands may not reflect cost causation as accurately for these investments. The ISO believes the proposed approach for implementation of a hybrid billing determinant more closely reflects the ISO's objectives for TAC structure modifications, while balancing the tradeoffs of utilizing coincident versus non-coincident peak demand measurements.

Discussion of stakeholder feedback on treatment of non-PTO and MSS areas under hybrid approach

- BAMx/CCSF, City of Vernon, CDWR, Clean Coalition, CLECA, DMM, ITC, NCPA, ORA, PG&E, SCE, SDG&E, SVP, and SWC have all expressed general support for exploring the need for alignment of the treatment of non-PTO and MSS entities billing determinant with the hybrid approach proposed for traditional PTO/UDC areas. These stakeholders believe assessment of TAC charges to non-PTO and MSS entities should be revised to better align with the assessment of the TAC to PTO/UDC entities, if the TAC is revised from the current energy-only approach. Some stakeholders agree that these Non-PTO and MSS entities are treated similarly to other internal load in the ISO TPP and are less similar to wheeling and exporting entities that are also charged on a volumetric WAC billing determinant basis. No stakeholders have expressed general opposition to the ISO exploring this potential alignment with the hybrid billing determinant approach. Clean Coalition and SDG&E believe that the ISO should reconsider the point of measurement for the Non-PTO and MSS entities. CDWR, NCPA, and SVP believe that there is no basis or changed circumstances that would necessitate the modification of the point of measurement for the Non-PTO and MSS entities.

The ISO appreciates the stakeholder feedback on this issue. The ISO proposes to adopt a hybrid billing determinant approach including peak demand and a volumetric measurement for the for these Non-PTO and MSS entities to align with the approach for measuring use of other traditional PTO/UDCs customers. The ISO agrees with CDWR, NCPA, and SVP on the point of measurement issue for Non-PTO and MSS entities and does not plan to include further consideration of the point of measurement for these entities in its proposal.

Discussion of additional stakeholder comments on other aspects of the hybrid billing determinant proposal:

- CLECA and Six Cities believe that it may be necessary to include a phase-in for the hybrid billing determinant approach, to reduce possible billing impacts, should the cost allocations among PTOs change significantly. CLECA states that it is imperative to acknowledge that these costs are collected from end-use customers, regardless of their LSE, so the customers would see these changes in their retail bills. CLECA also notes that a phase-in is frequently used in retail ratemaking to mitigate bill impacts resulting from dramatic changes in allocation among customers and a phase-in was also used to establish the current postage stamp TAC rate.

The ISO agrees with CLECA that a phase-in to the hybrid billing determinant approach may be warranted and should be explored. The ISO notes that the impact analysis for the proposed hybrid approach included in this proposal has shown relatively small impacts to most UDC areas. This does not mean that a phase-in is not needed, however, as the impact analysis is based on forecast peak and volumetric use data and does not reflect actual outcomes that could vary widely from the modeling results. The ISO believes this suggestion for a phase-in is worthy of additional consideration, so it has been included in this proposal. The ISO requests additional feedback from stakeholders on this issue.

- DMM believes that the ISO should also consider adjustments to TAC that could enhance the Congestion Revenue Right (CRR) allocation process— the ISO's mechanism for allocating day-ahead market congestion rents back to the entities that pay TAC. In particular, DMM states the ISO should develop a process by which market participants can pre-pay TAC associated with delivering energy across the CAISO system. In exchange, the market participant could receive the privilege of nominating CRRs in the CRR allocation process and being included in the CRR balancing account allocations.

The ISO appreciates the DMM suggestion to consider this concept on prepayment of TAC to receive eligibility for CRR allocation, however, the ISO believes this suggested modification is outside of the scope of this initiative and suggests that DMM raise this concept in the ISO's active CRR initiative that is considering enhancements to the CRR process.

- Six Cities and PG&E have requested information on how the ISO intends to address the risk for stranded costs. Six Cities suggests the need for an assessment of whether modification of the existing methodology for ensuring that PTOs recover their TRRs is needed in the event of possible changes to the TAC allocation methodology. Six Cities and PG&E indicate that any changes to the TAC (or WAC) billing methodologies should not affect the ability of PTOs to recover their TRRs. PG&E notes that the modifications may incentivize entities to try to avoid paying TAC by reducing their peak demand via storage or other resources. PG&E believes that, to the extent such reductions in peak demand do not actually reduce transmission costs, a revised TAC structure should not allow for TAC avoidance.

