Review Transmission Access Charge Structure

Straw Proposal

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Market & Infrastructure Policy

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1. Executive summary

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

Stakeholders that support this proposal seek to change the existing TAC billing determinant's point of measurement by moving 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 where distribution-connected generation serves part of the load in an area, potentially lowering the energy down flow from the transmission grid required to serve load. Rather than proposing modifications focused more narrowly on the point of measurement as originally contemplated, stakeholders urged the ISO to broaden the initiative's scope and holistically look at the overall TAC structure given today's transforming grid. In response, the ISO launched this Review TAC Structure initiative to consider a more holistic review of the ISO's high voltage TAC structure.

There are two basic issues the ISO addresses in this proposal: (1) where to measure transmission usage; and (2) how to measure transmission usage. The ISO received considerable stakeholder feedback on where to measure transmission usage, *i.e.*, the "point of measurement." A vast majority of stakeholders are opposed to moving the current point of measurement away from the end-use customer and to the T-D interface. The most serious stakeholder concern expressed was the resulting cost shift that would occur without justification. In summary, the stakeholder's major concerns with moving the point of measurement up to the T-D interface is that the embedded costs of the existing transmission grid would simply shift to those who do not have, or cannot afford to have, distributed generation serve their load. Due to overwhelming stakeholder concerns about changing the point of measurement, and the consequential cost-shifts, the ISO is proposing to maintain its existing practice of summing hourly gross load metered at that end-use customer as the point of measurement. The ISO included stakeholder feedback received on this issue in appendix B of this proposal.

The second issue the ISO addresses in this initiative is how to measure transmission usage. The ISO is proposing to modify the current volumetric billing determinant to better reflect customer usage and the cost causation and benefits of the transmission system. The ISO believes that a hybrid approach is preferable, utilizing both peak demand and volumetric measurements of customer use to assess TAC charges. 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.

The transmission system provides both energy and capacity functions, and other reliability benefits. A two-part hybrid approach that captures both peak demand and throughput (volume) 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 approach would. Restricting TAC to only recover transmission system costs through peak demand charges may not capture cost causation benefits since the benefits of policy projects and other energy delivery functions of the transmission system accrue throughout all hours of the day and year, not just during peak demand periods. The ISO believes preserving a volumetric charge component is appropriate and better reflects cost causation given the benefits policy projects and the energy delivery capability of the system. Saying this, peak demand TAC charges are used in other regions and are appropriate for assigning costs and benefits for the transmission system's use during system peak demand periods. Peak demand has been a reason for investment in the existing transmission system, and, therefore, is a cost driver that should be captured and appropriately assessed to users of the grid. Utilizing a hybrid approach that adds a peak demand measurement to the existing volumetric approach would provide customers a signal to consider the costs and impacts of their consumption decisions at different times. The existing volumetric-only approach means customers can be indifferent to when their consumption occurs, which may not reflect cost causation as accurately. 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 presents the details and justification for approach in this straw proposal. This proposal provides essential background material on the TAC structure and it describes the considerations the ISO examined and weighed in reviewing the current TAC structure.

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.

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

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

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

In June 2017, the ISO published an issue paper outlining the fundamental principles and key considerations it has identified and sought stakeholder feedback. The ISO has also held two stakeholder working group meetings to assist in parties understanding of the current TAC structure and settlements process, and also, to review the Clean Coalition's suggested modifications and allow for other interested stakeholders to present questions for the Clean Coalition representatives to consider. The ISO has received comments on the proposed scope of this effort and provides a recap including the ISO's responses to stakeholder recommendations in Section 3. The ISO also posed several questions for stakeholders to provide feedback on the issue paper and prior working groups and has incorporated the comments received into developing the present straw proposal. The following sections reflect the ISO's most current positions on this initiative.

3. Initiative scope and schedule

Through this initiative the ISO proposes to address at least two major TAC structure issues and has updated the description of these scope items:

1. Whether to modify the TAC billing determinant to more accurately reflect customer utilization and benefits. The ISO proposes to explore modifications to the billing determinant to accomplish policy 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. Whether to modify the current volumetric billing determinant of the TAC structure to more accurately 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 believes this initiative must have some clear boundaries and therefore proposes to exclude these topics from the scope:

- 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. ISO proposes not to consider changes to this aspect of TAC structure in this initiative, even if we revise the TAC structure from purely volumetric to something else.
- 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.[1] 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

[1] For details see CAISO's December 2016 Draft Regional Framework Proposal at: http://www.caiso.com/Documents/DraftRegionalFrameworkProposal-TransmissionAccessChargeOptions.pdf

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.[2] Some of the other regions offer different transmission service options (*e.g*., point-to-point versus network integration service), whereas the ISO offers only one form of service through our day-ahead and real-time markets. This initiative will not consider expanding or modifying the types of transmission service the ISO offers.
- 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 suggestions of some stakeholders to include consideration of revisions to export charges, the ISO believes this question 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 who export from or wheel through the ISO BAA. The ISO believes that such consideration, while not without merit, would be a substantial expansion of the already ambitious scope and effort anticipated for this initiative.

The ISO also has received feedback on the proposed scope of this initiative from several interested parties. Stakeholders' suggestions and recommendations on the initiative scope and ISO's responses are included below.

Stakeholder feedback and ISO responses on proposed initiative scope:

California Public Utilities Commission (CPUC): *The CPUC suggests the ISO should consider whether the ISO should recommend to FERC that the California IOUs' retail transmission rates be restructured to include either coincident peak-related demand charges or time-of-use volumetric rates (or both).*

The ISO understands this issue raised by the CPUC is important and has considered the linkages and impacts of the ISO HV TAC structure with the California IOUs' FERC and CPUC approved retail transmission rates under this initiative. However, the ISO does not believe that it should incorporate a specific item to consider ISO intervention in IOU FERC TRR proceedings within this initiative. The CPUC and other interested parties may evaluate the outcome of this initiative in their considerations for how to participate in those proceedings.

Northern California Power Agency (NCPA): *NCPA suggests that considering different billing determinants for different categories of facilities should be within the scope.*

The ISO believes this question is appropriate to consider in this initiative's comprehensive consideration of how to adjust the TAC structure. The ISO has not explicitly listed the potential

[2] See June 30 Issue Paper at: http://www.caiso.com/Documents/IssuePaper-ReviewTransmissionAccessChargeStructure.pdf

for utilizing different approaches for different categories of facilities, but the ISO believes this issue is a potential aspect of potential TAC structure modifications. If the initiative considers a hybrid TAC structure that is partly volumetric and partly demand or time-of-use based, the different categories of transmission projects could be used to determine what share of the regional TRR should be collected through each mechanism.

California Office of Ratepayer Advocates (ORA): *ORA recommends limiting the scope of this initiative to a single topic, which is "whether to modify the TAC billing determinant to reduce TAC charges in PTO service areas for load offset by DG output."*

The ISO respectfully disagrees with this suggestion by ORA. The ISO believes that comprehensive review of the current TAC structure should also consider potential modifications to the current approach in order to potentially better align the cost allocation with cost causation principles if determined to be necessary after thorough consideration.

Clean Coalition: *Clean Coalition recommends that CAISO should first change where usage is measured as the basis for calculating transmission access charges (TAC), regardless of how charges for that usage of the transmission grid is ultimately calculated. Clean Coalition's position is that changing the measurement of transmission usage to the end of the transmission grid by using transmission energy downflow (TED, or the hourly load flowing from the transmission-distribution interface substation) is a discrete and fundamental issue that can and should be addressed first. As currently scoped, there are two basic issues to be addressed in this initiative: (1) where to measure transmission usage, and (2) how to measure transmission usage. Where to measure transmission grid usage is a straightforward and simple issue that can be resolved independently of the more complex and technical issue of how best to adjust the underlying TAC structure—based on total downflow, peak downflow or other basis.*

The ISO respectfully disagrees with Clean Coalition's suggestion to change the point of measurement first and regardless of other possible considerations. The ISO and the vast majority of stakeholders believe that comprehensive review of the current TAC structure should also consider potential modifications to the current volumetric billing structure with any potential changes to the point of measurement. This more comprehensive evaluation will be necessary in order to potentially better align cost allocation with cost causation principles. The ISO does not agree that the question of transmission usage and benefits is as straightforward as Clean Coalition suggests. A holistic review of both major aspects of the TAC structure should be considered together.

Pacific Gas and Electric Company (PG&E): *PG&E recommends that only the second of the CAISO's proposed two main topics, "Whether to modify the current volumetric TAC structure to incorporate other approaches such as demand based or time-of-use structure," should be the overall objective of the Review TAC Structure initiative. This topic appropriately recognizes the need to consider many possible alternatives to the status quo to achieve the objective. PG&E supports framing the scope of the initiative using just this inclusive language. In contrast, the topic of "whether/how to modify the TAC billing determinant…" should be removed as a main topic. Instead, the consideration of TAC billing determinants is one possible mechanism to be* *explored in the stakeholder process to evaluate the overall TAC structure. Therefore, the topic of revising the TAC billing determinant should be considered later in the process as one of various options.*

The ISO understands PG&E's scope recommendation to focus on the issue of the TAC structure and consider the other main scope item of modifying the TAC billing determinant as a secondary issue. The ISO believes that both issues are of primary importance as aspects of a holistic review and declines to specify a specific prioritization of scope.

PG&E: *PG&E also suggests that the CAISO not unnecessarily restrict the scope of the initiative. Elsewhere in the issue paper, the CAISO suggests that several aspects of existing TAC structure be excluded from the initiative. However, given the interrelatedness of the topics, the CAISO needs to consider the TAC structure holistically. …Though PG&E is not taking a position at this time on whether or not a postage stamp rate would be most appropriate under an updated TAC structure, for example, excluding such a consideration from the discussion would artificially narrow the range of options that stakeholders can evaluate. …Though PG&E appreciates the effort to simplify a challenging task, such a restriction would only limit the range of potential solutions and not the complexity of the issues or the number of up and down-stream consequences that could result from changes.*

The ISO appreciates PG&E's suggestion to avoid unnecessarily restricting the scope of the initiative. While the ISO has listed the primary scope issues under consideration, the points raised by PG&E have merit for consideration under the scope of this initiative. The ISO recognizes there are numerous issues and considerations that may need to be further explored depending on the potential modifications that may be considered under this initiative. The ISO believes that the current proposal scope represents important modifications with the ability to improve the alignment of cost causation and transmission cost recovery and will consider how related issues should be recognized in the further development of the ISO proposal. The ISO is committed to a holistic review of the overall TAC structure but has importantly focused on several primary issues explained within the proposal. The ISO also has provided explanation for those potential issues and elements it believes should be out of the scope of this initiative.

San Diego Gas and Electric (SDG&E): *SDG&E believes all existing mechanisms should be on the table for review. This would include the mechanism by which Metered Sub-Systems are billed for fixed transmission costs.*

The ISO describes the current point of measurement treatment for Non-PTO municipals and metered subsystem (MSS) areas. The ISO does not believe the point of measurement treatment for Non-PTO municipals and metered subsystems should be modified and is not considering changes to that treatment in this initiative. However, the ISO believes that a modification to the billing determinant aspect to measure usage of the transmission system by these entities may need to be considered for all customers, including Non-PTO municipals and metered subsystems. This potential modification is described in the proposal but the ISO has not made any specific proposal for this issue and seeks additional stakeholder feedback.

Silicon Valley Power (SVP): *SVP suggests the topic should be broader, and proposes the following: Explore whether/how the TAC billing determinant could be modified to more accurately allocate costs associated with, and necessary to meet, all facets of Transmission Planning, such that the costs of existing and future transmission built and maintained to serve existing and planned demand, is paid for by those who receive a benefit from the existing and future transmission system. To the extent that resources such as DG, energy storage, demand response, or others are able to provide a verifiable reduction in transmission costs (either the costs of the existing grid or the costs of the future grid) - explore whether there is a modified billing determinant that allows for such resources to monetize this benefit. Alternatively consider whether the benefits of DG are better captured through such resources contracting directly with the LSE particular to the area of the resource(s).*

The ISO appreciates SVP's suggestion to broaden the language used to describe the main scope issue and has made some related adjustments to better focus on the primary issues to scope item 1. The ISO believes that the issues raised by SVP regarding exploring potential modification to the TAC structure to consider treatment of resources that may reduce transmission costs are properly accounted for under the main scope items described herein.

SVP: *SVP suggests considering the modifying of topic 2 to read as follows: Identify issues associated with the current volumetric rate collection of TAC that causes market inefficiencies, does not send a market price signal that generates the desirable response, or potentially shifts costs from one market participant to another—where such shifts are not justified by cost causation principles. Once a list of potential issues are identified with the existing volumetric rate design, determine if other billing determinants, such as demand-based rates or time-of-use rates, would result in an improved outcome (SVP notes that a combination of volumetric and demand-based rates could also be considered)—while also being workable within the CAISO market structure and supporting efficient least-cost dispatch of generation resources.*

The ISO appreciates SVPs suggestions to broaden the description of scope item 2 to include the identification of issues with the existing design and potential benefits of modifications that could be made. This is essentially the intent of the ISO's proposed scope item 2 so the ISO does not feel it necessary to broaden the language to encompass these considerations that are included in the proposal under scope item 2 already.

SVP: *SVP questions whether the scope should be even further expanded to encompass a review of how TAC could be modified to help resolve existing seams issues. SVP questions if the existing treatment of how TAC is applied to intertie/Balancing Authority Area (BAA) exports accomplishes this goal. If the present CAISO market initiative is looking to resolve internal TAC issues, should the process also try to ensure the outcome is compatible with future BAA expansion and existing seams issues? separate and apart from trying to develop a regional TAC mechanism, for any changes to the TAC mechanisms being considered in this initiative CAISO should consider: (1) Whether the modified TAC billing determinants would make potential BAA expansion more likely, or less likely, to succeed?; (2) How would the use of a demand-based charge in combination with, or instead of, a volumetric charge potentially affect* *market awards at interties?; and (3) How would the CAISO market handle scheduling limit congestion under such a rate structure?*

The ISO believes that SVP has suggested some reasonable issues related to how the TAC structure is applied for exports, but the ISO believes this initiative should be focused on the internal TAC structure and potential modifications to recovering the HV TRR for internal loads for which the existing California transmission system was built to serve. The ISO appreciates the suggestions to include other BAA expansion and seams issues under scope in this initiative but disagrees these items should be included for consideration. The ISO is not opposed to potentially exploring these issues in future initiatives.

Initiative schedule with major milestones:

The updated schedule for this stakeholder initiative is provided in Table 1 below. The ISO plans to present its proposal to the ISO Board of Governors for their approval in mid-2018, with the specific date determined in early 2018 based on the ISO's assessment of how much additional work is needed to develop a final proposal.

