Transmission Access Charge Structure Enhancements

Draft Final 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. Many stakeholders criticized this narrow approach, and instead urged the ISO to broaden the initiative's scope to look at the TAC structure holistically, given today's transforming grid. The ISO agreed and launched this initiative.

There are two basic issues the ISO addresses in this proposal: (1) how to measure transmission usage; and (2) where to measure transmission usage. On the question of "How?" the ISO has used a volumetric approach 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 proposes 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 recover transmission system costs only through peak demand charges may not capture all benefits because 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 opposed moving the current point of measurement away from the end-use customer to the T-D interface. Specifically, 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 other 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 effectuate the intended purpose of changing the point of measurement, and there is currently no state regulatory consideration of the merit and implementation issues associated with 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 and regulatory authorities, after careful consideration of the merits and implementation issues, support 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 how the Transmission Access Charge (TAC) is assessed, recommending the ISO 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 of 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 recovery works within the ISO.[2]

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. The ISO published its initial straw proposal on January 11, 2018, revised straw proposal on April 4, 2018, and second revised straw proposal on June 22, 2018. The ISO

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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

received significant stakeholder feedback incorporated in developing this draft final proposal. The following sections reflect the ISO's draft final proposal for this policy initiative.

3. Changes from second revised straw proposal

The ISO has made limited changes for the draft final proposal for this initiative. The only major changes included relate to the use of historical coincident peak demand data to bifurcate the HV-TRR components, and set the 12 coincident peak (12CP) demand HV-TAC rates under the hybrid billing determinant proposal. The ISO also provides additional analysis to evaluate historical coincident peak demand data for rate setting purposes. This analysis demonstrates the reasonableness of the ISO's proposed approach in response to some stakeholder concerns related to the utilization of historic data. The ISO also has proposed a two year phase-in period for the hybrid billing determinant proposal in response to stakeholder feedback.

4. Initiative scope and schedule

Through this initiative the ISO proposes to address these 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 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 consideration in either Q1 or Q2 of 2019 (TBD).

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

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

		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
Second Revised Straw Proposal	June 22	Post second revised straw proposal
	June 28	Hold stakeholder meeting or call
	July 12	Stakeholder written comments due
Draft Final Proposal	Sept 17	Post draft final proposal
	Sept 24	Hold stakeholder meeting or call
	Oct 9	Stakeholder written comments due
Final Proposal	Q1/Q2 (TBD)	Present final proposal at CAISO Board meeting

5. EIM classification

For this initiative, the ISO will seek approval from the ISO Board only. The subjects addressed in this initiative are outside the scope of the EIM Governing Body's advisory role since this 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 paid by participants outside of the ISO's balancing authority area.

Stakeholders that opined on the ISO's initial EIM classification agreed with the ISO that this initiative falls outside of the scope of the EIM Governing Body's advisory role. The ISO plans to seek approval from the ISO Board only for this initiative. The ISO has not received any stakeholder comments in opposition to the proposed EIM classification throughout the various iterations of this initiative. The ISO continues to seek stakeholder feedback on the EIM classification of the initiative.

6. Stakeholder feedback on second revised straw proposal

The ISO received feedback from stakeholders on the second revised straw proposal iteration of the initiative from 13 stakeholders. The ISO summarizes this stakeholder feedback and ISO responses in appendix A. Stakeholder comments are available in their entirety on the initiative webpage here: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=EBB2F922-BEDC-426E-8287-082538BD8880.

7. TAC Structure Enhancements draft final proposal

This initiative has considered potential modifications to the current HV-TAC rate structure. The ISO proposes modifying the billing determinants for measuring customer use. As described in previous proposals, the current approach is a volumetric measurement (MWh). The ISO believes that a hybrid approach, utilizing both peak demand (MW) and a volumetric measurement is more appropriate and better reflects cost causation and the benefits delivered to load. The ISO considered stakeholder feedback on the hybrid billing determinant proposal and the details of implementing the proposed approach. In response to stakeholders input, the ISO made additional enhancements to the hybrid billing determinant proposal described in these sections.

The ISO also received considerable stakeholder feedback on the point of measurement issue considered throughout this initiative. A significant majority of stakeholders have consistently opposed modifying the current point of measurement. They cite numerous concerns, primarily focused on the potential for the unjustified shifting of the embedded costs of existing transmission investments. In addition, effectuating any DG procurement incentives through changing the point of measurement would be ineffective without a commensurate change to the UDCs' retail rate design. Given the significant stakeholder opposition to a point of measurement change, and the fact that changing the ISO's TAC structure alone does not resolve the issue, the ISO believes there is no basis to pursue a TAC point of measurement modification at this time.

The ISO consistently has explained that the transmission system is integral to operating the electric grid and provides not only for the simple volumetric delivery of electricity, but also the necessary support that allows for the reliable, safe, and efficient utilization of both transmission and distribution connected resources. The grid provides stability and support to serve all load, even load in close proximity to distributed energy resources. The ISO is committed to enabling the participation and the effective planning and operation of distributed energy resources and believes that when planned and thoughtfully integrated into the system, these resources will be an important component of California's energy future. However, inferences that widespread DG procurement and operation is *de facto* net beneficial is not correct if DG resources are not carefully planned, developed, and operated in ways beneficial and cost-effective to the grid. Thus, one cannot assume that transmission costs are reduced by the mere existence of DG unless that DG is expressly and purposely designed to avoid or defer more expensive investments in the transmission system.

The ISO is obligated to carefully consider the impact and costs of new transmission investment and works closely with state agencies such as the CPUC and CEC to assist decision makers in determining when, where, and how much to invest in future resources. The costs of transmission (and distribution) that connects renewable resources can factor into which resources are procured.

However, the ISO believes this consideration is best accomplished in an integrated planning and procurement process with oversight by the relevant local regulatory authority, not in an ISO stakeholder initiative. An ISO stakeholder initiative is not the appropriate forum to reallocate the existing fixed costs of the grid, which were derived and approved over the years under various regulatory compacts.

The ISO is willing to revisit the TAC point of measurement issue– for purposes of prospectively allocating the costs of future transmission facilities, but not for existing facilities or their embedded costs– if state policy makers and regulatory authorities, after careful consideration of the merits and implementation issues, support 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 the purview of the ISO and this stakeholder initiative. The ISO further describes numerous challenges faced with any future reconsideration of the point of measurement issue for future transmission costs.

For a full background on the current structure of transmission cost recovery in California, the ISO provided a background whitepaper published April 12, 2017 titled: "How transmission cost recovery through the Transmission Access Charge works today."[5] This background information is intended to explain the complexities surrounding transmission cost recovery in California broadly, and how it impacts considerations taken for the proposed modifications to the HV-TAC structure. It is also vital to identify and explain the benefits provided to customers through the use and access of the transmission system, as well as how various resources and load modifiers impact the ISO transmission planning process, and ultimately, the Transmission Revenue Requirement (TRR). These benefits and transmission impacts are discussed in detail in the ISO's January 11, 2018 straw proposal. [6]

TAC structure rate design objectives

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.[7] The major objectives the ISO reflects in its proposed TAC structure modifications are two overarching concepts. First, TAC allocation should reflect 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 change somewhat over time; the regulatory compact still stands. Second, TAC allocation should also reflect benefits provided to users, which may differ from cost causation. To accomplish this second objective, the ISO must decide how to best measure customer benefits. The ISO supports a rate structure that fairly links the billing determinants to the benefits accrued to grid users. The ISO believes the proposed modifications to the TAC billing determinants described herein appropriately balance these two primary objectives and reflects both cost causation and benefits received by users of the transmission system.

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[5] See Review TAC Structure Background White Paper.

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

[7] See Review TAC Structure Issue Paper.

The ISO also recognizes that any TAC rate design might modify future behavior, which may or may not directly or indirectly support intended policy goals. However, the ISO does not believe policy incentives should be a major driver for revising the TAC rate design for several reasons. First, transmission cost allocation is complicated by the multifaceted ratemaking layers present in California. The ISO allocates transmission costs to UDCs with 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 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 would also need to be developed to properly assign any costs and benefits associated with DG procurement to individual LSEs. The ISO discusses these concepts in section 7.2. For these reasons, the ISO does not believe creating procurement incentives should be an objective of the proposed modifications to the TAC structure. More specifically, a majority of stakeholders and the ISO believe that changes to the TAC point of measurement to effectuate procurement incentives should not be a primary TAC rate design objective.

7.1. Modifications to TAC structure

The ISO's proposed modifications to the TAC structure are intended to better align the cost allocation with the cost drivers and beneficiaries of transmission investment. The ISO proposes to modify the measurement of customer's transmission usage. This aspect of the TAC structure is also referred to as the billing determinant. The ISO proposes to modify the TAC billing determinant to utilize a hybrid approach that reflects both peak demand (MW) and volumetric (MWh) measurements of customer use. The proposed billing determinant modifications alter the basis for measuring customer use applied to calculate TAC allocation among the UDCs.

The ISO also considered modifying the point of measurement for the TAC structure, but determined it was appropriate to maintain the current end-use-customer point of measurement. Many stakeholders have indicated that modifying the point of measurement for the allocation of existing transmission costs would inaccurately reassign some of the embedded costs among UDCs in an unreasonable manner. This concept is also complicated by numerous factors, including how to determine the level of usage of various components of the transmission system if subsets of future TRR costs versus existing costs are measured at different points on the system, especially to the level of scrutiny required by regulators and courts to make reasonable cost allocation decisions. Additionally, the ISO and stakeholders have identified the need for additional modifications to retail rates, which is outside of the ISO's purview, so that incentives flow to the LSEs who make the decisions about whether or not it is best and most cost-effective to invest in DG or in other alternatives. These issues present potential barriers to designing an effective change to the point of measurement for future transmission costs. Such modifications are better addressed through procurement process enhancements, not by attempting to reallocate existing transmission costs determined under prior regulatory compacts. The ISO has carefully considered the level of stakeholder opposition and the major objectives of the TAC structure review, as well as the other important factors described above, in determining not to pursue the potential modification of the TAC point of measurement further under this initiative.

7.1.1. Hybrid 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 the ISO's proposed 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 modifications. The ISO believes that 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 transmission system driven by an evolving resource mix in California. The transmission system today provides services beyond simply energy delivery. 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 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 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 such approach to ignore the capacity function and other reliability benefits provided by the transmission system. A hybrid billing determinant approach measures a portion of customer use through a volumetric measurement and a portion through a peak demand measurement. This hybrid approach captures both the volumetric and peak demand benefits and uses of the system, and it mitigates some of the individual shortcomings of the volumetric or demand approach when applied alone. Numerous 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, of the existing grid.

A hybrid approach has an advantage over other billing determinant approaches because it can reflect the use and benefits of the system more comprehensively and accurately than either a wholly volumetric or wholly peak demand billing determinant approach. The transmission system provides both energy and capacity functions and several reliability benefits.[8] A two-part hybrid approach can better reflect each of these functions. A hybrid approach would not limit TAC cost recovery to just peak demand periods. Not imposing this limitation is advantageous since the benefits of policy projects and other energy delivery functions accrue throughout all hours of the year, not just during peak demand periods.

[8] See Review TAC Structure Straw Proposal.

However, adding a peak demand usage measure more appropriately captures the costs and benefits of serving customers with low load factors and high peak demands than a purely volumetric approach. Additionally, a hybrid rate design mitigates the potential rate burdens placed on certain customers, while retaining the proposed usage charge's sensitivity to seasonal changes while encouraging energy conservation. These reasons support the proposed modifications to the current volumetric billing determinant.

Under the hybrid billing determinant proposal, a portion of the HV-TRR will be recovered through a coincident peak demand charge and a portion through a volumetric charge. To utilize a hybrid approach for the TAC billing determinant, the ISO 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 options for assigning the HV-TRR that have been explored in the ISO's previous proposals. The ISO has received considerable stakeholder support for the latest approach proposed for determining the portions of the HV-TRR to be collected under hybrid billing determinants with an annual system gross load factor calculation. The ISO believes this approach better reflects the benefits of both the volumetric energy delivery and peak demand and reliability functions being provided by the transmission system. This aspect of the proposal is described below.

To implement the peak demand measurement component of a hybrid billing determinant, the ISO will define the peak definition and the frequency of the peak demand measurements. The ISO has previously discussed options related to these aspects during the previous proposal iterations and has incorporated significant stakeholder feedback in developing these peak demand billing determinant details. The ISO previously considered both coincident peak and non-coincident peak demand definitions and the majority of stakeholders agree that a coincident peak definition is the most appropriate approach for the HV-TAC peak demand billing determinant.

The ISO also has considered different options for the frequency of peak demand measurements including 1 (annual), 4 (top 4 monthly peaks), and 12 (monthly) coincident peak (CP) measurement approaches. Most stakeholders have agreed with the ISO's justification and support the proposed utilization of a 12 CP frequency of peak demand measurements for the demand component of the TAC billing determinant. The ISO has provided additional support for the proposed 12CP demand measurement frequency and describes this aspect's impacts on related TAC rate structure issues below in section 7.1.1.2.

7.1.1.1. HV-TRR bifurcation for hybrid billing determinants

The ISO has described some of the ways to determine the percentage of the HV-TRR that will be collected through the separate components of a hybrid rate design. The ISO sought feedback from stakeholders and explored the potential approaches that could be used for transmission cost recovery under the proposed hybrid approach for the HV-TRR. The ISO believes that a preferred approach for splitting transmission costs between volumetric and peak demand that also 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 by the transmission system. Specifically, any bifurcation will be intended to 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 first explored the potential for allocating costs based on analysis of the costs of historically approved categories of transmission projects and to categorize such costs by the above mentioned functions. Some stakeholders agree this approach could be useful, while others believe it would be difficult to determine with the level of precision necessary for cost allocation purposes. In attempting to categorize historically approved TPP costs, the ISO determined such an approach may lead to false precision and could cause 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. The ISO will not pursue the previous efforts to categorize the costs of the previously approved transmission projects any further under this initiative.

The ISO has reviewed the stakeholder input and discussed other potential options for determining the appropriate approach to the HV-TRR cost bifurcation. The ISO proposes to utilize a system-wide annual gross load factor calculation as the preferred method for determining the HV-TRR split. After reviewing the options, the ISO believes this is a more accurate and appropriate method for bifurcation of the HV-TRR under a hybrid approach.

System-wide annual gross load factor calculation for hybrid HV-TRR bifurcation

A metric to assess system utilization and efficiency is the system-wide annual gross load factor (load factor), or the ratio of the annual average system load (average load) and the annual system peak 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. [9] As utility peak loads rise, utility load factors and system capacity utilization decreases. Conversely, as average load

[9] 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

increases, load factors and system capacity utilization increase. 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 reflects the degree that the system is being utilized for peak capacity delivery and reliability functions versus energy delivery functions. The ISO proposes to utilize a system-wide annual gross load factor calculation to split the HV-TRR for each year because this approach reflects the primary functions that make up the basis for splitting the HV-TRR under a hybrid billing determinant approach. This approach will allow the ISO to calculate a HV-TRR split that reflects the utilization and benefits provided by the transmission system in a manner that more closely aligns with the functions of the overall electric grid. The ISO believes this approach is preferable to other previously proposed approaches for splitting the HV-TRR described above. 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 comprehensible, thus making it likely to withstand scrutiny. A majority of stakeholders have indicated support for this bifurcation approach of the HV-TRR.

Calculation steps and example figures for system-wide gross load factor HV-TRR bifurcation:

The ISO proposes to utilize the previous annual period historic data, for the prior period of October 1 through September 30, to calculate the annual system load factor for bifurcation of the upcoming annual TAC rate period. The following steps describe the proposed calculations that will be conducted annually to set the percentage split of the HV-TRR to be applied to recover through the demand charge and volumetric portions of the HV-TAC billing determinants. The ISO has included data from the 2017 year as inputs to demonstrate the proposed calculation.

- **Step 1:** The ISO will start with approved annual HV-TRR (*e.g.*, $2,165,294,596 from the HV Transmission Access Charge Rates effective Jan 1, 2017).[10]

- **Step 2:** The ISO will divide this amount by the pervious annual system-wide coincident peak multiplied by 8760 hours in a year to determine the amount of MWh's that would reflect system utilization at 100% load factor. The ISO proposes the actual calculation will utilize the prior year's annual actual coincident peak identified from available historic settlements data.
    - The ISO will use the reported system-wide annual coincident peak used for settlement purposes[11] (49,900 MW for 2017) multiplied by annual hours (8760): **49,900 MW x 8760 hours = 437,124,000 MWh**.

[10] http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffective1Jan_2017.pdf

[11] For actual implementation, the ISO will utilize the PTO approved forecasted peak demand values to determine the system wide forecasted peak value to use for this system wide load factor calculation aspect of the proposal. See section 7.1.1.3 for additional details on this aspect of the proposal.

