Stakeholder Comments Template

Review TAC Structure Straw Proposal

This template has been created for submission of stakeholder comments on the Review Transmission Access Charge (TAC) Structure Straw Proposal that was published on January 11, 2018. The 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

Submitted by	Organization	Date Submitted
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Upon completion of this template, please submit it to initiativecomments@caiso.com.

Submissions are requested by close of business on **February 15, 2018.**

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

EIM Classification

1. **Please indicate if your organization supports or opposes the ISO's initial EIM classification for the Review TAC Structure initiative. Please note, this aspect of the initiative is described in Section 4 of the Straw Proposal. If your organization opposes the ISO initial classification, please explain your position.**

The CLEAN Coalition supports CAISO's position on the EIM classification. Although the TAC structure could potentially alter LSE procurement decisions, the reform has no direct impact on market tariffs that would require approval by the EIM board.

Ratemaking Approaches

2. **Please provide your organization's feedback on the three ratemaking approaches the ISO presented for discussion in Section 7.1 of the Straw Proposal. Does your organization support or oppose the ISO relying on any one specific approach, or any or all of these ratemaking approaches for the future development of the ISO's proposals? Please explain your position.**

The CLEAN Coalition endorses following the approach FERC lays out in FERC Order No. 1000 of understanding "cost causation" to include identification of all beneficiaries and benefits as a critical component. Assessing "cost causation" without reference to the benefits that flow even to those that did not trigger transmission investments creates a serious potential for free rider issues. Please see section IV of the attached white paper for additional analysis of FERC no. 1000.

In addition, the CLEAN Coalition also supports CAISO's prior statements that the economic efficiency impacts of any rate design must also be evaluated. Rate design can create cost shifts onto parties that are lowering overall costs, as the current CED-based structure does, create free-rider issues and penalize economically efficient behavior. As the Market Surveillance Committee analysis makes clear, where transmission costs are variable and DG can substitute for bulk generation, TED is the most economically efficient approach. (See Section III.3.c of the attached white paper, and Section 5.2 of the memo by Prof. Benjamin Hobbs.)

In addition, CAISO should bear in mind two critical considerations: First, all of the proposals and the current structure follow the "benefits-based" approach to cost recovery. Since none are designed to lock cost recovery to the load "for which the grid was planned," this consideration plays no logical role in distinguishing between them. Under CED and TED alike, cost recovery follows load and benefits as an empirical matter. Whether load declines due to population declines, energy efficiency, behind the meter devices or in-front-of-the-meter DG or storage, cost recovery always shifts to those loads and UDC territories that actually use the transmission system in any given year, whether or not that load was envisioned in the planning process when the transmission was built. This system exists both as a practical matter, but also because allocating cost recovery without references to changes in the beneficiaries would create and entire class of free-riders. Any new development or new population that was not envisioned during the planning process some decades before would theoretically pay nothing for using the transmission grid if cost recovery was locked into the load "for which transmission was planned." Clearly, such an approach would be a failure of rate design. Please See Section III.A.1 of the attached white paper for further discussion.

Second, stakeholders have expressed considerable confusion about the relationship between benefits and usage. Broadly, the transmission and distribution grids provide a range of benefits to customers, of which by far the largest benefit is the delivery of energy to power devices in homes and businesses. Thus, usage for energy delivery is one of several benefits. In addition, customers benefit from other ancillary services that provide power quality and reliability in energy delivery. Finally, customers also benefit from some existence value of having the grid available as a back-up, which is typically incorporated in reliability analyses.

Taken together, these benefits must add up to 100% of the total value stack of the grid, such that rate design should consider the relative proportion of benefits made up by each service. It is important to bear in mind that the grid provides delivery of these services, but the services themselves are provided by resources connected to the grid, and flow from these generation and load management resources to customers. Some services are delivered to customers directly behind their meter, some are delivered solely through the distribution system, and some are delivered through the transmission system. The transmission system does not provide all the services utilized by customers.

Fortunately, most of these benefits are actually compensated in markets of one kind or another, which allows comparisons of the dollar value of each service. Our understanding is that the total dollar spend on energy dwarfs the total spending on ancillary services and reliability, suggesting that by far the largest component of the benefit stack is simply energy delivery. Please see Section III.A.2 of the attached white paper.