Table 1 – Stakeholder Initiative Schedule

Step	Date	Milestone
Kick-off	Feb 6, 2017	Publish market notice announcing initiative beginning mid-year 2017
White Paper	Apr 12	Post background white paper
Issue Paper	Jun 30	Post issue paper
	Jul 12	Hold stakeholder meeting
	Jul 26	Stakeholder written comments due
Working Groups	Aug 29	Hold stakeholder working group meeting to review and assess options
	Sep 25	Hold stakeholder working group to review stakeholder proposals and allow additional Q&A
	Oct 13	Stakeholder written comments due
	Dec 1	Discuss TAC initiative with Market Surveillance Committee (MSC) members and stakeholders
Straw Proposal	Jan 11, 2018	Post straw proposal
	Jan 18	Hold stakeholder meeting or call
	Feb 15	Stakeholder written comments due
Revised Straw Proposal	Mar 22,	Post revised straw proposal
	Mar 29	Hold stakeholder meeting or call
	Apr 20	Stakeholder written comments due

Step	Date	Milestone
Draft Final Proposal	June	Post draft final proposal
	June	Hold stakeholder meeting or call
	July	Stakeholder written comments due
Final Proposal	TBD	Present final proposal at CAISO Board meeting

4. EIM classification

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

5. Transmission system background

5.1. Services provided by transmission

In the June 30 Issue Paper, the ISO has provided detailed background on the range of services provided by the transmission system. The ISO reviews these services and transmission cost drivers in this section.

As noted in the ISO's issue paper and stakeholder comments, the following key functions are enabled by the transmission system: (1) reliably serving the system's peak load and net peak load, (2) reliably serving load in locally-constrained areas, (3) delivering energy to loads, and (4) meeting public policy goals by providing access to preferred resources. These key transmission functions are focused on the delivery of energy and capacity using the bulk power transmission system from generation sources to substations.

The ISO's transmission planning process considers transmission needs to address reliability, public policy, and economic drivers for new transmission. The planning process addresses these needs to allow for the continued ability to provide the key functions listed above. These planning functions are described in further detail below. The ISO has also described the additional services and benefits enabled by the transmission system more generally further below.

Needs addressed through the ISO Transmission Planning Process

Reliability requirements can include providing thermal capacity and adequate voltage control, considering the range of stressed conditions on the system. In this regard, the maximum demands placed on the system by the distribution load is relevant, as well as demands placed at times when different transmission paths sourcing the load may be more heavily stressed. A broader range of potential transfer paths must be considered as the system evolves to more use-limited and highly variable energy resources backstopped by more flexible generation resources. In its transmission planning studies, the ISO models the expected growth of distributed resources and their impacts on distribution-connected load over the 10-year planning horizon, as reflected in the CEC's IEPR demand forecast. Assessing both the volume and the profiles of these resources is becoming increasingly complex, but it is necessary to ensure the impacts and benefits are properly assessed.

The transmission planning studies also test dynamic system stability reliability issues, although more recently these factors less frequently drive the need for reinforcement. Relevant factors in considering these issues include keeping the overall system reliable, the volume and nature of the gross load, the magnitude, type, and control systems of all offsetting generation and whether the generation is connected to the transmission system, distribution system, or located is behind-the-meter. The increasing amount of inverter-based generation and the economic disincentives to maintain "headroom" for inertia-like response will cause a greater focus on these issues moving forward.

Policy and economic drivers share a common end effect: to allow access to a broader range of new or existing resources, albeit for different reasons. Policy-driven transmission has focused on access to large volumes of transmission-connected renewable generation typically responding from state policy direction and resulting in relatively quick transitions in the generation fleet that requires proactive transmission investment. Although these policy goals have largely been energy-volume based (*e.g.*, to meet an RPS mandate), the transition from identifying the need to developing the most cost-effective transmission solution necessitates considering the capacity of the new resources and their output profiles. The corresponding output profiles of existing and anticipated distribution-connected resources must be considered. For policy-driven transmission planning, the ISO relies on resource portfolios provided by the CPUC to specify areas of the system, including the distribution side, where resource procurement to meet policy directives is expected to occur.

Over time, and with less dramatic changes in the generation fleet, access to lower cost energy and capacity, rather than "stated policy" likely will drive new transmission. As with policy-driven transmission, considering distribution-connected resources to offset transmission needs involves considering specific profiles of the resources involved and the nature of the transmission constraints being addressed.

The above discussion focused on needs that can result, or have resulted, in new or increased transmission capacity being approved through the ISO's transmission planning process. Approvals for new transmission has declined dramatically in recent years and more attention is being paid by stakeholders to transmission owner-driven costs and annual cost increases associated with transmission expenditures not subject to the ISO's transmission planning process. Most of these costs are associated with activities to maintain the capabilities of the existing transmission grid, as opposed to expanding capacity for new services. These include activities such as like-for-like equipment replacement of aging or deteriorating equipment or improvements to meet new or existing design or safety standards. Although rate design considerations for these costs can be complex because they reflect costs associated with maintaining a range of both old and new equipment based on planning decisions spanning decades, they clearly relate to the services being provided by the grid as it exists today.

Other transmission owner-driven costs can be more complex to consider. New and more sophisticated control centers managing a broader range of operating parameters and increasing communications costs for data acquisition and system control do not as obviously translate only to the capacity and energy services contemplated above. Some of these are discussed below.

Other services and benefits provided by transmission

There are also several other related reliability, capacity, and energy benefits provided through interconnection to the transmission system. These additional services include:

- Balancing and frequency control – balancing load with demand
- Voltage support – maintaining local voltages within customer limits
- Dynamic stability – providing response to safely control disturbances on the system
- Ramping capability – providing energy to meet extreme changes in demand
- Fault detection and control – ensuring safety is an outage situation
- Black start capability – delivering start-up energy in an outage situation
- Reserves – allowing for access to resources if loss of local generation occurs

Very few loads being served by on-site or distribution-connected generation truly leave the grid, *e.g.*, disconnect from the transmission grid altogether. These customers are accessing most or all of the benefits described above at any given time under normal system conditions, and especially during peak and contingency conditions. These benefits are enabled by the reliable operation of the transmission system, and are neither easily quantified nor necessarily proportional to a net energy transfer to or from the transmission grid.

For example, a reliable transmission system can enable back-up service. The transmission system also can enable balancing and frequency control services on a day-to-day, minute-to-minute, and second-to-second basis. Besides the more traditional costs associated with upgrading and reinforcing transmission lines and substations, providing these services may also contribute to costs on the transmission system. Also, the increased variability of operating conditions is driving a wider range of transient and dynamic power flow and voltage control conditions to be managed, which contributes to increased need for communication and upgraded control center SCADA.

Back-up service can be tremendously valuable to the distribution load, but results in little energy transfer through the billing period. While the distribution load may have contributed to the capacity of the interconnecting facilities, the service is enabled by the overall reliable operation of the grid.

Balancing and frequency control services on a day-to-day, minute-to-minute, and second-to-second basis also provide value to customers, which again is not necessarily proportional to any net energy consumption. (Note that a DG resource could suggest that it is also contributing to balancing other loads and resources; however, that interaction with other generation still requires reliance on the transmission grid.)

5.2. Role of DG in offsetting new transmission costs

Certain stakeholders have advocated that DG provides significant benefits to the transmission system and that customer demands served by DG production are not receiving benefits from the transmission system. The vast majority of stakeholders disagree with this assertion stating that reduced demand attributable to DG does not reflect a reduced reliance on transmission for reliability and does not necessarily result in lower transmission costs. Numerous stakeholders submit that only customers whose demand is entirely served by DG, and who can fully island and isolate themselves from the grid, can potentially claim they receive less benefits from the transmission system during those periods of isolation.

All DG characteristics must be considered when evaluating the benefits and avoided costs DG provides and whether, and to what extent, DG might reduce the need for future transmission additions and avoid cost increases. For instance, it is vital to compare DG output profiles to the load profile and how well that DG matches that load profile. It is also important to consider how the combination of resources mitigate reliability issues and stresses on the transmission system. Since resource output and load profiles vary, planning processes must consider various scenarios to match the needs of the grid and meet all applicable reliability criteria. DG's presence on the grid does not equate to a reduced need for other resources or transmission and distribution investments since DG resources may not be producing when needed or not effective at relieving certain stresses on the grid based on their location or attributes. Further, power quality and transfer considerations such as capacity deliverability, reactive power, and voltage support (*i.e.*, in MW and MVAr) are essential to reliability and drive upgrade needs. Simple energy production (*i.e.*, MWh) is not the sole determinant for transmission need or investment. These additional reliability needs, like voltage support, must be considered when evaluating the potential for DG resources to avoid or defer transmission and distribution investments, and may even demonstrate that certain DG installations add costs if certain mitigations or re-configurations are required to integrate DG resources in certain areas and circumstances.

There may be opportunities for DG to avoid or defer future transmission reinforcements, depending on the nature the DG resource relative to the needs of the grid in that particular instance. However, "new additions" and its cost recovery is a different issue than how to allocate the sunk costs of existing transmission or who benefits from such transmission. Most stakeholders argue that customers served by DG still receive the transmission system benefits described above.

Stakeholder comments on this subject reflect a general consensus that DG does not provide a megawatt for megawatt offsetting benefit to the transmission system. Many stakeholders point out that because existing transmission capital costs are embedded, fixed costs, DG does not reduce these existing transmission capital costs.[3] The embedded costs of the existing transmission must be recovered. Some of these costs are associated with transmission additions approved as part of the ISO's TPP for reliability, congestion reduction, and public policy reasons. Some costs are associated with operation, maintenance, and amortization of transmission facilities that predate the ISO's TPP or even the ISO itself. Other costs are associated with repair and replacement of existing transmission facilities that have reached the end of their useful life. Stakeholders stress these costs are not avoidable unless those facilities are abandoned and decommissioned.[4]

Beyond the embedded system costs, much of the stakeholder feedback describes how DG may effectively reduce costs associated with future transmission. This is only possible when particular DG projects meet a need that is identified through transmission or distribution planning processes. Most stakeholders agree that the ISO and PTO planning processes are the appropriate venues for performing the analysis to identify needs and determine which solution is the most cost effective or efficient for meeting those needs. The ISO's TPP already provides opportunities for evaluating non-transmission resources such as DG, energy storage, and demand response as potential solutions to meet identified needs and, if the transmission planning process identifies such non-transmission alternatives as the preferred alternative, then the ISO will work to support regulatory approvals for those projects. The ISO's transmission planning process has studied several non-transmission alternatives and will continue to do so.

The ISO and stakeholders agree that DG can benefit the transmission system, particularly when DG is a least cost solution to an identified need traditionally served by transmission facilities. However, DG production on its own does not inherently obviate or reduce the need for the transmission system. DG and other resources may reduce or increase some of the ongoing expense of maintaining and operating the existing transmission system. However, as several stakeholders argued, large cost drivers for maintaining the transmission system are not affected by DG or other resources. Tree trimming or other vegetation management is unlikely to be affected by peak load or the energy that flows across the line.[5]

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[3] See Office of Ratepayer Advocates (ORA) comments: http://www.caiso.com/Documents/ORAComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

[4] See California Large Energy Consumers Association (CLECA) comments: http://www.caiso.com/Documents/CLECAComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

[5] See Southern California Edison (SCE) comments at: http://www.caiso.com/Documents/SCEComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf, and see Pacific Gas and Electric Co. (PG&E) comments at: http://www.caiso.com/Documents/PG-EComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

The impacts of DG that may reduce the need for transmission capital additions are fully available to the ISO and PG&E transmission planning processes.[6] Some stakeholders indicated that adding DG at levels exceeding those already incorporated in the CEC's Integrated Energy Policy Report (IEPR), the ISO TPP, and included in CPUC-ordered procurement plans, is unlikely to materially impact future investment in transmission infrastructure. For additional transmission investments falling outside of the ISO's TPP purview, most are driven by maintenance requirements, communication needs, municipal undergrounding initiatives, safety considerations, and unique reliability issues (*e.g.*, fire hardening). Stakeholders stated that additional DG will not change the need for these types of transmission additions. [7]

The ISO and most parties agree that the potential for DG to reduce future transmission costs depends largely on a DG resource's impacts on the system, *i.e.*, how well do the DG's attributes and output profile align with the particular needs of the grid where investment is needed. The ISO also agrees that the costs and benefits of DG resources are properly accounted for through the current planning processes. The ISO believes that future transmission investment cost savings associated with DG resources can and will be realized through cases where DG addresses specific needs identified through formal planning and investment decision making processes.

6. Review of current TAC design

The ISO believes there is still a wide variation in stakeholders' respective understandings of the mechanics of the current TAC structure. It was apparent during the prior ISO stakeholder working group discussions there is not a clear understanding on how the TAC is currently calculated and assessed, what portion of load associated with distribution-connected generation already offsets TAC, what the capabilities are regarding current metering infrastructure, and whether (and what) retail rate and billing practice revisions would be needed to accomplish any particular policy goal through changes to the TAC. Some of these issues have already been described in the ISO's prior TAC background whitepaper[8] and the ISO encourages stakeholders to review that material to ensure a consistent understanding. The ISO also provides a review of the most important aspects of this TAC background information in Appendix A.

Clarification of Gross Load definition and treatment of end use customer meter load data

The ISO tariff definition of Gross Load was also noted in the ISO's TAC background whitepaper. The term "Gross Load" may be somewhat confusing because some parties understand gross

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[6] See Northern California Power Agency (NCPA) comments at: http://www.caiso.com/Documents/NCPAComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

[7] See San Diego Gas & Electric (SDG&E) comments at: http://www.caiso.com/Documents/SDG-EComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

[8] See ISO TAC Background Whitepaper at: http://www.caiso.com/Documents/BackgroundWhitePaper-ReviewTransmissionAccessChargeStructure.pdf

load to be the physical end-use consumption before its measurement at the meter is reduced by any behind-the-meter (BTM) supply. Thus, in more common understanding one might say “metered load” or “net load” equals “gross load” minus “behind-the-meter supply.” To be consistent with the ISO tariff definition, however, in this paper “Gross Load” means metered load.

ISO Tariff Appendix A provides the following definition for “Gross Load”:

> **Appendix A Definition - Gross Load**:
>
> “For the purposes of calculating the transmission Access Charge, Gross Load is all Energy (adjusted for distribution losses) delivered for the supply of End-Use Customer Loads directly connected to the transmission facilities or directly connected to the Distribution System of a Utility Distribution Company or MSS Operator located in a PTO Service Territory. ***Gross Load shall exclude*** (1) Load with respect to which the Wheeling Access Charge is payable; (2) Load that is exempt from the Access Charge pursuant to Section 4.1 of Appendix I; and ***(3) the portion of the Load of an individual retail customer of a Utility Distribution Company, Small Utility Distribution Company or MSS Operator that is served by a Generating Unit that: (a) is located on the customer’s site or provides service to the customer’s site through arrangements as authorized by Section 218 of the California Public Utilities Code;*** (b) is a qualifying small power production facility or qualifying cogeneration facility, as those terms are defined in the FERC's regulations implementing Section 201 of the Public Utility Regulatory Policies Act of 1978; and (c) secures Standby Service from a Participating TO under terms approved by a Local Regulatory Authority or FERC, as applicable, or can be curtailed concurrently with an Outage of the Generating Unit serving the Load. Gross Load forecasts consistent with filed Transmission Revenue Requirements will be provided by each Participating TO the CAISO.” [9]

This definition is important for understanding the treatment of Net Energy Metering (NEM) resource production. End-use metered load used for TAC billing already accounts for BTM NEM production. The ISO believes that it is important to clarify the distinction between “in-front-of-the-meter” (IFOM) DG and NEM DG resources. NEM BTM exports represent the amount of generation that is produced by a NEM customer generator not otherwise consumed by its host load (*i.e.*, in excess of the host load). Load associated with NEM is already receiving netting treatment for TAC billing purposes for the BTM generation production on site at its location. This is because any NEM production is already not reflected in the customer meter readings. The ISO also clarifies that the treatment of NEM BTM exports should not be netted from the Gross Load data reported to the ISO. The ISO plans to discuss this treatment of NEM BTM exports issue further in future efforts, potentially outside of this initiative.