- **Step 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.

- **Step 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 revenue expected to be collected by the volumetric component.
    - For this example year (2017) the volumetric component would comprise **~48%** of overall HV-TRR.

- **Step 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 for determining how to bifurcate the HV-TRR to allocate the costs through each part of a proposed hybrid billing determinant. To determine actual HV-TRR bifurcation and resulting HV-TAC rates when implemented, the ISO will utilize the prior year's annual actual coincident peak identified from available historic settlements data. The ISO will use the PTO's forecasted annual gross load for the volumetric portion of this calculation. This PTO provided target year filed and approved forecasted gross load (MWh) and ISO historic annual actual coincident peak (MW) will be used to determine this system-wide annual gross load factor calculation for bifurcation of the HV-TRR under the proposed hybrid billing determinant approach.

The ISO believes that the prior year's annual actual coincident peak value identified from available historic settlements data will be appropriate to utilize for this calculation because it will avoid potential challenges that would arise if forecast coincident peak data was used. Some of the challenges that were indicated by stakeholders were related to the difficulty in developing PTO hourly coincident peak forecasts that would be overly burdensome for some PTOs and would not align with the frequency of some PTO's triennial rate case filings, and other less frequent rate filings. The ISO considered this stakeholder feedback carefully in determining to modify this aspect of the proposal to utilize the prior year's annual actual coincident peak identified from available historic settlements data in the proposed HV-TRR bifurcation calculation.

This process will set the proportions of the HV-TRR that will be applied to determine the volumetric and peak demand TAC rates for each annual period.

Example comparison of current rate and proposed HV-TRR bifurcation approach

The following tables compare the historical volumetric ($/MWh) TAC rates and the proposed hybrid approach volumetric rate, and the potential HV-TRR bifurcation applied historically under the proposed system-wide gross load factor calculation. These values are for example purposes only and actual future results will vary depending on changes to the inputs described above.

Table 2 - Historic volumetric HV-TRR rates

Year	Filed Annual HV-TRR ($)	Filed Annual Gross Load (MWh)	Volumetric TAC Rate ($/MWh)	ISO Annual System-Wide Coincident 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 3 - Proposed hybrid HV-TRR split calculation applied to historic data

Year	ISO Annual Coincident Peak Load (MW)	Filed Annual HV-TRR ($)	Filed Annual Gross Load (MWh)	Volumetric TAC Rate ($/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 charge ($)**	**Volumetric HV-TRR portion (%)**	**TRR amount to be collected through peak demand charge ($)**	**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. Peak demand billing determinant measurement frequency

For a hybrid billing determinant's peak demand measurement component, a key consideration is what frequency to use for the peak demand measurements. As discussed in the ISO's previous proposals, many options can be used for the frequency of peak demand measurements. Different regions have employed these various methods and they all can measure customer usage of the transmission system.

The ISO has considered different options for the frequency of peak demand measurements including 1 (annual), 4 (top 4 monthly peaks), and 12 (monthly) coincident peak (CP) measurement approaches. An analysis of the potential cost impacts related to these three options are provided in the TAC proposal cost impact sensitivities included in appendix B. A majority of stakeholders have supported the proposed utilization of a 12 CP frequency of peak demand measurements for the demand component of the TAC billing determinant because a 12CP frequency because it reflects the benefits associated with monthly delivery of peak capacity and reliability services and also aligns with the current TAC settlements process and many PTO's retail rate structures.

The ISO believes that the choice of peak demand measurement frequency should reflect the way the transmission system has been planned and how 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 to recover 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.[12] FERC settled on demand as the *pro forma* billing determinant in Order No. 888, and indicated a general preference for using a 12CP allocation method.[13] The ISO believes that a 12CP approach strikes a 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 also reflects the benefits associated with monthly delivery of peak capacity and reliability services.

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[12] See ISO Review TAC Structure issue paper.

[13] *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 frequency of peak demand measurements is appropriate because it will result in the collection of a larger amount of the peak demand portion of the HV-TRR in the months that experience relatively higher loads, because the overall peak MW usage will be greater during those months. A lower frequency of CP demand measurements will also result in the demand charge component of the rate to be relatively higher rate per MW ($/MW). Even though the proposed 12CP frequency will collect peak demand TAC charges monthly, a greater proportion the costs collected under peak demand charges will be recovered through the months with relatively higher peaks. The ISO believes this approach is consistent with the major rate design objectives previously discussed, specifically, better aligning the recovery of the HV-TRR with cost causation and benefits provided to users of the transmission system.

The proposed 12CP approach provides advantages over other coincident peak demand measurements, such as 1CP or 4CP. A 12CP frequency of peak demand measurements will help mitigate the potential for certain UDC areas to avoid some of the potential costs that should be allocated to the area that could be occur due to 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 cause costs being allocated to, or avoided by particular UDC areas in a manner inconsistent with the cost causation and overall benefits provided to certain UDCs. In other words, a higher frequency of CP demand measurements can reduce the 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.

The ISO has provided additional modeling results to demonstrate the potential cost impacts of 12CP, 4CP, and 1CP approaches in appendix B, which details a number of TAC cost impact modeling sensitivities for stakeholder review. The ISO has not provided additional frequencies for the CP demand measurements in this iteration because the TAC cost impact model was not designed in a manner that would easily allow for other frequencies to be analyzed. The ISO appreciates stakeholder request for additional analysis but does not believe it would be cost effective to update the modeling to provide the additional sensitivities that have been requested. Additionally, the ISO notes that a majority of stakeholders have supported the proposed 12CP frequency of demand measurements for the implementation of the proposed hybrid approach. The ISO also concurs with the stakeholder feedback that indicates all of the monthly peak loads throughout the year contribute to the use of the transmission grid and the benefits provided to users, and therefore should be reflected in the peak billing determinant. Narrowed definitions of peak load, such as 4CP or 1CP would not accurately reflect the peak related costs in the other months of the year.

7.1.1.3. Implementation details for hybrid billing determinant approach

The ISO provides additional details for hybrid billing determinant implementation details for stakeholders to consider. The ISO has developed an example TAC rate worksheet to demonstrate the proposed hybrid rate design formulation. The ISO is also including a net settlements invoice example to help illustrate the intended implementation and assist stakeholders in understanding the potential impacts of the proposed hybrid rate design. The ISO encourages stakeholders to provide feedback on these rate design implementation details and examples.

Proposed hybrid HV-TAC rates formulation example

The following example describes the formula and data that will be used to set the HV-TAC rates under the proposed hybrid billing determinant rate structure.

The ISO has based these example calculations on the January 2017 HV-TAC rate worksheet available on the ISO public website.[14] The January 2017 TAC rate worksheet provides the initial inputs which include the total HV-TRR: **$2,165,294,596**, and the total forecasted gross load: **209,260,146 MWhs**.

The values and resulting rates included here are for illustrative purposes only. Actual future HV-TAC rates will vary based upon numerous variables.

- **Step 1:** Establish split of annual HV-TRR for hybrid billing determinant approach:
    - Multiply the total annual HV-TRR by the resulting percentage from the system-wide annual gross load factor calculation, as determined by calculation in section 7.1.1.1.[15]
    - Portion of HV-TRR to be collected under volumetric rate: $2,165,294,596 x 50% = $1,082,647,298.
    - Remaining portion of HV-TRR to be collected under 12CP demand charge rate: $2,165,294,596 x 50% = $1,082,647,298.

- **Step 2:** Determine system-wide volumetric HV-TAC rate:
    - Divide the volumetric portion of HV-TRR by total filed annual gross load MWhs.
    - Volumetric TAC rate ($/MWh): $1,082,647,298 ÷ 209,260,146 MWh **= $5.1737/MWh**.

- **Step 3:** Determine system-wide 12CP demand HV-TAC rate:
    - Divide the peak demand portion of HV-TRR by sum of historic annualized 12CP demand MWs for the previous annual period from October 1 through September 30.
    - 12CP Peak demand TAC rate ($/MW): $1,082,647,298 ÷ 380,496 MWs = **$2,845.3579/MW**.

[14] http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffective1Jan_2017.pdf

[15] For this example assume a 50% bifurcation of HV-TRR was determined through proposed system-wide annual gross load factor calculation described in section 7.1.1.1.

Hybrid billing determinant proposal example rate worksheet

The following example HV-TAC rate worksheet demonstrates how the ISO will develop the PTO-specific and system-wide volumetric and peak demand HV-TAC rates under the hybrid billing determinant proposal.

Table 4 - Example TAC rate worksheet for proposed hybrid rate design (based on January, 2017 TAC Rates Worksheet)[16]

PTO	Filed Annual TRR ($) [1]	Volumetric HV-TRR Amount ($) [2]	Filed Annual Gross Load (MWh) [3]	HV Utility Specific Volumetric Rate ($/MWH) [4]	Volumetric TAC Rate ($/MWH) [5]	Volumetric TAC Amount ($) [6]
		[50% assumed TRR split]		= [2] ÷ [3]	= total [2] ÷ total [3]	= [3] × [5]
PG&E	468,014,921	234,007,461	91,500,000	**$ 2.5575**	**$ 5.1737**	473,392,711
SCE	1,030,478,735	515,239,368	88,983,449	**$ 5.7903**	**$ 5.1737**	460,372,854
SDG&E	404,386,165	202,193,083	20,467,098	**$ 9.8789**	**$ 5.1737**	105,890,437
Anaheim	29,782,928	14,891,464	2,507,620	**$ 5.9385**	**$ 5.1737**	12,973,651
Azusa	3,096,475	1,548,237	257,416	**$ 6.0145**	**$ 5.1737**	1,331,791
Banning	1,460,226	730,113	144,652	**$ 5.0474**	**$ 5.1737**	748,385
Pasadena	15,039,959	7,519,979	1,120,049	**$ 6.7140**	**$ 5.1737**	5,794,787
Riverside	35,543,842	17,771,921	2,180,985	**$ 8.1486**	**$ 5.1737**	11,283,742
Vernon	2,985,548	1,492,774	1,181,728	**$ 1.2632**	**$ 5.1737**	6,113,895
Colton	4,110,870	2,055,435	372,179	**$ 5.5227**	**$ 5.1737**	1,925,539
VEA	10,685,478	5,342,739	544,970	**$ 9.8037**	**$ 5.1737**	2,819,506
DATC Path 15	25,457,786	12,728,893	-	**-**	**$ 5.1737**	-
Startrans IO	3,224,199	1,612,100	-	**-**	**$ 5.1737**	-
Trans Bay Cable	120,454,400	60,227,200	-	**-**	**$ 5.1737**	-
Citizens Sunrise	10,573,065	5,286,533	-	**-**	**$ 5.1737**	-
ISO Total	**2,165,294,596**	**1,082,647,298**	**209,260,146**			**1,082,647,298**

[16] http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffectiveJan1_2017_RevisedSep26_2017.pdf

Table 4 (continued) - Example TAC rate worksheet for proposed hybrid rate design

PTO	Peak Demand HV-TRR Amount ($) [7]	Filed Annualized 12CP Demand (MW) [8]	HV Utility-Specific Peak Demand Rate ($/MW) [9]	Peak Demand TAC Rate ($/MW) [10]	Peak Demand TAC Amount ($) [11]
	[50% assumed TRR split]	[from approved PTO rate case forecasts[17]]	= [7] ÷ [8]	= total [7] ÷ total [8]	= [8] × [10]
PG&E	234,007,461	154,560	**$ 1,514.0234**	**$ 2,845.3579**	439,778,516
SCE	515,239,368	170,436	**$ 3,023.0665**	**$ 2,845.3579**	484,951,418
SDG&E	202,193,083	40,128	**$ 5,038.7032**	**$ 2,845.3579**	114,178,522
Anaheim	14,891,464	4,668	**$ 3,190.1165**	**$ 2,845.3579**	13,282,131
Azusa	1,548,237	504	**$ 3,071.8995**	**$ 2,845.3579**	1,434,060
Banning	730,113	264	**$ 2,765.5788**	**$ 2,845.3579**	751,174
Pasadena	7,519,979	2,088	**$ 3,601.5227**	**$ 2,845.3579**	5,941,107
Riverside	17,771,921	4,272	**$ 4,160.0939**	**$ 2,845.3579**	12,155,369
Vernon	1,492,774	2,184	**$ 683.5046**	**$ 2,845.3579**	6,214,262
Colton	2,055,435	672	**$ 3,058.6828**	**$ 2,845.3579**	1,912,081
VEA	5,342,739	720	**$ 7,420.4708**	**$ 2,845.3579**	2,048,658
DATC Path 15	12,728,893	-	**-**	**$ 2,845.3579**	-
Startrans IO	1,612,100	-	**-**	**$ 2,845.3579**	-
Trans Bay Cable	60,227,200	-	**-**	**$ 2,845.3579**	-
Citizens Sunrise	5,286,533	-	**-**	**$ 2,845.3579**	-
ISO Total	**1,082,647,298**	**380,496**			**1,082,647,298**
				ISO Total HV-TRR to be collected: [6] + [11]	**$ 2,165,294,596**

17 The ISO has utilized annualized 12CP demand values obtained from its TAC cost impact model for example purposes. The values used in the example were chosen to avoid revealing confidential data. For implementation purposes, the ISO will utilize historic settlements data.

Historic coincident peak demand data for setting peak demand TAC rates under hybrid billing determinants proposal

The ISO previously indicated that it would utilize the California Energy Commission (CEC) demand forecast as an input to establish the HV-TAC peak demand rates in the ISO's April 4, 2018 revised straw proposal. However, after receiving stakeholder feedback and concern over this potential approach in the revised straw proposal, the ISO agrees that the CEC forecast would not be appropriate to utilize for TAC rate development. The ISO also explored the potential to utilize PTO-specific FERC approved peak demand forecast data to set the peak demand rates in the ISO's June 22, 2018 second revised straw proposal. To implement this approach, the ISO hybrid billing determinant proposal would have required PTOs to include monthly forecast coincident peak demand information in their filed PTO rate case information. Additionally, the ISO would have also needed to develop an iterative process, in which the ISO received FERC approved PTO-specific demand forecasts and determines the forecasted monthly coincident peak hour time period and provided that information back to the PTOs, who would then provide their PTO-specific monthly coincident peak demand forecasts to determine the correct values to be used for setting PTO-specific peak demand rates. After further consideration, the ISO believes that this iterative process would unnecessarily complicate the rate setting process and would be too burdensome for some PTO's to use in developing the PTO-specific and system-wide peak demand rates.

In addition, this aspect of the previous proposal was the subject of concern for numerous stakeholders who raised issues with the rate case timing and staffing and/or forecasting burden that the approach would have imposed with the forecast approach. The ISO received feedback from some stakeholder's indicating the ISO should consider the use of historic data for this purpose that would be more readily available and create a less burdensome process for PTOs. The ISO did not receive any significant stakeholder opposition to utilizing historic data for this purpose. In response, the ISO has modified its approach to utilize historic data for the inputs for establishing the HV-TAC peak demand rates, rather than the previously proposed forecast data.

PTO-specific peak demand rates for implementing the hybrid billing determinant proposal

Stakeholders also indicated that to allow for the ISO to utilize PTO specific peak demand forecasts for setting the system-wide peak demand TAC rate, there is a need to develop PTO-specific peak demand rates. Doing so will accomplish the correct allocation of TAC costs and associated net settlement invoicing. The ISO has provided an example TAC rate worksheet for the proposed hybrid rate design, which describes the proposed process for developing PTO-specific and system-wide peak demand TAC rates, shown in table 6 above.

The ISO will utilize the PTO's actual monthly coincident peak values for the previous annual period, from October 1 through September 30, with the PTO specific monthly coincident peak values identified through available historic settlement data. The ISO proposes using the prior annual period from October 1 to September 30 to avoid data lag and timing issues, as well as potential confidentiality concerns related to publishing historical load data. To demonstrate the timing of this proposed historic coincident peak data approach, the ISO provides the following timing example:

- For setting TAC rates for the 2021 annual period, the ISO will utilize historic coincident peak demand figures from October 1, 2019 through September 30, 2020.

The ISO believes this approach is appropriate and workable while being responsive to stakeholder concerns.

Historic peak demand data analysis

Following the previously proposed approach and discussions related to this aspect of the hybrid billing determinant proposal, the ISO received feedback from certain stakeholders who indicated the ISO should provide additional analysis of historic data to reflect the proposed approach and to provide stakeholders with a sense of how volatile the use of historic data might be when applied to past annual periods. Some stakeholders suggested the ISO may need to consider using an average of multiple years of historic data, or a rolling period where the time frame is longer than one year. In response to these requests, the ISO has performed this analysis, which is included in the tables below.