Hybrid Approach for Measurement of Usage Proposal

3. **Does your organization support the concept and principles supporting the development of a two-part hybrid approach for measurement of customer usage, including part volumetric and part peak-demand measurements, which has been proposed by the ISO as a potential TAC billing determinant modification under the current Straw Proposal? Please provide any additional feedback on the ISO's proposed modification to the TAC structure to utilize a two-part hybrid approach for measurement of customer usage. If your organization has additional suggestions or recommendations on this aspect of the Straw Proposal, please explain your position.**

In principle, the CLEAN Coalition supports a structured, bifurcated, or hybrid approach to rate design. Although such elements add complexity, the entities that are subject to the tariff are among the most sophisticated players in the energy industry and should be well able to understand and work with very sophisticated rate designs. Since TAC is charged to UDCs, wheeling entities, and other LSEs, CAISO can err on the side of a more complex but better functioning rate design rather than oversimplifying the design and risking serious market distortions.

As to the specific notion of employing a demand charge within the rate structure, CAISO should carefully consider whose behavior CAISO is seeking to influence with such a design and whether it aligns with either a cost-trigger approach or a benefit-following approach to rate design. Certainly, demand charges can send economic signals, but here the signal would be to UDCs and non-participating wheeling entities to reduce peak load behind customer meters. Since CAISO seems to want to influence UDC and wheeling entities' behavior, CAISO should be clear about what behavior CAISO is hoping to incentivize with this demand charge.

Second, CAISO should also align the demand charge with the specific problem CAISO is seeking to address without trying to dictate to UDCs how they should address the issue. Thus, since CAISO is charged with management of the transmission system, it is unclear why CAISO would seek to reach all the way downstream past the distribution system to behind the customer meter. Instead, if CAISO is seeking to reduce peak flows on the transmission system (which is CAISO's regulatory domain), then CAISO should focus demand charges on peak transmission flows. This would be more straightforwardly done by imposing the demand charge where it has the most direct impact on the transmission system: at the T-D interface. Attaching demand charges to peak transmission flows would let the UDCs (and wheeling entities) chose how to address those peak flows downstream of CAISO's system rather trying to dictate that the UDCs and wheeling entities need to address these issues solely with behind the meter solutions.

The demand charge at the customer meter is incredibly indirect, and amounts to setting a price signal to one entity to induce it to create a price signal to a second entity. In the case of the UDCs, CAISO would be making UDCs indirectly responsible for customer behavior, since the demand charge would be charged to UDCs based on what happens below the customer meter. This means that UDCs could only modify the transmission flows CAISO wants to shape by incentivizing customer behavior to influence behind the meter load reductions by customers. That would entail revisions of existing customer rate tariffs or implementation of other programs before the demand charge could have any influence on the customer behavior CAISO apparently is seeking to indirectly influence. This would clearly be less effective than sending price signals to UDCs to modify its own behavior and open up a much wider toolbox of options for the UDCs to use to address CAISO's immediate concerns. Utilities are deploying gigawatts of distribution connected resources, both in response to mandates for procurement of energy storage and distributed generation, and where these provide cost effective alternatives to grid upgrades and conventional generation generation. These resources reduce transmission loads, and can be deployed or operated in consideration of providing value and services to the transmission system. However, failure to account for their contribution in TAC billing determinant assessments discourages their deployment and operation to reduce transmission costs to both the UDC and systemwide. Where demand is measured matters.

It is unclear why CAISO would adopt a change in billing determinant while limit UDC options for managing transmission load while wheeling entities have options to use any distribution level solution to manage peak flows. It is equally unclear why UDCs should be more restricted than non-participating wheeling entities.

Split of HV-TRR under Proposed Hybrid Approach for Measurement of Usage

4. **The ISO proposed two initial concepts for splitting the HV-TRR under two-part hybrid approach for measurement of customer use for stakeholder consideration in Section 7.2.1.2 of the Straw Proposal. Please provide your organization's feedback on these initial concepts for determining how to split the HV-TRR to allocate the embedded system costs through a proposed two-part hybrid billing determinant. Please explain your suggestions and recommendations.**

    a. **Please provide any additional feedback or suggestions on potential alternative solutions to splitting the HV-TRR costs for a two-part hybrid approach.**

First, CAISO's discussion of marginal costs omits any mention of new investment on delivery infrastructure. Given that the impacts on future investment is a critical consideration, this a serious oversight. It is critical that any rate design include analysis of how the rate design affects the drivers of new transmission investment which are clearly a component of the marginal cost of electricity.