[9] Appendix A to the ISO Tariff (emphasis added).

Treatment of Non-PTOs

The ISO also provides a recap of the treatment of Non-PTO entities because there was extended discussion related to the way these entities are assessed TAC charges during the TAC working groups. The ISO wishes to clarify this aspect of the TAC process to avoid any further confusion related to their treatment.

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

These entities pay the WAC based on the amount their load is served by supply sources (generation and imports) that use the ISO Controlled Grid, i.e., the net load measured at the point of interconnection with the ISO grid. For some, 100 percent of their load is served by ISO Controlled Grid facilities because all their supply is remote from their load, and therefore they pay the Regional-WAC (R-WAC) and Low Voltage-WAC (L-WAC) based on their Gross Load. For others, some of their supply is internal to their service area or delivered over non-ISO transmission and some of their supply uses the ISO Controlled Grid, so they pay the R-WAC and (as appropriate) the L-WAC for the net load served over the ISO Controlled Grid. In one case, the entity has transmission connecting its generation directly to its load and therefore pays no R-WAC or L-WAC. Beyond this distinction between how the TAC and WAC charges are applied, however, the actual dollar amounts of the WAC rates are set to equal the corresponding TAC rates.

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

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

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

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

6.1. CAISO's TAC design is just and reasonable and consistent with FERC Order No. 1000

Some stakeholders have alleged that the current TAC design may be unjust and unreasonable. This ignores that FERC has found the TAC design to be both just and reasonable and compliant with Order No. 1000. Although the existing TAC design is just and reasonable, the ISO has opened this initiative to examine if there are potential modifications that might better align TAC cost allocation with cost causation and the benefits provided (similar to any ISO stakeholder initiative). Below is a discussion of prior decisions regarding the ISO's TAC rates.

Going back to CAISO start-up, FERC found that the ISO's volumetric access rate was just and reasonable and economically efficient.[10] In particular, FERC found that the ISO's transmission pricing satisfied the five principles in FERC's Transmission Pricing Policy Statement.[11]

On March 31, 2000, the ISO filed with FERC Amendment No. 27 that sought to assess the volumetric access charge based on the combined revenue requirements of all transmission owners and, after a ten year transition period, form a single high voltage, ISO-wide grid access charge. Following a hearing regarding the transmission rate design, the Presiding Administrative Law Judge (ALJ) issued an Initial Decision finding the ISO' s MW-based methodology to be just and reasonable and not unduly discriminatory.[12] The ALJ found that the methodology satisfied transmission pricing and cost allocation principles and sends the appropriate price signals. The ALJ also stated that if the ISO moved to a locational marginal pricing framework further consideration of time-of-use and coincident peak pricing methodologies might be worthwhile. Opinion No, 478, FERC summarily affirmed the ALJ's findings regarding the ISO's volumetric rate design.[13] On rehearing, the Commission found that the ISO's TAC design was just and reasonable and not unduly discriminatory, and that opposing parties had not met their burden of showing differently.[14] FERC reiterated its prior findings that the flat, volumetric rate was just and reasonable and consistent with FERC's Transmission Pricing Policy. FERC noted there was

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10 *Pacific Gas & electric Company, et al.,* 80 FERC ¶ 61,128 (1997)

11 *Id.* at 61,430, citing *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Policy Statement,* FERC Stats. & Regs, Regulations Preambles, January 1 1991-1996, ¶ 31.005 (1994), *order on reconsideration,* 71 FERC ¶ 61,195 (1995). The five principles are: meets the revenue requirement; reflects comparability; promotes economic efficiency; promotes fairness; and pricing should be practical.

12 *California Independent System Operator Corporation,* 106 FERC ¶ 63,026 (2004).

13 *California Independent System Operator Corporation,* 109 FERC ¶ 61,301 (2004).

14 *California Independent System Operator Corporation,* 111 FERC ¶ 61,337 (2005).

record evidence that the TAC should recover those portions of transmission revenue requirements not paid by congestion charges or congestion revenue rights auction revenues, not to provide price signals in and of itself. Rather, it is the congestion pricing mechanism that primarily provides price signals.[15] Further, the record showed that changes to the design and allocation would require many market participants to incur significant expense in modifying their scheduling and settlement systems, and new metering would be required for millions of end users serve by the ISO grid. FERC stated that the TAC methodology was not inconsistent with FERC precedent or general principles of cost causation.

The U.S. Court of Appeals for the Ninth Circuit, in an unpublished opinion, denied the petitions for review of FERC's orders finding that FERC's approval of the ISO's TAC rate was not arbitrary and capricious and did not violate FERC's policy of requiring rates to convey price signals.[16]

On October 11, 2012, the ISO submitted its filing to comply with the requirements of FERC Order No. 1000. The ISO proposed to retain its existing cost allocation method, which uses access charges to allocate the costs of the transmission facilities to all users of the ISO-controlled grid based on their actual MWh use of the system. The filing continued to distinguish between facilities 200 kV and above (*i.e.,* regional transmission facilities) and facilities below 200 kV (*i.e.,* local transmission facilities). The ISO proposed to allocate the costs of regional transmission facilities to all users of the ISO-controlled grid, and the costs of upgrades and/or additions of local transmission facilities would be allocated only to the users of those transmission facilities. The ISO's Order No. 1000 compliance filing demonstrated how the TAC design satisfied the cost allocation principles specified in Order No. 1000.

In the ISO's Order No. 1000 compliance docket, FERC found that the regional cost allocation methodology the ISO proposed to retain complied with the cost allocation principles of Order No. 1000.[17] Specifically, FERC found that such cost allocation methodology: (1) allocates costs in a manner that is at least roughly commensurate with estimated benefits; (2) does not involuntarily allocate costs to those who receive no benefits; (3) does not include a benefit-to-cost threshold that exceeds 1.25; (4) allocates costs solely within the affected transmission planning region; (5) provides for methods for determining the benefits and beneficiaries that are transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility; and (6) represents a single cost allocation method for all types of transmission facilities selected in the regional transmission plan for purposes of

[15] FERC found that CAISO lines can be congested in both peak and off-peak hours, and that the CAISO considers peak and off-peak conditions in the transmission expansion planning process and, as such, time-of-use pricing was not required.

[16] *State Water Contractors v. FERC*, 285 F. App'x 397 (9th Cir. 2008).

[17] *California Independent system Operator Corporation,* 143 FERC ¶ 61,057 (2013), *order on clarification and compliance,* 146 FERC ¶ 61,198 (2014), *order on reh'g and compliance,* 149 FERC ¶ 61,249 (2014).

cost allocation.[18] The Commission also noted that ISO's current cost allocation method has been previously accepted by the Commission and upheld by the Ninth Circuit.

In particular, FERC found that the ISO's regional cost allocation method complies with Regional Cost Allocation Principle 1—that the cost of transmission facilities must be allocated to those within the transmission planning region that benefits from those facilities in a manner that is at least roughly commensurate with estimated benefits.[19] FERC found persuasive the ISO's explanation that its high voltage regional transmission facilities provide a backbone function that supports regional flows, reduces congestion, facilitates reserve sharing, and facilitates import and export of power, thus benefitting all users of the grid.[20] FERC also agreed with the ISO that although the regional benefits from high voltage transmission facilities may inure to some areas of the regional grid more than others, the benefits will vary over time, as will the sectors of the grid that benefit. For the ISO-controlled grid, any effort to parse the benefits out further could lead to an allocation of costs that would not be roughly proportionate to benefits over the long run.[21]

FERC similarly found find that ISO's regional cost allocation method complies with Regional Cost Allocation Principle 2, which requires those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities.[22] FERC found that because the ISO's regional cost allocation method allocates costs in a manner at least roughly commensurate with estimated benefits, it does not allocate costs to those that receive no benefit.[23] Although costs of regional transmission facilities are allocated to all users of ISO's high voltage grid as they benefit from that use, there is no allocation to non-beneficiaries regarding low voltage facilities because customers that do not take service on low voltage facilities do not pay for them.
FERC found also persuasive the ISO's explanations for why its regional cost allocation method meets the requirement of Regional Cost Allocation Principle 5 that the cost allocation methods be transparent.[24] FERC agreed with ISO that its proposed bright-line voltage level split is a transparent method for determining the benefits and identifying the beneficiaries of transmission facilities on the ISO-controlled grid. In that regard, the ISO stated in its compliance filing that the current high and low voltage cost allocation distinction was based on the historic engineering principles used by California's investor-owned utilities in designing their transmission networks. The ISO worked with stakeholders for over two years and during the process modeled and

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18 143 FERC ¶ 61,957 at P 297.
19 *Id.* at P 298.
20 *Id.* 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. CAISO Transmittal Letter in Docket No, ER13-103, p. 28-29 (Oct. 11, 2012)
21 *Id.*
22 *Id.* at P 299.
23 *Id.*
24 *Id*. at P 303.

evaluated extensive data across the potential scenarios, including different voltage levels, to arrive at the existing bright-line voltage level split.

Also relevant to this initiative, FERC found that, although the ISO's regional cost allocation methodology did not use different cost allocation methods for different types of transmission facilities, the transmission cost allocation framework still complied with Regional Cost Allocation Principle 6.[25] Under the ISO's cost allocation method, regardless of the need that justifies the construction of a specific transmission facility, high voltage transmission facilities provide regional benefits and their costs are allocated regionally, and local transmission facilities provide only local benefits and their costs are allocated locally.

The ISO understands there may be potential modifications to the current TAC structure that could potentially align the cost causation and relevant cost allocation of the TAC with the current utilization and benefits being provided to customers. However, in opening this initiative and dialogue on potential modifications to the current TAC structure, the ISO is seeking to explore various enhancements, but does not believe that the current structure has been shown to be unjust or unreasonable through any stakeholder comments provided to date.

7. TAC structure straw proposal

The following sections present the ISO's straw proposal for this initiative. The ISO provides some relevant principles and describes the important issues that must be carefully considered for any potential TAC structure modifications.

The ISO is proposing modifications to the billing determinant approach for measurement of customer use. The current approach is a volumetric measurement and the ISO believes that a hybrid approach, utilizing both peak demand and volumetric methods for measurement of customer use to collect TAC charges is more appropriate. The ISO explains the justification for this aspect of the proposal in the following sections.

The ISO has also received considerable stakeholder feedback on the point of measurement issue that has been discussed during stakeholder working groups. A significant majority of stakeholders are opposed to modification of the current point of measurement, citing many concerns over inappropriate cost shifting. Due to the overwhelming opposition to changing the point of measurement the ISO proposes to maintain the current end use customer meter point of measurement. The ISO has provided the stakeholder feedback opposing changes to the point of measurement in appendix B. The issues and concerns related to potential modifications to the point of measurement are discussed in further detail.

7.1. TAC structure rate making principles

The ISO has identified three key ratemaking approaches to consider for allocating costs of the HV transmission system. The ISO believes that a rate structure intended to meet the objectives

25 *Id.* at P 304.

of any of these major approaches can potentially be designed to comport with the traditional FERC ratemaking principles and ISO cost allocation principles described in the ISO's June Issue Paper.[26]

The three ratemaking approaches the ISO presents for this discussion are:

1. Charge TAC according to cost causation and cost drivers when decisions to invest in transmission infrastructure were made. *i.e*., load for whom the facilities were built should continue to pay for transmission built to serve them, regardless if their usage patterns have changed.
2. Charge TAC according to current usage (and benefits), which may be different than the previous usage. If the ISO took this approach, then it needs to decide how to best characterize and measure current usage and benefits.
3. Charge TAC to send price signals as incentives to modify future behavior. This principle can potentially reduce future cost drivers and incent behavior that will support public policy goals or mandates. This approach is complicated by the multifaceted ratemaking layers regarding transmission cost recovery currently present in California.

These three ratemaking approaches should be weighed and evaluated in this process to determine the most appropriate proposal for any modification to the TAC structure.

Under the first approach, a proposal should clearly demonstrate the linkage of the billing determinants to the cost drivers and needs that were present when the existing system was built. This means that the ISO should attempt to classify the various cost drivers of the existing system, should it want to apply this ratemaking principle.

Under the second approach, a proposal should clearly demonstrate the linkage of the billing determinants to the usage and benefits of the current users of the grid that can be identified in a fair manner. To apply this consideration, the ISO should identify accurate methods of determining the usage of and benefits provided by the existing system.

Under the third approach, a proposal should clearly demonstrate an effective nexus between changing TAC structure and the incentive created. In other words, any proposal relying on the third approach should show the incentive created by the modified TAC structure accurately reaches the party who makes the decision the ISO seeks to incentivize. For example, it might be necessary to show the linkages (a) from the modified TAC structure to the decision process of the LSE that makes procurement decisions, (b) from the LSE procurement decisions to the overall achievement of the policy objective, or (c) from the policy to the non-incurrence of transmission costs or the lack of benefit from transmission costs.

Linkages between policies and transmission cost incurrence and benefit should be sufficiently demonstrated. Some factors must be considered in assessing the foregoing ratemaking approaches. First, the initiative is only considering the HV-TRR, so any change in ISO policy would not change billing for the LV-TRR (which comprises 55% of the PG&E TRR, 40% of the

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

SDG&E TRR, and 2% of the SCE TRR). Second, among the three major California IOUs, the entire cost for the full transmission system (HV and LV TRRs) only accounts for approximately 9% of the overall SCE annual revenue requirement, 11% of the overall PG&E annual revenue requirement, and 16% of the overall SDG&E revenue requirement.[27] The vast majority of the overall costs that must be recovered by ratepayers annually are comprised of generation and distribution costs. Specifically, generation and distribution costs comprise these percentages of each IOU's annual revenue requirement: 91% for SCE; 89% for PG&E; and 84% for SDG&E. This demonstrates that it will be challenging to influence end use customer behavior and future transmission usage through a rate design mechanism traditionally intended only to recover the embedded costs of the existing HV transmission system.

Third, UDCs and LSEs have retail ratemaking proceedings, and this additional layer of retail rates will mute the price signals the ISO TAC rate design might otherwise provide to end use customers. Fourth, the ISO bills UDCs for TAC, not LSEs, which are the entities that make generation procurement decisions. The CPUC and local regulatory authorities regulate LSEs, not the ISO or FERC. Thus, to provide any meaningful incentive for procurement, an additional ratemaking mechanism must be developed to properly 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. The ISO discusses these concepts and has described the significant stakeholder feedback on this concept in its discussion of the point of measurement issue in section 7.2.3.

Finally, some stakeholders have argued that reduced flow across transmission facilities can reduce overall transmission costs for many reasons, but other stakeholders disagree. The ISO discusses this consideration further in section 5.2.

The ISO has considered these important issues and questions in developing the current proposal. The ISO describes the potential modifications it is considering in the following sections.

