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?

   BAMx supports the hybrid billing determinant proposal elements of an energy and demand based components and the gross load factor approach to allocate the HV TRR among these two components. This relatively simple approach provides both transparency of the calculation and stability and predictability of the results.

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

[1] BAMx consists of City of Palo Alto Utilities and City of Santa Clara, Silicon Valley Power.

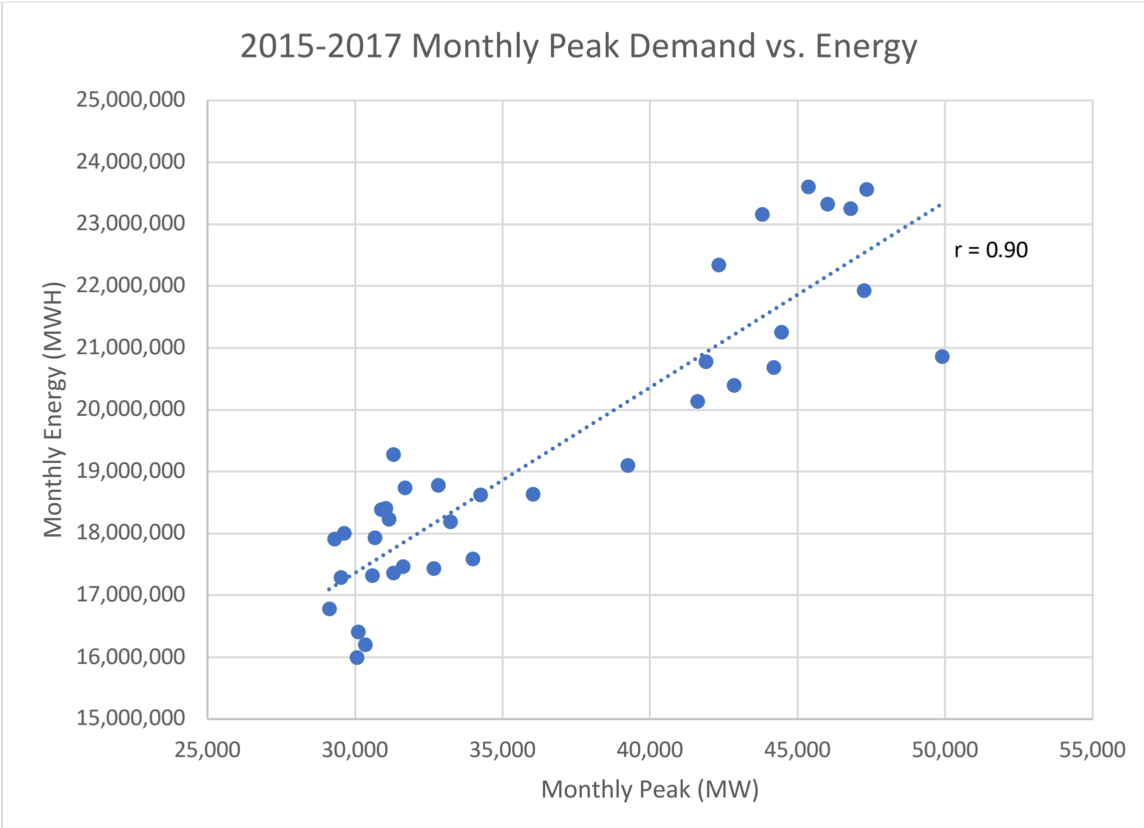
[2] CAISO Second Revised Straw Proposal, p. 19 & p. 40.

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

The proposal to use a hybrid billing determinant is significantly different in the other regions that the CAISO investigated that use a 12 CP based demand charge. Per the CAISO Review TAC Structure Issue Paper, June 30, 2017, pages 12-18 most other regional markets have no, or very limited, energy-based charges, instead recovering nearly all of their transmission costs through a demand charge. SPP and ISO-NE recover their transmission costs through a 12 CP based demand charge and have no energy charge. MISO recovers all of its transmission costs through a 12 CP demand charge, except for the costs of multi-value (public policy and economic) projects, which are recovered through a volumetric energy-based charge. ERCOT recovers its transmission costs through an annual peak demand charge tied to 4 summer month peaks (no energy-based TAC charge).[3] Of particular note is these regions are using a monthly peak demand charge to recover all the TRR of the facilities, rather than 12 CP in conjunction with energy charges to recover the costs of the same facilities. So while it *may be* appropriate to use a 12 CP approach to capture both the capacity function and reliability benefits provided to system users on a monthly basis when 100% of the facility costs are recovered through a demand charge, using the 12-CP demand charge in a hybrid approach places too much emphasis on the other costs/benefits that should be captured in the energy component, and does not properly reflect the capacity function, which is driven by annual peak demands, and which should be the focus of the demand component.

In the below graph, we have plotted the monthly energy versus the monthly peak demands for 2015-2017 CAISO loads. The correlation is 0.90, which supports a strong correlation between the monthly peak demands and loads. Bifurcating the HV TRR and then developing rates that apply to metrics that have a strong correlation undercuts the logic of bifurcating the rate in the first place. If, on the other hand, the annual peak value is used, the correlation drops to 0.01.

[3] PJM used daily peaks, which almost certainly has an extremely high correlation with energy consumption.



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.

      No comment at this time.

   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.

      During the stakeholder meeting, it appeared that the use of the PTO load forecasts may result in additional complexity and possibly the need to iterate to find the coincident peak demands. BAMx could potentially support the use of historic data, provided provisions were made to reduce the impact of annual variations due to factors such as weather. One potential method would be to use a rolling average of, possibly 3 to 5 years. Investigation of the data would be needed to balance reduced volatility against the desire to provide price signals without an excessive time lag.

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

   BAMx continues to be interested in the potential for a weather adjustment in the peak demands to track the way in which the transmission system is planned. However, if all the loads are subject to a similar adjustment, the overall impact may be small and not support the additional complexity. Also, if a 12 CP methodology is used, it is unclear how a weather adjustment would be applied as the methodology does not comport with the way load data is used in current transmission planning practices. The weather adjustment is applied to reflect a 1-in-10 year heat storm during summer peak conditions. The meaning of an adverse weather condition is less clear in spring and autumn conditions.

Additional comments

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

   The Second Revised Straw Proposal includes additional information on the changes in HV TRR cost allocation associated with both energy/demand split and the frequency of coincident peaks. The tables include data for all the UDCs for five years.[4]

   For simplicity of comparing the many data points, the below table only captures the 2018 cost shift for the PG&E area.

Energy/ Demand	12CP	4CP	1CP
50/50	-2.95%	-4.99%	-2.09%
60/40	-2.36%		
58/42	-2.48%		
56/44	-2.60%		
54/46	-2.71%		
52/48	-2.83%		
50/50	-2.95%		
48/52	-3.07%		
46/54	-3.19%		
44/56	-3.30%		
42/58	-3.42%		
40/60	-3.54%		

[4] The percentage allocation remains constant for all five years, suggesting that the annual increases in the TAC dollars allocated to each UDC over the five years is due to an overall annual increase in the HV TRR.

The cost shift changes consistently as the energy/demand split is modified. However, the cost shift follows an erratic pattern as the methodology moves from 12 CP to 4 CP to 1 CP. BAMx requests that the underlying data be provided so that this pattern can be better understood.