Second, recovery of embedded costs should follow the same approach as any other costs. As elaborated in Section III of the attached white paper, all three rate design approaches lead to the same conclusion: use of the TED is superior in each case. Even under a historical cost-trigger allocation approach with declining overall system load, TED more accurately, if not perfectly, reflects cost causation and proportionate allocation .

Third, CAISO's rationale for ignoring embedded costs of delivery infrastructure fails to recognize that this infrastructure continues to contribute to the marginal costs of energy delivery. CAISO suggests that charges should reflect the marginal costs of energy, but omits the real costs of delivery infrastructure that also are part of the marginal costs of energy. After all, generation with no capability to deliver has no value. Marginal costs include all costs that would not have been incurred *but for the activity of which it is a marginal cost.* That is, the marginal cost of energy includes all costs that go into producing useful energy that wouldn't have been incurred otherwise. Thus, if energy use requires delivery investment so the energy can be delivered and used, then the marginal cost of that energy would include the costs of that new delivery investment.

What this means is that when new delivery infrastructure is built, it is a marginal cost for all of the energy it was built to deliver, *even if the energy is not delivered until decades later because those costs would not have been incurred but for that energy delivery and use.* Since delivery is a necessary marginal cost for any energy, those costs should be spread across all of the energy it is used to deliver. Otherwise, we would have a circumstance in which the cost of transmission would be marginal in its first year and have to have 100% rate recovery associate with that first year at some phenomenal per kWh cost, which is clearly an absurd result. Thus, the fact that transmission is built earlier for the purpose of delivering energy today, it remains a marginal cost that *would not be incurred but for the energy forecasted and delivered.*

Likewise, the ability of a resource to serve load through non-transmission alternative delivery should be seen as "freeing up" or effectively creating new capacity on existing infrastructure. This can be achieved by shifting the load to periods free of transmission constraints, or more fully by shifting locational relationship between load and energy through local generation or conservation. In so doing, it reduces the marginal cost of delivery, and the cost to ratepayers of delivered energy.

Finally, demand charges are generally tools for incentivizing current and future behavior, but do not bear any particular relationship to historical cost-triggers in past planning processes. As noted above, the price signals are delivered to UDCs, not customers, unless and until UDCs change their own tariffs for retail rates. Thus, CAISO's rationale for demand charges is misguided. In fact, there is no guarantee that "[a]dding 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"[1] As with the proposal to change the point of measurement toTED, a change in CAISO's tariff is not sufficient in of itself to allocate costs to those responsible for cost causation or influence their actions. In both cases, the UDCs must also reflect CAISO's actions in their own tariffs.

b. Please indicate if your organization believes additional cost data or other relevant data could be useful in developing the approach and ultimate determination utilized for splitting the HV-TRR under the proposed two-part hybrid approach.

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[1] Review Transmission Access Charge Structure First Straw Proposal, January 11, 2018, at 33.

Please explain what data your organization believes would be useful to consider and why.

The CLEAN Coalition is gratified to see CAISO consider data-driven approaches to setting key parameters of the cost allocators. As we have noted in our comments, CAISO should develop methods for empirical analysis of four key factors:

1) What proportion of projects have historically been in the four categories of transmission drivers that can be deferred with load reductions or locational factors in development of new generation (See Section III.A.3.c for discussion of the drivers of transmission spending).
2) What proportion of future transmission growth is deferrable using TPP planning methodologies through increasing DG deployment by 50%, 100% or 200%? Clean Coalition included generation profiles of existing DG as defined in PG&E's published Distribution Resource Plan in analysis of the contribution of the DG resource portfolio in peak demand reduction. CAISO should use this or a comparable alternative in assessing potentially deferrable future transmission investment.
3) What is the range of forecasts of customer load growth and transmission load growth, especially under a range of assumptions about building and transportation fuel switching and EV deployment.
4) What impact have DER deployments and forecasts had on the identification of grid needs addressed in the TPP. It is important to quantify the role of energy efficiency, demand response, distributed generation and distributed storage on load growth drivers of transmission project identification, including both behind the meter and in front of the meter distribution resources.