7.2. Potential modifications to TAC structure

There are two basic issues to address in this initiative: (1) where to measure transmission usage; and (2) how to measure transmission usage. These two primary aspects of the TAC structure are referred to as the point of measurement and the billing determinant, respectively. The billing determinant is the basis for measuring the consumption used to calculate a customer's bill or to determine the aggregate revenue from rates from all customers, *e.g.*, volumetric (MWhs). The point of measurement is the point from where the billing determinant is measured and reported, which is currently taken from the end use customer meter. The ISO further discusses these two issues and potential considerations regarding each feature in the following sections. The ISO also summarizes stakeholder feedback and presents its proposals regarding these two fundamental TAC structure components.

[27] See *California Electric and Gas Utility Cost Report Public Utilities Code Section 913 Annual Report to the Governor and Legislature*, April 2017, at: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2017/AB67_Leg_Report_PDF_Final_5-5-17.pdf

7.2.1. Billing determinant options

The TAC billing determinant is the unit of measure for customer use, which may consist of several approaches, including demand, usage, or consumption, used to calculate TAC rates collected from all customers, *e.g.*, volumetric (MWh), peak demand (MW), and time of use (MWh per time period). The ISO utilizes a volumetric billing determinant. The ISO has considered the following potential options and discusses each approach for comparison.

Volumetric approach

The ISO currently uses a volumetric measurement to assess customer use for TAC billing purposes. The volumetric billing determinant measures end-use customer metered MWh consumption to assess current TAC charges. The volumetric approach was approved as described in section 6.2 above, which is premised on the delivery of energy versus capacity. Certain stakeholders' views align with the volumetric approach, while others' views align with peak capacity delivery. Certain stakeholders consider several other vital reliability functions associated with the delivery of capacity and services, including delivery during peak load periods, and believe that should be reflected in the measurement of transmission use.

Using a volumetric approach for the TAC billing determinant has advantages and shortcomings. Some advantages are that the volumetric aspect mirrors the energy-based ISO markets, is easily understandable, and reflects benefits provided during all periods. The volumetric approach also closely measures usage correlated with RPS-driven and economic transmission project investment benefits (*e.g.*, carbon reduction, production cost savings). Some shortfalls of the volumetric approach are that it does not reflect capacity delivery cost and benefits, and it socializes costs incurred due to peak times and/or needs in certain areas of the system. The volumetric approach may be useful for capturing usage and benefits delivered during all periods and from policy driven investments needed to deliver energy; however, a pure volumetric approach may not reflect the costs and benefits associated with the delivery of capacity, especially during peak load periods.

Volumetric usage charges also benefit customers with low load factors, that require greater amounts of load following services, rather than high load-factor customers, with stable load profiles that use the system more efficiently, imposing fewer costs on the system. A volumetric charge may not appropriately capture the costs caused by particularly low load factor customers. Volumetric usage charges may not provide a clear enough signal to encourage economical peak period demand response and energy efficiency by giving both peak and off-peak reductions equal weight.

The volumetric approach also may negatively affect ISO dispatch efficiency because the volumetric approach includes fixed costs in the marginal cost of energy, which may not reflect a user's true willingness to pay for a marginal unit of energy.

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. 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 some benefits associated with using a volumetric approach may still be useful for capturing the benefits of policy-driven transmission investment and off-peak use of the transmission system.

Peak demand approach

The ISO previously noted that most other ISO/RTOs rely on peak demand measurements for billing transmission costs.[28] FERC settled on demand as the *pro forma* billing determinant in Order No. 888, finding that:

> "Network service permits a transmission customer to integrate and economically dispatch its resources to serve its load in a manner comparable to the way that the transmission provider uses the transmission system to integrate its generating resources to serve its native load. Because network service is load based, it is reasonable to allocate costs on the basis of load for purposes of pricing network service. This method is familiar to all utilities, is based on readily available data, and will quickly advance the industry on the path to non-discrimination. We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet an annual system peak (e.g., ConEd and Duke) are free to file another method if they demonstrate that it reflects their transmission system planning."[29]

Demand-based billing determinants are a commonly accepted approach for measuring the usage and benefit provided to users of the grid to recover transmission costs. Peak demand measurement is particularly consistent in determining usage and benefits correlating with system peak load periods, which has been a historic cost driver of much of the investment in the existing system. One benefit of a demand-based billing determinant is the ability to better support efficient market dispatch when compared to a pure volumetric approach. Also, it is a well-understood billing construct. Additionally, with demand charges customers only pay their contribution to peak conditions, which may more closely correlate cost drivers with use of the system. A demand charge would allow customers to consider the costs of their consumption decisions at different times, whereas a volumetric usage charge conveys to customers they should be indifferent as to when their consumption occurs.

As explained above, there are numerous advantages to using demand charges; however, there are some potential shortcomings that are important to recognize. One potential negative is that demand charges can disregard or discount the assignment of costs and benefits provided during off-peak periods. Demand charges may socialize costs incurred due to off-peak needs and locations needing more investment to meet off-peak needs. Additionally, they may not fully

[28] See ISO Review TAC Structure Issue Paper.
[29] *Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities*, 61 F.R. 21540-01 at 21599, Order No. 888 (1996).

reflect the costs and benefits of energy delivery from policy driven investments and other energy (volumetric) delivery driven investments and related transmission system. Although there are both positive and negative aspects associated with any billing determinant measurement approach, a peak demand measurement approach can balance ratemaking principles.

A variety of options can be used to employ demand based billing determinant measurements. One potential option is the number/frequency of peak demand measurements, *e.g.*, annual peak (1), seasonal peaks (4), monthly peaks (12), or daily peaks (365). Different regions have employed these various methods, and they can all measure customer usage of transmission. Depending on the way the transmission system has been planned, and the intended benefits to be provided based on the planning process and investments previously approved, it is reasonable to align these planning and investment decisions with the frequency of the peak demand measurement.[30] In the ISO's TPP, the ISO plans the system to meet the system's coincident peaks each month. The California Energy Commission IPER load forecasting process and California Public Utilities Commission resource adequacy program are both based on monthly peaks. Accordingly, a monthly peak-based demand charge aligns with California transmission planning.

Under a peak demand approach, a key consideration is what peak definition to use for the peak demand measurement. The ISO could utilize a coincident peak demand measurement, in which usage is measured for each customer based upon the customer's contribution to the overall coincident system peak. Coincident peak demand is the most commonly used for transmission cost recovery at the wholesale level. Alternatively, the ISO could utilize a non-coincident peak demand measurement, where usage is measured for each customer based upon that customer's own non-coincident peak demand, regardless of the overall system peak. Non-coincident peak demand charges are most commonly used by utilities for commercial and industrial customers. Non-coincident peak demand measures may better capture some of the usage and benefits provided to specific customers that peak frequently different from the overall coincident system peak.

Coincident and non-coincident peak demand charges are not mutually exclusive, and the ISO intends to explore how a non-coincident peak demand measurement could be used with coincident peak demand charges to mitigate some of the potential drawbacks associated with each approach. The ISO has received stakeholder feedback supporting both approaches. The ISO seeks additional feedback from stakeholders regarding coincident versus non-coincident peak demand measurements and would like to understand if stakeholders believe that a combination of both approaches could potentially be used, *i.e.*, would it help mitigate the potential disadvantages of demand charges if some combination of coincident and non-coincident peak demand methods were proposed to be utilized for the TAC billing determinant?

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

Time-of-Use approach

Another approach for measuring customer usage to assign TAC charges is known as a Time-of-Use, or TOU, measurement. TOU measurement is a variant of the basic volumetric approach, where the billing determinant is based on volumetric measurement of use during specified time periods, and charges are allocated at time varying rates, depending on the cost to serve loads during various time periods during the day. The ISO indicated that the TOU approach would be considered in this initiative, and some stakeholders expressed support for exploring a TOU based billing determinant.

A TOU measurement would require a minimum of two specific time periods with distinct, differentiated rates associated with each time period, *i.e.*, on-peak and off-peak time periods. Use of this approach also assumes there are different costs for using the transmission system associated with the different time periods. It would also require the identification of specific time periods and associated cost drivers.

Like the other approaches presented above, TOU has both advantages and disadvantages. An advantage is TOU may reflect both energy and capacity delivery costs and benefits if properly designed, due to the different costs related to delivering energy and capacity during different time periods. One of the shortcomings is that TOU is more difficult to understand and implement because a TOU approach requires identifying the time periods that accurately reflect different cost levels required to serve loads, and specifically identifying the differences in these cost levels to set appropriate rates for each identified time period.

This need to identify the different costs associated with specified periods may be relatively straightforward when considering peak versus off peak generation capacity needs for issues such as retail ratemaking purposes. However, it is not as clear and straightforward when considering the recovery of the costs of the HV transmission system at the wholesale level. These transmission investment costs are not easily differentiated on an on-peak and off-peak basis, and they are even more difficult to differentiate on an hour-to-hour basis. The only timeframes that would generally show higher costs are those periods that regularly experience heavy congestion. The periods of heavy congestion on certain facilities have been observed to be variable across different parts of the year and across different facilities. They also change when new transmission facilities are constructed (as they are designed to in the ISO TPP). Congestion costs are also intended to be captured in the congestion component of locational marginal prices in the ISO energy markets.

These factors indicate that a TOU approach would likely be complicated to develop for the purposes of the TAC billing determinant. Developing a TOU approach would also present a significant implementation challenge and would be difficult to understand and update in the future if the time periods and costs shift due to changed circumstances. These issues may be a challenge for reaching stakeholder consensus on developing TOU rates. Thus, the ISO believes a TOU approach may not be best suited for recovery of transmission costs at the wholesale level.

Hybrid approach (part volumetric and part peak demand)

A hybrid billing determinant approach would measure a portion of customer use through a volumetric measurement and a portion through a peak demand measurement. This approach would capture benefits of both the volumetric and the peak demand approaches. Using a hybrid approach also would mitigate some of the potential shortcomings of each approach. Some stakeholders have advocated for this hybrid approach because they believe it may more closely reflect the different cost drivers associated with both energy and capacity functions and the related benefits provided by the transmission system.

A hybrid approach may have an advantage over other billing determinant approaches because it can reflect the use and benefits of the system more accurately then either volumetric or peak demand can in isolation. The system provides both energy and capacity functions, and other reliability benefits, and a two-part hybrid approach can measure each of these functions. A hybrid approach would not limit TAC cost recovery to only peak demand periods, which may be appropriate because the benefits of policy projects and other energy delivery functions would accrue throughout all hours of the year, not just during peak demand periods. A two-part hybrid rate design could also help mitigate the potential rate burdens placed on certain customer classes, while retaining the proposed usage charge's sensitivity to seasonal changes and encouragement of energy conservation efforts.

There are different ways to determine which portion of the HV-TRR is collected through each component of the hybrid rate design (*e.g.*, existing versus new, category of project, TPP-approved versus refurbishment). The ISO plans to explore the potential variations that could be collected under a potential hybrid approach for the HV-TRR. For example, in the Midcontinent ISO (MISO) the costs for transmission facilities designed to meet peak load conditions are subject to a demand rate, and the costs for transmission facilities designed to meet RPS and public policy goals are subject to a volumetric rate. The ISO seeks additional stakeholder feedback on using a hybrid volumetric and peak demand measurement approach for the TAC billing determinants.

7.2.1.1. Potential billing determinant comparison matrix

Table 2 below summarizes the potential billing determinant measurement approaches described above.

Table 2 - Potential TAC billing determinant modifications comparison matrix

Billing Determinant	Pros	Cons
Volumetric (Status Quo)	• Volumetric aspect mirrors energy-based (not capacity-based) market • Easily understandable	• Does not reflect capacity delivery cost/benefits • Socializes costs incurred due to peak times and/or areas

Billing Determinant	Pros	Cons
	• No implementation for status quo • Reflects benefits provided during all periods • Correlates with RPS-driven construction benefits (*e.g.*, carbon reduction, production cost savings)	
Peak Demand	• Best supports efficient market dispatch among all options • Customers only pay in relation to their contribution to peak conditions (no more, no less) • Easily understandable • Relatively easy implementation	• Ignores benefits provided during off peak periods • Does not reflect all policy driven related energy delivery cost/benefits • Socializes costs incurred due to off-peak times and/or areas
Time of Use	• Supports efficient market dispatch • May reflect both energy and capacity delivery cost/benefits	• Difficult implementation
Hybrid *(part peak demand & part volumetric)*	• Supports efficient market dispatch better than pure volumetric • May reflect both energy and capacity delivery cost/benefits • Reflects the advantages of both volumetric and peak demand to some extent	• Volumetric aspect of billing determinant conflicts with efficient market dispatch • Also reflects the disadvantages of both volumetric and peak demand to some extent

7.2.1.2. Billing determinant proposal

It is possible to change the way usage is measured that would improve the alignment of transmission cost recovery with the cost causation and benefits provided by the transmission system. After considering stakeholder feedback and reviewing the current TAC structure, the ISO believes it is appropriate to modify the TAC billing determinant approach from the current volumetric measure. The ISO proposes to utilize a hybrid measurement approach, composed of part peak demand and part volumetric measurements for determining transmission system use to recover HV transmission system costs.

Aligning transmission system cost drivers and functions with the approach utilized for measuring customer use is a vital aspect of a well-designed transmission cost recovery mechanism and a foundational element of the ISO's proposed modification. The current volumetric approach may no longer closely align with the cost drivers and functions delivered by the transmission system because of the transformation of the grid and resource mix, and the functions and services provided by the transmission system include more than simple energy delivery.[31] Because a volumetric measurement approach primarily reflects the energy delivery function of the system, there is a potential for the capacity delivery function and other reliability benefits to be ignored if used alone.

TAC cost recovery impacts on efficient marginal pricing and market dispatch

The ISO's Department of Market Monitoring (DMM) and Market Surveillance Committee (MSC) have also identified potential negative impacts on the efficiency of the ISO market dispatch and the overall cost of delivering supply to loads associated with the current volumetric only approach.

The MSC has stated that economists argue that the marginal price of electricity (price of consuming 1 more unit of energy, *i.e*., kWh) would ideally be set at the societal cost of supplying that kWh.

These societal costs include the costs associated with:

- Incremental generation (fuel, and O&M) costs
- Network congestion and contingency costs
- Scarcity
- Environmental externalities (e.g. cost of carbon)

Ideally, the marginal price should not include:

- Recovery of sunk costs (embedded, unavoidable costs)
- Exercise of market power

The goal of efficient marginal pricing is to align the marginal cost of supply with the marginal benefit of consumption. Misalignment creates deadweight loss from too much or too little consumption.[32]

Many stakeholders have noted that the costs of the existing transmission system are embedded, sunk costs. These costs are unavoidable unless the assets are shown to no longer be needed for reliable operation of the grid and decommissioned. Maintenance costs associated with the existing system's embedded costs may be deferrable but are also largely unavoidable.

The current volumetric structure of TAC results in a charge to load on a per megawatt hour (MWh) basis. This charge is incurred by participating load, and UDCs that pass through the costs to ratepayers, also largely on a per MWh basis. In a competitive market, the price of electricity faced by load should represent the marginal cost of delivered electricity. However, a

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[31] See Section 5.1 & 5.2 above.