Table 5 – Historic system-wide monthly coincident peak and annualized peak demand data[18]

2014	System-wide monthly coincident peak (MW)	Date	HE		2015	System-wide monthly coincident peak (MW)	Date	HE
Jan	30,538	1/8/2014	19		Jan	29,638	1/20/2015	19
Feb	29,937	2/3/2014	19		Feb	30,056	2/11/2015	19
Mar	29,154	3/5/2014	19		Mar	31,147	3/26/2015	20
Apr	33,188	4/30/2014	17		Apr	33,998	4/30/2015	17
May	41,480	5/15/2014	17		May	33,228	5/1/2015	17
Jun	40,339	6/30/2014	17		Jun	41,892	6/30/2015	16
Jul	44,004	7/30/2014	17		Jul	42,329	7/29/2015	17
Aug	43,526	8/1/2014	17		Aug	46,785	8/28/2015	17
Sep	44,704	9/15/2014	17		Sep	47,257	9/10/2015	17
Oct	37,908	10/6/2014	17		Oct	41,602	10/13/2015	17
Nov	30,986	11/6/2014	18		Nov	30,594	11/30/2015	19
Dec	31,581	12/15/2014	19		Dec	31,683	12/15/2015	19
Annualized 12CP demand 2014 (MW)	**437,345**				**Annualized 12CP demand 2015 (MW)**	**440,209**		

[18] Source of data is CAISO EMS hourly load data, available here: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=A6FD5B3B-3638-4F4B-9EDF-B24AEF1DCC44

Table 5 – (continued)

2016	System-wide monthly coincident peak (MW)	Date	HE		2017	System-wide monthly coincident peak (MW)	Date	HE
Jan	30,669	1/6/2016	19		Jan	31,291	1/23/2017	19
Feb	30,096	2/1/2016	19		Feb	30,348	2/6/2017	19
Mar	29,294	3/1/2016	19		Mar	29,530	3/14/2017	20
Apr	31,619	4/19/2016	21		Apr	29,118	4/21/2017	21
May	34,250	5/31/2016	19		May	36,039	5/22/2017	18
Jun	44,452	6/20/2016	18		Jun	44,182	6/20/2017	18
Jul	46,008	7/27/2016	17		Jul	45,365	7/7/2017	18
Aug	43,798	8/15/2016	18		Aug	47,344	8/28/2017	17
Sep	42,837	9/26/2016	17		Sep	49,900	9/1/2017	17
Oct	32,823	10/20/2016	19		Oct	39,247	10/24/2017	17
Nov	32,664	11/9/2016	18		Nov	31,307	11/22/2017	18
Dec	31,039	12/7/2016	19		Dec	30,887	12/20/2017	19
Annualized 12CP demand 2016 (MW)	**429,549**				**Annualized 12CP demand 2017 (MW)**	**444,558**		

Table 6 – Comparison of historic peak demand rate with historical data based inputs

Annualized 12CP demand 2014	Annualized 12CP demand 2015	Annualized 12CP demand 2016	Annualized 12CP demand 2017	Two-year rolling average annualized 12CP demand (2016 - 2017)	Three-year rolling average annualized 12CP demand (2015 - 2017)	Four-year rolling average annualized 12CP demand (2014 - 2017)
437,345	440,209	429,549	444,558	437,053.50	438,105.33	437,915.25

	Variance from: two-year rolling average (2016 - 2017)	Variance from: three-year rolling average (2015 - 2017)	Variance from: four-year rolling average (2014 - 2017)	Variance from: annualized 12CP demand 2017	Variance from: annualized 12CP demand 2016	Variance from: annualized 12CP demand 2015	Variance from: annualized 12CP demand 2014
Two-year rolling average historic (2016 - 2017)	-	-0.24%	-0.20%	-1.69%	1.75%	-0.72%	-0.07%
Three-year rolling average historic (2015 - 2017)	-0.24%	-	0.04%	-1.45%	1.99%	-0.48%	0.17%
Four-year rolling average historic (2014 - 2017)	0.20%	-0.04%	-	-1.49%	1.95%	-0.52%	0.13%

Table 7 – Comparison of historic time periods and resulting rate variances[19]

	Annualized 12CP demand (MWs)	HV-TRR demand charge component (assuming Jan 2017 HV-TRR with 50% HV-TRR bifurcation; for static comparison purposes) ($)	Resulting 12CP Demand HV-TAC Rate ($/MW)	Variance in resulting 12CP demand rates versus 2017 only 12CP demand rate (%)
2014	437,345	$ 1,082,647,298	$ 2,475.4994	1.65%
2015	440,209	$ 1,082,647,298	$ 2,459.3938	0.99%
2016	429,549	$ 1,082,647,298	$ 2,520.4279	3.49%
2017	444,558	$ 1,082,647,298	$ 2,435.3342	-
Two-year rolling average (2016 - 2017)	437,053.50	$ 1,082,647,298	$ 2,477.1505	1.69%
Three-year rolling average (2015 - 2017)	438,105.33	$ 1,082,647,298	$ 2,471.2032	1.45%
Four-year rolling average (2014 - 2017)	437,915.25	$ 1,082,647,298	$ 2,472.2759	1.49%

The ISO has provided the analysis above to provide stakeholders with a better sense of the impacts of the proposed historic data use and the associated variance in historic data that would be utilized for implementation year over year and compared to rolling average approaches over longer time frames. This analysis also demonstrates the potential differences in resulting rates and shows that the level of volatility is relatively minor and should not present a large concern or material impact for utilizing only the proposed one year period of historic data in the implementation of the proposed hybrid TAC structure.

The ISO believes that the data and analysis provided shows a small variance in the resulting annualized peak demand data when comparing individual years and a number of longer time periods with rolling average annualized peak demand figures. The analysis indicates that the proposed one year historic period is reasonable for use in setting the 12CP demand rate component of the hybrid HV-TAC structure. The ISO believes that the proposed one year historic period is not inconsistent with the intended rate design principles for the purposes of setting the 12CP demand charge HV-TAC rates under the proposed modifications to the HV-TAC structure.

[19] Assuming Jan 1, 2017 TAC Rates (revised 9/26/2017): http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffectiveJan1_2017_RevisedSep26_2017.pdf

The past four annual periods indicate a relatively low volatility in the resulting historic annualized peak demand figures that have been provided.

Some stakeholders also stated they believe that the ISO should consider weather normalization of the historic data in order to potentially be more consistent with the data used in the transmission planning process. Further, as requested by some stakeholders, the ISO considered if any type of weather normalization should be applied to the historical data in order to avoid anomalous or overly volatile/ highly varying results. The ISO does not believe that any weather normalization adjustments should be applied to the historic data utilized for the setting of the 12CP demand charge rates because the complexity associated with the addition of weather based adjustments is unnecessary, as shown by the analysis above. The historic annualized peak demand data is relatively stable year over year and the lack of volatility indicates that these suggested adjustments are not necessary in the ISO’s opinion. The ISO believes that the use of rolling average annualized peak demand figures over a longer historic period as well as weather based adjustments will not have a material impact on the resulting rates and the potential complexity and resulting effects do not justify the inclusion of either suggestion for the proposed TAC structure modifications.

HV-TAC net settlements invoicing example worksheet

The ISO provides the following example worksheets for the HV-TAC net settlements invoicing process to demonstrate the intended implementation of the hybrid rate design and assist stakeholders in understanding the potential impacts of the proposal. This example demonstrates how the proposed hybrid billing determinants would be applied for settlements purposes.

Table 8: HV-TAC net settlements invoicing example worksheet - TRR Information[20]

PTO Name	Total Filed Annual TRR ($) [1]	Volumetric HV-TRR Amount [2]	Filed Annual Gross Load (MWh) [3]	Percent of Total TRR [4]	**HV Utility Specific Rate ($/MWH)** [5]	Percent of Total Volumetric TRR (W/Load) [6]	**Volumetric TAC Rate ($/MWH)** [7]
		[Assumed 50% split]		*=[2] / sum of [2]*	*= [2] / [3]*	*=[2] / sum of [2] w/Load*	*= sum of [2] / sum of[3]*
PG&E	$ 468,014,921	$ 234,007,461	91,500,000	21.61%	**$ 2.5575**	23.34%	**$ 5.1737**
SCE	$ 1,030,478,735	$ 515,239,368	88,983,449	47.59%	**$ 5.7903**	51.38%	**$ 5.1737**
SDG&E	$ 404,386,165	$ 202,193,083	20,467,098	18.68%	**$ 9.8789**	20.16%	**$ 5.1737**
Anaheim	$ 29,782,928	$ 14,891,464	2,507,620	1.38%	**$ 5.9385**	1.48%	**$ 5.1737**
Azusa	$ 3,096,475	$ 1,053,599	257,416	0.14%	**$ 6.0145**	0.15%	**$ 5.1737**
Banning	$ 1,460,226	$ 1,548,237	144,652	0.07%	**$ 5.0474**	0.07%	**$ 5.1737**
Pasadena	$ 15,039,959	$ 730,113	1,120,049	0.69%	**$ 6.7140**	0.75%	**$ 5.1737**
Riverside	$ 35,543,842	$ 7,519,979	2,180,985	1.64%	**$ 8.1486**	1.77%	**$ 5.1737**
Vernon	$ 2,985,548	$ 17,771,921	1,181,728	0.14%	**$ 1.2632**	0.15%	**$ 5.1737**
Colton	$ 4,110,870	$ 2,055,435	372,179	0.19%	**$ 5.5227**	0.20%	**$ 5.1737**
VEA	$ 10,685,478	$ 5,342,739	544,970	0.49%	**$ 9.8037**	0.53%	**$ 5.1737**
DATC Path 15	$ 25,457,786	$ 12,728,893	-	1.18%	**-**	-	**$ 5.1737**
Startrans IO	$ 3,224,199	$ 1,612,100	-	0.15%	**-**	-	**$ 5.1737**
Trans Bay Cable	$ 120,454,400	$ 60,227,200	-	5.56%	**-**	-	**$ 5.1737**
Citizens Sunrise	$ 10,573,065	$ 5,286,533	-	0.49%	**-**	-	**$ 5.1737**
Total	**$ 2,164,416,245**	**$ 1,082,208,122**	**209,260,146**	**100.00%**		100.00%	

[20] Assuming Jan 1, 2017 TAC Rates (revised 9/26/2017): http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffectiveJan1_2017_RevisedSep26_2017.pdf

Table 8 (continued): HV-TAC net settlements invoicing example worksheet - TRR Information – (assuming Jan 1, 2017 TAC Rates)

PTO Name	Peak Demand HV-TRR Amount	Filed Annualized 12CP Demand (MW)[21]	Percent of Total TRR	**HV Utility Specific 12CP Demand Rate ($/MW)**	Percent of Total Peak Demand TRR (W/Load)	**12CP Demand TAC Rate ($/MW)**
	[8] [Assumed 50% split]	*[9]*	*[10] =[8] / sum of [8]*	*[11] = [8] / [9]*	*[12] =[8] / sum of [8] w/Load*	*[13] = sum of [8] / sum of[9]*
PG&E	$ 234,007,461	154,560	21.62%	**$ 1,514.0234**	23.35%	**$ 2,874.9464**
SCE	$ 515,239,368	170,436	47.61%	**$ 3,023.0665**	51.40%	**$ 2,874.9464**
SDG&E	$ 202,193,083	40,128	18.68%	**$ 5,038.7032**	20.17%	**$ 2,874.9464**
Anaheim	$ 14,891,464	4,668	1.38%	**$ 3,190.1165**	1.49%	**$ 2,874.9464**
Azusa	$ 1,548,237	504	0.10%	**$ 3,071.8995**	0.11%	**$ 2,874.9464**
Banning	$ 730,113	264	0.14%	**$ 2,765.5788**	0.15%	**$ 2,874.9464**
Pasadena	$ 7,519,979	2,088	0.07%	**$ 3,601.5227**	0.07%	**$ 2,874.9464**
Riverside	$ 17,771,921	356	0.69%	**$ 49,921.1264**	0.75%	**$ 2,874.9464**
Vernon	$ 1,492,774	2,184	1.64%	**$ 683.5046**	1.77%	**$ 2,874.9464**
Colton	$ 2,055,435	672	0.19%	**$ 3,058.6828**	0.21%	**$ 2,874.9464**
VEA	$ 5,342,739	720	0.49%	**$ 7,420.4708**	0.53%	**$ 2,874.9464**
DATC Path 15	$ 12,728,893	-	1.18%	**-**	-	**$ 2,874.9464**
Startrans IO	$ 1,612,100	-	0.15%	**-**	-	**$ 2,874.9464**
Trans Bay Cable	$ 60,227,200	-	5.57%	**-**	-	**$ 2,874.9464**
Citizens Sunrise	$ 5,286,533	-	0.49%	**-**	-	**$ 2,874.9464**
Total	**$ 1,082,647,298**	**376,580**	100.00%		100.00%	

[21] This example uses data from the ISO's TAC cost impact modeling, but for actual implementation this data will be sourced from CAISO historic settlements data.

Table 9: HV-TAC net settlements invoicing example worksheet – UDC metered data inputs

PTO Name	Volumetric TAC Rate ($MWh) [1]	Utility Specific Volumetric Rate ($MWh) [2]	**Metered Gross Load (MWh)** [3]	12CP Demand TAC Rate ($MW) [4]	Utility Specific 12CP Demand Rate ($MWh) [5]	**Metered Peak Demand [22] (MW)** [6]
	= [7 from TRR Information]	= [5 from TRR Information]		= [13 from TRR Information]	= [11 from TRR Information]	
PG&E	$ 5.1737	$ 2.5575	**9,098,475**	$ 2,874.9464	$ 1,514.0234	**13,228**
SCE	$ 5.1737	$ 5.7903	**9,698,936**	$ 2,874.9464	$ 3,023.0665	**14,656**
SDG&E	$ 5.1737	$ 9.8789	**1,972,843**	$ 2,874.9464	$ 5,038.7032	**3,224**
Anaheim	$ 5.1737	$ 5.9385	**246,220**	$ 2,874.9464	$ 3,190.1165	**396**
Azusa	$ 5.1737	$ 4.0930	**27,786**	$ 2,874.9464	$ 3,071.8995	**39**
Banning	$ 5.1737	$ 10.7032	**17,886**	$ 2,874.9464	$ 2,765.5788	**24**
Pasadena	$ 5.1737	$ 0.6519	**118,556**	$ 2,874.9464	$ 3,601.5227	**171**
Riverside	$ 5.1737	$ 3.4480	**251,386**	$ 2,874.9464	$ 49,921.1264	**33**
Vernon	$ 5.1737	$ 15.0389	**104,931**	$ 2,874.9464	$ 683.5046	**185**
Colton	$ 5.1737	$ 5.5227	**39,120**	$ 2,874.9464	$ 3,058.6828	**58**
VEA	$ 5.1737	$ 9.8037	**42,718**	$ 2,874.9464	$ 7,420.4708	**62**
DATC Path 15	$ 5.1737	-		$ 2,874.9464	-	**-**
Startrans IO	$ 5.1737	-		$ 2,874.9464	-	**-**
Trans Bay Cable	$ 5.1737	-		$ 2,874.9464	-	**-**
Citizens Sunrise	$ 5.1737	-		$ 2,874.9464	-	**-**
Total			**21,618,857**			**32,076**

22 These values are hypothetical metered peak demand for example purposes only. For implementation the ISO will utilize actual metered peak demand settlement data.