Overall, the CLEAN Coalition recommends two general steps to determining the cost allocation between hybrid components. First, specify the rate components based on a clear rationale of what benefits or incentives support the implementation of the component and second, identify and assess data to determine how large those incentives or benefits actually are. Without these key data, it will be difficult to assess whether a 50% split meets the intended purposes or not.
As it is, the CLEAN Coalition believes ignoring that energy delivery is a real cost of energy consumption leads to market inefficiencies.

5. **The ISO seeks feedback from stakeholders regarding if a combination of coincident and non-coincident peak demand charge approaches should potentially be used as part of the two-part hybrid approach proposed in Section 7.2.1.2. Does your organization believe it would be appropriate to utilize some combination of coincident and non-coincident peak demand methods to help mitigate the potential disadvantages of only use of coincident peak demand charges? Please provide any feedback your organization may have on the potential use of coincident versus non-coincident peak demand measurements, or some combination of both under the proposed two-part hybrid measurement of usage approach.**

    a. **What related issues and data should the ISO consider exploring and providing in future proposal iterations related to the potential utilization of part coincident**

peak demand charge and part non-coincident peak demand charge? Please explain your position.

Again, it is critical to be clear on the basis of cost causation, and what behaviors the demand charges are designed to incentivize. If the demand charge is designed to assess contribution to system peaks so as allocate costs and to reduce transmission spending related to peak demand, then only a coincident peak metric captures the proportional contribution and sends that signal to reduce that peak demand. If the demand charge is designed for some other purpose such, then the choice of peaks should reflect that purpose. The Straw Proposal notes that non-coincident peak better reflects the benefits received by customers, however allocation of costs based on receipt of benefits instead of cost causation disincentivizes most efficient use of the system. We believe this should only be considered after the cost reduction benefits to all ratepayers have been considered through assignment based on cost causation, while maintaining equal access; only then should cost allocation be considered for redistribution based on benefit received. However, cost causation must be aligned with actual use (benefit), not simply planned use. In addition, to avoid "free rider" issues, it is essential to distribute costs proportionate to each contributor of cost causation. Non-coincident peak may be considered a cost driver but for the coincident peak, while acknowledging that it making efficient use of capacity and would respond to peak pricing.

Treatment of Non-PTO Municipal and Metered Sub Systems (MSS) Measurement of Usage

6. Under Section 7.2.1.2 of the Straw Proposal the ISO indicated there may be a need to revisit the approach for measuring the use of the system by Non-PTO Municipal 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. Because the Straw Proposal includes modifications for utilization of a two-part hybrid measurement approach for measurement of customer usage the ISO believes that it may also be logical and necessary to modify the measurement used to recover transmission costs from Non-PTO Municipal and Metered Sub Systems (MSS) entities. The ISO has not made a specific proposal for modifications to this aspect of the TAC structure for these entities in the Straw Proposal, however, the ISO seeks feedback from stakeholders on this issue. Please indicate if your organization believes the ISO should pursue modification to the treatment of the measurement of usage approach for Non-PTO Municipal and Metered Sub Systems to align treatment with the proposed hybrid approach in the development of future proposals. Please explain your position.

Generally, we believe that the customers throughout California should be on equal footing absent some compelling reason that the non-PTO municipals and MSS pose unique issues. The principles and mechanisms to determine cost responsibility should be applied consistently to all customers. CAISO should first evaluate the contractual and legal options under which it may offer or require changes in the billing determinant for these entities, and model the financial effect of a transition to the hybrid approach on the non-PTO municipals and MSS. Of course, our view is that the uniformity should be created by treating the IOUs with the same point of measurement structure that the non-PTO municipal utilities use.

Point of Measurement Proposal

CAISO QUESTION 7. Does your organization support the concepts and supporting justification for the ISO's current proposal to maintain the current point of measurement for TAC billing at end use customer meters as described in Section 7.2.3.2 of the Straw Proposal? Please explain your position.