[32] See *Addressing Retail Problems with Wholesale Products MSC presentation*, CAISO Market Surveillance Committee, December 2017, at: http://www.caiso.com/Documents/Presentation-LoadShift_LoadConsumptionDiscussion-Dec1_2017.pdf

fixed cost recovery mechanism for transmission does not represent a marginal cost of producing electricity, nor does it represent a marginal cost of providing transmission. This apparent marginal cost of transmission is simply a convenient means to allocate recovery of fixed costs associated with transmission assets.

Recovering fixed costs on the basis of marginal energy consumption results in load perceiving a spot market price of energy that exceeds the marginal cost of energy. This results in market inefficiency when load considers these non-marginal costs in the decision to consume incremental quantities of energy. Because these fixed costs are considered by load on a per MWh basis, participating load and exports will have incentive to submit spot market bids which are lower than the true marginal willingness to pay for any quantity of incremental energy.

The regulated and static nature of retail electricity rates and the fact that TAC charges are indirectly charged to end users by LSEs, may introduce market inefficiencies by distorting price signals. Including fixed costs in incremental energy prices can further contribute to these potential inefficiencies as the price realized by retail load increasingly departs from the marginal cost of energy. Market efficiency may improve to the extent any fixed costs can be removed from retail and spot market energy prices realized by end users such that these prices more accurately reflect marginal cost of delivered electricity.

The ISO's DMM has recommended that the ISO consider revisions to the TAC structure to prevent fixed cost recovery from being reflected as a marginal cost in spot market prices realized by load. Historically, this has not been a major issue because most load has self-scheduled in real-time and therefore could not respond to price signals. However, this issue could become very significant for the efficiency of energy markets as load increasingly can respond to price signals in the low carbon energy network of tomorrow.[33]

Consistent with DMM's and the MSC's positons, modifying the billing determinant to utilize a hybrid measurement approach will help mitigate some of the negative impacts to these market efficiency issues associated with a purely volumetric billing determinant because a hybrid approach allows for some recovery of the HV-TRR based upon a peak demand, which is a MW measurement assessed on end use customer's peak demand. Under a hybrid approach only a portion of the overall HV-TRR would be recovered through a volumetric measurement of end use customer's consumption. Adding a peak demand usage measure will allow the costs and benefits of serving customers with low load factors and high peak demands to be reflected in the costs recovery more appropriately than a volumetric approach alone.

Determining hybrid method HV-TRR cost recovery split

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 peak demand billing determinant. There are several options for splitting the HV-TRR, including some

[33] See DMM Comments at: http://www.caiso.com/Documents/DMMComments-ReviewTransmissionAccessChargeStructure-IssuePaper.pdf

that have been mentioned in the hybrid approach description above, *e.g.*, existing versus new, or by category of project.

Any split should reflect the ratemaking principles discussed previously. One potential approach for splitting transmission costs between volumetric and peak demand that meets the previously mentioned principles would be to allocate the costs of the existing system in a manner that reflects the functions and benefits provided. Specifically, the split could allocate costs associated with energy delivery functions through the volumetric portion of the hybrid approach and allocate the costs of the system that can be associated with capacity and reliability functions through the peak demand portion of the hybrid approach.

It may be difficult to precisely determine what the cost drivers of the existing system were and what amounts are associated with energy delivery versus capacity and reliability functions. One way to provide a general proxy for the costs of the system associated with these functions of energy delivery or capacity and reliability would be to determine the proportion of costs associated with specific project types approved under the ISO's TPP or predecessor planning processes. Some stakeholders have indicated this approach could be a useful mechanism to determine the split if a hybrid approach was used. These stakeholders suggested that a fair assessment of these approved TPP costs could associate specific projects types with these functions of the system. The three current project types considered under the ISO's TPP are (1) reliability projects, (2) economic projects, and (3) public policy projects. Policy projects are based on a RPS requirement of delivering MWhs and economic projects that enable lower cost energy could be considered energy functions. Reliability projects could be considered a capacity function because they help ensure that peak loads are served reliably.[34]

The ISO has provided a rough estimate of these different project costs in the following table.

Table 3: ISO approved transmission investment breakdown by project category

	Transmission Plan									
Project Category	*Prior to 2010*	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	Cumulative TOTAL	**(%)**
Reliability	-	1,198	647	1,343	1,833	352	288	24	5,685	**41.66%**
Policy	~7,000 [35]	40	-	421	135	-	-	-	7,596	**55.66%**
Economic	-	-	-	-	359	7	-	-	366	**2.68%**
Annual TOTAL	7,000	1,238	647	1,764	2,327	359	288	24	13,647	100%
($ costs provided in millions)										

[34] See California Large Energy Consumers Association (CLECA) comments.

[35] These policy project costs are included here for the purpose of categorizing costs of prior approved transmission investment by project type, but it should be noted that the ISO redesigned the TPP in 2010

As stated in the table above, if the ISO split the HV-TRR consistent with the project types, the ISO could propose that for the previously approved investments, approximately 42% of the costs serve a capacity function of the overall system (costs associated with reliability projects) and 58% of the costs are related to the energy delivery function of the overall system (costs associated with policy and economic projects).

The ISO could propose to apply a similar breakdown for the ratio of the hybrid billing determinant approach by associating each function of the system with a specific project type and related billing determinant measurement. The portion of the HV-TRR that could be collected through a volumetric billing determinant would be 58% of the overall HV-TRR. This portion of the overall HV-TRR would be associated with the energy delivery function of the transmission system and the volumetric billing determinant would align with the identified costs and benefits provided by policy and economic transmission project investments. The portion of the HV-TRR that could be collected through a peak demand billing determinant would be 42% of the overall HV-TRR. This portion of the HV-TRR would be associated with capacity and reliability functions of the transmission system and the peak demand billing determinant would align with the identified costs and benefits provided by reliability projects. These suggested HV-TRR cost ratios to be recovered through volumetric and peak demand approaches could be fixed or variable, depending on adding future projects and other non-ISO approved costs included in the HV-TRR.

The nature of benefits provided by policy and economic projects may be primarily based on energy delivery functions, as explained previously. However, these investments also provide some additional reliability benefits, allowing for additional peaking capacity to be delivered during certain periods. Policy and economic projects may have reliability benefits, but the reliability requirements are usually measured and set based on forecasted peak demand, and some portion of those costs may be appropriately allocated on a demand basis. Reliability projects can also have some additional benefits beyond the peak capacity delivery function, providing energy delivery function benefits as well. This demonstrates that determining the magnitude and type of benefits provided by individual transmission investments is not an exact science.

Because all investments in the transmission system have some benefits for both energy and capacity functions it may be appropriate to split the HV-TRR in a less specific manner than applying the ratio of costs of project types as described above. The ISO could apply a more straightforward split of these costs, assigning half (50%) to be collected through a volumetric approach and half (50%) through a demand charge approach. This 50-50 split of the HV-TRR cost recovery under a hybrid approach may more accurately capture the fact that all transmission investments can deliver both types of benefits, providing some energy delivery

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to include policy projects as a specific category that did not exist prior to 2010. All of these costs are included under policy category because they were incurred due to investments approved as necessary to meet the California public policy goal of 33% RPS. The majority of public policy driven investment has occurred before 2010 so the ISO believes that it is important to incorporate these investments in this categorizations.

function and some peak capacity delivery functions, and the exact benefits accruing to specific customers are difficult to quantify with a great deal of precision.

The approaches described above are potential solutions to the issue of determining how to split the HV-TRR to allocate the costs through each part of a proposed hybrid billing determinant. The ISO is open to refining these concepts further as it develops future proposals. The ISO seeks stakeholder feedback on this proposal and welcomes suggestion for any potential alternative solutions to splitting the costs for a hybrid billing determinant approach.

Treatment of Non-PTO Municipal and Metered Sub Systems under a hybrid billing determinant approach

There also may be a need to revisit the approach for measuring the use of the system by Non-PTO municipals and Metered Sub Systems (MSS) to align the TAC billing determinant approaches for these entities with the other TAC structure modifications under any hybrid billing determinant measurement approach. These entities are currently billed for their use of the HV transmission system through the Wheeling Access Charge (WAC).[36] The ISO is not making a specific proposal for modifications to this aspect of the TAC structure at this time, however the ISO seeks feedback from stakeholders on this related issue.

Because the ISO is proposing a hybrid approach for the billing determinant measurement of use, there may be an opportunity to align the treatment of the Non-PTO muni and MSS customers charged for use of the system through the WAC. These entities are treated in this manner for the reasons described in section 6, but these customers also are more similar to internal loads than exports in several ways. These similarities include that these entities loads are planned for and served by the transmission system similarly other internal loads. These entities use of the HV transmission system is also currently measured volumetrically, although charged WAC instead of the standard TAC. This approach for measuring their usage is similar to the way other traditional customers charged TAC are measured, using a volumetric billing determinant. Because the ISO is proposing a hybrid measurement for the current TAC billing determinant approach, and because of the similarities described above, it also may be logical to also modify the measurement used to recover transmission costs from these entities.

To accomplish this change the ISO would have to develop a new category of rates for transmission cost recovery that would differ from the current TAC rate and WAC rates charged to these customers currently. The ISO would need to apply a peak demand and a volumetric measurement to the billing determinant approach for these entities to mirror the approach for measuring use of other customers. This would require a separate calculation of each entity’s peak demand charge and volumetric charge. Based on stakeholder input, ISO will consider further developing this potential modification in future straw proposal iterations

[36] See ISO TAC Background Whitepaper.

The ISO seeks feedback from stakeholders on this issue and would like to understand their views on whether it make sense to apply a similar hybrid approach for Non-PTO municipal and MSS entities.

7.2.2. Analysis of TAC structure billing determinant options

The ISO has engaged the Brattle Group to develop a spreadsheet model that analyzes alternative approaches to the ISO's TAC structure. The goal of this modeling effort is to analyze the potential cost shifts among UDCs in the ISO when different approaches would be used in calculating and billing the TAC. The model includes the flexibility to analyze different TAC designs.

TAC modification impact model description

The existing TAC rates spreadsheet that the ISO maintains,[37] including all supporting data used in the calculation (*e.g.*, TRRs, load data for all UDCs, wheeling fees collected, other credits and adjustments to TRRs) is the starting point for the data that underlies this modeling exercise. The ISO also has gathered the necessary transmission cost and billing unit information and data needed to use different billing units to evaluate the options described above.

The ISO has attempted to collect and utilize actual data that is publically available to provide a model that is accurate while being transparent and available for public use by Stakeholders. For some inputs the ISO worked to develop an approximation of the billing units based on: (a) UDC-level load data, (b) quantity of distribution generation resources that exist on each UDC's system, and (c) historical output of those resources or similar resources in the different regions of the ISO.

Items (b) and (c) each have two essential components: (1) output of generation connected directly to the UDC system, and (2) output of behind-the-meter generation injected into the UDC system in hours when that output exceeds the on-site load. The ISO has engaged with PTOs and IOUs to understand if there is any aggregate level data they may provide on these two components that may be disclosed publically and used in the model inputs. The ISO may also have to consider utilizing certain input assumptions on some of these aspects of the modeling if the data needed is not publically available.

The ISO has determined a useful starting point for this modeling effort and input into the proposal is to analyze some combination of these TAC designs:

a) Existing volumetric charge

b) Coincident peak (CP) demand charge approach

c) Hybrid approach that includes an volumetric and CP demand charges, with ability to vary the percentage that TRR is split between the two charge modes

[37] See CAISO HV-TAC rates at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=570d3e00-5ab5-408d-9142-5aa547d419a8

d) Time-of-use (TOU) volumetric charge

The results produced by the modeling effort in this phase will indicate what the TAC costs would be for various UDC areas under the different alternative structures/designs and demonstrate how the analyzed alternative TAC calculation approaches potentially shifts costs between UDCs.

The ISO believes that the merits of this proposal should be considered by stakeholders based upon the principles identified and not only based upon the specific impact to individual entities. For this reason, the ISO does not provide specific impact analysis of the proposed billing determinant modifications that the model illustrates at this time. The ISO plans to provide this cost impact model and associated results of the analysis after it has received meaningful feedback on the merits of the proposal based upon the principles discussed during this round of discussions.

7.2.3. Point of measurement options and considerations

The point of measurement is the point that the billing determinant is measured and reported from. This is currently performed at the end use customer meter. The ISO has received stakeholder feedback suggesting that the ISO consider modifying the point of measurement used for the billing of TAC. Some stakeholders strongly advocate for using the energy down flows at the T-D interfaces for the point of measurement as an alternative to the current end use customer metered demand point of measurement. The ISO has discussed this issue in depth with stakeholders during stakeholder working groups and has solicited written comments on this topic. In response, the ISO received significant stakeholder feedback opposing changes to the point of measurement noted in the following sections and been utilized to develop the ISO's current proposal.

7.2.3.1. Stakeholder feedback on TAC point of measurement

Some stakeholders have advocated for a change in the point of measurement for TAC to the T-D interface; however, most stakeholders oppose this suggestion. The ISO has received comments from 19 parties in response to the ISO issue paper and two TAC structure working group discussions. A majority of these parties (at least 14 stakeholders) explicitly oppose a change to the point of measurement and provided significant evidence supporting their position that this potential change would not result in fair and reasonable outcomes. The ISO has included the stakeholder feedback received on this issue in appendix B.

7.2.3.2. Point of measurement proposal

This sections provides the ISO's proposal for the point of measurement. Based on substantial stakeholder feedback and the ISO's own analysis, the ISO believes the procedures in place today for recovering PTOs' transmission revenue requirements (TRRs), the single change of the ISO's point of measurement from the end use customer meters to the T-D interface would not create an appropriate or effective incentive to procure additional DG resources. There are several fundamental reasons for this as noted by stakeholders. Moreover, there are several structural ratemaking issues that present challenges based on today's transmission cost recovery process.

The ISO has sought to describe the potential changes needed to overcome these challenges and ratemaking structural issues that would arise if the ISO pursued changing the point of measurement. The ISO has discussed these existing structural issues with stakeholders during working group discussions. The ISO reiterates these issues initially described in the ISO's June 30 issue paper:

1. Load-serving entities (LSEs) procure supply resources, either through ownership or contract, to serve their load. The financial impact of changing the cost recovery process must flow to the LSEs and its customers directly to create the desired outcome.
2. The ISO bills the TAC to utility distribution companies (UDCs), not to LSEs. For the municipal PTOs, this distinction is not an issue because there are no alternative retail providers serving end-use customers in their service areas; *i.e.*, the LSE and the UDC are essentially the same entity. But for the IOUs, this distinction is important because end-use customers in their service areas may be served by direct access electric service providers (ESPs) or community choice aggregators (CCAs) and by the IOU. Retail LSEs make the resource procurement decisions, so if the only change to the transmission cost recovery process is to the ISO's wholesale billing determinant, there would be no financial impact on the LSE and the desired incentive would not be achieved.
3. The ISO bills the TAC only for the high-voltage or "regional" portion of the TRRs, which is slightly less than two-thirds of the total TRRs; the low-voltage or "local" portion is billed and collected by the PTOs themselves. Changing the ISO's billing determinant would not, by itself, change how the other one-third of the overall TRR is billed. Moreover, the two-thirds to one-third split is not uniform across the ISO area; for PG&E the local share is greater than 50 percent, whereas for SDG&E the local share is about 40 percent and for SCE only a few percent.
4. It is also worth considering that the overall costs for the three major California IOUs for the entire transmission system (HV and LV TRRs) only accounts for approximately 9% of the overall SCE annual revenue requirement, 11% of the overall PG&E annual revenue requirement, and 16% of the overall SDG&E annual revenue requirement.[38] The vast majority of the overall costs that must be recovered by ratepayers annually are comprised by generation and distribution costs, which means any modification to TAC rates for future behavior modification or incentives would have minimal effect on end use customer behavior when compared to the impact of rate design for recovery of generation and distribution costs.
5. FERC approves the PTOs' TRR amounts. The settlement process must provide each PTO the approved amount. To the extent a change to the ISO's billing determinant shifts

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[38] See *California Electric and Gas Utility Cost Report Public Utilities Code Section 913 Annual Report to the Governor and Legislature*, April 2017, at: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2017/AB67_Leg_Report_PDF_Final_5-5-17.pdf

revenues among the PTOs, the ISO would have to apply a correction that provides each PTO its FERC-approved TRR amount.