Table 10 - HV-TAC net settlements invoicing example worksheet – allocation process for volumetric HV-TAC settlement

PTO Name	**Total Volumetric HV TAC Due From UDCs ($)** [8]	Proportion of Total TRR (%) [9]	Amounts PTO Would Receive Under Volumetric Utility-Specific ($) [10]	Difference ($) [11]	Proportion of Total Volumetric TRR (w/ Load) (%) [12]	Allocation of Total Volumetric TAC Difference ($) [13]	**Total Volumetric HV TAC Due to PTOs ($)** [14]
	*= [1] * [3]*	*= [4 from TRR Information]*	*= [2] x [3]*	*= Sum of [8] - Sum of [10]*	*= [6 from TRR information]*	*= Sum of [11] x [12]*	*= [10] + [13]*
PG&E	**$ 47,072,695**	21.61%	$ 23,268,972	$ 23,803,723	23.34%	$ (151,708)	**$ 23,117,265**
SCE	**$ 50,179,296**	47.59%	$ 56,159,586	$ (5,980,290)	51.38%	$ (334,031)	**$ 55,825,555**
SDG&E	**$ 10,206,881**	18.68%	$ 19,489,585	$ (9,282,704)	20.16%	$ (131,082)	**$ 19,358,503**
Anaheim	**$ 1,273,867**	1.38%	$ 1,462,175	$ (188,308)	1.48%	$ (9,654)	**$ 1,452,521**
Azusa	**$ 143,756**	0.14%	$ 167,120	$ (23,364)	0.15%	$ (1,004)	**$ 166,116**
Banning	**$ 92,537**	0.07%	$ 90,278	$ 2,259	0.07%	$ (473)	**$ 89,805**
Pasadena	**$ 613,370**	0.69%	$ 795,980	$ (182,609)	0.75%	$ (4,875)	**$ 791,105**
Riverside	**$ 1,300,596**	1.64%	$ 2,048,441	$ (747,846)	1.77%	$ (11,522)	**$ 2,036,920**
Vernon	**$ 542,880**	0.14%	$ 132,550	$ 410,330	0.15%	$ (968)	**$ 131,582**
Colton	**$ 202,393**	0.19%	$ 216,047	$ (13,653)	0.20%	$ (1,333)	**$ 214,714**
VEA	**$ 221,011**	0.49%	$ 418,798	$ (197,787)	0.53%	$ (3,464)	**$ 415,335**
DATC Path 15	-	1.18%	$ 1,315,034	$ (1,315,034)	-	-	**$ 1,315,034**
Startrans IO	-	0.15%	$ 166,547	$ (166,547)	-	-	**$ 166,547**
Trans Bay Cable	-	5.56%	$ 6,222,127	$ (6,222,127)	-	-	**$ 6,222,127**
Citizens Sunrise	-	0.49%	$ 546,157	$ (546,157)	-	-	**$ 546,157**
Total	**$ 111,849,283**	100%	**$ 120,342,163**	**$ (650,113)**	100%	**$ (650,113)**	**$ 111,849,283**

Table 11 - HV-TAC net settlements invoicing example worksheet – allocation process for peak demand HV-TAC settlement

PTO Name	**Total 12CP Demand HV VAC Due From UDCs ($)** [15]	Proportion of total TRR (%) [16]	Amounts PTO Would Receive Under 12CP Demand Utility-Specific ($) [17]	Difference ($) [18]	Proportion of total 12CP Demand TRR (w/ Load) (%) [19]	Allocation of Total 12CP Demand TAC Difference ($) [20]	**Total 12CP Demand HV TAC Due to PTOs ($)** [21]
	= [4] x [6]	= [10] TRR Information	= [5] x [6]	= Sum of [15] - Sum of [17]	= [12] TRR information	= Sum of [18] x [19]	= [17] + [20]
PG&E	**$ 38,029,790**	21.61%	$ 20,027,502	$ 18,002,289	23.34%	$ 84,007	**$ 20,111,509**
SCE	**$ 42,135,214**	47.59%	$ 44,306,063	$ (2,170,849)	51.38%	$ 184,968	**$ 44,491,031**
SDG&E	**$ 9,268,827**	18.68%	$ 16,244,779	$ (6,975,952)	20.16%	$ 72,586	**$ 16,317,365**
Anaheim	**$ 1,138,479**	1.38%	$ 1,263,286	$ (124,807)	1.48%	$ 5,346	**$ 1,268,632**
Azusa	**$ 112,123**	0.14%	$ 119,804	$ (7,681)	0.15%	$ 556	**$ 120,360**
Banning	**$ 68,999**	0.07%	$ 66,374	$ 2,625	0.07%	$ 262	**$ 66,636**
Pasadena	**$ 491,616**	0.69%	$ 615,860	$ (124,245)	0.75%	$ 2,700	**$ 618,560**
Riverside	**$ 94,873**	1.64%	$ 1,647,397	$ (1,552,524)	1.77%	$ 6,380	**$ 1,653,777**
Vernon	**$ 531,865**	0.14%	$ 126,448	$ 405,417	0.15%	$ 536	**$ 126,984**
Colton	**$ 166,747**	0.19%	$ 177,404	$ (10,657)	0.20%	$ 738	**$ 178,141**
VEA	**$ 178,247**	0.49%	$ 460,069	$ (281,823)	0.53%	$ 1,918	**$ 461,987**
DATC Path 15	-	1.18%	$ 1,084,210	$ (1,084,210)	-	-	**$ 1,084,210**
Startrans IO	-	0.15%	$ 137,314	$ (137,314)	-	-	**$ 137,314**
Trans Bay Cable	-	5.56%	$ 5,129,979	$ (5,129,979)	-	-	**$ 5,129,979**
Citizens Sunrise	-	0.49%	$ 450,292	$ (450,292)	-	-	**$ 450,292**
Total	**$ 92,216,779**	100.00%	**$ 91,856,782**	$ 359,997	100.00%	**$ 359,997**	**$ 92,216,779**

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 coincident peak demand data provided through UDCs gross load settlement data. The ISO believes the current UDC gross load data submissions include the necessary hourly average coincident peak demand data that can also be utilized for HV-TAC settlements.

The ISO will use each UDC's hourly average coincident peak demand, coinciding with each monthly system coincident peak hour to determine the 12CP monthly demand usage and associated HV-TAC 12CP demand charges. The ISO believes this proposed approach is appropriate because the ISO will set the 12CP demand charge HV-TAC rates using historical 12CP demand figures.

Updating HV-TAC rates for approved TRR and forecast demand 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 peak demand TAC rates will be determined through the PTOs forecasted annual gross load and historical coincident peak demand data from the prior annual period, as described above.

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 volumetric and 12CP demand charge HV-TAC rates based on the effective date approved by FERC.

Similarly, the ISO will provide updates to the HV-TAC rates if the ISO receives updated volumetric gross load forecast values from PTO's when FERC approves changes to their PTO-specific forecasts. When PTOs provided updated volumetric gross load forecast values the ISO will recalculate the resulting volumetric and 12CP demand charge HV-TAC rates based on the effective date approved by FERC.

Some stakeholders indicated potential concerns related to the possibility of increased updates to the HV-TAC rates during the annual periods that would be associated with the hybrid billing determinant proposal. The ISO understands these concerns; however, this potential for a higher frequency of intra-year TAC rate updates due to the addition of more inputs to the rate setting process is necessary for the implementation of the proposal. The ISO does not believe this will be a significant issue due to the expected magnitude of these potential rate updates.

Proposed phase-in for hybrid billing determinant TAC structure

Some stakeholders have expressed that they believe it would be prudent to implement a phase-in to the new rate structure to reduce possible billing impacts. Other stakeholders have stated they believe there is no demonstrated need for a phase-in period due to relatively small rate impacts. 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 understands stakeholders' reasons for supporting a phase-in of the hybrid billing determinant approach.

Previously, the ISO agreed that a phase-in was not needed and noted that the impact analysis for the proposed hybrid approach provided in this proposal indicates relatively small impacts to most UDCs. However, numerous stakeholders have raised issues with the accuracy of the ISO impact analysis, and the ISO agrees that these figures may be potentially divergent from actual resulting rate and cost allocation impacts for some PTO areas due to the load profiling techniques applied in the analysis to mask confidential load information for some smaller PTOs. In response to this potential concern and continued support for the ISO to include a phase-in period, the ISO proposes to phase-in the hybrid billing determinant proposal over a two year period.

The ISO will phase-in the proposed modifications to the TAC billing determinant through the following approach related to the annual bifurcation of the HV-TRR components to be collected under the volumetric and 12CP demand charge TAC rates:

1. For setting HV-TAC rates in year one of implementing the hybrid billing determinant approach – the ISO will administratively bifurcate the HV-TRR components so that **15%** of the HV-TRR will be collected under the 12CP peak demand HV-TAC rate and **85%** of the HV-TRR will be collected under the volumetric HV-TAC rate.

2. For setting HV-TAC rates in year two of implementing the hybrid billing determinant approach – the ISO will administratively bifurcate the HV-TRR components so that **30%** of the HV-TRR will be collected under the 12CP peak demand HV-TAC rate and **70%** of the HV-TRR will be collected under the volumetric HV-TAC rate.

3. Starting in year three – the ISO will begin calculating the HV-TRR bifurcation through the proposed system load factor approach, as detailed in section 7.1.1.1, and the resulting bifurcation will be applied as proposed starting in year three of implementation of the hybrid billing determinant proposal.

The ISO believes that this short phase-in will sufficiently mitigate any sudden change in rate impact among CAISO transmission owners. The ISO believes that a longer phase-in is not warranted and would be unlikely to prevail if submitted to FERC.

Potential for over or under-recovery of transmission costs

The ISO has received stakeholder feedback indicating that it should consider the need to address the potential risk for additional over or under-recovery of transmission costs under the proposed modifications to the billing determinants. 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 principle. However, the ISO does not intend to adopt further modifications to address under- or over-recovery beyond the current mechanisms in place today. The ISO also notes that individual outcomes will be affected by the rate structure of each PTO as described further below.

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 TRR that must be recovered through the HV-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.

With stated rates, there is no adjustment mechanism, either through the TRBA or some other mechanism, for over- or under-collection due to differences between the actual and forecasted gross load. This lack of adjustment mechanism for differences between actual and forecasted loads would still occur for PTOs with stated rates that do not utilize this aspect of the TRBA mechanism under their PTO specific rate design.

The ISO does not believe the proposal for a hybrid billing determinant approach requires the addition of any further modifications to further protect against, or otherwise address the under or over-recovery of the TAC amounts collected under the proposed approach.

7.1.1.4. Modifications to WAC rate structure for treating non-PTO entities comparably under hybrid billing determinant proposal

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 entities with the proposed billing determinants for other PTOs/UDCs. This aspect of the proposal will only apply to those non-PTO entities currently billed for their use of the HV transmission system through the Wheeling Access Charge (WAC).[23] This change will not be applied to the WAC rates assessed to traditional exports and wheeling transactions. The ISO has received feedback from stakeholders that is widely supportive of 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

[23] See Review TAC Structure background whitepaper.

approach. These entities are treated similar to internal loads in some important ways that support the ISO's proposal. These entities' loads are planned for and served by the transmission system similarly to other internal loads. Their use of the HV transmission system is measured volumetrically, although they are charged WAC, instead of TAC. This approach for measuring their usage is similar to the way other traditional transmission customers 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 entities.

The ISO proposes to adopt a hybrid billing determinant approach including peak demand and volumetric measurements for the for these non-PTO 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.

This proposal will result in three separate and distinct WAC rates:

1. Volumetric WAC rate ($/MWh) for traditional exports and wheeling transactions.
    - This traditional volumetric WAC rate will be calculated the same as current practice, corresponding to full annual HV-TRR amount ($) and total sum of approved PTO gross load forecasts (MWh).
    - This rate will continue to be charged to all traditional exports and wheeling transactions.

2. Hybrid billing determinant volumetric WAC rate ($/MWh) for non-PTO entities.
    - This hybrid billing determinant volumetric WAC rate will be calculated corresponding with the annual volumetric HV-TRR amount[24] ($) and the total sum of approved PTO gross load forecasts (MWh).
    - This rate will be charged monthly to non-PTO entities currently taking ISO transmission service under the WAC charge.

3. Hybrid billing determinant 12CP demand rate ($/MW) for non-PTO entities.
    - This hybrid billing determinant 12CP demand WAC rate will be calculated corresponding to the annual peak demand HV-TRR amount[25] ($) and historical annualized 12CP demand[26] (MW).
    - This rate will be charged monthly to non-PTO entities currently taking ISO transmission service under the WAC charge based on their monthly coincident peak

[24] As proposed in section 7.1.1.1.
[25] As proposed in section 7.1.1.1.
[26] As proposed in section 7.1.1.3.

demand (The ISO will use the average hourly demand corresponding to the ISO system-wide monthly coincident peak for settlements purposes).

The ISO will continue to calculate the standard volumetric ($/MWh) WAC rate used for traditional exports and wheeling purposes as done today. The ISO notes this standard WAC rate will be based upon the full HV-TRR (non-bifurcated) and approved PTO annual gross load MWhs. The resulting WAC rate for traditional exports and wheeling transactions will be different from the proposed hybrid WAC rates for the non-PTO entities taking transmission service through the modified treatment under this proposal (these entities will be charged under the hybrid billing determinant rates calculated as described above).

The ISO previously discussed the potential to provide a cost impact on the non-PTO entities that will take service under this aspect of the proposal. The ISO has determined that it cannot provide analysis related to this impact publically, due to potential confidentiality of the data that is required. The ISO notes that the entities impacted by this aspect of the proposal may have the ability to calculate the potential impacts to their cost responsibility based upon their forecasted volumetric and peak demand the hybrid billing determinant rate calculations described above.

7.2. Point of measurement issue

The point of measurement is the point where the billing determinant is measured and reported. Currently, this measurement is taken at the end use customer meter. The ISO has received stakeholder feedback suggesting the ISO consider modifying the point of measurement used for TAC billing. Some stakeholders strongly advocate 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 discussed this issue in depth with stakeholders during multiple stakeholder meetings and working groups and solicited written comments on this topic. The ISO received significant stakeholder feedback opposing changes to the current point of measurement at the end-use customer meter. The ISO does not believe it is appropriate to change the point of measurement for the reasons described herein. For a complete background on the point of measurement issue and the impacts and treatment of DG and other non-wire alternatives in the ISO's transmission planning process, see the ISO's January 11, 2018 straw proposal.[27]

Throughout prior iterations of this initiative, the ISO has consistently explained that the transmission system is integral to the overall operation of the overall electric grid. The transmission system is the backbone needed to deliver the energy and reliability services that enable the safe, affordable, and efficient use of both transmission and distribution connected resources; without this backbone, these resources would have limited to no viability. The grid provides reliable service to all loads, even those located in close proximity to distributed energy resources. The safe and reliable delivery of energy from distributed energy resources is

[27] See Review TAC Structure straw proposal.

enabled, supported, and backed by the transmission system; without it a distributed energy resource and the load it serves would be wholly dependent on that capabilities and reliability of that resource.

The ISO is committed to participation from distributed energy resources and believes they are an important and growing component of California's energy ecosystem. However, the ISO concurs with the views expressed by many stakeholders that it is not accurate to suggest robust procurement and operation of local distributed energy resources is viable independent of, or distinct from, the transmission grid. The transmission system is integral to the delivery of all energy sources interconnected to the grid. The current TAC billing determinant proposal will enhance the approach to allocating costs in a more fair and equitable manner, which reflects cost causation and how benefits accrue to its users.

The ISO is also obligated to carefully consider the impact and costs of new transmission investment and works closely with state agencies such as the CPUC and CEC to assist decision makers in determining when, where, and how much to invest in future resources. The costs of capital-intensive transmission that connects distant renewable resources should factor into whether or not those distant renewable resources are selected for procurement, and who pays for the transmission. However, the ISO believes this consideration is best accomplished in an integrated planning and procurement process by the relevant local regulatory authorities.

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. 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 prior proposals.

Also, a majority of stakeholders expressed concern this change would inappropriately shift embedded costs among UDC areas, and it ignores the full benefits provided by the transmission system to all 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 shifts responsibility for the embedded costs of the existing system among the UDC areas; it would not create any cost reduction or new efficiency. It would simply shift costs away from one UDC's customers with high DG penetration to another UDC's customers with low DG penetration, ignoring that both UDCs and their customers are dependent on the transmission system for the reliability and support of the entire electric system.

Numerous stakeholders noted that only future transmission costs might 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, where such alternatives constitute a more efficient or cost effective solution. The ISO notes that the TPP and current procurement processes already account for the impacts of DG and other non-wire alternatives in avoiding 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 and would reallocate costs among UDC areas in a manner that is not reflective of cost causation and benefits provided. Because the existing transmission system costs are embedded (sunk) costs, these costs cannot be reduced. The ISO believes that modifying the point of measurement will not improve efficiency or reduce these embedded transmission costs.

The ISO understands there is some merit that LSEs may have relatively less benefit from any approved new transmission due to their choice to serve some of their load from local DG resources, and it may be fair that these LSEs customers be allocated less of the costs associated with new transmission. While this concept may have merit, it is outside the ISO's ability to effectuate this concept at the LSE specific level and to provide any useful incentive or credit for DG resource procurement and production. Additionally, the ISO believes the potential crediting mechanism that would be necessary may be overly complex to implement and be justified at the current levels of DG production (current estimates indicate ~1-3% of overall gross load served by DG production, annually).

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 absent state regulatory authority support for the necessary changes in retail rate design, the ISO proposes to maintain the current point of measurement at the end use customer meter 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 and regulatory authorities, after careful consideration of the merits and implementation issues, support 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 change the point of measurement for only future transmission costs in response to its straw proposal. Most stakeholders that provided feedback on this issue have also strongly opposed the concept, citing numerous concerns described below.

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 could not determine an accurate cost estimate for even the initial installation of the infrastructure 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 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 in densely populated urban areas with substations limited to existing footprints.

A second area of 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, and the treatment of other TRR costs such as future operations and maintenance costs (O&M). Additionally, numerous stakeholders believe that it would be challenging 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. It's likely the ISO 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. 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. These issues present challenges to designing a potential split point of measurement concept.

Next Steps

The ISO will discuss this draft final proposal with stakeholders during a meeting on September 24, 2018. Stakeholders are asked to submit written comments by October 9, 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

The ISO will present this draft final proposal to its' Board of Governors in Q1/Q2 of 2019 (exact date TBD).