The ISO agrees that it should try to address any risk for stranded costs under the proposed modifications to the billing determinant, to the extent possible. The ISO recognizes stakeholder concerns that have stressed that any changes to the TAC (or WAC) billing methodologies should not affect the ability of PTOs to recover their TRRs and the ISO agrees with this concept generally but notes that particular outcomes will also be impacted by the rate structure of each PTO as described further here. The ISO proposes to continue to utilize the current transmission revenue balancing account (TRBA) mechanism, which tracks revenues received by the PTO outside of the TAC that reduce the amount of TRR that must be recovered through the TAC. Under the ISO tariff, the PTO must file at FERC its proposed TRBA adjustment (TRBAA) for annual approval based on revenue received between October 1 of the prior year and September 30 of the current year. The approved TRBA and the standby charge revenues then apply as offsets to the TRR to be collected starting January 1 of the coming year. 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. This lack of adjustment mechanism would still occur for PTOs with stated rates that do not utilize the TRBA mechanism under their rate design. Recognizing that this may still be an issue for some PTOs under the proposed modifications, the ISO is open to feedback on additional methods that could be utilized to address any further concerns with the potential for over/under-collection.

- Bonneville, SVP, and other stakeholders have asked the ISO to explain how it intends to apply the hybrid rate structure to exports that are assessed under the current WAC rate.

The ISO has indicated that this initiative will not consider modifications to the current treatment of WAC for exports, also known as "wheeling out charges". The ISO believes this initiative should be focused on the internal TAC structure and potential modifications for recovering the HV TRR from internal loads that the existing ISO transmission system was built to serve. The ISO will continue to calculate the standard WAC rate in the same manner it does currently, on a volumetric basis only.

- CLECA supports the concept of a standby-type charge that could be used to appropriately assign costs to a PTO with a large proportion of these standby customers to appropriately set their rate commensurate with the benefits they receive. SCE requests that the ISO consider a third category for TAC assessment that is based on the number of service meters. SCE explains that this would allow for an equitable assessment of costs that are not based on energy or demand. An example would be costs expended for vegetation management that are driven by the geospatial expanse of the transmission network more-so than the demand or energy needs provided by the system. CLECA indicates that the hybrid approach may not take into account the increasing number of customers that have behind the meter generation and storage. CLECA also explains that these customers' usage and peak demand will only appear when their on-site system(s) are down for maintenance or failure, or if it is financially advantageous to exchange power with the grid from their storage systems. These customers effectively appear as standby customers, but still receive benefits from being connected to the electric grid. These benefits include reliability and access to purchase from or sell to the grid. CLECA and SCE note their support for additional work to determine if the standby charge or similar method is needed, and if so, how it would be set.

The ISO appreciates the suggestions by SCE and CLECA regarding the potential need for standby or similar charges to address some of the issues they note. The ISO believes that this issue will require significantly complex assessments to determine an appropriate approach that can be included in billing determinant modifications. At this time, the ISO believes that, while not without merit, the additional complexity associated with the development of the suggested stand-by type charges is not warranted. The ISO also notes that this issue may become more relevant and important to address in the future, if the ISO revisits the point of measurement for assessing TAC charges. If the point of measurement were to be modified in the future, the ISO believes that it would also need to seriously consider developing the suggested stand-by type charges.

Stakeholders supporting the point of measurement proposal:

The ISO has received feedback from 17 stakeholders generally supporting the ISO's point of measurement proposal. These entities include: Alliance for Retail Energy Markets (AReM), Bay Area Municipal Transmission Group/City and County of San Francisco (BAMx/CCSF), Bonneville Power Administration (BPA), City of Vernon, California Large Energy Consumers Association (CLECA), California Public Utilities Commission (CPUC), Independent Energy Consumers Association (IEP), International Transmission Company (ITC), Northern California Power Agency (NCPA), NRG Energy Inc. (NRG), California Office of Ratepayer Advocates (ORA), Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Six Cities, Silicon Valley Power (SVP), and Transmission Agency of Northern California (TANC).

Discussion of stakeholder feedback supporting the point of measurement proposal:

- AReM, BPA, City of Vernon, CLECA, CPUC, IEP, ITC, NCPA, NRG, ORA, PG&E, SCE, SDG&E, Six Cities, SVP, and TANC have all expressed general support on various levels for the ISO's rationale and proposal to maintain the current end-use customer meter point of measurement. CPUC supports retaining the point of measurement for TAC billing at the end-use customer metering site because the resulting shift of embedded costs in TAC rates to customers not providing DG resources is inappropriate and unjustified because while customers of DG resources might avoid some TAC charges, all other customers would have to cover those costs proportionately. In effect, ratepayers of UDCs with lower penetration of DG resources would be obligated to pay higher electric rates through no fault of their own. Stakeholders have indicated numerous concerns related to cost shifts and note that modifying the point of measurement could result in free ridership by some connected loads at the expense of others, which should be avoided. Many stakeholders also note that supporters of changing the point of measurement are mistaken in attempting to address procurement issues through the TAC structure point of measurement. Some stakeholders believe that to the extent certain parties are concerned that their projects are not treated properly during procurement evaluations because of the way transmission costs are accounted for, those parties need to seek changes to procurement practices, which are outside of the ISO's purview. Stakeholders also note their agreement that the TPP already considers the impacts and cost reduction that DG, demand response, and energy efficiency may have on transmission planning activities.