6. FERC approves the IOUs' retail transmission rates, so UDCs will collect from all retail customers the same total amount of money irrespective of any change to the ISO's TAC billing determinant. This means that although changes to the TAC structure may result in different allocations to the respective UDCs, the retail customers may not see a corresponding difference in the total transmission charges they pay because of their LSEs procuring more or less energy from DG, unless there are corresponding changes to the retail billing structure.
7. Initially, the ISO believed that the down-flow at each T-D interface could be less than the corresponding gross load due to two factors: (1) the energy output of generating resources connected to the distribution system on the utility side of the customer meter, and (2) the output from behind-the-meter generation in excess of the corresponding end-use load during the same hour and is injected into the grid (e.g., NEM exports). The general assumption that DG output will cause T-D measurements to be less than Gross Load measurements does not always hold true. The conceptual down-flow measurement at the T-D interface may be larger than gross load due to distribution system losses. The relative measure of T-D volume compared to gross load volume would ultimately depend on the magnitude of distribution losses and the magnitude of DG resources' production on the distribution system. The volume of DG resource output on the distribution system would have to be large enough to offset the distribution losses incurred on the same distribution systems to observe reduced T-D volume measurements, as compared to gross load volumes measured at end-use customer meters.
8. If the point of measurement for TAC rates was moved to the T-D interface so customers of DG resources might avoid some TAC charges, however all other customers would have to cover those costs proportionately. This would shift TAC costs away from areas with high IFOM DG production, which would see a reduction in total costs recovered through rates relative to other areas. Because the TRR costs are embedded, the overall recovery of TRR costs would not be reduced, and the areas with proportionally lower IFOM DG production would see an increase in the total cost recovered through rates relative to other areas. This demonstrates that the impact of moving the point of measurement amounts to a cost shifting exercise, with no demonstrable justification. The vast majority of stakeholders have indicated they believe that the potential change would not increase efficiency or lower overall transmission costs.

The ISO agrees with the numerous concerns and issues stakeholders have raised in opposition to the suggested use of the T-D interface. Stakeholders expressed significant concern this potential change inappropriately shifts costs between UDC areas and ignores the benefits provided by the transmission system. There was no credible demonstration that changing the point of measurement would not produce such inappropriate cost shifts. The ISO agrees with the stakeholders concerns about potential inappropriate cost shifts and the recommendations against changing the point of measurement to the T-D interface for assessing TAC charges.

The potential TAC cost savings of such a change are premised on the assumption that DG production may offset existing sunk transmission costs and avoid future transmission costs. A majority of stakeholders asserted this assumption is incorrect. The majority of stakeholders argued that embedded costs of the transmission system cannot be avoided. No stakeholders have provided credible evidence that changing the point the measurement would actually produce measureable benefits or provide any effective price signal to procure additional DG.

Numerous stakeholders noted that future transmission costs may only be avoided by DG where there a need identified through the ISO TPP or by PTOs and a non-wires alternative, like DG, demand response, or energy efficiency, is a viable and more cost effective or efficient solution. The ISO recognizes that current planning and procurement processes already account for DG and other non-wire alternatives to avoid future transmission costs. Based on its review and consideration of stakeholder input, the ISO agrees that changing the point of measurement alone will not produce the significant additional cost savings benefits claimed by some parties.

Further, because the ISO bills UDCs for TAC, not LSEs who make generation procurement decisions, an additional ratemaking mechanism would need to be developed to properly 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 likely require additional action from other ratemaking authorities outside of the ISOs purview, and require significant accounting complexity. The ISO agrees with the majority of stakeholders this additional accounting mechanism's added complexity may not be warranted, particularly considering that transmission costs make up a relatively small portion of total system costs, and due to the multiple layers of ratemaking, any intended price signals or incentive would not be realized, nor worth the additional complexity.

Due to the significant stakeholder opposition to changing the point of measurement, and the reasons discussed herein, the ISO proposes to maintain the current point of measurement of end use customer meters (*i.e.*, gross load). The ISO seeks additional feedback on this proposal to maintain the status quo for the point of measurement and any related interactions with the proposed hybrid billing determinant that should be further considered for the future development of the proposal.

8. Next Steps

The ISO will discuss this straw proposal with stakeholders during a meeting on January 18, 2018. Stakeholders are asked to submit written comments by February 15, 2018 to initiativecomments@caiso.com. Please use the template available at the following link to submit your comments:
http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx

Appendix A: Overview of transmission cost recovery

Due to the need for a clear and complete understanding of how transmission cost allocation and recovery within the ISO works today, including the role and function of the ISO's wholesale TAC and WAC settlement. The ISO developed the following overview that was initially provided in the TAC background whitepaper. The ISO has also provided this description of the overall process for transmission cost recovery in order to better explain the issues once more. The general process for transmission cost recovery is as shown in Figure 1 below. The process will differ somewhat for the following types of PTOs.

A. IOU PTOs (PG&E, SCE, SDG&E). These entities provide the majority of transmission facilities that comprise the ISO Controlled Grid. Their distribution service areas may also contain several municipal utilities, some of which are PTOs and some non-PTOs. If an embedded entity is a PTO, it pays the Regional TAC (R-TAC) and, if applicable, the Local TAC (L-TAC), as well as costs for any existing transmission contracts (ETCs) with the IOU in whose area it is embedded. If the embedded entity is a Non-PTO, it pays the WAC or, if applicable, any ETC-related costs. Thus, the IOU PTOs recover a portion of their TRRs from their internal municipal utilities, in addition to the distribution service customers of their affiliated distribution companies, and exports that utilize their intertie facilities.
B. Municipal PTOs (Anaheim, Azusa, Banning, Colton, Pasadena, Riverside, Vernon) and a rural electric association (VEA). These entities' R-TRRs are included in the total ISO system R-TRR and recovered by the ISO via the postage-stamp R-TAC and R-WAC rates. Except for VEA, these entities do not have Local transmission facilities in the ISO Controlled Grid. In addition, the municipal PTOs are electrically connected to SCE, so if they were connected to SCE's Local transmission they would be subject to SCE's L-TAC (as well as the R-TAC collected by the ISO). However, none of these entities is connected to Local facilities.
C. Non-utility or non-load-serving PTOs. (DATC Path 15, Startrans IO, Trans Bay Cable, Citizens Sunrise).[39] These entities do not have load service areas. They are companies that have built and are currently responsible for maintaining and physically operating transmission facilities in the ISO Controlled Grid. Therefore, the costs associated with their Regional transmission facilities comprise a portion of the total R-TRR for the

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

system. In addition, a non-utility PTO can have an L-TRR that is combined and collected with the L-TRR of the IOU in whose service area the facilities are located.

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

The process shown in Figure 1 is summarized in these steps:

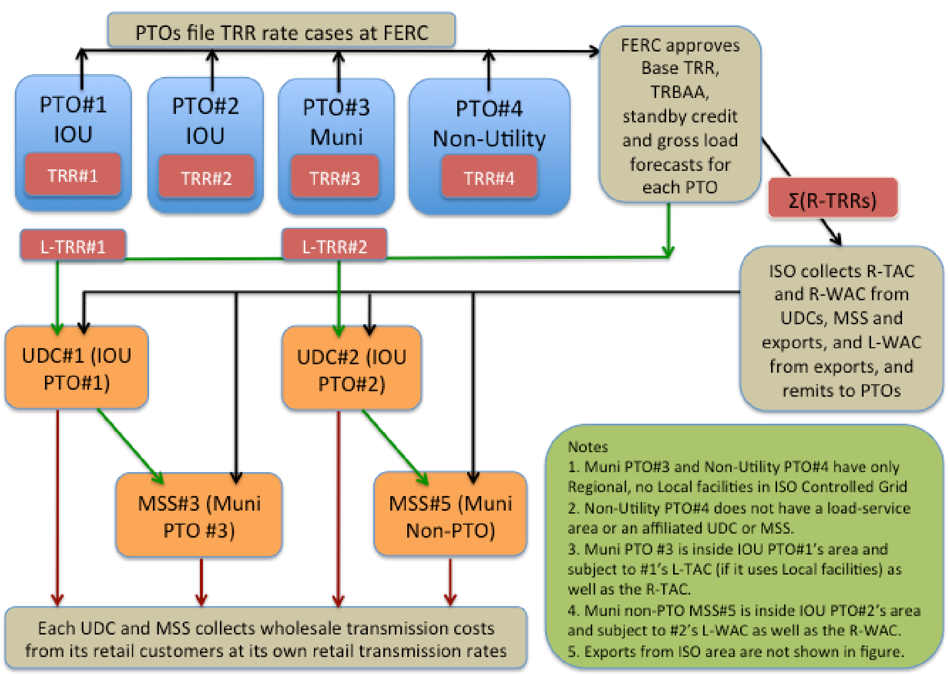
1. Each of the PTOs (groups A, B, C above) files their proposed TO Tariff and TRR with FERC. The TRR is usually specified in an appendix to the PTO’s TO Tariff, and can include forecasted O&M and A&G expenses, and forecasted capital additions. A FERC ruling determines the TRR amount each PTO may collect in rates. The rate cases and the FERC rulings for the load-serving PTOs also address the forecasted Gross Load quantities from which the TRRs will be recovered. For the IOU PTOs, FERC also approves each PTO’s retail transmission rate structure for the various customer classes and the exact amounts of its retail transmission rates. However, the IOUs generally align the retail transmission rate structures they file at FERC with the CPUC’s overall retail rate policies prior to making their FERC filings. For the municipal PTOs, FERC rules on the TRR amounts and Gross Load, and the municipal utility’s governing authority determines its retail transmission rates.
2. In its TRR filing to FERC, each PTO with both Regional and Local facilities proposes a breakdown of its TRR into Regional and Local amounts (R-TRR and L-TRR) based on voltage level and ISO tariff Appendix F, Schedule 3, Section 12. The FERC ruling determines the approved R-TRR and L-TRR amounts.
3. The R-TRR amounts for all PTOs are combined to comprise the R-TRR amount for the ISO system, which is divided by the total Gross Load for the ISO area to produce the RTAC and R-WAC rates the ISO collects through its settlement process in the postage-stamp R-TAC and R-WAC. The ISO settlement process collects the R-TAC from utility distribution companies (UDCs) and metered subsystems (MSS) within the IOU and Municipal PTOs (groups A and B above), and the R-WAC from the Non-PTOs (group D). The ISO remits revenues from both the R-TAC and R-WAC to the PTOs, including the non-load-serving PTOs (groups A, B, and C, above). The ISO also collects the L-WAC from Non-PTOs that use local take-out points and exports that use local intertie facilities, but this detail is not shown in Figure 1.
4. Except for the L-WAC amounts just mentioned that the ISO collects, each of the load serving PTOs collects its L-TRR amount through its own process. The three IOU PTOs collect their L-TRR from the distribution service customers that use their local facilities,

and for which the IOU PTOs have transmission cost billing responsibilities.[40] Among the Municipal PTOs (group B, above) only VEA has Local facilities, and it collects its L-TRR from its distribution service customers. The ISO collects all L-TRR for exports and Non PTOs that use local take-out points and remits the revenues to the appropriate PTOs.

5. Each IOU PTO UDC or other distribution utility or LSE then recovers the transmission charges from its retail end-use customers that use its distribution facilities (and for which the UDC has transmission cost billing responsibilities) through its own retail transmission rate structure.

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

Simplified Overview of Transmission Cost Recovery Figure: *Direction of arrows indicates flow of charges from origination of costs for each PTO to FERC approval to assessment of TAC charges by ISO (Regional) and PTOs (Local) to billing of retail charges to end-use customers by UDCs and MSSs.*



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

The ISO also notes the key takeaways from the TAC background whitepaper that included:

1. Recovery of the costs associated with building, owning, maintaining, and physically operating transmission facilities in the ISO Controlled Grid is a complex process with many steps, including PTOs filing TRRs with FERC, the ISO collecting a portion of the TRRs through the R-TAC and R-WAC, and UDCs and other utilities collecting retail transmission charges from end-use customers.
2. The processes are somewhat different for each of the entities with FERC-approved costs to recover; *i.e.*, the various PTOs in the ISO system.
3. The parties that receive shares of the revenues collected through the TAC and WAC (*i.e.*, the PTOs) are not always the same parties whose end-use customers pay these charges. Some PTOs do not have service areas and customers who pay transmission costs, and there are some UDCs and MSS whose customers pay transmission costs but do not contribute to the transmission costs collected for the ISO controlled grid.
4. The ISO's role in calculating and billing TAC and WAC charges and remitting the revenues to PTOs applies only to:
    a. The Regional or high-voltage facilities in the ISO Controlled Grid used by wholesale customers in the ISO's markets; and
    b. The Regional and Local facilities in the ISO Controlled Grid used for wholesale exports.

Appendix B: Stakeholder comments on TAC point of measurement

Southern California Edison (SCE): *SCE is strongly opposed to changing only the measurement point of the current TAC recovery construct as it would result in unreasonable cost shift away from customers that still receive benefits by being connected to the transmission system. However, SCE is open to any TAC billing structure that can be demonstrated to be superior to the current TAC structure in terms of matching TAC bills to benefits received and costs caused by transmission customers.*

At this point in time, without a thorough assessment of the nature of benefits received by transmission customers, transmission cost causation, and the relationship between these factors and possible billing determinants, SCE prefers the continued assessment of the TAC to EUML. SCE is opposed to revising the TAC billing structure until a thorough study is performed that would show convincing evidence that another TAC billing structure would be superior to the current TAC billing structure.