Appendix A – Stakeholder comment summary and ISO responses

The ISO received feedback from 13 stakeholders on the second revised straw proposal.

The stakeholder comments are available in their entirety on the initiative webpage here: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=EBB2F922-BEDC-426E-8287-082538BD8880. The ISO provides a summary of this feedback and ISO responses below.

Stakeholders supporting the hybrid billing determinant proposal:

For the latest iteration of the proposal, the ISO received feedback from nine stakeholders supporting the ISO's hybrid billing determinant proposal on various levels. These entities include: Bay Area Municipal Transmission Group (BAMx), City of Vernon, California Large Energy Consumers Association (CLECA), California Public Utilities Commission (CPUC), CAISO Department of Market Monitoring (DMM), Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and the Six Cities.

Discussion of stakeholder feedback supporting the hybrid billing determinant proposal:

- *A majority of stakeholders have consistently expressed support for including a peak demand component in the TAC billing determinant throughout this initiative. Most stakeholders agree this is appropriate because adopting a methodology where a significant portion of the HV TRR is recovered based upon peak demands on the system reflects cost causation and sends appropriate price signals for maximizing usage of existing transmission facilities. Stakeholders supportive of the proposed modifications cite the ability to better reflect the role of coincident peak demand in cost causation for transmission investment and use of the transmission system during system peaks. Most stakeholders support these modifications and believe they are a substantial improvement over the current methodology. These stakeholders agree this hybrid billing approach will better reflect the nature of transmission usage as compared to the current volumetric/energy-only approach. The support provided also acknowledges that the transmission system provides a variety of benefits that go beyond simply transporting energy and note that the hybrid billing determinant modifications would more appropriately reflect the multiple drivers and functions of transmission facilities.*

The ISO appreciates the support for the proposed hybrid billing determinant approach. The ISO agrees the proposed modifications will better reflect the nature of transmission use and the benefits provided. The ISO has provided additional analysis and implementation details on its proposal for a hybrid billing determinant in the draft final proposal.

Stakeholders opposing the hybrid billing determinant proposal:

The ISO has received feedback from two stakeholders opposing the ISO's hybrid billing determinant proposal to some extent. The two stakeholders that oppose this aspect of the proposal in their written comments are Clean Coalition and the California Office of Ratepayer Advocates (ORA).

Discussion of stakeholder feedback opposing the hybrid billing determinant proposal:

- *The Clean Coalition has previously supported the concept of a hybrid billing determinant for many of the same reasons expressed by other supportive stakeholders, however their latest feedback on the revised straw proposal includes a number of criticisms of the proposed hybrid rate design. The Clean Coalition feedback states they believe the CAISO's currently proposed hybrid approach has seven substantial flaws under CAISO's stated rate design principles.*

  First, the proposed demand charge doesn't reflect the contributions to peak energy flows on transmission system that theoretically drive transmission spending. Second, because the demand charge treats in front of the meter resources differently than behind the meter resources, even though they have the same impact on reducing peak transmission flows, the proposed demand charge creates a new market distortion that has no rational justification. Third, the demand charge gives identical credit to any behind the meter storage or self-generation for reducing peak transmission flows, even though not all behind the meter resources have identical impacts on the transmission system. Fourth, neither the proposed demand charge nor the volumetric charge reflect the historical embedded cost causation, and therefore do not allocate costs proportional to historical cost drivers and fails to assign transmission costs to the customers for whom the system was built. Fifth, the proposed demand charge would create substantial unjustified costs shifts that would allow UDCs to avoid paying TAC for a system built for their customers. Sixth, the hybrid design has only a tangential relationship to the historical cost causation. Seven, CAISO suggests that all customers should be required to contribute to paying transmission costs for the capacity service, yet the current proposal allows TAC charges to go to zero even while the capacity benefit remains.

  Clean Coalition has also indicated that they believe the ISO must provide a solid justification for the appearance of a disparate treatment of in front of the meter resources and behind the meter resources under the proposed hybrid approach.

In contrast to the Clean Coalition's critiques, the ISO and nearly all other stakeholders believe that the addition of a demand charge component to the TAC rate billing determinants is appropriate and will actually result in a better reflection of the impacts to the transmission system and customer use. Similarly, other stakeholders and the ISO have concluded that the proposed demand charge better reflects cost causation of the peak demand cost drivers in a manner that will more appropriately assign transmission costs to the customers for whom the system was built compared to the current volumetric approach. The ISO disagrees with the Clean Coalition's statement that the ISO has rejected the balanced approach to cost causation and beneficiaries pay by ignoring the allocation of benefits and rejecting the prospective reallocation of costs as the beneficiaries change. The ISO's proposed addition of a peak demand component to the TAC billing determinants actually better reflects the appropriate allocation of costs as the beneficiaries change by more accurately accounting for their actual use of the transmission system beyond the current volumetric-only measurement approach.

The ISO disagrees with claims that the hybrid billing determinant proposal would create unjustified costs shifts or that it would allow UDCs to avoid paying TAC for the investments made to serve their customers. The ISO believes the cost impacts of the proposal are justified and reasonable. The ISO has received the strong support of a majority of stakeholders that agree the hybrid billing determinant proposal and resulting TAC cost allocation are appropriate. The ISO has never indicated that a primary rate design principle was to avoid any potential cost shifts related to any aspects of potential modifications. The ISO has supported the examination of TAC, acknowledging that it could result in justifiable cost shifts to better align cost allocation with both cost causation and benefits received by users. Additionally, the ISO does not agree the proposed modification would create substantial unjustified costs shifts that would allow UDCs to avoid paying TAC for a system built for their customers and. In contrast, most stakeholders and the ISO agree that the proposed hybrid design will better reflect current usage by customers and the benefits delivered to those customers.

Clean Coalition has also indicated that they believe the ISO must provide a solid justification for the appearance of disparate treatment of in front of the meter resources and behind the meter resources. The ISO responds that the outcome describe by the Clean Coalition is justified and appropriate because of the fact that IFOM distributed resource production is supported by the transmission system as described in the section on the point of measurement issue above. The ISO also recognizes that DER resources can reduce future transmission costs and has explained how the ISO believes that retail rate design changes should also be considered to more appropriately reflect that fact before the ISO reconsiders the issue of the TAC point of measurement for future transmission costs, these details are discussed in section 7.2 above.

The ISO believes the impacts of the proposed modifications are appropriate because the changes will better reflect the impacts of customer demands and use of the transmission system and account for differences in load factors and utilization of the transmission more appropriately than the current volumetric-only approach. The ISO has only stated concerns over problematic, unjustified cost shifts related to the point of measurement modification. The ISO's opposition to the unreasonable reallocation of the embedded transmission costs that would result from a change in the point of measurement is based on the fact that it will cause certain UDC customers to be allocated TAC costs in a manner inconsistent with cost causation, actual usage, and benefits received.

- *The California Office of Ratepayer Advocates (ORA) has also indicated it cannot support the proposed modifications to adopt hybrid billing determinants because they believe that, based on ORA's assessment of the Hybrid TAC proposal, this alternative TAC structure does not appear to better align costs with the benefits received from the transmission system and appears unlikely to produce outcomes that are more just or reasonable than the existing all-volumetric TAC rate structure.*

The ISO understands the feedback provided by ORA on the hybrid billing determinant proposal. The ISO disagrees that the proposed rate design modifications would not provide outcomes that are more just or reasonable than the existing all-volumetric TAC rate structure. Most stakeholders and the ISO support the proposed hybrid approach because it can produce more accurate results that better reflect the cost causation and benefit received by users. In addition, the ISO believes that the current proposal to include a peak demand component in the TAC billing determinants will better reflect many of the benefits provide by the transmission system, including the reliability and standby benefits (which generally occur during peak periods).

Discussion of additional stakeholder feedback regarding the hybrid billing determinant proposal:

- *SCE previously indicated a belief that a third billing determinant should be considered: number of service meters. This third billing determinant would allow for an equitable assessment of costs that are not based on either energy or demand. An example would be costs expended for vegetation management that are driven by the geo-spatial expanse of the transmission network more so than the demand or energy needs provided by the system. SDG&E submitted feedback that supports this previous SCE recommendation: SDG&E proposes that 20% of the HV-TRR be allocated to PTOs based on the number of end-use meters served by each PTO. The remaining 80% of the HV-TRR would be allocated between peak load and end-use energy consumption using each PTO's load factor as described in the CAISO's current proposal.*

The ISO appreciates the suggestions for this additional concepts however continues to respond similarly to the previous response to SCE on this issue. The ISO agrees that it may be appropriate to reflect this concept of assessing costs that are not based on energy or demand in the TAC rate structure to the extent possible. However the inclusion of some level of fixed charges for customer meters in the rate design will be complex to determine and justify. While it seems relatively straightforward to incorporate a billing determinant based on total number of service meters, the ISO believes that is too unclear how it could actually determine a factual, analytical based approach to establish the correct level of cost recovery to be applied to this potential additional fixed charge type of billing determinant. While the ISO agrees that these concepts do have merit and this will become a larger issue as the number of behind the meter solar installations continues to expand, the ISO does not believe it would appropriate to include these additional components in the TAC rate structure modifications under this initiative due to the difficulty in determining and justifying an appropriate identification of the correct cost allocation of this potential elements. Moreover, the ISO is concerned that including this additional billing determinant could create irrational incentives to increase service meters solely for its effect on billing determinants.

- *The CAISO Department of Market Monitoring (DMM) provided feedback on the hybrid billing determinant proposal. DMM believes that while the ISO's proposal to use a hybrid approach to assess TAC charges is an improvement over the purely volumetric approach today, eliminating a volumetric TAC billing determinant completely would further enhance spot market efficiency. A demand-based approach better aligns transmission cost allocation with the current use of the transmission system. The ISO's analysis shows that when TAC charges are increasingly demand-based, UDCs in Southern California incur a greater percentage of total TAC charges.1 These* *results are consistent with the pattern of increased north to south power flows and congestion during periods of high load. Over time, a demand-based TAC could incentivize those who use the system more heavily during high load periods to reduce or shift load, potentially reducing future transmission buildout and associated costs. DMM supports the ISO's proposal to base peak demand rates on forecasted coincident peak loads and to base demand charges on measured demand during actual coincident peak intervals. The ISO's proposed approach would make the peak intervals used in actual billing less predictable, thus reducing the incentive for entities to incorporate TAC charges into spot market offers in predetermined intervals. DMM also appreciates the ISO's responses to and consideration of DMM's past comments. DMM continues to encourage the ISO to further evaluate various issues related to TAC charges:*

- *Eliminating a volumetric TAC billing determinant completely could further enhance spot market efficiency.*
- *The inefficiency of a volumetric TAC or WAC also applies to export and wheeling transactions; the ISO should evaluate alternative billing determinants for exports and wheeling transactions*
- *DMM supports the ISO revisiting the TAC point of measurement issue for allocating costs of future transmission facilities.*
- *The ISO should consider developing a process through which any entity that may have an obligation to deliver energy across the ISO transmission system could pre-pay TAC and participate in the CRR allocation process.*

The ISO appreciates the feedback provided by DMM and agrees with the concepts as described. The ISO has attempted to strike a balance on its hybrid billing determinant proposal, recognizing that DMM and some stakeholders would prefer a fully demand based TAC billing determinant. The ISO also has received feedback indicating that a hybrid approach is preferable due to the ability to reflect the cost causation and functions of the transmission system better than a purely volumetric or peak demand billing determinant can alone. The ISO recognizes there may be some outstanding concerns with the impacts to the ISO markets but believes that the hybrid billing determinant proposal is an improvement over the *status quo*. The ISO will continue to keep these important DMM recommendations under consideration for further discussion in future related stakeholder initiatives.

Discussion of historic versus forecast data for use in setting 12CP demand rates under proposed hybrid approach

The ISO previously proposed to utilize CEC forecast data or PTO forecast data for setting the 12CP demand rate for implementation of the proposed hybrid approach. The ISO received feedback from some stakeholder's indicating the ISO should consider the use of historic data for this purpose that would be more readily available and create a less burdensome process for PTOs. Some stakeholders indicated strong opposition to the use of forecast data, stating serious concerns over the additional burdens that would be imposed on their rate case processes. The ISO did not receive any significant stakeholder opposition to utilizing historic data for this purpose. In response, the ISO has modified its approach to utilize historic data for the inputs for establishing the HV-TAC peak demand rates, rather than the previously proposed forecast data. The changes to utilize historic data for this aspect of the implementation are provided in the sections above, along with supporting analysis that shows that a one year annual historic period will be a reasonable approach, due to the relatively low volatility in historic annualized peak demand figures year over year.

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

The ISO has previously received feedback from numerous stakeholders that indicated support for the proposed 12CP monthly frequency of peak demand measurements under a hybrid billing determinant approach.

- *Stakeholders previous input supporting the proposed 12CP approach also provided additional input in their written feedback. Some stakeholders noted that the use of a 12CP approach is a widely accepted practice by FERC, increasing its viability, and a 12CP approach is also consistent with the retail ratemaking for some of the large IOUs who already use 12CP approach to allocate the TRR among some of their retail customer classes. Other merits of the 12CP proposal that stakeholders raised were that it reasonably represents cost causation for the peak related portion of the HV-TAC revenue requirement and is a reasonable balance between summer and non-summer transmission peak demand cost causation and benefits. Stakeholders also agreed with the ISO's belief that the 12CP approach makes it less likely that anomalous peak demands in a given year or season could skew the allocation of transmission costs.*
- *SCE also provided comments in the current iteration of feedback indicating that they believe all of the monthly peak loads throughout the year contribute to the use of the transmission grid and the benefits provided to users, and therefore should be reflected in the peak billing determinant. Narrowed definitions of peak load, such as 4-CP (four summer peaks, and no consideration of the other eight months at all), would not accurately reflect the peak related costs in the other eight months of the year.*

The ISO appreciates the stakeholder's additional input in support of the 12CP approach. The ISO continues to believe that this approach is appropriate and this additional support provides further justification for this aspect of the hybrid billing determinant proposal. The ISO looks forward to further development of the justification and implementation details of the 12CP approach as it finalizes the ultimate TAC structure proposal for consideration.

Previously some stakeholders, including; BAMx, BPA, CCSF, ORA, and SVP, have indicated general opposition to the proposed 12CP frequency of peak demand measurements under a hybrid billing determinant approach. For the latest iteration of the proposal the ISO received feedback opposing the proposed 12CP frequency of peak demand measurements from two stakeholders, BAMx and ORA.

- *BAMx continues to object to the 12 CP methodology in favor of a metric that focuses more on the month (or months) with the highest peak demand on the system. The Second Revised Straw Proposal rationalizes a 12 CP methodology, in part, "because it will result in the collection of a* *larger amount of the peak demand portion of the HV-TRR in the months that experience relatively higher loads, because the overall peak MW usage will be greater during those months." 2 This statement would apply to any billing method that utilizes monthly demand or energy billing determinants, including the current 100% volumetric approach. Both the 1 CP and 4 CP methods are much more directly linked to the drivers of the need for transmission infrastructure. Therefore, the 12 CP method does not demonstrate movement in the direction of the TAC structure design objectives.*

- *BAMx believes the proper focus of the demand component should be on recovering transmission demand related costs driven by peak load and should not be blended in with the other costs/benefits reflected in the volumetric charge. The load driven transmission costs are better captured by metrics that focus on demand around the annual coincident peak (e.g., 1 CP or 4 CP). As BAMx noted in its comments on the revised straw proposal, using 12 CP effectively becomes a surrogate for a volumetric measurement by spreading the measurement points throughout the entire year, which will result in much less than 50% of the costs being collected based on demand and instead effectively increase the portion of costs collected based on energy volume.*

The ISO understands the issues raised by BAMx related to their opposition to the 12CP approach. The ISO believes that a 12CP approach reflects both the capacity function and reliability benefits provided to system users on a monthly basis. The 12CP approach also allows for more stability in rate design and cost recovery by applying a consistent demand TAC rate and measuring coincident peak usage for monthly billing settlements purposes. The ISO also believes that the proposed 12CP frequency of peak demand measurements is appropriate because it will result in the collection of a larger amount of the peak demand portion of the HV-TRR in the months that experience relatively higher loads, because the overall peak MW usage will be greater during those months. Due to this impact the ISO disagrees that the 12CP approach will be effectively the same as a volumetric rate design. The 12CP approach will still set a demand based TAC rate ($/MW) and billing of UDCs will be based on their coincident peak demand, which allocates transmission costs differently than a volumetric billing determinant and does not shift costs away from demand. The ISO also concurs with the SCE feedback that all of the monthly peak loads throughout the year contribute to the use of the transmission grid and the benefits provided to users, and therefore should be reflected in the peak billing determinant. Narrowed definitions of peak load, such as 4-CP (four summer peaks, and no consideration of the other eight months at all), would not accurately reflect the peak related costs in the other eight months of the year.