No. We disagree with several of CAISO's characterizations. CAISO is incorrect that a change in the TAC structure will not be critical to resolving the distortion in California's procurement market. First, a moving to TED-based TAC should shape procurement by all LSEs using the CPUC LCBF methodology. Second, without moving to a TED-based TAC, the further reforms needed to deliver the price signals to CCAs and other LSEs using other methodologies. UDCs cannot pass through the savings to CCAs and their customers unless CAISO reflects the DER contribution in its billing determinant to the UDCs. Without TAC savings for DG, the UDCs will have no funds with which to properly compensate CCAs for their efforts to reduce use of the transmission grid. CAISO must consider whether it intends to preclude removing the distortion against DG in California's procurement market.

1) Whether aligning the TAC with cost-causation affects other flawed TAC structures is immaterial. The CAISO TAC shifts costs onto LSEs working to avoid transmission capacity use, which is justification enough for reform. Furthermore, if CAISO leads the way, implementing LV-TAC reform to bring those into conformity will be significantly easier.
2) Whether the TAC is a small proportion of the total energy service cost is immaterial to whether the TAC is introducing a cost shift and market distortion. In the procurement market, TAC is on track to exceed the cost of generation in coming years, which means that TAC cannot simply be ignored as a factor shaping our energy markets. The change on the order of 3 cents per kWh from moving the point of measurement is large relative to procurement costs for generation. Since LSE procurement decisions are the primary driver of transmission investment and use, an accurate cost large signal in procurement would provide proper incentives to LSEs to consider the transmission effects of their choices.
3) Reforming the TAC tariff would involve drafting a tariff that would ensure that the cost allocations meet the required TRRs. However, this is not a justification for not addressing the existing cost shifts and market distortions.
4) The relatively small shift in customer bills that would occur today (under 1%) is a significant advantage to the proposal to change to a TED-based TAC, because it could implement significant cost savings with minimal impacts on customers. The proposal would align costs to the respective LSEs and UDCs without introducing a substantial rate adjustment on any ratepayers. Since transmission costs are driven in part by LSE behavior rather than customer behavior, it is appropriate that the TAC reflect the LSE cost drivers without affecting customer rates.
5) Whether TED is greater or less than CED is immaterial. Either TAC structure allocates costs on a proportional basis relative to a UDC's share of the total of either measure. Thus, the fact that the distribution losses exist do not alter the market distortion caused by the use of CED. If anything, distribution line losses suggest that TED is preferable, because then UDCs would be paying TAC on energy lost in inefficient distribution networks. Right now, distribution line losses increase energy flows

across the transmission grid, creating stresses on transmission but for which there is no cost recovery because that energy never reaches the point of measurement at the customer meter.

6) CAISO is correct that implementation would change in the allocation of costs among UDC territories in small amount, but this represents a correction of the misaligned cost shifts that the current TAC structure imposes. The new TAC would reflect the actual contribution of each UDC area to past cost causation. Under the current structure, the LSEs in a UDC territory could make significant efforts to reduce their demand for existing and future investment but their IFOM DER are not counted. This DER frees up existing transmission capacity, and avoids the need for new capacity, reducing costs for all ratepayers. Retaining the current customer level billing determinant means that LSEs are being assessed TAC disproportionate to their use of the transmission system.
7) CAISO is profoundly mistaken that there is no justification for removing the existing cost shift onto LSEs that are working to save all ratepayers from unnecessary transmission investment. The tens of billions of dollars that a change to TED-based TAC could save California ratepayers in unnecessary transmission capacity is a powerful justification for reforming to a TED-based TAC. Furthermore, the fact that the CED-based TAC fails to follow cost causation or use alone should be sufficient justification. The change to a TED-based TAC is justified because current point of measurement fails to account for the contribution of all in front of the meter (IFOM) DG and energy storage facilities toward reducing either volumetric or peak loading of the transmission system. The current point of measurement fails to account for differences in each UDC's or LSE's development of these resources. These defeat any potential price signal for differential cost causation of transmission spending and unfairly overcollects from those who are doing the most to avoid cost-causation.
8) Furthermore, TAC should not have a market distorting effect on California's energy markets. Removal of that inappropriate market distortion is also adequate justification for changing to a TED-based TAC. The current TAC has a substantial effect on procurement of DG by the entities that are responsible for driving transmission investment: the LSEs. Changing the point of TAC measurement to properly reflect both past and future influences on cost causation would provide a necessary price signals that can and should be passed through to the LSEs that are ultimately influencing transmission investment through their procurement decisions. While the impact on end use customers would be trivial (which is good from a ratemaking standpoint), the effects on LSE procurement could be significant.

