Stakeholder Comments Template

Review TAC Structure
Stakeholder Working Groups

This template has been created for submission of stakeholder comments on the Review Transmission Access Charge (TAC) Structure Working Group Meetings that were held on August 29 and September 25, 2017. The working group presentations and other information related to this initiative may be found on the initiative webpage at: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx

Submitted by	Organization	Date Submitted
Barbara R. Barkovich *Barkovich & Yap, Inc.* *707 937-6203* *Barbara@barkovichandyap.com.*	*California Large Energy Consumers Association)*	*October 13, 2017*

Upon completion of this template, please submit it to initiativecomments@caiso.com. Submissions are requested by close of business on **October 13, 2017.**

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

NOTE: See last page for definitions of some key acronyms and terms.

Introduction

The questions in this template focus too much on the Clean Coalition proposal. The purpose of this stakeholder process should be to review whether the cost allocation and rate design aspects of recovering the costs of the transmission system are appropriate or should change, recognizing that the CAISO does not actually charge either consumers or LSEs for transmission. The CAISO redistributes transmission revenue among PTOs to adjust for the difference between the CAISO's postage stamp transmission access charge (TAC) and wheeling access charge (WAC) and the transmission revenue requirements of the various PTOs. Transmission cost allocation and rate design are performed in individual PTO rate proceedings at FERC.

Clean Coalition claims that its interest is in eliminating the advantage that grid-connected generation has compared to distribution-connected generation because all load pays for the transmission grid. Rather than proposing that transmission costs be taken into account in procurement decisions, which would appear to be the most straightforward means of addressing this issue, Clean Coalition proposes to change where usage of the grid is measured, based on the assumption that distribution-connected, IFOM (in front of the meter) resource output is delivered through the distribution system to local load and does not use the grid. There has been no demonstration that this is true. Furthermore, Clean Coalition claims that distribution-connected IFOM resources pay for all of their impacts on the distribution system so that there is no cost impact on consumers from their interconnection. Clean Coalition has not demonstrated that this is true either. The cumulative impact of distribution-connected resources can create costs on the distribution system that are recovered from all customers, such as the need for larger transformers and “smart grid” investments. Clean Coalition’s broad and simplistic assumptions are not only unsubstantiated, they are also insufficient to support the proposal to change the point of measurement for assessing the TAC.

1. One concept for allocating the costs of the existing transmission infrastructure is to charge each user of the grid in accordance with their usage of or benefits received from the grid. What do you believe is the most appropriate way to measure each end-use customer’s or load-serving entity’s (LSE) benefits or usage of the grid? What specific benefits should be considered? Please explain you answer.

It is not possible to directly measure a customer’s or LSE’s usage of the grid per se, since it is not possible track electrons flowing to either. It is more appropriate to look at the functions served by the grid and determine which type of usage drives those functions. As CLECA pointed out in its presentation on August 29, the grid provides reliable service to peak system and local loads, which is a capacity function, and also is used to deliver energy to load and meet public policy goals like RPS, which is an energy function. Thus, on a very high level, it is likely that a combination of a measure of demand and energy would appropriately reflect cost causation to serve these functions. As the CPUC pointed out, the costs associated with these uses may vary with time of use. However, in this stakeholder process we have no data on what drives the loading on the grid, either diurnally, monthly, or annually or how its costs vary.

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.

The question refers to existing transmission infrastructure. It is important to understand that the costs of this infrastructure are embedded costs that must be recovered. Some of this cost is associated with transmission additions approved as part of the CAISO’s TPP for reliability, congestion reduction, and public policy reasons. Some of it is associated with repair and replacement of existing transmission facilities that have reached the end of their useful life. The latter are not avoidable unless it is possible to abandon use of part of the grid. The former were approved and built because they provide identified benefits. The only transmission that can be avoided is new transmission.

2. The example the ISO presented at the August 29 working group meeting (slides 21-22 of the ISO presentation) illustrated how using transmission energy downflow (TED) as the high-voltage TAC billing determinant (instead of end-use metered load) affects all ratepayers of each utility distribution company (UDC) irrespective of which LSE serves that load. If the ISO were to adopt TED as the billing determinant for the high-voltage TAC, what further procedures would be needed to ensure that the benefits of reduced TAC payments go to the correct LSEs that make the decisions to procure DG? Please explain your answer.