- *ORA feedback indicates their belief that there are at least three issues with using the 12 CP demand measurement for the proposed Hybrid TAC structure:*
  - *A 12 CP measurement does not align with how the CAISO plans for transmission reliability needs. The CAISO currently plans for peaks in the summer and the winter. For this reason, ORA agrees with Silicon Valley Power (SVP) that a 12 CP measurement could mute the price signal regarding the drivers for most transmission planning decisions and costs.*
  - *PTOs with peaks that are not coincident with the system peak will pay less. Based on the CAISO's hourly load data for four Participating Transmission Owners (PTOs) within the CAISO balancing area, which are Pacific Gas and Electric Company (PG&E), Southern California*

Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and Valley Electric Association (VEA), the PTOs with the greatest load each month drive the system's coincident peak hours. Currently, on average, these PTOs are PG&E and SCE. As a result, if the Hybrid TAC relies on a purely 12 CP demand measurement, PTOs with significantly different peak hours than PG&E and SCE, such as VEA, will pay less with the Hybrid TAC than under the current volumetric TAC based structure. With the implementation of a Hybrid TAC using a 12 CP demand measurement as illustrated in CAISO's Hybrid TAC cost impact modeling analysis, it is estimated that VEA could pay approximately 8.4% less than it does today. This is because VEA has comparatively lower load and its system peaks in the morning, whereas the systems of PGE, SCE, and SDG&E peak in the evening per ORA's review of the CAISO's hourly load data. SVP's Hybrid TAC proposal, which is similar to the CAISO Hybrid TAC proposal and includes volume and peak demand components and relies on the system load factor to determine the TAC recovery allocation for these components, estimates an increase in the VEA TAC burden with the implementation of its Hybrid TAC, not a decrease. ORA, therefore, recommends further evaluation of this disparity as well as SVP's modified 12 CP demand measurement proposal for the Hybrid TAC as described in SVP comments on May 1, 2018.

  - *The peak time frame for the CAISO system shifts from month to month and is greater than one hour. Because PTOs' peak time frames vary from month to month, it is important to further evaluate the preferred peak time frame for the Hybrid TAC so that it will produce equitable results. As illustrated in the SVP's May 1, 2018 comments,7 during the colder months (November, December, January, February, and March), the system's peak hours fall within a one to three hour Time frame that is generally between hours 18 and 20. During the warmer months (April through October), there is a wider spread in the peak hours, and the peak time frame ranges from hours 16 to 20. For this reason, ORA agrees with SVP that using a single hour for the coincident peak time frame for the Hybrid TAC is not likely the most equitable solution. ORA recommends further evaluation of the system coincident peak time frame options in the next iteration of this Hybrid TAC proposal to determine the time frame that would have the most equitable outcome.*

- *Given the issues described above and ORA's analysis, ORA predicts that implementing the Hybrid TAC proposal with the proposed 12 CP demand measurement that relies on a one-hour system coincident peak could result in an under collection of revenues for the high-voltage (HV) transmission costs obligations, while not producing rates that are more just and reasonable than the existing volumetric TAC rate structure.*
- *ORA recommends that the CAISO consider changes in weather patterns from year to year in determining the 12 CP demand measurement. If the CAISO relies on historic data to determine the 12 CP demand measurement, it should consider possible weather extremes or an average demand measurement over a three to five-year time-frame.*

The ISO appreciates the feedback provided by ORA, however the ISO disagrees with the reasons provided in the ORA feedback. A 12CP approach is consistent with the intent of the rate design principles stated by the ISO previously. Further, all of the monthly peak loads throughout the year contribute to the use of the transmission grid and the benefits provided to users, and therefore should be reflected in the peak billing determinant. Narrowed definitions of peak load, such as 4-CP (four summer peaks, and no consideration of the other eight months at all), would not accurately reflect the peak related costs in the other eight months of the year.

The ISO concurs that PTOs with peaks that are not coincident with the system peak will most likely pay less under the proposed modifications, however, the ISO and a majority of stakeholders believe this outcome is accurate and appropriate. Outcomes wherein certain PTOs that do not peak coincidently with the system-wide monthly peak are intended to be part of the design of the proposed modifications and are appropriate. Further, the continued use of the volumetric billing determinant will ensure that PTOs are allocated a fair and accurate share of the overall transmission costs that reflects the energy delivery, peak capacity use, and reliability benefits provided to users. This aspect of the rate structure is also intended to address the last concern raised by ORA that the peak time frame for the CAISO system shifts from month to month and is greater than one hour. This concern is addressed by aspects of the 12CP approach and the volumetric component of the rate design.

The ISO disagree with the ORA claim that the proposed 12 CP demand measurement that relies on a one-hour system coincident peak could result in an under collection of revenues for the high-voltage (HV) transmission costs obligations. The ISO believes this is inconsistent with the intent of the proposed modifications and also notes that over or under collection protections are already included in the existing mechanisms to address potential over and under collection of the existing volumetric only rate and these will continue to be utilized under the proposed modifications.

The ISO has provided its position on the need for weather adjustments and average approaches with longer time frames for setting the 12CP demand rates under the proposed hybrid approach. The ISO also provides analysis indicating the data from historic periods is relatively stable and does not justify the use of weather normalization or rolling averages longer than the proposed one year period. The additional complexity is not warranted given the relatively small effects of such a design modification.

Stakeholder feedback on the point of measurement issue:

The ISO did not specifically request additional feedback on the point of measurement issue for this iteration of the initiative. For a full discussion of the previously received stakeholder feedback on the point of measurement topic please see the ISO's previous proposals, including the straw, revised straw, and second revised straw proposals, available at the ISO's initiative webpage. The ISO has included detailed stakeholder feedback and ISO responses on the point of measurement issue in the appendices of those proposal iterations.

Appendix B – Hybrid billing determinant proposal TAC cost impact modeling analysis with additional sensitivities

The ISO provides 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 prior proposals. The ISO stresses that the future year's cost impact figures are only modeled impacts based on forecasts; they do not reflect firm future outcomes. These values are for illustrative purposes only. The actual TAC cost allocation and billing for future years will be based on the actual usage measurements, which will differ due to differences in several 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 will vary from the forecasts.

The ISO received feedback from stakeholders that indicated the ISO should consider providing further clarification of the sources and inputs that were used to develop the following impact analysis. Stakeholders believe they must validate the ISO analysis in order to support any final proposed modifications. The ISO notes that the modeling provided below utilizes publicly available data and this required the ISO to apply load profiles to some of the smaller PTO UDCs in this analysis. This aspect of the modeling that has used load profiles for the larger PTO areas, available on the ISO webpage in the form of historical hourly load data for 2016.[28] This data is public and is provided for SCE, SDG&E, PG&E, and VEA. The load profile technique that has been applied to the modeling analysis included below is the source of any reported discrepancies between this impact analysis and the impacts that individual stakeholders have attempted to verify, using actual settlements gross load data for their organizations. The ISO notes that this issue is the source of previous requests for clarification received from stakeholders and clarifies that this potential for discrepancy is relatively small in magnitude but was necessary in order to avoid any potential confidentiality concerns. The ISO believes that the example rate development worksheets and the example TAC net settlements invoicing worksheets that have been provided in this proposal above will allow for any interested stakeholders to estimate the potential impacts to their organizations based on their own assumptions of forecasted load or actual settlements data, applied to the example hybrid billing determinant rates provided in the included examples. The ISO is willing and able to meet individually with any interested stakeholders to review the potential impacts and discuss these analysis results if requested.

The ISO has provided hybrid billing determinant cost impact modeling sensitivities for 1CP, 4CP, and 12CP demand measurement approaches (with a 50% HV-TRR bifurcation assumption). The ISO also provides a number of sensitivities for HV-TRR bifurcation amounts ranging from 40% volumetric – 60% peak demand split through a 60% volumetric – 40% peak demand split, in 2% increments. The ISO reiterates that these values are based on forecasts and actual results will vary – the following sensitivities are provided for illustrative purposes only.

[28] http://www.caiso.com/Documents/HistoricalEMSHourlyLoad-2016.xlsx

TAC charges under current volumetric rate design

	2018	2019	2020	2021	2022
PG&E	$1,009.6	$1,063.1	$1,143.5	$1,223.6	$1,299.9
SCE	$1,016.7	$1,070.5	$1,151.4	$1,232.1	$1,308.9
SDG&E	$220.8	$232.5	$250.0	$267.6	$284.2
Anaheim	$27.2	$28.7	$30.8	$33.0	$35.0
Azusa	$2.9	$3.1	$3.3	$3.5	$3.8
Banning	$1.7	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.4	$13.1	$14.1	$15.0	$16.0
Riverside	$25.5	$26.9	$28.9	$31.0	$32.9
Vernon	$12.8	$13.5	$14.5	$15.6	$16.5
Colton	$4.1	$4.3	$4.6	$4.9	$5.2
VEA	$5.3	$5.6	$6.0	$6.4	$6.8
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Existing Rate ($/MWh)	**$11.11**	**$11.63**	**$12.42**	**$13.25**	**$13.94**

Coincident Peak measurement frequency scenarios

Scenario: 12CP frequency (12 demand measurements, Hybrid TRR split: 50% Volumetric - 50% Peak Demand)

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$979.9	$1,031.7	$1,109.8	$1,187.5	$1,261.5
SCE	$1,032.2	$1,086.8	$1,169.0	$1,250.9	$1,328.9
SDG&E	$233.7	$246.1	$264.7	$283.3	$300.9
Anaheim	$28.0	$29.5	$31.7	$33.9	$36.0
Azusa	$3.0	$3.2	$3.4	$3.7	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.6	$13.3	$14.3	$15.3	$16.2
Riverside	$25.9	$27.3	$29.3	$31.4	$33.3
Vernon	$13.1	$13.8	$14.9	$15.9	$16.9
Colton	$4.1	$4.3	$4.7	$5.0	$5.3
VEA	$4.9	$5.1	$5.5	$5.9	$6.3
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$5.56**	**$5.82**	**$6.21**	**$6.63**	**$6.97**
Coincident Peak 12 Periods - Gross Load ($/MW)	**$3,071.53**	**$3,215.25**	**$3,432.31**	**$3,663.12**	**$3,854.27**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(29,779,795)	(31,356,864)	(33,727,689)	(36,091,342)	(38,340,631)
SCE	15,509,378	16,330,718	17,565,448	18,796,444	19,967,878
SDG&E	12,949,226	13,634,986	14,665,898	15,693,692	16,671,756
Anaheim	760,691	800,976	861,536	921,913	979,368
Azusa	92,978	97,902	105,304	112,684	119,707
Banning	(1,605)	(1,690)	(1,817)	(1,945)	(2,066)
Pasadena	204,341	215,162	231,430	247,649	263,083
Riverside	344,029	362,248	389,637	416,943	442,928
Vernon	311,066	327,539	352,304	376,993	400,488
Colton	57,590	60,640	65,224	69,795	74,145
VEA	(447,898)	(471,618)	(507,276)	(542,826)	(576,656)
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-2.9496%	-2.9496%	-2.9496%	-2.9496%	-2.9496%
SCE	1.5255%	1.5255%	1.5255%	1.5255%	1.5255%
SDG&E	5.8654%	5.8654%	5.8654%	5.8654%	5.8654%
Anaheim	2.7957%	2.7957%	2.7957%	2.7957%	2.7957%
Azusa	3.1805%	3.1805%	3.1805%	3.1805%	3.1805%
Banning	-0.0972%	-0.0972%	-0.0972%	-0.0972%	-0.0972%
Pasadena	1.6465%	1.6465%	1.6465%	1.6465%	1.6465%
Riverside	1.3468%	1.3468%	1.3468%	1.3468%	1.3468%
Vernon	2.4234%	2.4234%	2.4234%	2.4234%	2.4234%
Colton	1.4216%	1.4216%	1.4216%	1.4216%	1.4216%
VEA	-8.4204%	-8.4204%	-8.4204%	-8.4204%	-8.4204%

Scenario: 4CP frequency (4 overall monthly peaks, Hybrid TRR split: 50% Volumetric - 50% Peak Demand)

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$959.3	$1,010.1	$1,086.5	$1,162.6	$1,235.1
SCE	$1,061.6	$1,117.8	$1,202.3	$1,286.5	$1,366.7
SDG&E	$223.4	$235.2	$253.0	$270.8	$287.6
Anaheim	$27.9	$29.4	$31.6	$33.8	$35.9
Azusa	$3.1	$3.2	$3.5	$3.7	$3.9
Banning	$1.8	$1.9	$2.0	$2.2	$2.3
Pasadena	$12.9	$13.6	$14.6	$15.6	$16.6
Riverside	$27.2	$28.6	$30.8	$32.9	$35.0
Vernon	$12.6	$13.3	$14.3	$15.3	$16.3

Colton	$4.3	$4.5	$4.8	$5.2	$5.5
VEA	$5.0	$5.3	$5.7	$6.1	$6.5
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$5.56**	**$5.82**	**$6.21**	**$6.63**	**$6.97**
Coincident Peak 4 Periods - Gross Load ($/MW)	**$7,191.23**	**$7,527.73**	**$8,035.92**	**$8,576.31**	**$9,023.85**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(50,344,618)	(53,010,751)	(57,018,780)	(61,014,685)	(64,817,248)
SCE	44,895,947	47,273,531	50,847,781	54,411,220	57,802,241
SDG&E	2,633,451	2,772,913	2,982,567	3,191,586	3,390,493
Anaheim	680,760	716,812	771,008	825,041	876,459
Azusa	135,838	143,032	153,846	164,628	174,888
Banning	150,379	158,343	170,315	182,250	193,609
Pasadena	498,238	524,624	564,289	603,835	641,467
Riverside	1,623,210	1,709,171	1,838,398	1,967,234	2,089,836
Vernon	(203,759)	(214,550)	(230,772)	(246,944)	(262,334)
Colton	208,299	219,330	235,913	252,446	268,179
VEA	(277,745)	(292,454)	(314,566)	(336,611)	(357,589)
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-4.9864%	-4.9864%	-4.9864%	-4.9864%	-4.9864%
SCE	4.4160%	4.4160%	4.4160%	4.4160%	4.4160%
SDG&E	1.1928%	1.1928%	1.1928%	1.1928%	1.1928%
Anaheim	2.5019%	2.5019%	2.5019%	2.5019%	2.5019%
Azusa	4.6466%	4.6466%	4.6466%	4.6466%	4.6466%
Banning	9.1102%	9.1102%	9.1102%	9.1102%	9.1102%
Pasadena	4.0147%	4.0147%	4.0147%	4.0147%	4.0147%
Riverside	6.3543%	6.3543%	6.3543%	6.3543%	6.3543%
Vernon	-1.5874%	-1.5874%	-1.5874%	-1.5874%	-1.5874%
Colton	5.1418%	5.1418%	5.1418%	5.1418%	5.1418%
VEA	-5.2216%	-5.2216%	-5.2216%	-5.2216%	-5.2216%

Scenario: 1CP frequency (Single annual peak, Hybrid TRR split: 50% Volumetric - 50% Peak Demand)

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$988.6	$1,040.9	$1,119.6	$1,198.1	$1,272.7
SCE	$1,042.6	$1,097.8	$1,180.8	$1,263.6	$1,342.3
SDG&E	$215.0	$226.4	$243.5	$260.6	$276.8
Anaheim	$27.2	$28.6	$30.8	$32.9	$35.0
Azusa	$3.0	$3.1	$3.4	$3.6	$3.8
Banning	$1.8	$1.9	$2.0	$2.2	$2.3
Pasadena	$12.6	$13.3	$14.3	$15.3	$16.2
Riverside	$26.7	$28.1	$30.2	$32.4	$34.4
Vernon	$12.0	$12.6	$13.6	$14.5	$15.4
Colton	$4.2	$4.4	$4.7	$5.1	$5.4
VEA	$5.4	$5.7	$6.1	$6.6	$7.0
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$5.56**	**$5.82**	**$6.21**	**$6.63**	**$6.97**
Coincident Peak 1 Period - Gross Load ($/MW)	**$27,692.13**	**$28,987.93**	**$30,944.86**	**$33,025.80**	**$34,749.22**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(21,085,439)	(22,202,075)	(23,880,726)	(25,554,300)	(27,146,897)
SCE	25,935,459	27,308,940	29,373,710	31,432,235	33,391,158
SDG&E	(5,772,899)	(6,078,618)	(6,538,209)	(6,996,410)	(7,432,441)
Anaheim	(27,603)	(29,065)	(31,262)	(33,453)	(35,538)
Azusa	59,552	62,706	67,447	72,174	76,672
Banning	158,539	166,934	179,556	192,139	204,114
Pasadena	195,698	206,062	221,642	237,175	251,956
Riverside	1,159,401	1,220,800	1,313,102	1,405,125	1,492,695
Vernon	(850,517)	(895,559)	(963,270)	(1,030,776)	(1,095,016)
Colton	127,874	134,646	144,826	154,976	164,634
VEA	99,935	105,228	113,184	121,116	128,664
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-2.0884%	-2.0884%	-2.0884%	-2.0884%	-2.0884%
SCE	2.5510%	2.5510%	2.5510%	2.5510%	2.5510%