CAISO QUESTION 8. The ISO has indicated that the recovery of the embedded costs is of paramount concern when considering the potential needs and impacts related to modification of the TAC point of measurement. The ISO seeks additional feedback on the potential for different treatment for point of measurement for the existing system's embedded costs versus future transmission costs. Does your organization believe it is appropriate to consider possible modification to the point of measurement only for all future HV-TRR costs, or additionally, only for future ISO approved TPP transmission investment costs? Please provide supporting justification for any recommendations on

this issue of point of measurement that may need to be further considered to be utilized for embedded versus future transmission system costs. Please be as specific as possible in your response related to the specific types of future costs that your response may refer to.

a. First, TAC fails to assign costs proportional to historic cost causation. Existing DG and other DER investment have already reduced transmission embedded costs, because existing and forecast DG has long been incorporated in the transmission planning process. Thus, DER have reduced the need for new transmission for decades, but the current structure has never reflected demand reductions occurring within the distribution system between the customer meter and the transmission system . Thus, the current system applies proportionally higher costs on those territories that have done the most to reduce past need for transmission investment even before CAISO was founded. Thus, changing the determinant for embedded costs would more accurately reflect causation of embedded costs by capturing the DER contribution embedded in the forecasts used for the Transmission Planning Process .

b. Second, cost recovery for transmission infrastructure is like all other infrastructure in that the cost recovery follows current use patterns as they change, not historical patterns. If a UDC area reduces its customer load through efficiency, DG production, or simple loss of population, recovery from the UDC customers goes down proportionately, while areas with increasing load contribute more based on their increased use. This is the case currently and neither the proposal to move the position of the billing determinant nor the possible adoption of demand charges changes that. This principle remains regardless of the TAC structure and is therefore immaterial in deciding between the alternatives. [See example and chart in section 3 of the separate white paper for description of how this is distorted under the current point of measurement.]

c. Third, future costs clearly are avoidable through DG procurement. California has already seen several planned projects cancelled because of DG procurement. (Albeit without any credit to the parties responsible for saving money for all ratepayers.) Thus, it is clearly inappropriate to maintain a billing structure that fails to account for these impacts.

d. Finally, how much transmission costs can be reduced is an empirical question that CAISO has not begun to address, so suggestions that few costs are avoidable are without merit unless and until the supporting data and modeling is developed. Clean Coalition has provided stakeholders with a detailed model for estimating savings based on the share of new load met through DG based on public CAISO and PG&E data, and invited parties to run their own scenarios and to offer refinements to the data or equations. To date, no stakeholders have have offered more accurate alternatives.

9. The ISO seeks additional stakeholder feedback on the proposal to maintain the status quo for the point of measurement. Please provide your organizations recommendations

related to any potential interactions of the point of measurement proposal with the proposed hybrid billing determinant that should be considered for the development of future proposals. Please indicate if your organization has any feedback on this issue and provide explanations for your positions.

If the hybrid billing determinant or any other alternative is adopted, the point of measurement must still be adjusted to correct for the inherent distortion realized by measuring at the customer meter.

Customer level measurements of both volumetric and hourly or peak demand are incapable of capturing the effect of distributed generation or energy storage located on the utility side of the meter, including both utility owned facilities and those owned and operated by independent providers. With several gigawatts of energy storage and wholesale distributed generation already deployed or planned in accord with legislative mandates and CPUC Decisions, and additional capacity being added in response to CCA local investment goals, local grid needs, and replacement of conventional peaker facilities, it is increasingly important to ensure TAC assessment measurements capture this contribution. Failing to do so will greatly inhibit the ability of LSEs to mitigate which ever factors are used as a billing determinant, while also failing to assign costs in accord with actual transmission usage.

Distributed Generation and energy storage has major potential for ratepayer savings given its ability to contain the growth of transmission costs in an era of electric vehicles and fuel switching. The current rate structure fails to account for cost avoidance and fails to reflect either historical or existing patterns of use or cost causation.

Additional Comments

10. Please offer any other comments your organization would like to provide on the Review TAC Structure Straw Proposal, or any other aspect of this initiative.

From our perspective, we recognize that California is missing a distributed generation sector that is vibrant and vital in many other states because practices the systematically inhibit in-front-of-the-meter DG, including through the existing structure of its TAC system.