The ISO appreciates the stakeholder feedback in support of the proposal to maintain the current point of measurement. The ISO shares similar concerns as expressed by stakeholders regarding the potential for unreasonable cost shifts. The ISO agrees that a change in the point of measurement would result in UDC areas with lower penetration of DG resources being obligated to pay higher TAC costs through no fault of their own. This outcome would likely result in rates and cost allocation to certain UDCs that do not comport with traditional FERC ratemaking and ISO's cost allocation principles. The ISO agrees with stakeholders that indicate the TPP already appropriately considers the impacts and cost reduction that DG has on transmission planning activities and reducing future transmission costs.

- AReM, CLECA, IEP, ITC, NCPA, NRG, ORA, PG&E, SCE, SDG&E, Six Cities, and SVP have provided feedback also generally opposing a change to the point of measurement for only future transmission costs. These stakeholders have indicated such a change would unduly complicate billing and cost recovery for no apparent benefit. CLECA notes that changing the measurement point to recover new costs versus embedded costs implies that the use of those assets is different, which is not possible in an AC electric system. Consider two parallel lines, where one is new and other is old- the power will always flow equally across the two lines. CLECA believes that it does not make sense that the measurement should be different for the two lines. IEP does not support modifying the point of measurement to distinguish between the existing transmission investment and new transmission investment. The moment the transmission investment is approved to serve forecast load, the new transmission investment effectively becomes an embedded cost of the integrated system that serves the entire load. PG&E comments that the same problems with changing the point of measurement apply to both embedded and future transmission costs. The change would result in a cost shift that has not been justified; there are several structural ratemaking issues; and distinguishing between future and embedded transmission costs would add significant complexity to the TAC structure. ITC notes that, although the ISO observes that it is possible that certain distributed generation resources may avoid or defer the need for transmission investment in certain locations on the system, such avoidance or deferral is dependent on many factors (resource size, type, location, etc.) and is by no means universal to all such distributed resources or their locations. Moreover, assuming for the sake of argument that a measurable set of avoided transmission costs can be attributed to certain distributed generation resources, it is unclear how those specific distributed resources would be 'credited' for avoided costs. For many of these reasons, the FERC-established standard for transmission cost allocation is that it should be "roughly commensurate" with benefits, and retaining the current point of measurement for existing and future transmission investments is generally consistent with that standard.

The ISO appreciates stakeholder feedback on the point of measurement issue for future transmission investments. The ISO recognizes the multitude of issues and challenges with the concept of multiple points of measurement for subsets of transmission assets. At this time, the ISO does not propose any change to the point of measurement for any subset of transmission investment costs. The ISO is willing to revisit the point of measurement issue– for purposes of prospectively allocating the costs of future transmission facilities– if state policy makers adopt retail rate changes that provide a transmission cost credit (*i.e.*, relief from retail rate charges for certain new transmission facilities) to load-serving entities (LSEs) that have procured distributed generation (DG) resources.

Stakeholders opposing the point of measurement proposal:

The ISO has received feedback from 11 stakeholders generally opposing the ISO's point of measurement proposal. These entities include: 350 Bay Area, Borrego Solar, California Alliance for Community Energy (CACE), Clean Coalition, Local Clean Energy Alliance (LCEA), San Diego 350, San Diego Community Choice Alliance (SDCCA), San Diego Energy District (SDED), Sierra Club, SkyCentrix, and World Business Academy.

Discussion of stakeholder feedback opposing the point of measurement proposal:

- 350 Bay Area, Borrego Solar, CACE, Clean Coalition, LCEA, San Diego 350, SDCCA, SDED, Sierra Club, SkyCentrix, and World Business Academy have expressed general opposition to the ISO's proposal to maintain the current point of measurement. These stakeholders argue that TAC should be assessed at the T-D interface to more accurately reflect the use and benefits of the grid and the impacts of DG resources. 350 Bay Area, Borrego Solar, CACE, Clean Coalition, LCEA, San Diego 350, SDCCA, SDED, Sierra Club, SkyCentrix, and World Business Academy claim that charging the TAC at the customer interface distorts the cost of DER's by adding costs that DER's do not incur and is inconsistent with the principle of linking charges to cost causation. These stakeholders state that there is a market distortion caused by the current TAC point of measurement that inappropriately affixes transmission system charges to electricity that was not delivered via the transmission system. These stakeholders also believe the current point of measurement results in a cost shift that disadvantages distributed energy resources and does not adequately compensate load serving entities that procure such resources for the avoided use of the transmission system. These stakeholders claim the current point of measurement forces local clean energy generators to subsidize distant central generation by subsidizing transmission infrastructure. These stakeholders also assert that this prevents LSEs from capturing the full value of local renewable energy and makes wholesale distributed generation (WDG) projects look artificially more expensive. These stakeholders have also stated that WDG serving load on the distribution system without ever crossing transmission lines should not be subject to TAC.