SDG&E	-2.6148%	-2.6148%	-2.6148%	-2.6148%	-2.6148%
Anaheim	-0.1014%	-0.1014%	-0.1014%	-0.1014%	-0.1014%
Azusa	2.0371%	2.0371%	2.0371%	2.0371%	2.0371%
Banning	9.6046%	9.6046%	9.6046%	9.6046%	9.6046%
Pasadena	1.5769%	1.5769%	1.5769%	1.5769%	1.5769%
Riverside	4.5387%	4.5387%	4.5387%	4.5387%	4.5387%
Vernon	-6.6261%	-6.6261%	-6.6261%	-6.6261%	-6.6261%
Colton	3.1565%	3.1565%	3.1565%	3.1565%	3.1565%
VEA	1.8788%	1.8788%	1.8788%	1.8788%	1.8788%

HV-TRR split scenarios under hybrid approach with 12CP demand measurements

Scenario: Hybrid, 60% Volumetric - 40% Peak Demand, 12CP demand measurements

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$985.8	$1,038.0	$1,116.5	$1,194.7	$1,269.2
SCE	$1,029.1	$1,083.6	$1,165.5	$1,247.2	$1,324.9
SDG&E	$231.1	$243.4	$261.8	$280.1	$297.6
Anaheim	$27.8	$29.3	$31.5	$33.7	$35.8
Azusa	$3.0	$3.2	$3.4	$3.6	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.6	$13.2	$14.2	$15.2	$16.2
Riverside	$25.8	$27.2	$29.2	$31.3	$33.2
Vernon	$13.1	$13.8	$14.8	$15.9	$16.8
Colton	$4.1	$4.3	$4.6	$5.0	$5.3
VEA	$5.0	$5.2	$5.6	$6.0	$6.4
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$6.67**	**$6.98**	**$7.45**	**$7.95**	**$8.37**
Coincident Peak 12 Periods - Gross Load ($/MW)	**$2,457.22**	**$2,572.20**	**$2,745.85**	**$2,930.50**	**$3,083.42**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(23,823,836)	(25,085,491)	(26,982,151)	(28,873,074)	(30,672,504)
SCE	12,407,502	13,064,574	14,052,359	15,037,155	15,974,302
SDG&E	10,359,380	10,907,989	11,732,719	12,554,953	13,337,405
Anaheim	608,553	640,780	689,229	737,530	783,494
Azusa	74,383	78,322	84,244	90,147	95,766

Banning	(1,284)	(1,352)	(1,454)	(1,556)	(1,653)
Pasadena	163,473	172,130	185,144	198,119	210,466
Riverside	275,223	289,798	311,710	333,554	354,342
Vernon	248,853	262,031	281,843	301,595	320,391
Colton	46,072	48,512	52,180	55,836	59,316
VEA	(358,319)	(377,294)	(405,821)	(434,261)	(461,325)
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-2.3596%	-2.3596%	-2.3596%	-2.3596%	-2.3596%
SCE	1.2204%	1.2204%	1.2204%	1.2204%	1.2204%
SDG&E	4.6923%	4.6923%	4.6923%	4.6923%	4.6923%
Anaheim	2.2365%	2.2365%	2.2365%	2.2365%	2.2365%
Azusa	2.5444%	2.5444%	2.5444%	2.5444%	2.5444%
Banning	-0.0778%	-0.0778%	-0.0778%	-0.0778%	-0.0778%
Pasadena	1.3172%	1.3172%	1.3172%	1.3172%	1.3172%
Riverside	1.0774%	1.0774%	1.0774%	1.0774%	1.0774%
Vernon	1.9387%	1.9387%	1.9387%	1.9387%	1.9387%
Colton	1.1373%	1.1373%	1.1373%	1.1373%	1.1373%
VEA	-6.7363%	-6.7363%	-6.7363%	-6.7363%	-6.7363%

Scenario: Hybrid, 58% Volumetric - 42% Peak Demand, 12CP demand measurements

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$984.6	$1,036.8	$1,115.2	$1,193.3	$1,267.7
SCE	$1,029.7	$1,084.2	$1,166.2	$1,247.9	$1,325.7
SDG&E	$231.7	$243.9	$262.4	$280.7	$298.2
Anaheim	$27.8	$29.3	$31.5	$33.8	$35.9
Azusa	$3.0	$3.2	$3.4	$3.6	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.6	$13.2	$14.2	$15.2	$16.2
Riverside	$25.8	$27.2	$29.3	$31.3	$33.3
Vernon	$13.1	$13.8	$14.8	$15.9	$16.9
Colton	$4.1	$4.3	$4.6	$5.0	$5.3
VEA	$4.9	$5.2	$5.6	$6.0	$6.4
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$6.44**	**$6.75**	**$7.20**	**$7.69**	**$8.09**
Coincident Peak 12 Periods - Gross Load ($/MW)	**$2,580.08**	**$2,700.81**	**$2,883.14**	**$3,077.02**	**$3,237.59**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(25,015,028)	(26,339,766)	(28,331,258)	(30,316,727)	(32,206,130)
SCE	13,027,877	13,717,803	14,754,977	15,789,013	16,773,017
SDG&E	10,877,349	11,453,388	12,319,354	13,182,701	14,004,275
Anaheim	638,981	672,820	723,690	774,407	822,669
Azusa	78,102	82,238	88,456	94,655	100,554
Banning	(1,348)	(1,419)	(1,527)	(1,634)	(1,735)
Pasadena	171,646	180,736	194,401	208,025	220,990
Riverside	288,984	304,288	327,295	350,232	372,059
Vernon	261,295	275,133	295,935	316,674	336,410
Colton	48,375	50,937	54,789	58,628	62,282
VEA	(376,235)	(396,159)	(426,112)	(455,974)	(484,391)
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-2.4776%	-2.4776%	-2.4776%	-2.4776%	-2.4776%
SCE	1.2814%	1.2814%	1.2814%	1.2814%	1.2814%
SDG&E	4.9269%	4.9269%	4.9269%	4.9269%	4.9269%
Anaheim	2.3484%	2.3484%	2.3484%	2.3484%	2.3484%
Azusa	2.6716%	2.6716%	2.6716%	2.6716%	2.6716%
Banning	-0.0817%	-0.0817%	-0.0817%	-0.0817%	-0.0817%
Pasadena	1.3831%	1.3831%	1.3831%	1.3831%	1.3831%
Riverside	1.1313%	1.1313%	1.1313%	1.1313%	1.1313%
Vernon	2.0357%	2.0357%	2.0357%	2.0357%	2.0357%
Colton	1.1941%	1.1941%	1.1941%	1.1941%	1.1941%
VEA	-7.0731%	-7.0731%	-7.0731%	-7.0731%	-7.0731%

Scenario: Hybrid, 56% Volumetric - 44% Peak Demand, 12CP demand measurements

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$983.4	$1,035.5	$1,113.8	$1,191.9	$1,266.1
SCE	$1,030.3	$1,084.9	$1,166.9	$1,248.7	$1,326.5
SDG&E	$232.2	$244.5	$262.9	$281.4	$298.9
Anaheim	$27.9	$29.4	$31.6	$33.8	$35.9
Azusa	$3.0	$3.2	$3.4	$3.6	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.6	$13.3	$14.3	$15.3	$16.2

Riverside	$25.8	$27.2	$29.3	$31.3	$33.3
Vernon	$13.1	$13.8	$14.8	$15.9	$16.9
Colton	$4.1	$4.3	$4.6	$5.0	$5.3
VEA	$4.9	$5.2	$5.6	$6.0	$6.3
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$6.22**	**$6.51**	**$6.95**	**$7.42**	**$7.81**
Coincident Peak 12 Periods - Gross Load ($/MW)	**$2,702.94**	**$2,829.42**	**$3,020.43**	**$3,223.55**	**$3,391.76**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(26,206,220)	(27,594,040)	(29,680,366)	(31,760,381)	(33,739,755)
SCE	13,648,252	14,371,032	15,457,595	16,540,871	17,571,733
SDG&E	11,395,318	11,998,788	12,905,990	13,810,449	14,671,145
Anaheim	669,408	704,859	758,151	811,283	861,844
Azusa	81,821	86,154	92,668	99,162	105,342
Banning	(1,412)	(1,487)	(1,599)	(1,711)	(1,818)
Pasadea	179,820	189,343	203,658	217,931	231,513
Riverside	302,746	318,778	342,880	366,910	389,776
Vernon	273,738	288,234	310,027	331,754	352,430
Colton	50,679	53,363	57,398	61,420	65,248
VEA	(394,150)	(415,024)	(446,403)	(477,687)	(507,457)
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-2.5956%	-2.5956%	-2.5956%	-2.5956%	-2.5956%
SCE	1.3425%	1.3425%	1.3425%	1.3425%	1.3425%
SDG&E	5.1615%	5.1615%	5.1615%	5.1615%	5.1615%
Anaheim	2.4602%	2.4602%	2.4602%	2.4602%	2.4602%
Azusa	2.7988%	2.7988%	2.7988%	2.7988%	2.7988%
Banning	-0.0855%	-0.0855%	-0.0855%	-0.0855%	-0.0855%
Pasadena	1.4490%	1.4490%	1.4490%	1.4490%	1.4490%
Riverside	1.1851%	1.1851%	1.1851%	1.1851%	1.1851%
Vernon	2.1326%	2.1326%	2.1326%	2.1326%	2.1326%
Colton	1.2510%	1.2510%	1.2510%	1.2510%	1.2510%
VEA	-7.4099%	-7.4099%	-7.4099%	-7.4099%	-7.4099%

Scenario: Hybrid, 54% Volumetric - 46% Peak Demand, 12CP demand measurements

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$982.2	$1,034.3	$1,112.5	$1,190.4	$1,264.6
SCE	$1,030.9	$1,085.5	$1,167.6	$1,249.4	$1,327.3
SDG&E	$232.7	$245.0	$263.5	$282.0	$299.6
Anaheim	$27.9	$29.4	$31.6	$33.8	$35.9
Azusa	$3.0	$3.2	$3.4	$3.6	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.6	$13.3	$14.3	$15.3	$16.2
Riverside	$25.9	$27.2	$29.3	$31.3	$33.3
Vernon	$13.1	$13.8	$14.9	$15.9	$16.9
Colton	$4.1	$4.3	$4.6	$5.0	$5.3
VEA	$4.9	$5.2	$5.6	$5.9	$6.3
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$6.00**	**$6.28**	**$6.70**	**$7.16**	**$7.53**
Coincident Peak 12 Periods - Gross Load ($/MW)	**$2,825.80**	**$2,958.03**	**$3,157.72**	**$3,370.07**	**$3,545.93**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(27,397,412)	(28,848,315)	(31,029,474)	(33,204,035)	(35,273,380)
SCE	14,268,627	15,024,261	16,160,213	17,292,728	18,370,448
SDG&E	11,913,287	12,544,187	13,492,626	14,438,196	15,338,015
Anaheim	699,836	736,898	792,613	848,160	901,019
Azusa	85,540	90,070	96,880	103,669	110,130
Banning	(1,476)	(1,554)	(1,672)	(1,789)	(1,901)
Pasadena	187,993	197,949	212,916	227,837	242,036
Riverside	316,507	333,268	358,466	383,587	407,493
Vernon	286,181	301,336	324,119	346,834	368,449
Colton	52,983	55,788	60,007	64,212	68,214
VEA	(412,066)	(433,888)	(466,694)	(499,400)	(530,524)
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-2.7136%	-2.7136%	-2.7136%	-2.7136%	-2.7136%
SCE	1.4035%	1.4035%	1.4035%	1.4035%	1.4035%

SDG&E	5.3961%	5.3961%	5.3961%	5.3961%	5.3961%
Anaheim	2.5720%	2.5720%	2.5720%	2.5720%	2.5720%
Azusa	2.9261%	2.9261%	2.9261%	2.9261%	2.9261%
Banning	-0.0894%	-0.0894%	-0.0894%	-0.0894%	-0.0894%
Pasadena	1.5148%	1.5148%	1.5148%	1.5148%	1.5148%
Riverside	1.2390%	1.2390%	1.2390%	1.2390%	1.2390%
Vernon	2.2295%	2.2295%	2.2295%	2.2295%	2.2295%
Colton	1.3079%	1.3079%	1.3079%	1.3079%	1.3079%
VEA	-7.7468%	-7.7468%	-7.7468%	-7.7468%	-7.7468%

Scenario: Hybrid, 52% Volumetric - 48% Peak Demand, 12CP demand measurements

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$981.0	$1,033.0	$1,111.1	$1,189.0	$1,263.1
SCE	$1,031.6	$1,086.2	$1,168.3	$1,250.2	$1,328.1
SDG&E	$233.2	$245.6	$264.1	$282.6	$300.2
Anaheim	$27.9	$29.4	$31.6	$33.9	$36.0
Azusa	$3.0	$3.2	$3.4	$3.7	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.6	$13.3	$14.3	$15.3	$16.2
Riverside	$25.9	$27.2	$29.3	$31.4	$33.3
Vernon	$13.1	$13.8	$14.9	$15.9	$16.9
Colton	$4.1	$4.3	$4.7	$5.0	$5.3
VEA	$4.9	$5.1	$5.5	$5.9	$6.3
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$5.78**	**$6.05**	**$6.46**	**$6.89**	**$7.25**
Coincident Peak 12 Periods - Gross Load ($/MW)	**$2,948.66**	**$3,086.64**	**$3,295.01**	**$3,516.59**	**$3,700.10**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(28,588,604)	(30,102,589)	(32,378,581)	(34,647,689)	(36,807,005)
SCE	14,889,002	15,677,489	16,862,830	18,044,586	19,169,163
SDG&E	12,431,257	13,089,587	14,079,262	15,065,944	16,004,885
Anaheim	730,264	768,937	827,074	885,036	940,193
Azusa	89,259	93,986	101,092	108,177	114,919
Banning	(1,540)	(1,622)	(1,745)	(1,867)	(1,983)
Pasadena	196,167	206,556	222,173	237,743	252,560
Riverside	330,268	347,758	374,051	400,265	425,210
Vernon	298,623	314,438	338,212	361,914	384,469

Colton	55,286	58,214	62,616	67,004	71,179
VEA	(429,982)	(452,753)	(486,985)	(521,113)	(553,590)
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-2.8316%	-2.8316%	-2.8316%	-2.8316%	-2.8316%
SCE	1.4645%	1.4645%	1.4645%	1.4645%	1.4645%
SDG&E	5.6307%	5.6307%	5.6307%	5.6307%	5.6307%
Anaheim	2.6839%	2.6839%	2.6839%	2.6839%	2.6839%
Azusa	3.0533%	3.0533%	3.0533%	3.0533%	3.0533%
Banning	-0.0933%	-0.0933%	-0.0933%	-0.0933%	-0.0933%
Pasadena	1.5807%	1.5807%	1.5807%	1.5807%	1.5807%
Riverside	1.2929%	1.2929%	1.2929%	1.2929%	1.2929%
Vernon	2.3265%	2.3265%	2.3265%	2.3265%	2.3265%
Colton	1.3647%	1.3647%	1.3647%	1.3647%	1.3647%
VEA	-8.0836%	-8.0836%	-8.0836%	-8.0836%	-8.0836%