This question switches from asking appropriate foundational questions about the drivers for transmission cost allocation to specific questions about the Clean Coalition proposal, which is a far narrower topic and one that should not be addressed without laying that foundation. We respond to the question with that caveat.

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. The concept put forth by Clean Coalition that scheduling coordinators would provide this information to the CAISO is based on the assumption that all such DG is scheduled or bid into the CAISO markets by the LSE. As WPTF pointed out, this is not necessarily the case.

3. The ISO could (a) continue to use the end-use metered load (EUML) or customer energy downflow (CED) as the basis for assessing high-voltage TAC, or (b) propose a change to assess HV TAC based on downflow at the transmission-distribution interface (T-D TED), or (c) assess HV TAC based on downflow at the interface between the high-voltage and low-voltage transmission systems (HV-LV TED). Does your organization prefer one of these approaches at this time? Please explain the reasons for your preference.

Repeating by reference the caveat in the previous answer, 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 volumetric charges. No remotely sufficient evidence has been presented to support a change in the point of measurement.

4. Does your organization believe that any of the options in the previous question present any potential problems or issues that have not been identified or explained during the stakeholder process thus far? If so, please explain. Also, please indicate what other analyses could be done to help understand the impacts of changing the point of measurement?

No answer at this time.

5. Does your organization believe that the ISO should change *only* the point of measurement utilized for assessing TAC apart from considering other changes to the TAC structure? Alternatively, should the ISO change the point of measurement in conjunction with other changes to the TAC structure? Please explain your position.

No, the CAISO should not change the point of measurement for assessing TAC. It is appropriate for the CAISO to consider whether to continue to only use a volumetric charge. However, as noted above, the type of charge and the cost of transmission paid for by end use consumers is a result of cost allocation and rate design under FERC jurisdiction. The CAISO only charges and credits the difference between the postage stamp rate and the TRRs of the PTOs.

6. Does your organization believe that changing the point of measurement for assessing TAC to use TED instead of metered customer demand will result in increased procurement of DG by LSEs? Please explain your position.

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. It is our understanding that in the recent IRP workshops the CPUC indicated minimal need for new transmission.

7. Does your organization believe that increased procurement of DG by LSEs will reduce the need for future investment in transmission infrastructure? Please explain your position.

It is possible that this will be the case, depending on the extent to which there are economic and/or policy reasons for additional procurement of in-state or out-of-state renewable resources from areas with insufficient transmission. Another important consideration will be the challenges associated with too much of the same type of DG, such as solar, and its impact on the distribution system and the grid. If most of the DG is solar, the cost of storage and/or needed distribution system upgrades to handle its simultaneous output may be greater than the cost of additional transmission.

8. The Clean Coalition provided a spreadsheet and documentation (available at the ISO's TAC initiative web page link on page 1) showing their approach for estimating the savings from avoided future transmission investment that could result from increased DG procurement in response to the ISO adopting TED as the point of measurement for assessing TAC. Does your organization believe that Clean Coalition's analysis provides a reasonable projection of transmission cost savings as a result of DG growth? Please explain your position.

No. Clean Coalition's assumptions regarding future transmission investment and TAC growth are not reasonable. Clean Coalition projects a 5% real increase in the TAC each year based on past TAC increases. However, CLECA explained at the August 29 workshop that recent patterns of transmission investment have been triggered by integrating the CAISO-controlled grid, reducing congestion, meeting NERC reliability requirements, and repair and replacement, as well as delivering grid-connected resources including renewables. The CAISO has stated in the 2016-2017 TPP that it does not anticipate the need for new transmission for load growth, reliability, or local capacity. Repair and replacement will be necessary to maintain the current grid.

Thus, the only new transmission that could be avoided would be new policy-driven transmission to deliver additional renewable energy. As noted in the previous answer, it is not clear how much new transmission would be needed for this purpose or where. Regardless, the cost of that transmission cannot be inferred from recent increases in the TAC. It would require a forecast of specific projects needed to deliver additional renewable energy.

9. If you do not agree with Clean Coalition's projections of transmission cost savings, what approach would you suggest for estimating savings from reduced need for future investment in transmission that could result from increased DG development?

