Stakeholder Comments Template

Review TAC Structure Second Revised Straw Proposal

This template has been created for submission of stakeholder comments on the Review Transmission Access Charge (TAC) Structure Second Revised Straw Proposal that was published on June 22, 2018. The Second Revised Straw Proposal, Stakeholder Meeting presentation, and other information related to this initiative may be found on the initiative webpage at: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx

Upon completion of this template, please submit it to initiativecomments@caiso.com.

Submitted by	Organization	Date Submitted
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Submissions are requested by close of business on **July 18, 2018.**

Please provide your organization's comments on the following issues and questions.

Hybrid billing determinant proposal

1. **Does your organization support the hybrid billing determinant proposal as described in the Revised Straw Proposal?**

In principle, hybrid billing determinants can allow for different components of cost causation to be allocated independently. However, to do so, each component of a hybrid charge must properly reflect the component of cost causation it is designed to reflect. Here, neither the demand charge nor the volumetric component aligns with the cost causation elements they purportedly reflect.

Hybrid determinant is worthwhile to divide cost allocation according to service

A hybrid billing determinant has strong promise in allowing transmission cost recovery to address distinct aspects of cost causation. As CAISO and FERC make clear, cost causation allocation involves a combination of 1) past justifications in planning transmission infrastructure, 2) allocation to current beneficiaries of infrastructure, whether or not the infrastructure was built for those beneficiaries, and 3) the distorting impacts of cost allocations. Despite FERC's clear caution against cost allocations based solely on past causation,[1] CAISO claims to be placing a strong and disproportionate emphasis on past cost causation while disregarding who actually benefits from the existing infrastructure.

A hybrid structure can be valuable in allocating different components of the overall costs on different bases that reflect different aspects of cost causation, provided each component correctly reflects the aspect of cost causation it is designed to capture. For example, to the extent that peak transmission flows drive historical costs, some component of the overall cost allocation should reflect peak transmission flows. To the extent that transmission is built to provide capacity as back up independent of any use, another component of a hybrid structure might involve a standby charge, while policy driven transmission infrastructure might be spread across all energy use and transmission built for reliability needs as back up against transmission system failures could be properly allocated to transmission-served load.

Unfortunately, neither element of the hybrid accurately reflects the aspects of cost causation they purport to reflect. In fact, CAISO's proposal unfortunately fails to meet any of the standards it lays out as the rate design principles it is trying to meet. Therefore, CAISO should either revise the hybrid billing determinant or it should recognize that the rate design principles it lays out are in fact not the rate design principles it is in fact following.

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[1] FERC Order no. 1000, Paragraph 495.

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

Since many of these same rationales were the basis for rejecting the use of transmission energy downflow as the point of measurement, CAISO's rationales are internally inconsistent which would constitute the kind of arbitrary and capricious decision making that federal agencies such as FERC may not engage in under the federal Administrative Procedures Act, 5 U.S.C. § 500 *et seq.*

1 - The demand charge will fail to correctly reflect transmission flows if it is measured at the customer meter.

The demand charge component of the hybrid determinant does not reflect peak transmission flows because it conflates peak transmission energy flows with all energy flows on the distribution system. CAISO suggests that the demand charge component is designed specifically to assign costs based on energy function in order to allocate costs based on contributions to peak transmission energy flows. Therefore, it would be logical to actually base this demand charge on peak energy flows, which the proposed demand charge does not do. Since the proposed demand charge is based on customer meter load rather than transmission-end load it mistakenly treats in front of the meter distributed generation as if it were contributing to peak transmission energy flows. Clearly, given the conservation of current, distributed generation serving local load does not contribute to peak energy transmission flows. Thus, this component of the billing determinant does not align well with the usage that the demand charge is designed to address. As a result of this error, the current demand charge proposal neither allocates costs based on the FERC Order no. 1000 principle that cost allocation should follow the beneficiaries of the system nor based on CAISO's preferred principles of allocating embedded costs based on historical cost drivers and avoiding cost shifts. If the purpose of a demand charge is to reflect either the cost causation or to incentivize reductions of peak transmission use because peak demand disproportionately drives transmission investments, then the charges should be based on peak *transmission* use, not peak overall use.