The ISO does not believe that the current point of measurement should be changed to the T-D interface to better reflect the use and benefits of the transmission system and the impacts of DG resources. Based on substantial stakeholder feedback and the ISO's analysis, a change of the ISO's point of measurement for allocating TAC from the end use customer meters to the T-D interface would not create an appropriate or effective incentive for load serving entities to procure additional DG resources. Additionally, allocating the embedded costs of the existing transmission system (which is what TAC is designed to recover) in this manner would produce several inappropriate outcomes. Stakeholders have identified several fundamental reasons for this, and the ISO previously discussed them in its' straw proposal. Also, most stakeholders expressed concern that this change would inappropriately shift costs among UDC areas, and it ignores the full benefits provided by the transmission system to particular customers. The ISO agrees with other stakeholders' concerns about potential inappropriate cost shifts for existing transmission and the recommendations against changing the point of measurement to the T-D interface. Changing the point of measurement simply would move responsibility for the embedded costs of the existing system among UDC areas, shifting cost responsibility for costs incurred to meet customer needs to others customers in UDC areas that have not procured comparable amounts of DG resources, regardless of their actual transmission use or dependence on the transmission system.

- Clean Coalition and its supporters claim the current TAC structure inappropriately shifts the costs of existing infrastructure from the customers of Load Serving Entities (LSEs) that rely more heavily on transmission resources onto the customers of LSEs that have historically reduced their use of transmission resources by procuring local energy from DG, which does not use transmission capacity. Clean Coalition states the current TAC structure places a proportionally higher burden of future transmission investments on the customers of LSEs that act to reduce overall transmission spending by procuring DG. Clean Coalition argues that it is incorrect to claim transmission-connected resources hundreds of miles from load and distribution connected resources next door to load cost precisely the same amount to deliver. Clean Coalition believes the current CED-based TAC structure fails to and appropriately credit LSEs for their DER contributions to lowering historic and future transmission system costs. The lack of any price signal that differentiates transmission costs between local and remote energy means that local energy resources are actively discriminated against in procurement because there is no mechanism for capturing the real differences in value between resources. SkyCentrix believes that the current approach impedes the adoption of distributed generation by passing the cost of transmission down to end customers whose use of that infrastructure is decreasing. Distributed generation, by not using that transmission capacity, reduces the load on existing infrastructure which, in turn, reduces the cost of maintenance and avoids upgrades. World Business Academy claims the point of measurements results in a lack of any price signal differentiating transmission costs between local and remote energy resources and local DERs are actively discriminated against because there is no mechanism for accurately valuing the real differences between centralized and distributed resources.

Numerous stakeholders noted that future transmission costs potentially can be avoided by DG where the ISO identifies a need through the TPP, and non-wires alternatives, like DG, demand response, or energy efficiency, constitute a more efficient or cost effective solution. The ISO recognizes that the TPP and current procurement processes already account for DG and other non-wire alternatives to avoid future transmission costs. Based on its review and consideration of stakeholder input, the ISO agrees that changing the point of measurement will not produce transmission cost savings benefits. Because the existing transmission system costs are embedded (sunk) costs, these costs cannot be reduced. Thus, the ISO believes that modifying the point of measurement will not improve efficiency or reduce these embedded transmission costs. Because the ISO TPP already accounts for DG and other load reducing resources in the planning process, the potential reduction in future transmission costs due to these DG resources and other load reduction efforts is already largely being captured from a planning standpoint on whether to approve new transmission. However, from a cost allocation standpoint, there is some merit to the notion that LSEs that would not benefit (or would have relatively less benefit) from any approved new transmission due to choosing to serve some or all of their load from local distributed resources, should bear less of the associate costs of the new transmission. The ISO also believes that, in order to provide any useful incentive or credit for DG resource procurement and production, changes beyond the ISO's purview would be needed. Because the ISO bills UDCs for TAC –not the LSEs who make generation procurement decisions– to effectuate the goals of any TAC point of measurement, changes in retail rate design would be needed to assign the DG related costs and benefits to individuals LSEs, as opposed to accruing to the UDC and all LSEs with loads in the area. This necessary change would require action by state regulatory authorities and is outside of the ISO's purview. Due to the amount of stakeholder opposition and because changes to the TAC point of measurement alone would not produce the outcome desired by stakeholders supporting such change, absent a corresponding change in retail rate design, the ISO proposes to maintain the current point of measurement of end use customer at this time.