Scenario: Hybrid, 50% Volumetric - 50% Peak Demand, 12CP demand measurements

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$979.9	$1,031.7	$1,109.8	$1,187.5	$1,261.5
SCE	$1,032.2	$1,086.8	$1,169.0	$1,250.9	$1,328.9
SDG&E	$233.7	$246.1	$264.7	$283.3	$300.9
Anaheim	$28.0	$29.5	$31.7	$33.9	$36.0
Azusa	$3.0	$3.2	$3.4	$3.7	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.6	$13.3	$14.3	$15.3	$16.2
Riverside	$25.9	$27.3	$29.3	$31.4	$33.3
Vernon	$13.1	$13.8	$14.9	$15.9	$16.9
Colton	$4.1	$4.3	$4.7	$5.0	$5.3
VEA	$4.9	$5.1	$5.5	$5.9	$6.3
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$5.56**	**$5.82**	**$6.21**	**$6.63**	**$6.97**
Coincident Peak 12 Periods - Gross Load ($/MW)	**$3,071.53**	**$3,215.25**	**$3,432.31**	**$3,663.12**	**$3,854.27**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(29,779,795)	(31,356,864)	(33,727,689)	(36,091,342)	(38,340,631)
SCE	15,509,378	16,330,718	17,565,448	18,796,444	19,967,878
SDG&E	12,949,226	13,634,986	14,665,898	15,693,692	16,671,756
Anaheim	760,691	800,976	861,536	921,913	979,368
Azusa	92,978	97,902	105,304	112,684	119,707
Banning	(1,605)	(1,690)	(1,817)	(1,945)	(2,066)
Pasadena	204,341	215,162	231,430	247,649	263,083
Riverside	344,029	362,248	389,637	416,943	442,928
Vernon	311,066	327,539	352,304	376,993	400,488
Colton	57,590	60,640	65,224	69,795	74,145
VEA	(447,898)	(471,618)	(507,276)	(542,826)	(576,656)
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-2.9496%	-2.9496%	-2.9496%	-2.9496%	-2.9496%
SCE	1.5255%	1.5255%	1.5255%	1.5255%	1.5255%
SDG&E	5.8654%	5.8654%	5.8654%	5.8654%	5.8654%
Anaheim	2.7957%	2.7957%	2.7957%	2.7957%	2.7957%
Azusa	3.1805%	3.1805%	3.1805%	3.1805%	3.1805%
Banning	-0.0972%	-0.0972%	-0.0972%	-0.0972%	-0.0972%
Pasadena	1.6465%	1.6465%	1.6465%	1.6465%	1.6465%
Riverside	1.3468%	1.3468%	1.3468%	1.3468%	1.3468%
Vernon	2.4234%	2.4234%	2.4234%	2.4234%	2.4234%
Colton	1.4216%	1.4216%	1.4216%	1.4216%	1.4216%
VEA	-8.4204%	-8.4204%	-8.4204%	-8.4204%	-8.4204%

Scenario: Hybrid, 48% Volumetric - 52% Peak Demand, 12CP demand measurements

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$978.7	$1,030.5	$1,108.4	$1,186.1	$1,260.0
SCE	$1,032.8	$1,087.5	$1,169.7	$1,251.7	$1,329.7
SDG&E	$234.2	$246.6	$265.3	$283.9	$301.6
Anaheim	$28.0	$29.5	$31.7	$33.9	$36.0
Azusa	$3.0	$3.2	$3.4	$3.7	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.6	$13.3	$14.3	$15.3	$16.3
Riverside	$25.9	$27.3	$29.3	$31.4	$33.3
Vernon	$13.2	$13.9	$14.9	$15.9	$16.9
Colton	$4.1	$4.3	$4.7	$5.0	$5.3

VEA	$4.9	$5.1	$5.5	$5.9	$6.2
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$5.33**	**$5.58**	**$5.96**	**$6.36**	**$6.69**
Coincident Peak 12 Periods - Gross Load ($/MW)	**$3,194.39**	**$3,343.86**	**$3,569.60**	**$3,809.64**	**$4,008.45**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(30,970,987)	(32,611,138)	(35,076,796)	(37,534,996)	(39,874,256)
SCE	16,129,753	16,983,947	18,268,066	19,548,302	20,766,593
SDG&E	13,467,195	14,180,386	15,252,534	16,321,439	17,338,626
Anaheim	791,119	833,015	895,997	958,789	1,018,543
Azusa	96,697	101,818	109,517	117,192	124,495
Banning	(1,669)	(1,757)	(1,890)	(2,022)	(2,148)
Pasadena	212,514	223,769	240,687	257,555	273,606
Riverside	357,790	376,738	405,222	433,621	460,645
Vernon	323,508	340,641	366,396	392,073	416,508
Colton	59,893	63,065	67,833	72,587	77,111
VEA	(465,814)	(490,483)	(527,567)	(564,539)	(599,722)
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-3.0675%	-3.0675%	-3.0675%	-3.0675%	-3.0675%
SCE	1.5865%	1.5865%	1.5865%	1.5865%	1.5865%
SDG&E	6.1000%	6.1000%	6.1000%	6.1000%	6.1000%
Anaheim	2.9075%	2.9075%	2.9075%	2.9075%	2.9075%
Azusa	3.3077%	3.3077%	3.3077%	3.3077%	3.3077%
Banning	-0.1011%	-0.1011%	-0.1011%	-0.1011%	-0.1011%
Pasadena	1.7124%	1.7124%	1.7124%	1.7124%	1.7124%
Riverside	1.4006%	1.4006%	1.4006%	1.4006%	1.4006%
Vernon	2.5204%	2.5204%	2.5204%	2.5204%	2.5204%
Colton	1.4785%	1.4785%	1.4785%	1.4785%	1.4785%
VEA	-8.7572%	-8.7572%	-8.7572%	-8.7572%	-8.7572%

Scenario: Hybrid, 46% Volumetric - 54% Peak Demand, 12CP demand measurements

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$977.5	$1,029.2	$1,107.1	$1,184.6	$1,258.5
SCE	$1,033.4	$1,088.1	$1,170.4	$1,252.4	$1,330.5
SDG&E	$234.8	$247.2	$265.9	$284.5	$302.2
Anaheim	$28.0	$29.5	$31.7	$34.0	$36.1
Azusa	$3.0	$3.2	$3.4	$3.7	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.6	$13.3	$14.3	$15.3	$16.3
Riverside	$25.9	$27.3	$29.4	$31.4	$33.4
Vernon	$13.2	$13.9	$14.9	$16.0	$17.0
Colton	$4.1	$4.3	$4.7	$5.0	$5.3
VEA	$4.8	$5.1	$5.5	$5.9	$6.2
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$5.11**	**$5.35**	**$5.71**	**$6.10**	**$6.41**
Coincident Peak 12 Periods - Gross Load ($/MW)	**$3,317.25**	**$3,472.47**	**$3,706.89**	**$3,956.17**	**$4,162.62**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(32,162,179)	(33,865,413)	(36,425,904)	(38,978,650)	(41,407,881)
SCE	16,750,128	17,637,175	18,970,684	20,300,159	21,565,308
SDG&E	13,985,164	14,725,785	15,839,170	16,949,187	18,005,496
Anaheim	821,546	865,054	930,459	995,666	1,057,717
Azusa	100,417	105,734	113,729	121,699	129,284
Banning	(1,733)	(1,825)	(1,963)	(2,100)	(2,231)
Pasadena	220,688	232,375	249,945	267,461	284,129
Riverside	371,551	391,228	420,808	450,298	478,362
Vernon	335,951	353,742	380,488	407,153	432,527
Colton	62,197	65,491	70,442	75,379	80,077
VEA	(483,730)	(509,347)	(547,858)	(586,252)	(622,789)
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-3.1855%	-3.1855%	-3.1855%	-3.1855%	-3.1855%
SCE	1.6476%	1.6476%	1.6476%	1.6476%	1.6476%
SDG&E	6.3346%	6.3346%	6.3346%	6.3346%	6.3346%

Anaheim	3.0193%	3.0193%	3.0193%	3.0193%	3.0193%
Azusa	3.4349%	3.4349%	3.4349%	3.4349%	3.4349%
Banning	-0.1050%	-0.1050%	-0.1050%	-0.1050%	-0.1050%
Pasadena	1.7783%	1.7783%	1.7783%	1.7783%	1.7783%
Riverside	1.4545%	1.4545%	1.4545%	1.4545%	1.4545%
Vernon	2.6173%	2.6173%	2.6173%	2.6173%	2.6173%
Colton	1.5353%	1.5353%	1.5353%	1.5353%	1.5353%
VEA	-9.0940%	-9.0940%	-9.0940%	-9.0940%	-9.0940%

Scenario: Hybrid, 44% Volumetric - 56% Peak Demand, 12CP demand measurements

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$976.3	$1,028.0	$1,105.7	$1,183.2	$1,256.9
SCE	$1,034.0	$1,088.8	$1,171.1	$1,253.2	$1,331.3
SDG&E	$235.3	$247.7	$266.5	$285.1	$302.9
Anaheim	$28.1	$29.5	$31.8	$34.0	$36.1
Azusa	$3.0	$3.2	$3.4	$3.7	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.6	$13.3	$14.3	$15.3	$16.3
Riverside	$25.9	$27.3	$29.4	$31.4	$33.4
Vernon	$13.2	$13.9	$14.9	$16.0	$17.0
Colton	$4.1	$4.3	$4.7	$5.0	$5.3
VEA	$4.8	$5.1	$5.5	$5.8	$6.2
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$4.89**	**$5.12**	**$5.46**	**$5.83**	**$6.13**
Coincident Peak 12 Periods - Gross Load ($/MW)	**$3,440.11**	**$3,601.08**	**$3,844.18**	**$4,102.69**	**$4,316.79**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(33,353,371)	(35,119,687)	(37,775,011)	(40,422,303)	(42,941,506)
SCE	17,370,503	18,290,404	19,673,302	21,052,017	22,364,023
SDG&E	14,503,133	15,271,185	16,425,806	17,576,935	18,672,366
Anaheim	851,974	897,093	964,920	1,032,542	1,096,892
Azusa	104,136	109,651	117,941	126,206	134,072
Banning	(1,797)	(1,892)	(2,035)	(2,178)	(2,314)
Pasadena	228,862	240,982	259,202	277,367	294,653
Riverside	385,313	405,718	436,393	466,976	496,079
Vernon	348,394	366,844	394,580	422,232	448,547
Colton	64,501	67,916	73,051	78,171	83,043
VEA	(501,646)	(528,212)	(568,149)	(607,965)	(645,855)

CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-3.3035%	-3.3035%	-3.3035%	-3.3035%	-3.3035%
SCE	1.7086%	1.7086%	1.7086%	1.7086%	1.7086%
SDG&E	6.5692%	6.5692%	6.5692%	6.5692%	6.5692%
Anaheim	3.1312%	3.1312%	3.1312%	3.1312%	3.1312%
Azusa	3.5622%	3.5622%	3.5622%	3.5622%	3.5622%
Banning	-0.1089%	-0.1089%	-0.1089%	-0.1089%	-0.1089%
Pasadena	1.8441%	1.8441%	1.8441%	1.8441%	1.8441%
Riverside	1.5084%	1.5084%	1.5084%	1.5084%	1.5084%
Vernon	2.7142%	2.7142%	2.7142%	2.7142%	2.7142%
Colton	1.5922%	1.5922%	1.5922%	1.5922%	1.5922%
VEA	-9.4308%	-9.4308%	-9.4308%	-9.4308%	-9.4308%

Scenario: Hybrid, 42% Volumetric - 58% Peak Demand, 12CP demand measurements

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$975.1	$1,026.7	$1,104.4	$1,181.8	$1,255.4
SCE	$1,034.7	$1,089.4	$1,171.8	$1,253.9	$1,332.1
SDG&E	$235.8	$248.3	$267.1	$285.8	$303.6
Anaheim	$28.1	$29.6	$31.8	$34.0	$36.2
Azusa	$3.0	$3.2	$3.4	$3.7	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.6	$13.3	$14.3	$15.3	$16.3
Riverside	$25.9	$27.3	$29.4	$31.4	$33.4
Vernon	$13.2	$13.9	$14.9	$16.0	$17.0
Colton	$4.1	$4.3	$4.7	$5.0	$5.3
VEA	$4.8	$5.1	$5.4	$5.8	$6.2
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011
Volumetric - Gross Load ($/MWh)	**$4.67**	**$4.89**	**$5.21**	**$5.57**	**$5.86**
Coincident Peak 12 Periods - Gross Load ($/MW)	**$3,562.97**	**$3,729.69**	**$3,981.48**	**$4,249.22**	**$4,470.96**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(34,544,563)	(36,373,962)	(39,124,119)	(41,865,957)	(44,475,132)

SCE	17,990,878	18,943,633	20,375,920	21,803,875	23,162,738
SDG&E	15,021,102	15,816,584	17,012,442	18,204,682	19,339,237
Anaheim	882,402	929,132	999,381	1,069,419	1,136,067
Azusa	107,855	113,567	122,153	130,714	138,860
Banning	(1,861)	(1,960)	(2,108)	(2,256)	(2,396)
Pasadena	237,035	249,588	268,459	287,273	305,176
Riverside	399,074	420,208	451,979	483,654	513,796
Vernon	360,836	379,945	408,672	437,312	464,566
Colton	66,804	70,342	75,660	80,963	86,008
VEA	(519,562)	(547,077)	(588,440)	(629,678)	(668,921)
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-3.4215%	-3.4215%	-3.4215%	-3.4215%	-3.4215%
SCE	1.7696%	1.7696%	1.7696%	1.7696%	1.7696%
SDG&E	6.8038%	6.8038%	6.8038%	6.8038%	6.8038%
Anaheim	3.2430%	3.2430%	3.2430%	3.2430%	3.2430%
Azusa	3.6894%	3.6894%	3.6894%	3.6894%	3.6894%
Banning	-0.1128%	-0.1128%	-0.1128%	-0.1128%	-0.1128%
Pasadena	1.9100%	1.9100%	1.9100%	1.9100%	1.9100%
Riverside	1.5622%	1.5622%	1.5622%	1.5622%	1.5622%
Vernon	2.8112%	2.8112%	2.8112%	2.8112%	2.8112%
Colton	1.6490%	1.6490%	1.6490%	1.6490%	1.6490%
VEA	-9.7677%	-9.7677%	-9.7677%	-9.7677%	-9.7677%

Scenario: Hybrid, 40% Volumetric - 60% Peak Demand, 12CP demand measurements

Proposed TAC Charge for Hybrid - Gross Load ($ million)

	2018	2019	2020	2021	2022
PG&E	$973.9	$1,025.5	$1,103.0	$1,180.3	$1,253.9
SCE	$1,035.3	$1,090.1	$1,172.5	$1,254.7	$1,332.9
SDG&E	$236.3	$248.8	$267.6	$286.4	$304.2
Anaheim	$28.1	$29.6	$31.9	$34.1	$36.2
Azusa	$3.0	$3.2	$3.4	$3.7	$3.9
Banning	$1.6	$1.7	$1.9	$2.0	$2.1
Pasadena	$12.7	$13.3	$14.3	$15.3	$16.3
Riverside	$26.0	$27.3	$29.4	$31.5	$33.4
Vernon	$13.2	$13.9	$15.0	$16.0	$17.0
Colton	$4.1	$4.3	$4.7	$5.0	$5.3
VEA	$4.8	$5.0	$5.4	$5.8	$6.2
CAISO Total	$2,339	$2,463	$2,649	$2,835	$3,011

Volumetric - Gross Load ($/MWh)	**$4.44**	**$4.65**	**$4.97**	**$5.30**	**$5.58**
Coincident Peak 12 Periods - Gross Load ($/MW)	**$3,685.83**	**$3,858.30**	**$4,118.77**	**$4,395.74**	**$4,625.13**

Difference between Proposed TAC Charge and Existing TAC Charge ($)

	2018	2019	2020	2021	2022
PG&E	(35,735,754)	(37,628,236)	(40,473,226)	(43,309,611)	(46,008,757)
SCE	18,611,253	19,596,862	21,078,538	22,555,733	23,961,453
SDG&E	15,539,071	16,361,984	17,599,078	18,832,430	20,006,107
Anaheim	912,829	961,171	1,033,843	1,106,295	1,175,242
Azusa	111,574	117,483	126,365	135,221	143,648
Banning	(1,926)	(2,027)	(2,181)	(2,334)	(2,479)
Pasadena	245,209	258,195	277,716	297,179	315,699
Riverside	412,835	434,698	467,564	500,331	531,513
Vernon	373,279	393,047	422,764	452,392	480,586
Colton	69,108	72,768	78,269	83,755	88,974
VEA	(537,478)	(565,941)	(608,731)	(651,391)	(691,987)
CAISO Total	0	0	0	0	0

Difference between Proposed TAC Charge and Existing TAC Charge (%)

	2018	2019	2020	2021	2022
PG&E	-3.5395%	-3.5395%	-3.5395%	-3.5395%	-3.5395%
SCE	1.8306%	1.8306%	1.8306%	1.8306%	1.8306%
SDG&E	7.0384%	7.0384%	7.0384%	7.0384%	7.0384%
Anaheim	3.3548%	3.3548%	3.3548%	3.3548%	3.3548%
Azusa	3.8166%	3.8166%	3.8166%	3.8166%	3.8166%
Banning	-0.1167%	-0.1167%	-0.1167%	-0.1167%	-0.1167%
Pasadena	1.9759%	1.9759%	1.9759%	1.9759%	1.9759%
Riverside	1.6161%	1.6161%	1.6161%	1.6161%	1.6161%
Vernon	2.9081%	2.9081%	2.9081%	2.9081%	2.9081%
Colton	1.7059%	1.7059%	1.7059%	1.7059%	1.7059%
VEA	-10.1045%	-10.1045%	-10.1045%	-10.1045%	-10.1045%