2- *Using customer meter means only behind the meter resources can mitigate transmission charges, even though distribution connected resources have precisely the same impact on the transmission grid.*

Although CAISO suggests it is uninterested in considering the market impacts of its rate design, it is clear that CAISO is creating disparate treatment of in-front-of-the-meter and behind the meter resources even though they have precisely the same impacts on peak transmission energy flows. CAISO offers no rationale for this disparate treatment. Presumably part of the rationale for instituting demand charges is to provide UDCs with incentives to mitigate their own contributions to peak transmission energy flows so as to ameliorate the cost drivers of transmission spending. However, as currently structured, CAISO's proposal would properly credit UDCs for energy efficiency, demand response, behind the meter distributed generation, or behind the meter storage. However, in front of the meter storage or in front of the meter generation would not be credited, even though the electrical impacts of these latter two categories are identical.

Not only is there no rational justification for such disparate treatment, but this would disincentivize cost-effective in front of the meter resources in favor of finding behind the meter hosts for storage or generation projects. For example, CAISO has recently approved PG&E's Oakland Clean Energy Initiative, which would use some in-front-of-the-meter resources to meet grid needs.[2] While these resources could potentially be used to reduce peak transmission energy flows in order to defer transmission investments, under the current proposal, PG&E would be penalized for placing these in front of the meter, even if electrically that were the best location for the resources. Instead, UDCs such as PG&E will have incentives to find property owners to host these grid resources, forcing rate payers to pay rents to hosting property owners for rational reason. Thus, CAISO's proposal creates a new market distortion with respect to storage and distributed generation without any rational basis for the disparate treatment of these resources.

3 – The proposed demand charge fails to recognize that not all behind the meter resources provide identical benefit to the grid.

The proposed demand charge component proposes to give identical credit to any behind the meter resources, even though the value of resources in reducing the need for new transmission will vary by location. In principle, one of the justifications for a demand charge is that it influences UDCs to refrain from using capacity at system peak times. Theoretically, this is worthwhile because it tends to reduce the need for new transmission spending. However, not all resources that would get demand charge credit would actually contribute to reducing new transmission spending. As CAISO itself points out "one cannot assume that transmission costs are reduced by DG unless that DG is expressly designed to avoid or defer more expensive investments in the transmission system." In fact, some or many behind the meter resources would offset flows on transmission lines that are nowhere near at capacity

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2 https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20180323_caiso_approves_pge_oakland_clean_energy_initiative

because of where they are located. Thus, the transmission energy flows they offset aren't contributing meaningfully to transmission cost-causation, but under the proposed demand charge, they still would receive full credit for doing so. Thus, the current demand charge proposal would give credit for transmission cost reduction to all behind the meter resource whether or not they were designed to avoid or defer transmission costs. Some rooftop solar or storage might be useful to reduce peak flows on the transmission system to alleviate the need for transmission spending, but other rooftop solar or behind the meter storage might not. Since CAISO has identified inconsistent impacts on the transmission grid as a basis for refusing to recognize benefits for the transmission grid for in front of the meter resources, CAISO faces a burden of explaining why this same characteristic is not a barrier to the use of a customer meter downflow demand charge.

4. Neither the demand charge nor the volumetric component align with historical cost causation of embedded costs

Historical cost causation by itself is fixed and does not vary as a function of current energy usage. Thus, *any* rate design that allows charges to vary as a function of current energy use does not align with the historic cost causation. Just as embedded costs cannot be altered, neither can historic cost causation because decisions, once taken, are not altered by future behavior. Theoretically, aligning embedded costs with historical cost causation would require some kind of fixed assignment between investments and existing load. Naturally, such a rate design is untenable and undesirable. However, assigning embedded costs to new load based on use of existing infrastructure for energy delivery must be justified. Presumably, allocating embedded costs based on current energy delivery use is justifiable because current energy delivery use reflects current beneficiaries of embedded costs. However, if that is the case, then assigning embedded costs based on current energy delivery should be the same basis for evaluating rate design for all proposals. Rejecting some rate designs because they use current energy delivery use as the basis of allocating embedded costs while proposing other rate designs using precisely the same approach is logically inconsistent, and therefore arbitrary and capricious.