The appropriate place to consider the implications of transmission costs on procurement is the IRP process. RETI 2.0 discusses possible new transmission to meet renewable needs, but it is at a very high level and it is not clear how much of that grid-connected forecast renewable generation would be avoidable through DG. Regardless, changing the way the TAC is assessed is not the best means to address the issue of future transmission costs for RPS procurement. That should be considered in the procurement planning process.

10. The ISO must decide what types of analyses to perform to evaluate alternative TAC approaches, and how to prioritize them. Please provide your organization's view on what analyses would be most useful, and indicate the relative importance of each analysis you recommend to assist the ISO in determining which analyses should take precedence.

CLECA believes that it would be helpful to analyze the functions served by existing and proposed new transmission to inform rate design proposals. The CAISO and the PTOs would be the source of this information.

11. How can the ISO evaluate the downstream financial impacts of potential changes to the TAC structure? What data would best inform the ISO and stakeholders of the potential impacts to various entities? Does your organization believe the ISO should focus on this question now, or wait until potential TAC structure options are better defined (e.g., after the ISO issues a straw proposal)? Please explain your position.

The meaning of this question is not clear. What is meant by "downstream financial impacts"? On whom? End use customers? LSEs? CLECA believes that this question is premature.

12. How are transmission needs and costs driven by the delivery of energy versus the provision of capacity necessary to meet peak load conditions? Please explain your position.

As a starting point, as noted above, it would be helpful if the PTOs could provide information on the reasons for their recent transmission construction and their plans for new transmission and the drivers for that new transmission. Load-growth related transmission would clearly be capacity-driven whereas policy-driven transmission and congestion-driven transmission are arguably energy-driven. It would be good to have some discussion about reliability-driven transmission, but on a preliminary basis, it would probably be capacity-based, since it would be used to meet load. Repair and replacement are not marginal, but in an embedded cost analysis would probably be allocated to both energy and capacity based on the percentage shares of the other investments.

13. In considering potential changes to the TAC structure, what kinds of changes would best align with the impacts of energy delivery, peak load and other drivers of new transmission investment? Please explain your answer.

See the answer to question 12.

14. What are the cost drivers of operating and maintaining the existing transmission system and what, if anything, could materially affect these cost drivers? In particular, does your organization believe that increasing the share of load served by DG can reduce any costs associated with the existing transmission system? Please explain your position.

Increasing the share of load served by DG will not affect the costs of operating and maintaining the existing transmission system unless 1) lower loading would reduce maintenance costs or 2) parts of that system could be decommissioned in the future because they are no longer necessary. Again, data would be needed to substantiate any arguments that such circumstances are actually occurring.

15. Please offer any other comments your organization would like to provide on the material discussed in the two Review TAC Structure Working Group meetings (August 29 and September 25), or any other aspect of this initiative.

<u>Related Acronym Definitions:</u>

- **Community Choice Aggregator (CCA):** One type of non-utility Load Serving Entity that can operate in an investor-owned utility service area.

- **Customer Energy Downflow (CED):** Metered energy delivered from the grid to an end-use customer measured at a customer meter, also referred to as end-use metered load (EUML). Customer energy consumption that is met by output of DG located behind the same customer meter is not included in CED. Also, CED does not include any production of DG behind the customer meter in excess of consumption behind the same meter during the same interval.

- **Distributed Energy Resources (DER):** Energy resources connected at distribution level, either on the utility side or the customer side of the customer meter, without regard to technology type or size. DERs include distributed generation (DG), energy storage of various types, EV charging stations, as well as demand response and energy efficiency.

- **Distributed Generation (DG):** Generating resources deployed at the distribution system level, either on the utility side or the customer side of the customer meter; DG is one type of DER.

- **Electric Service Provider (ESP):** One type of non-utility Load Serving Entity that can operate in an investor-owned utility service area.

- **End Use Metered Load (EUML):** Another term for customer energy downflow (CED).

- **High Voltage (HV):** Transmission system 200kV and above.

- **Low Voltage (LV):** Transmission system below 200kV.

- **Transmission Energy Downflow (TED):** Gross metered energy flow measured at specified transmission system interfaces, either (a) from high-voltage to low-voltage transmission **(HV-LV TED)**, or (b) from transmission to distribution **(T-D TED)**. TED measurements do not reflect energy flows in the opposite direction from LV to HV transmission or from distribution to transmission.