If it is desired that a specific customer with DG receive a lower TAC bill to reflect a lower TED as a direct result of that customers DG production, then there would have to be some additional ratemaking mechanism created that would reduce either the base retail rate bill of the customer or the TACBAA bill of the customer. This would be a significant change to the current construct of recovering transmission cost in the CAISO. Currently, the cost of all approved High Voltage transmission projects are charged equally to PTO regardless of the identification of cost causation or benefits to specific customer groups. It would be inappropriate to implement a benefit to one type of customers (e.g. those with DG) without examining the structure of how costs are appropriately assigned based upon the identification cost causation or benefits received by different customer groups. SCE does not at this time have a proposal that would accomplish this.[41]

Turlock Irrigation District (TID): *TID is concerned that changing the point of measurement of energy conflicts with operating the electrical system as efficiently as possible. If the point of measurement is changed at all, the entire TAC structure should be examined to be sure it leads to the least cost transmission system and the least cost operation.*[42]

Independent Energy Producers (IEP): *Moving the point of measurement to the T-D interface does not reflect the reliability benefits that the high voltage system provides to the low voltage system. Those benefits in part are related to the capacity that is available and that can be called upon if necessary. The high voltage system also provides voltage support and frequency support to all customers connected to it (directly or indirectly). Changing the point of measurement to the T-D interface would assess TAC charges only to the energy that is delivered from the high voltage system. This would result in all generators on the low voltage*

[41] See SCE comments at: http://www.caiso.com/Documents/SCEComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf
[42] See TID comments at: http://www.caiso.com/Documents/TIDComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

system receiving a competitive advantage of the HV TAC rate. Some stakeholders argue that this provides an appropriate incentive for distributed renewable resources. However, it actually provides this competitive advantage to all generators connected to the low voltage transmission system. So a less efficient, more polluting generator might be dispatched prior to a more efficient, less polluting generator connected to the high voltage system.[43]

Northern California Power Agency (NCPA): *Clean Coalition argued that the proposed change to the TAC billing structure will have a direct and meaningful impact on utility procurement decisions and behaviors. As a utility that is directly involved in these types of investment decisions, NCPA does not agree that the proposed change will have a material impact on DG procurement behaviors. At this time, state policy objectives and mandates are the key variable driving forward-looking procurement decisions. Many of the mandates and requirements that have been adopted in California, including RPS and carbon emissions reduction goals, are multifaceted and complex, and have a much stronger influence on long term planning and investment decisions, as compared to what Clean Coalition itself claims will be a relatively small change in the TAC rate.*

While the generality of this concept could be debated at length, if the ultimate goal of the Clean Coalition is to modify the procurement policies and requirements set forth by each applicable jurisdictional authority, NCPA strongly believes that any further consideration of Clean Coalition's proposal should be taken up in the proper venue, as compared to the current back ended approach that is the immediate subject of this initiative. Establishment of long term procurement goals and requirements is a major component of the planning efforts that take place under the jurisdiction of the CPUC (including the current Integrated Resource Planning proceeding) and other Local Regulatory Authorities. These planning efforts take into consideration many variables, including state laws and policies and the cost of transmission investments. The fact that transmission investment costs make up a material share of the total cost of production has not been lost or forgotten. The Clean Coalition's proposal seems to imply that these costs are not currently accounted for or considered by decision makers. NCPA strongly believes that each respective authority that is responsible for establishing procurement requirements and targets for its jurisdictional entities, has sufficient information and data to take transmission related costs into consideration as they set policy. Simply changing the CAISO TAC billing structure will not result in a newfound understanding of costs associated with transmission investment decisions.

In addition, Clean Coalition's proposal would not appear to create a reliable economic incentive for LSEs to procure more DG. A TED-based TAC allocation will reduce the overall TAC allocation for LSEs that procure relatively more DG than other LSEs. If one LSE procures extra DG, but no other LSEs procure extra DG, the first LSE will pay a smaller share of the overall TRR. But if all LSEs procured proportionately the same amount of additional DG, all LSEs would then pay the same TAC as if none of them had procured additional DG (at least in the CAISO Review TAC Structure Initiative Working Group Comments Page 6 immediate future). So the amount of TAC savings a particular LSE will gain from procuring an extra MW of DG capacity is

[43] See IEP comments at: http://www.caiso.com/Documents/IEPComments-ReviewTransmissionAccessChargeStructure-IssuePaper.pdf

highly uncertain: the savings depend on how much DG other LSEs procure. Since LSEs cannot accurately predict the amount of TAC savings from purchasing extra DG, the TAC savings do not provide a reliable incentive to purchase extra DG when compared to lower-cost, but transmission-dependent, generation.

While Clean Coalition insists that it is entitled to the same rate treatment accorded to Non-PTOs, it has not shown a willingness to assume the financial obligations that Non-PTOs have assumed with respect to the transmission grid. Although a substantial amount of NCPA's generation predates the CAISO, NCPA and its members had to pay all costs related to connecting the vast majority of it generation to the system, whether it was central station power plants or DG located on a member distribution system. If the generation worsened congestion, NCPA or its members were required to pay to build any transmission facilities necessary to relieve congestion on the PG&E transmission system, and to recover those costs from their own ratepayers rather than spreading them to others. If the new generation created problems on their own distribution systems, NCPA members and their retail customers bore the costs of upgrading their distribution systems, and could not spread those costs beyond their respective city limits. By contrast, upgrades to the large PTO distribution systems to accommodate DG can be spread to that LSE's other customers, while costs associated with upgrading the transmission system are spread to all interconnected LSEs (regardless of their participation in the DG procurement) in the case of the LV system, and to all TAC ratepayers in the case of the HV system. Clean Coalition seeks to exempt its associated loads from TAC charges while continuing to use the TAC mechanism to spread any costs it creates to others.[44]

CAISO Department of Market Monitoring (DMM): *By only changing the point of energy measurement and retaining the current volumetric TAC structure, TAC charges would no longer be viewed by load as part of the marginal cost of energy from "behind-the-measure" distributed generation. However, the volumetric TAC charge may still impact load's willingness to pay for energy from transmission connected generation. When only load served by behind-the-measure generation does not pay the volumetric TAC charge, distributed generation appears less expensive and as a result load's willingness to pay for this quantity of energy from transmission connected resources falls.*

In a competitive market where generators offer at marginal cost, inefficiencies may result when the marginal cost of the distributed generation resource exceeds that of transmission connected resources, but load's willingness to pay for transmission connected generation is depressed by the TAC charge. A volumetric TAC charge increases load's willingness to allow distributed generation to offset some load in order to avoid TAC. As a result, a load serving entity has incentive to dispatch the expensive distributed generation resource before a less expensive transmission connected resource.

In this situation, a greater share of load may be served by distributed generation resources. However, this may not be the least-cost dispatch of generation resources. A volumetric TAC charge therefore creates an implicit, inefficient subsidy for resources behind the measuring

[44] See NCPA comments at: http://www.caiso.com/Documents/NCPAComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

point. A volumetric TAC charge can result in providing this subsidy to resources behind the measuring point in a way that is disproportionate to the resources' expected contribution to reducing future capital expenditures on transmission.

DMM also notes the ISO and some stakeholders have considered whether a revised TAC structure should be designed with the specific objective of providing an investment signal to distributed generation resources. DMM believes the objective of the ISO should be to create a competitive and efficient wholesale market design which does not provide incentive or subsidy to any particular generation technology. Public policies to incentivize a particular technology are more appropriately implemented outside of the competitive wholesale market by entities other than the ISO so as to not compromise the efficiency of the broader energy market design.[45]

California Office of Ratepayer Advocates (ORA): *ORA does not support adoption of the TED as the billing determinant for the high-voltage TAC at this time without further study on its impacts such as cost shifts. As stated in ORA's Comments on July 31, 2017 "Given that the existing transmission system was designed to provide reliability services to all customers, including customers on circuits that also include [distributed generation] DG installations, reducing existing transmission capital costs for DG customers would result in unjustified shifting of those costs to California ratepayers without DG. ORA recommends the continued use of reported gross load "end-use metered load" or "customer energy downflow" as the bases for assessing the high voltage TAC.*

ORA does not recommend changing the point of measurement for assessing TAC in order to increase the procurement of DG. California's existing policies already support the procurement of DG and distributed energy resources. At this time there is no evidence that revising the point of measurement for assessing the TAC would increase the procurement of DG or is necessary to support increased procurement of DG.

California's energy procurement and transmission planning processes (TPP) considers DG output in determining the resources and transmission improvements needed to address reliability needs. For example, during 2017-2018 TPP the CAISO and Pacific Gas and Electric Company (PG&E) recommended the procurement of distributed energy resources as mitigations for observed reliability needs. The 2017-2018 Integrated Resource Plan did not recommend procuring additional behind the meter solar. ORA supports the continued consideration of DG in new procurement and transmission decisions when it is the cost efficient option.[46]

California Public Utility Commission Staff (CPUC): *The Transmission Access Charge is essentially a cost recovery mechanism for the FERC approved costs of present and past transmission investments. The CPUC staff support cost of service ratemaking principles for TAC rate design. Any consideration of an exemption from TAC charges should be based on cost of*

[45] See DMM comments at: http://www.caiso.com/Documents/DMMComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf
[46] See ORA comments at: http://www.caiso.com/Documents/ORAComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

service principles. The exemption of a select group of ratepayers from TAC charges is a policy decision which has implications on other ratepayers' charges and must be justified based on cost causation principles. CPUC Staff sees the need for more intensive study to determine the extent to which DER/DG resources do not need transmission facilities or need significantly less transmission facilities and therefore should be exempt from the costs of transmission. A rigorous and fact-based analysis, using cost of service principles, is needed to determine whether load served by existing and new DER/DG resources eliminates the need for, or reduces the cost of, existing transmission investment. This analysis should include further study of whether existing DER/DG resources are currently paying for more (or less) transmission facilities than they use.

CPUC Staff does not favor the potential shifting of costs between ratepayer groups without justification or causal relationship based on a thorough analysis to determine cost causation. If the initiative prevails in establishing an additional billing determinant which changes the existing TAC structure, the result could be a shift in: 1) who pays for the existing transmission system, and 2) who will pay for the going-forward costs of the transmission system.

CPUC Staff notes that a very limited analysis of the possible consequences of adopting the Transmission Energy Downflow (TED) proposal was attempted by CAISO in the now closed energy Storage and Distributed Energy Resources Phase 2 (ESDER 2) Initiative. It is recommended that the CAISO undertake a more extensive review of the effects of this billing determinant mechanism on IOUs, ESPs, and CCA settlement charges for TAC.

Any consideration of the TED proposal should estimate the costs of new metering at the proposed substation locations (presumably using high voltage meters of billing accuracy), transmission/distribution losses, and other associated costs; as well as clarify who would pay for these costs.[47]

California Large Energy Consumers Association (CLECA): *There are clearly benefits from the grid that accrue to all customers, such as voltage support, balancing and frequency control, dynamic stability, backup and standby service, and fault detection and control. Thus, it is inappropriate to argue that some customers should not pay for these benefits.*

There is no logical reason to use TED as the HV TAC billing determinant. There is no logical reason to use transmission pricing to encourage DG. Transmission pricing should be designed to recover the costs of the existing transmission system on a cost of service basis. Having said this, if the CAISO were to adopt such a flawed proposal with the intention of encouraging DG through transmission pricing, the CAISO has no ability to charge LSEs or credit LSEs since it does not bill them. The CAISO charges and credits PTOs for the difference between its postage stamp TAC and WAC and their TRRs. Furthermore, the CAISO does not know how much DG is under contract to each LSE or how this changes over time.

CLECA sees no reason to change the billing determinant used to assess the HV TAC unless it decides that cost causation justifies the use of demand charges as opposed to or in addition to

[47] See CPUC comments at: http://www.caiso.com/Documents/CPUCComments-ReviewTransmissionAccessChargeStructure-IssuePaper.pdf

volumetric charges. No remotely sufficient evidence has been presented to support a change in the point of measurement. It is not appropriate to use transmission pricing to increase procurement of DG by LSEs. LSEs should consider the cost of transmission in weighing their procurement options in their IRPs, particularly where new transmission would be needed to bring in additional in-state and out-of-state RPS resources, and the CPUC and CEC IRP processes should take it into account.[48]

Clean Coalition: *Usage and benefits are two separate considerations. Usage refers to actual present use to deliver energy and energy services, while benefits largely represent either hypothetical needs (e.g., 'back up power") or services otherwise compensated for (e.g. frequency regulation through frequency markets).*

Ultimately, the overwhelming use of the transmission grid is to deliver energy to customers. Thus, measurement of the usage of the grid should be based on how much energy is delivered across the transmission grid, which is the Transmission Energy Downflow at the T-D interface. This structure is both aligned with rate design principles and is simpler than measuring at the HV-LV interface.

Any measurement of transmission usage must be distinguished from distribution usage. Transmission usage is most appropriately measured at the transmission level. If measured externally to the transmission system (e.g., CED), that measurement must be corrected to account for comingled usage and benefits provided not by the transmission system, but by distribution resources. Although theoretically possible, such an approach is logistically far more complex.

Some relatively small fraction of transmission grid cost recovery could be reserved to reflect benefits to customers separate from usage. Conceptually there are three categories of benefits. First, usage is still the best indication of benefit of the grid, since the actual delivery of energy is a realized benefit. Second, potential benefits of having a grid system, like "ready to serve" or "backup power," are those that may translate into actual use or may never actually occur. For most services and assets, these potential benefits are folded into usage charges. (For example, all people benefit from having a working taxi service, but we recover the entire costs of taxi services from usage fees rather than charging non-users a charge to reflect the potential benefit that they may use a taxi someday.) The third category of benefits are those derived from the joint operation of the distribution and transmission grids, such as reliability (since failures on any part of the grid can be addressed with dispatch onto other parts of the grid.), frequency regulation, etc.

Rate design principles may cut against expressly splitting out a benefit component of the rate structure in the TAC for three reasons. First, non-usage related benefits have a fairly indirect relationship to cost-causation, if any. As such, pricing and cost allocation should provide clear price signals to discourage cost causation, and not discourage maximization of benefits free

[48] See CLECA comments at: http://www.caiso.com/Documents/CLECAComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

from cost causation. Thus, when non-usage benefits are considered, it is critical to ask whether these benefits shape transmission planning and spending.

Often, the delivery of energy is the primary function and cost driver, and the appropriate measure of this cost-driver would be the average contribution to local, regional, and system-wide coincident peak capacity. At the most extreme, an islandable micro-grid with connection to CAISO will continue in operation regardless of whether it is islanded. Thus, it will not inherently use or benefit from the grid based simply on whether the connection is open or closed, although some abstract benefits analysis might suggest that the benefit it receives depends on whether it is connected, even if it uses no services from the grid. Indeed, benefits may flow in either direction as between Balancing Authorities, such that it isn't clear whether the microgrid should provide a "benefits fee" to the transmission operator or the other way around. In reality, an islandable grid that meets its own load would not appear in any transmission planning process as driving a need for new transmission.

Thus, any measurement of transmission usage must be distinguished from distribution usage, and is most appropriately measured at the transmission level. If measured externally to the transmission system, the measurement must be corrected to account for comingled usage and benefits not provided by the transmission system.

Second, the complexity of a precise quantification of abstract benefits for rate design may be more difficult than the marginal reduction in market distortions would warrant. Although we may be able to list many customers benefits that are not proportional to usage, the magnitude of these benefits may be so small relative to the basic benefit of receiving energy that the extra complexity of the rate design would simply not be worth the benefit of a strict accounting for these relatively small value (or rarely realized) benefits.

Third, several non-usage benefits already have independent mechanisms to pay for those benefits. For example, frequency regulation is a system wide joint transmission-distribution benefit that is quantified and paid for through frequency regulation markets. Where such mechanisms exist, compensation for those benefits should be handled independently from TAC or as a separate component.