5. - The Hybrid determinant allows cost shifting of embedded costs among UDCs without justification

CAISO suggests that a demand charge rate design that allows UDCs to shift costs to other UDCs by deploying behind the meter resources would constitute a justifiable cost shift, but fails to offer any actual justification for why using existing peak customer meter energy flows is a justifiable cost shift or why allowing UDCs to game the rate design by using behind the meter resources to shift costs onto other UDC territories would be a justifiable cost shift. Again, CAISO expresses that allowing UDS to shift costs among themselves with after-the-fact behavior, but this problem applies with full force to the demand charge component every bit as much as the proposal to move the point of measurement. In fact, the only substantive difference between shifting the point of measurement and using a demand charge is that the former would allow UDCs to reduce their share of cost recovery with distribution-connected and behind the meter exports, while the demand charge component allows UDCs to avoid costs and shift those costs onto other areas only by deploying behind the meter storage or rooftop solar (where the coincident peak falls within the solar production window.). The cost-shifting mechanic is precisely the same; only the technology used to mitigate and avoid charges differs between the two proposals. Thus, if a cost shift based on behind the meter resources is acceptable, but a cost-shift based on in front of the meter resources is not, CAISO must either provide a solid justification for the disparate treatment of in front of the meter resources or recognize that FERC will be unable to approve such a proposal without running afoul the requirements of federal law.

6 - The Hybrid Determinant does not assign embedded costs according to historical cost causation

The hybrid billing determinant has little relationship to any of the identified drivers of cost causation. CAISO has placed a strong emphasis on recovering costs from the load "for which it was built." This would suggest that the hybrid determinant should reflect the actual rationales offered for the construction of transmission grid projects. While historical peak loads would be closely correlated with the justifications for transmission projects, contemporaneous peak loads have shifted with time and can be gamed by UDCs seeking to avoid transmission costs, so the use of contemporaneous peak energy flows has only an indirect relationship to peak flow cost causation. At best, contemporaneous peak energy flows indirectly reflect cost causation for transmission projects that were justified to deliver peak energy. However, if the idea is to reflect the peak transmission flows that are used in transmission planning, then cost recovery should follow contemporaneous peak transmission flows. Similarly, where transmission spending is based on meeting RPS requirements for transmission connected renewable generation or connecting to cheap transmission connected resources, then charges based on transmission flows is the better reflection of those cost rationales. Similarly, where transmission projects are approved as back ups against the failure of other transmission infrastructure, then those costs should follow use of the transmission system. In the alternative, it would make sense to charge distributed generation served load for those transmission investments that were made expressly to provide "back up power" or services should DER fail to deliver.

7 – Assigning cost recovery for capacity or back up services should not vary depending on energy use.

Similarly, cost allocation to reflect the capacity or existence value of the transmission grid should not vary with energy use, because those capacity or existence benefits do not value with energy use. Theoretically if a UDC were to meet all load with behind the meter resources, perhaps because of aggressive rooftop solar and battery programs, the TAC for such a UDC would drop to zero, even while the capacity or existence value does not. Thus, using a volumetric component to recover for capacity is a poor rate design that does not correspond to the benefit being recovered for. Theoretically, the rate design might incorporate some form of stand-by charge for UDCs. However, we find no examples in the transmission planning process where the transmission system is designed for hypothetical back up functions. Indeed, the transmission system is not designed to handle all potential load, and if all Californians were to simultaneously switch on all devices, the transmission system would be unable to cope. Instead of planning for hypothetical use in some counterfactual scenario, transmission planning is actually done based on expected actual use based on the actual deployment of devices. Transmission planning is not conducted based on "what if" scenarios of simultaneous failures of behind the meter devices. Since it is not, attempting to charge for "what if" scenarios cannot in any sense reflect the actual cost-causation in the planning process. Thus, while there may be some theoretical benefit to the transmission grid, that theoretical value drives no costs and therefore is not a proper component of a cost-causation based rate design.

2. **Please provide any feedback on the proposal to utilize PTO-specific FERC rate case forecasts to implement the hybrid billing determinant proposal.**

   For context, under the second revised straw proposal, the ISO modified the proposal to use PTO specific rate case forecasts to set the HV-TRR bifurcation and resulting HV-TAC volumetric and demand rates. Does your organization support this modification to the proposal?

   a. **Please provide any feedback on the possibility that this proposal causes a need for PTO's FERC transmission rate case forecasts to be modified to include coincident hourly peak load forecasts.**

      The Clean Coalition has no feedback on this proposal.

   b. **Does your organization believe that the use of historic data from the prior annual period could be a viable alternative for this aspect of the proposal? Please explain your response; if you believe this would be more appropriate or potentially problematic please indicate support for your position.**

   The Clean Coalition has no feedback on this proposal.

3. **Please provide any additional feedback on any other aspects of the hybrid billing determinant proposal.**

Please see above

Additional comments

4. Please offer any other feedback your organization would like to provide on the Review TAC Structure Second Revised Straw Proposal.

   Ultimately, FERC will need a proposal that has an internally consistent rationale, lest it fail to meet the minimum requirements of federal law governing administrative decision-making.