As described in some of our prior filings, T-D TED is the clearest and most accurate measure of the delivery of energy and other services from transmission. T-D TED directly measures usage at the boundary of the transmission system, regardless of whether this is volumetric, time of delivery, or demand based. Although TED could also be used as a measure of usage between the HV and LV systems, the networked structure and potential for energy flows not directly related to a downstream load may complicate allocation of measured usage, as was pointed out by CAISO staff. Due to the radial structure of the distribution system, a clear boundary exists at the T-D interface that is not as clearly present between the HV and LV transmission grids.[49]

[49] See Clean Coalition comments at: http://www.caiso.com/Documents/CCComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

Pacific Gas and Electric Company (PG&E): *Influencing generation decisions through transmission rates is challenging because simplified rates do not adequately reflect location- and time-specific transmission system investment drivers. As described previously, numerous factors drive transmission system expenditures. As discussed, the CPUC's Least Cost Best Fit evaluation criteria address the selection of a resource that requires significant transmission system network upgrades over one that does not. However, this comparison is not the same as the evaluation process the Clean Coalition suggests. The comparison the Clean Coalition appears to suggest involves the selection of a resource that needs transmission compared to one that does not need the transmission system at all. All resources, even behind the meter resources, require the use of the transmission system, unless they serve load completely off the grid or have 24x7x365 islanding capabilities. Due to the inherent interconnected nature of the grid, it is extremely difficult to link an amount of transmission investment or avoided transmission investment to individual resource procurement decisions. This difficulty is not solved a change in rate design, as the challenge is more associated with the interconnectedness of the grid and how planning decisions associated with generation and transmission are made.*[50]

The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities): *The Six Cities believe that the costs of the existing transmission system represent sunk costs, and revising the methodology to allow some entities to avoid continuing to pay for those sunk costs would inappropriately shift costs to other transmission customers.*[51]

San Diego Gas and Electric (SDG&E): *SDG&E has yet to be convinced that a LSE-specific TED represents an improvement over the current method which relies on LSE-specific CED. The simple fact is that every connected end-use customer benefits from the transmission system. This is true regardless of whether the end-use customer consumes real- and reactive-power, injects real- and reactive power, or even if there were no real- and reactive power flow measured at the point of interconnection with the distribution system. This is not contestable.*

In SDG&E's opinion, compared to the Clean Coalition proposal, the existing LSE-specific CED based approach provides a better—though certainly not perfect—measurement of a LSE's usage of, or benefit from, the transmission system.

Changing the point of measurement for assessing the HV TRR creates an incentive to increase LSEs' procurement of distribution-connected generation because doing so shifts the allocation of the existing HV TRR from LSEs with more DG to LSEs with less DG. In SDG&E's opinion, this incentive has little to do with economic efficiency; it's mostly about cost shifting. A LSE's decision to procure distribution-connected generation should be based on whether such procurement is expected to reduce future costs compared to other resource procurement options, not on whether such procurement shifts existing HV TRR costs to other LSEs.

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[50] See PG&E comments at: http://www.caiso.com/Documents/PG-EComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf
[51] See Six Cities comments at: http://www.caiso.com/Documents/SixCitiesComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

Of course, while the Clean Coalition proposal creates an incentive to shift transmission costs to other LSEs, a LSE's decision to procure distribution-connected generation is subject to many other considerations, not the least of which is the cost of the procured distribution generation in relation to the magnitude of the shifted transmission costs.

As a general matter, adding distribution-connected generation – which is close to loads— tends to reduce the need to invest in future transmission infrastructure. However, from the perspective of consumer economics, this is not the important question. The important question is whether adding distribution-connected generation will reduce consumer costs compared to other supply options, including those that require future investment in transmission infrastructure.

For the foreseeable future, SDG&E does not believe adding DG at levels exceeding those already incorporated in the CEC's Integrated Energy Policy Report (IEPR), in the CAISO's annual Transmission Planning Process (TPP) and in CPUC-ordered procurement plans, is likely to have a material impact on future investment in transmission infrastructure. SDG&E anticipates that there will be little in the way of planned transmission infrastructure investment that can be economically avoided by adding incremental amounts of DG.

The CPUC's ongoing Distributed Resources Plan (DRP) proceeding is investigating mechanisms by which DG additions could compete to defer or avoid planned transmission. The CPUC's Integrated Resource Plan (IRP) proceeding will consider whether, and the extent to which, DG additions could, on a planning basis, be an economical way of meeting future resource needs and meeting aggressive Greenhouse Gas (GHG) reduction goals.

The CAISO's TPP identifies the "need" to add transmission infrastructure and then solicits solutions for meeting this need. One solution could be adding DG not otherwise accounted for in the CAISO's annual TPP. Where DG is an economic solution, compensation mechanics, wholesale market issues, cost recovery policies and jurisdictional matters would need to be sorted out. In summary, SDG&E believes the CAISO's annual TPP and existing CPUC regulatory proceedings are the right place for determining (i) which increments of DG would represent an economic alternative to otherwise planned investment in transmission infrastructure, and (ii) how such increments should be implemented.[52]

Institute for Local Self Reliance (ILSR): *The Institute for Local Self-Reliance supports the Clean Coalition's proposal to improve the transmission access charges (TAC). CAISO should change where usage is measured for TAC, regardless of how charges for that usage is ultimately calculated.*

The Clean Coalition's proposal to measure transmission usage at the end of the transmission grid by using transmission energy downflow (TED) would lead to a more level playing field for local renewables, reduce future transmission costs, slow growth in TAC rates, and cause massive ratepayer savings. TED is the only reasonable metering point for measuring transmission grid usage. The transmission grid boundary provides a consistent, unbiased, and

[52] See SDG&E comments at: http://www.caiso.com/Documents/SDG-EComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

technology-neutral point of measurement, and usage should be measured there. This change is critical to ensuring that distributed energy resources (DER) face a level playing field against transmission-dependent resources. Failure to correct this issue will perpetuate a market distortion that favors remote resources over distributed resources, and we urge you to correct it by adopting the Clean Coalition's proposal.

Failure to correct the TAC measuring point will lead to continued over-investment in transmission system where local resources are more cost-effective. DER reduce the stress on the transmission grid and avoid the need for future transmission grid investment, but the current TAC methodology obscures those benefits. The Clean Coalition proposal would reduce the market distortion on DER and create a market signal for resources that deliver services without using the transmission grid. This would result in avoided transmission investment and billions of dollars of ratepayer savings. For these reasons, we urge you to adopt the Clean Coalition's proposal.[53]

Local Clean Energy Alliance (LCEA): *This intrinsic value of local renewable energy—the potential to avoid billions of dollars in new transmission infrastructure—is not, however, recognized by the State's current method of recovering transmission infrastructure investments. Currently, all electricity customers in the service territories of the State's investor-owned utilities are levied with a transmission access charge (TAC), even when the electricity they consume is not delivered over transmission lines.*
This means that locally generated electricity that does not use the transmission system is still required to pay transmission access charges, negating one of the most important values of locally generated electricity. This creates an unfair disadvantage for local, distributed renewable energy generation installations, which hinders development and is counterproductive to achieving many of the State's economic, social and environmental goals.

To correct this TAC market distortion, TAC should only be assessed on energy delivered through the transmission system. The Clean Coalition has proposed that CAISO assess TAC on metered transmission energy downflow, the amount of energy that down-converts from high voltage transmission, to low voltage transmission, to distribution voltages at local substations, instead of being measured at the customer meter (referred to as- customer energy downflow). Therefore, changing the point of measurement to the interface—the point of entry from the transmission grid—it would better align with customer costs being more directly tied to their use of transmission energy.

This approach—the TAC Fix—appropriately applies the "user pays" principle, allowing energy that is generated and consumed without use of the transmission grid to avoid transmission charges. This Fix would recognize the avoided-transmission-cost value of locally generated electricity. It would send proper market signals to encourage investments in energy generating facilities that supply locally produced electricity to the distribution grid, where significant energy can be generated and delivered efficiently without using the transmission system, and thereby

[53] See ISLR comments at: http://www.caiso.com/Documents/ILSRComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

avoiding TAC costs. In this way, the TAC Fix would also reduce transmission load and minimize the need for additional transmission capacity.

The current TAC market distortion makes it difficult for Community Choice programs to realize the full value of locally-generated electricity. Smaller scale, community-based generation generally has higher installation costs than remote large-scale generation, making it difficult for local development to be competitive. However, if local development could benefit from the avoided transmission costs through the TAC Fix (roughly a 3¢/kWh advantage on about the10¢/kWh levelized cost of local wholesale solar PV electricity1), it would create a significant incentive for Community Choice programs to build local generation assets, and thereby open the door for the many other benefits of local resource development.

By providing an economic advantage for Community Choice programs to procure locally, the TAC Fix would help counter the claims of many consultants that the only way for these programs to be competitive with the investor-owned utilities is to procure remotely generated electricity, sacrificing the substantial long-term benefits that would be realized through the investment in local renewable assets for short-term advantages.[54]

Modesto Irrigation District (MID): *MID is cautious of proposals that could cause the TAC to increase. Significant investments in transmission infrastructure have been made over the past decade. Those investments were made on the premise of certain assumptions, including that they would be used to reliably serve certain, contemplated load. Changes in TAC should be careful not to effectively exempt load from payment of costs which were intended for facilities to benefit such load, through the netting of newly installed, distribution-level power supply services. Further, such changes should be aligned with sound, cost causation principles.*

MID is further concerned that the proposed TAC charge could effectively shift costs to and increase the cost of exports. The reduction in the TAC denominator would increase the Wheeling Access Charge ("WAC"), which MID pays as an entity located outside of the CAISO Balancing Authority Area ("BAA"). Further, a proposal to exempt certain distribution-level load, would shift costs from certain CAISO internal load to be paid by exports. It is not a desirable outcome for utilities located outside of the CAISO to pay part of the difference in transmission costs resulting from the exemption of CAISO-internal, distribution-level load.

Proponents of a new rate design for the TAC have the burden to show that the existing rate design is unjust and unreasonable. See PJM Interconnection, LLC, 119 FERC ¶ 61,063 at P 41 (2007). The Federal Energy Regulatory Commission ("Commission" or "FERC") is careful in reallocating costs of existing transmission facilities, given the potential effect that changing rates may have on expectations and future decisions about regional transmission organization ("RTO") participation. See id at P 43. In PJM Interconnection, the Commission held that it could not find that the existing and sunk costs of the PJM transmission system were required to be spread and shared equally among all customers within PJM in order to produce just and

[54] See LCEA comments at: http://www.caiso.com/Documents/LCEAComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

reasonable rates. See id. at PP 3, 42. The Commission's conclusion, however, was based on the finding that the transmission facilities were not constructed for customers who would not benefit from the facilities. See id. MID would have to see that the construction of facilities that have been rolled into the TAC was not intended to benefit the same load that is being sought to be exempted, but instead was intended for the benefit of customers other than that exempted load.

In Midwest Indep. Transmission Sys. Operator, 105 FERC ¶ 61,212 at P 48 (2003), FERC stated "[c]onsistent with the principle of cost causation, the load of an importing utility should pay a fair share of the costs of the exporting utility's transmission facilities for its use of those facilities." The Commission described that export transactions should pay appropriate transmission costs, but based on principles of benefits received. See id. at P 48. Proponents of {D0307768.DOCX / 1} a revised TAC would need to justify whether exports are receiving additional benefits to justify an increased export charge.

As noted above, the exempting of certain, distribution-level load from TAC would create disparate rates for different loads. That difference in rates requires convincing justification. In approving a proposal to roll-in the costs of certain location-constrained resources, the Commission explained that it "has determined that discrimination is undue when there is a difference in rates or service among similarly situated customers that is not justified by some legitimate factor." See Calif. Indep. Sys. Operator Corp., 119 FERC ¶ 61,061, at P 69 (2007). While the analysis presently before the CAISO is comparing treatment of load instead of different types of generation, MID has not yet seen a legitimate factor raised in this case that would justify exemption of certain CAISO-internal load from the TAC.[55]

Western Power Trading Forum (WPTF): *WPTF cannot support the Clean Coalition's proposal at any conceptual level because it creates an uneven playing field for resources simply because of where they connect to the grid. Under the Clean Coalition proposal, incremental procurement of distribution resources would lower load-serving entities' allocation of existing transmission costs. This would drastically change the incentives to contract with distribution resources versus grid resources and not in a reasonable way. Fundamentally the proposal would introduce a harmful market distortion in the decision to contract with lowest cost, best located resources.*[56]

Silicon Valley Power (SVP): *SVP believes that the LSEs who procure DG are compensated through a valuation of the PPA price associated with the specific DG project and the LMP of the DG resource. Right now, the particular LMP at a node reflects the value of generation at that node, and what is lacking is a means for the generation developer to lock in that value on a going forward basis through a means other than the PPA with a UDC/LSE – as the presence of the new DG will affect the existing LMPs. Implementing TED for all DG should not be the mechanism used to incent the growth of DG because it does not provide price signals that*

[55] See MID comments at: http://www.caiso.com/Documents/MIDComments-ReviewTransmissionAccessChargeStructure-IssuePaper.pdf
[56] See WPTF comments at: http://www.caiso.com/Documents/WPTFComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf

reflect the varying benefits (or burdens) of DG based on location and output characteristics. SVP believes EUML is the most appropriate location to measure transmission benefit, but TAC should also be adjusted to utilize a combination of peak usage and volumetric flow. SVP believes the TED approach will not result in the desired price signal to incent DG deployment at locations where the economic benefits of avoided future transmission in the Clean Coalition model will be realized.

SVP does not believe the CAISO should change the point of measurement associated with the TAC - unless studies clearly show that doing so would cause DG to be deployed only where there is a clear transmission system benefit. As of now SVP believes the TED proposal simply amounts to an across-the-board subsidy to DG that may or may not provide future transmission benefits (where such benefits will ultimately depend on where the DG is developed). Simply providing a subsidy to make DG economical at a location where it currently is not economical does not provide the assurances needed to justify the change.

SVP believes that changing the point of measurement for assessing TAC could result in a significant subsidy to DG regardless of location or future transmission cost benefit. A subsidy of this magnitude should cause an increased amount of DG deployment, but with no guarantees that the deployment will be at the most beneficial locations from a transmission cost avoidance viewpoint. Unless it provides transmission benefits, DG should not be subsidized through lower transmission charges for the load it serves. Again, SVP believes that the procurement need of DG falls under the jurisdiction of the CPUC or other LRA of the LSE as does the related IRP process.[57]

Transmission Agency of Norther California (TANC): *TANC supports the current methodology utilized by the CAISO (EUML) for current embedded costs. Resource decisions (both on transmission and generation) were made under the current market rules and CAISO Tariff, modification from the existing construct may be applicable to going forward costs; but should not result in the ability to bypass costs/obligations previously undertaken. Increased DG could potentially reduce the need for future transmission investment, depending upon deployment, storage and likely other factors that parties are not fully aware of at this time. However, as stated above, TANC strongly believes that all current users of the high-voltage grid need to pay for the cost of providing service. TANC does not support a change that would enable current grid users to avoid an equitable share of current costs.*[58]

[57] See SVP comments at: http://www.caiso.com/Documents/SVPComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf
[58] See TANC comments at: http://www.caiso.com/Documents/TANCComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf