California Independent System Operator

250 Outcropping Way

Folsom, CA

Attn: Christopher Devon

February 15th, 2018

RE: Stakeholder Letter in support of measuring transmission usage at the Transmission-Distribution interface in the Review Transmission Access Charges Stakeholder Process.

Dear Mr. Devon,

We are writing to express our joint opposition to CAISO's current straw proposal to continue measuring transmission usage at the customer meter, and to urge CAISO to reform the formula for transmission access charges to be based on measures of transmission usage at the transmission-distribution interface as Transmission Energy Downflow (TED). This change will correct five major drawbacks that currently disadvantage distributed generation (DG).

CAISO's proposed continued use of customer energy downflow (CED) at the customer meter as the measurement of transmission grid usage has the following drawbacks:

1) The current TAC structure inappropriately shifts the costs of existing infrastructure from the customers of Load Serving Entities (LSEs) that rely more heavily on transmission resources onto the customers of LSEs that have historically reduced their use of transmission resources by procuring local energy from DG, which does not use transmission capacity.

2) The current TAC structure places a proportionally higher burden of future transmission investments on the customers of LSEs that act to reduce overall transmission spending by procuring DG. Since increased use of DG has been shown

repeatedly to avoid or defer transmission investment, this penalty for those doing the most to reduce costs for all is inappropriate.

3) CAISO's proposed Demand Charge at the customer meter could only be mitigated with behind the meter generation. This means that LSEs could not reduce their customers' transmission charges with community-scale storage or local in-front-of-the-meter energy generation.

4) The current TAC structure distorts the energy procurement market because it prevents procuring entities from accurately accounting for delivery costs. It is absolutely untenable to suggest that transmission-connected resources hundreds of miles from load and distribution connected resources next door to load cost precisely the same amount to deliver. So long as Transmission Access Charges do not reflect the differential impacts of different resources on the transmission grid, there will be no mechanism for rewarding LSEs for acting to the benefit of all. The current CED-based TAC structure fails to and appropriately credit LSEs for their DER contributions to lowering historic and future transmission system costs.

5) The lack of any price signal that differentiates transmission costs between local and remote energy means that local energy resources are actively discriminated against in procurement because there is no mechanism for capturing the real differences in value between resources. This depresses California's wholesale distributed generation market relative to other states and countries which have far more robust and vigorous distributed generation sectors. As a result, California's communities do not benefit from local energy as they should.

We have reviewed the CAISO straw proposal and unfortunately find it lacks solid rationale for retaining the current market distortion and therefore oppose the straw proposal in its current form.

Sincerely,

Doug Karpa
Policy Director
The Clean Coalition

Clean Coalition
Making Clean Local Energy Accessible Now

A broad range of organizations support the goal of correcting the CAISO tariff language to assess Transmission Access Charges (TAC) on a utility's metered TED, better aligning charges with cost causation. The positions expressed herein are consistent with those expressed in the prior stakeholder process. Supporters designated with an * confirmed review and endorsement of these specific comments.

350 Bay Area*
350 San Diego*
3fficient
Appraccel*
BBL Solar Design & Consulting
Berkeley Climate Action Coalition*
Borrego Solar*
California Alliance for Community Energy*
California Consumers Alliance
Californians for Energy Choice
Carbon Free Mountain View*
Carbon Free Palo Alto
CalSEIA
Center for Biological Diversity
Center for Sustainable Energy
Civic Solar
Climate Action Campaign*
Commercial Solar Design
Community Choice Partners*
Community Environmental Council*
Community Renewable Solutions LLC
Cratus Energy*
Dan Kammen (UC Berkeley Energy & Resources Group)
Dynamic Grid Council
Earthwise Energy
East Bay Clean Power Alliance
eMotorWerks
Energy and Policy Institute
The Energy Coalition
Enphase*
Environment California
Foresight Renewable Solutions
Fossil Free California
Foundation Windpower
Green Lynx LLC*

ImMODO
Institute for Local Self-Reliance*
Integrated Resources Network
JKB Energy
JTN Energy LLC
LEAN Energy*
Local Clean Energy Alliance*
Local Power
McCalmont Engineering*
Menlo Spark*
Microgrid Media
Microgrid Resources Coalition
Mirasol Development LLC
Nectar Solar
Nutter Consulting
The Offset Project*
Pacific Environment
Panel the Planet
Pathion*
Photon Power
Preserve Wild Santee
Pristine Sun*
Promise Energy*
Récolte Energy*
REP Energy
San Diego Energy District
San Diego Community Choice Alliance*
Sierra Club California*
Simply Solar
SkyCentrics*
SLO Clean Energy*
SolAgra*
Solar Electric Solutions
Solar Engineering Consultants
Solar Land Partners
Soltage
Sunrun
Sustaenable
Sustainable Economies Law Center
Sustainable Silicon Valley
TeMix

Terra Verde Renewable Partners
UCLA Luskin Center for Innovation
Voltaic Capital Markets LLC
World Business Academy*

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
Doug Karpa (415)860-6681 doug@clean-coalition.org Sahm White (831)425-5866 sahm@clean-coalition.org	Clean Coalition	*February 15, 2018*

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.

[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.

Transmission-Energy Downflow is a superior Transmission Charge Basis Rate Design

Clean Coalition White Paper

CAISO First Straw Proposal, Review Transmission Access Charges Stakeholder Process

February 15, 2018

I. Summary

1) Transmission-Energy Downflow (TED) remains a superior basis for assessing transmission charges with fewer distortions and costs shifts when compared to Customer Energy Downflow, no matter whether examined from the standpoint of allocating embedded historical costs, current use and benefits, or incentives and market distortions. Consequently, TED is a superior approach under the standards applied in FERC Order No. 1000. Even if the existing structure has been approved under prior orders, the current structure is a strictly inferior rate design.
2) The formula for the calculation of Transmission Access Charges from the measure of usage should expressly incorporate allocation based on services provided, as valued by the total market transactions. While Demand Charges are a crude tool, they do not reflect drivers, benefits, or market incentives as effectively as a structured TAC.
3) In order to shape a strictly superior rate design, the Clean Coalition supplements the current TED proposal with two additional mechanisms
   a. A Seniority-based cost allocator triggered only if Distributed Generation deployment exceeds growth of customer load. This would allow charges to follow contemporary use of the transmission assets where new users make use of capacity freed by DG. However, in the unlikely case of stranded transmission assets associated with actual declining transmission use (as opposed to mitigated continued growth), credit for

an LSE's DER reduction in transmission load would not reduce their allocated costs for assets developed for their customers' benefit.

b. A TAC formula allocator that assigned total revenue requirement cost recovery between a fixed component, a volumetric component and demand charge, based on the proportion of the transmission value and cost driver stack as follows:

Component	Basis
Fixed Component	Proportional to Market Value of stand-by power option relative to total energy market value
Demand Charge	Proportional to proportion of transmission projects for peak demand
Volumetric charges	All remaining costs

4) In addition, many of the arguments and rationales presented for retaining the use of CED are not supported by evidence or depend on conclusions that have not been demonstrated. The Clean Coalition therefore urges CAISO to abandon unsupported rationales and to engage in the specific analyses that would provide a sound empirical basis for reforming CAISO's transmission access charge tariff.

II. <u>Organization</u>

These comments are organized into three parts.

First, an evaluation of the relative strengths of TED- and CED-based TAC is evaluated on each of the three identified bases for analysis:

1) Ability to allocate historical embedded costs based on cost causation
2) Ability to allocate costs based on current benefits and usage
3) Ability to send non-distorting efficient economic signals

The TED-based TAC is strictly superior on all criteria

Second, a review of standards for rate design laid out by FERC, primarily in Order No. 1000 which unequivocally require incorporation of allocating costs based on benefits and not just historical planning triggers.
Third, A review of the role of substantial evidence in administrative decision making, including a review of the critical outstanding factual questions that have not be addressed.
Fourth, a summary of the additional refinements of the TED-based TAC proposal that CAISO should consider incorporating into the TAC structure.

III. Transmission Energy Downflow is the superior allocator regardless of the basis of cost allocation.

A. Cost Allocation proceeds under a combination of considerations.

Use of Transmission Energy Downflow better reflects rate design principles, no matter which basis for evaluation is chosen. Both FERC and this stakeholder process have identified three separate bases upon which to allocate costs of transmission infrastructure[1]:

1) historical customer demand for transmission "for which the grid was built,"

2) current benefits and use of the transmission grid, and

3) the incentives to shape behavior of entities driving future cost trends.

Transmission Energy Downflow (TED) is a better cost allocator to reduce unjustified cost shifts under all three bases. Therefore, continued use of Customer Energy Downflow (CED) is unjustified and unsupportable under FERC Order no. 1000.

1. Basis 1: Historical Customer Demand shows that using Customer Energy Downflow causes a cost shift onto those LSEs which have helped reduce transmission use.

[1] See CAISO Straw Proposal, Section 7.1.

First, a CED-based rate structure shifts costs onto the customers of LSEs that have historically deployed DG and thus avoided use of the transmission grid.[2] Since the inception of CAISO, transmission planning has been based on *transmission* load, which reduces customer load for all DG, whether behind the meter or in front of the meter as a "load modifier" before modeling and planning transmission needs. Thus, LSEs that have deployed DG have reduced the transmission load and therefore planned transmission and transmission investment.

However, even though these LSEs have reduced the amount of transmission needed relative to the amount of total energy used, they are still billed at the same rate as LSEs that have not reduced or offset their need for transmission at all. Thus, per unit energy or capacity, they pay a higher rate and have costs of the (reduced) transmission system shifted onto them.

The various cases involving different transmission demand in the planning process illustrate the cost shift and demonstrate that the CED-based TAC creates a cost shift onto the customers of LSEs reducing transmission investment and costs for all ratepayers. In the following cases, TAC structures that allocate costs that accurately reflects the historical cost causation are highlighted in green and structures that fail are highlighted in red.

CASE 1: Historical Cost Causation: Equal Transmission use

Consider two Utility Distribution Companies (UDC) (e.g., PG&E, SCE, or SDG&E) each with 50 GWh of end customer load and no DG in the first planning period. Transmission planning is based on the full 100 GWh and TAC is based on 100 GWh in total regardless of the point of measurement.

Here, the cost allocation is equal at 50% each.
This is analogous to the historical situation before the development of Distributed Generation. This characteristic that TED-based and CED-based TAC perform identically is the case for all transmission planned before the advent of DG penetration.

[2] Please see Section V below.

CASE 1: Equal transmission use	UDC 1 Load	UDC 2 Load
Customer Load	50 GWh	50 GWh
DG	0 GWh	0 GWh
Transmission Load	50 GWh	50 GWh
Total Transmission load	100GWh	
Transmission load contribution	50%	50%
Cost Assignment (CED)	50%	50%
Cost Assignment (TED)	50%	50%

CASE 2: Historical Cost Causation: Unequal Transmission use because of avoided use. Instead, consider these two Utility Distribution Companies (UDC) (e.g., PG&E, SCE, or SDG&E) each with 50 GWh of end customer load but one with 10GWh of DG (20% of load) in 2010. Transmission planning is based on the full 100 GWh and TAC is based on 100 GWh in total regardless of the point of measurement.

Here, the second UDC actually reduced the amount of transmission needed by more than 10%, but under the CED cost allocation ends up pays 13% more per GWh of contribution to transmission planning, while the UDC that did not help reduce overall transmission load actually pays 11% less per GWh. This results in a cost shift from customers of the non-avoiding UDC and onto the customers of the UDC that did avoid transmission use. This penalizes those UDCs that are reducing overall system costs.

Here, CED-based TAC clearly results in a cost shift where DG is accounted for in planning, but not in TAC.

CASE 2: Unequal transmission use	**UDC 1 Load**	**UDC 2 Load**
Customer Load	50 GWh	50 GWh
DG	0 GWh	10 GWh
Transmission Load	50 GWh	40 GWh
Total Transmission load planned for	90GWh	
Transmission load contribution	56%	44%
Cost Assignment (CED)	50%	50%
Relative price	-11%	+13%
Cost Assignment (TED)	56%	44%

CASE 3: Historical Cost Causation: Unequal transmission use in the <u>second planning period</u> with offsetting DG eliminating the need for additional investment.

Consider that the same two UDCs from Case 1 in the next planning cycle. Both started with 50 GWh of customer load. The first LSE sees growth in load of 10 GWh in total customer load. The second LSE sees no load growth, but procures 10 GWh worth of DG. Thus, the first UDC relies entirely on transmission-connected resources, while the second offsets that growth with DG to serve its own load.

1) As a result, the total use of the transmission grid does not increase because UDC 2 is freeing transmission capacity for UDC1 to use.
2) Again, although UDC 2 is helping constrain transmission investment by freeing up capacity for others to use, under the CED-based TAC, UDC 2 is *penalized*. TED accurately shows that the total transmission load remains at 100 GWh, and TAC is split 60:40, proportional to cost causation in transmission planning. However CED indicates 110 GWh of transmission "use" is subject to cost recovery, and TAC is split 55:45, resulting in a 55%:45% cost assignment despite the fact that the UDC 2 is freeing up existing capacity for UDC 1 to use. Although UDC 2 is acting to prevent overall system costs from increasing 10%, it ends up paying more. Thus, CED shifts costs onto the UDC that has acted to reduce overall costs.

Here, CED results in a cost shift when DG frees capacity for others and that capacity finds a user.

CASE 3: Offset transmission Load Growth	UDC 1 Load	UDC 2 Load
Customer Load	60 GWh	50 GWh
Change	+10 GWh new load	-10 GWH DG reduction
Transmission Load	60 GWh	40 GWh
Total Transmission flow	**100GWh**	
Transmission Load Growth	**0 GWh**	
Total Customer Energy Downflow	**110 GWh**	
Transmission load contribution	60%	40%
Cost Assignment (CED)	56% (60 GWh/110GWh)	44% (50GWh/110 GWh)
Relative Price per GWh	-9%	+12.5%
Cost Assignment (TED)	60% (60GWh/ 100GWh)	40% (40GWh/100GWh

CASE 4: Historical Cost Causation: Unequal transmission use in the second planning period with DG avoiding overall use of the transmission grid.

The only corner case in which TED is not flatly superior is the case in which overall transmission load decreases over time due to DG deployment.

Consider the same two UDCs from Case 1 in the next planning cycle. Both started with 50 GWh of customer load. In the second planning period, neither load grows, but the second LSE procures 10 GWh worth of DG. Thus, overall transmission load actually declines. However, retaining CED-based TAC amounts to an claim that overall transmission load *will be* decreasing, because under any other circumstance, a CED-based system imposes a cost shift on UDCs that engage in reducing overall costs.

Here, the simple TED does not follow the 50%-50% split that was the basis for past transmission planning because of declining overall load. This Case shows that in cases of declining load, allocation of the cost of stranded assets may be an issue. This is distinct from the case where customer load growth is mitigated by DG resulting in less growth or no growth in transmission load. Here, there would be a need for a stranded asset cost allocator.

CASE 4: Overall transmission use declines	UDC 1 Load	UDC 2 Load
Customer Load	50 GWh	50 GWh
Change	0 GWh	-10 GWH DG reduction
Transmission Load	50 GWh	40 GWh
Total Transmission flow	**90GWh**	
Transmission Load Growth	**-10 GWh**	
Total Customer Energy Downflow	**100 GWh**	
Transmission load contribution (from first planning period)	50%	50%
Cost Assignment (CED)	50% (50 GWh/100GWh)	50% (50GWh/100 GWh)
Cost Assignment (TED)	56% (50GWh/ 90GWh)	46% (40GWh/90GWh)
Relative Price per GWh	+12.5%	-9%
Cost Assignment (TED with junior reduction charge)	50%	50%

Seniority based true-up mechanism

Ideally, the TAC should provide the correct outcome regardless of the changes in circumstances. Although it is exceptionally unlikely that DG would ever grow enough to offset load growth in an era of fuel switching and EV growth, it is conceivable. Therefore, the following principle should apply:

> New users are allocated cost recovery for resources they use as the senior use, unless there is no new user, in which case the original UDC that triggered the transmission remains responsible as a junior guarantor.

Thus, transmission that is freed up by DG deployment that finds a new user is paid for by the new user (see Case 3). If, however, freed capacity goes unused, then the UDC that contributed to the planning load acts as a secondary guarantor of that cost recovery.

Since CAISO would know both when overall load has declined and which UDCs were responsible for the load decline, any shortfall in TRR recovery would be assigned to the UDC(s) responsible for the unused infrastructure.

Under such a system, the TED-based TAC would perform as well or better in reflecting the historical cost drivers than a CED-based system under all scenarios.

2. **Basis 2: Using TED eliminates cost shifts onto customers of UDCs that are actively avoiding using transmission assets.**
    a. ***Identifying and evaluating benefits: Use is one of a set of benefits.***

The second basis for evaluating transmission cost recovery rate designs identified by both FERC and CAISO is whether a rate design accurately allocates costs based on which customers are currently using and benefitting from the transmission system. On this basis as well, TED is strictly superior to CED in all cases.

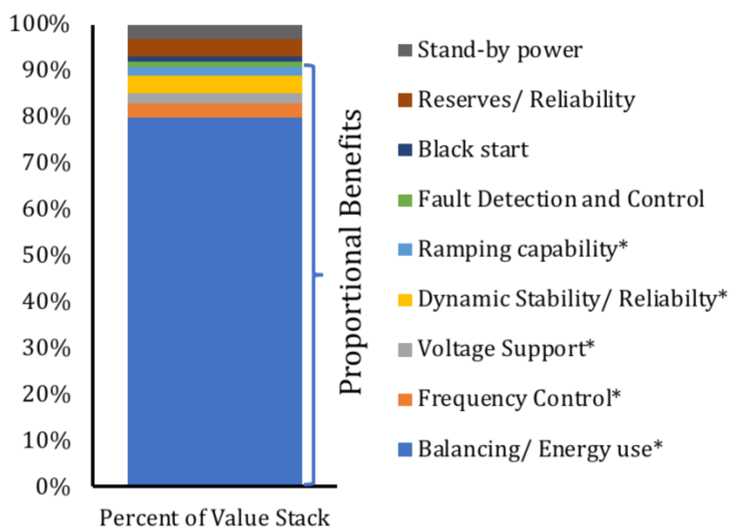
Identifying the beneficiaries of grid services and allocating costs proportional to those benefits involves identifying the benefits, evaluating their relative contribution to the full value stack of benefits of the transmission grid, and then allocating costs based on the degree to which different beneficiaries receive those benefits.

Benefits is a broad category of services and uses that add up to the full value stack of benefits provided by a transmission grid. These benefits fall broadly into "active" benefits that derive from using the grid and "passive" benefits that come from being connected to the grid without using the grid. The first category is largely benefits that are related to active energy delivery and services specific to managing the transmission grid and transmission assets. The second category are benefits that derive from having the option of using the grid.

Transmission services v. proportional services

Many "transmission" benefits or services are not strictly speaking benefits provided by the transmission grid, but are provided by *generation* no matter where it connects to the grid. These are not transmission-specific services, but are general services that are provided partly by transmission-connected assets and partly by distribution-connected resources. Services are provided by both distribution and transmission connected generation (none are provided by the transmission grid itself) in equal measure, so none can be characterized as "transmission services."

Figure 1 - Grid Benefits value stack conceptual illustration.



The energy system delivers a range of benefits to customers, but that full set of benefits must add up to 100% of all value. Many values are proportional to transmission usage, such that cost allocation should also be proportional to transmission usage. (The values here are chosen to be illustrative and would require empirical estimation to evaluation in practice.

These services and benefits only come from the transmission grid services only proportional to the degree to which transmission-grid resources provide them. For many grid system (transmission and distribution) services, the transmission grid provides only a fraction of the service, so the amount of services provided by the transmission grid is roughly proportional to the energy provided by transmission resources. For example, balancing generation with load is a system-wide service and if, for example, 90% of load is met with transmission resources and 10% from distributed resources, then the service is not a transmission-specific service.

Critically, proportional energy use is a reliable proxy for the degree to which benefits from a give resource are realized by a given customer group. This is the approach that CAISO has historically used in recovering costs based on volumetric measures. Those that use more energy are also getting more of the value from all the other services that come with that energy.

Different benefits call for different rate structures, and the diverse nature of benefits suggests that a hybrid of use-proportional and non-bypassable per customer charges would best reflect the distribution of these benefits. Charging for use-based benefits would then be assessed based on use of the transmission. This would apply to all proportional benefits, since customers would realize greater benefit with proportionally greater use of transmission-connected resources. On the other hand, existence benefits, such as back-up power, accrue whether the transmission grid is used or not. These benefits should instead be charged with a non-bypassable charge per customer rather than based on usage. A combination of two separate components would thus reflect the diverse characteristics of grid services.

b. ***Most Benefits are realized by Customers proportional to their use of the transmission grid.***

CAISO has listed a number of potential benefits provided by the transmission grid, but the critical question is to what extent that the value of those benefits scales proportionally to use or to the relative role transmission assets play in the energy system. Since many of those services can be equally well performed by DG as transmission-connected generation, these are actually services provided by a combination of transmission-connected resources and distributed generation.

Energy Delivery/ Balancing (proportional): The primary function of transmission is to deliver energy. Balancing is a function of ensuring that demand and load are met. However, customer load can be met with both DG and transmission-connected generation. Since the overall energy system involves energy consumed at the moment it is generated (except for energy storage), balancing services are in fact provided exactly proportionally between DG and Transmission. Thus, it is nonsensical to assert that balancing is any more a service provided by the transmission generation than it is by the distributed generation. The benefits provided by the transmission grid are proportional to how much energy is provided by transmission-connected resources.

Frequency control (proportional): Frequency maintenance is a function of the precise match of load and generation. In the first instance, maintaining frequency is a matter of matching load and generation and is proportional as balancing. Frequency control is otherwise a system-wide service that can be provided by either DG and remote generation equally. Neither can be said to be uniquely providing frequency stability to the whole system. If either falters, so does frequency.

In practice, frequency control is provided by the array of generators participating, who can be located anywhere. Thus, what proportion are transmission-connected is an empirical question, and statements that frequency control is a transmission grid service are misplaced.

In fact, since many DG resources are increasingly dispatchable due to co-located storage, increasingly DG can respond vastly faster and more efficiently than transmission connected turbines. Thus, frequency response is perhaps most properly thought of as a distribution grid service for which transmission grid can play a back-up role as turbine governors respond slowly. Particularly in light of FERC order No. 784, the distribution-connected energy storage is likely to displace slow-responding resources, leaving the distribution grid disproportionately responsible for frequency regulation.

Finally, since frequency control is managed through a distinct market, whether frequency regulation should be part of the rate design of TAC depends on whether those services are passed through to customers through TAC or some other mechanism. If they are not part of TAC, they are not germane to this discussion.

Voltage support (proportional): Maintaining local voltages within customer limits in particular is disproportionately a distribution generation service, not a transmission grid service. Voltage support depends critically on reactive power, which suffers massive line losses with distance. As a result, dispatching reactive power locally with advanced inverters is far more effective and efficient than relying on inefficient dispatch from distant generators. In this sense, voltage support also is best understood as distribution grid service that again is disproportionately best provided by DER.

Dynamic stability (proportional): To a real extent, dynamic stability services have similar system characteristics to frequency regulation or balancing in that the actual service is provided by rapid responses to small perturbations. As with frequency regulation, DER provide the fastest and most accurate responses to grid disturbances, fatally undermining any claim that dynamic stability is a specifically a transmission services. To our knowledge, CAISO has no distinct requirements or markets for dynamic stability, suggesting this service is proportionally too small to warrant distinct regulatory treatment.

Ramping capability (proportional): Ramping is another balancing function that turns on the characteristics of generation, not where it is connected. As ramping is increasingly handled through storage and demand response products, these are also likely to become distribution-provided services. Thus, there is nothing about the transmission grid that makes this specifically a transmission service. Again, how much the transmission grid is responsible for ramping capability is entirely proportional to how much transmission-connected resources are providing that particular service only.

Fault detection and control (distribution/transmission domain specific): Fault detection and control is only a transmission service with respect to transmission faults. Ultimately, modern approaches to fault detection depends entirely on where the fault in question is located. Certainly, when transmission components such as transmission lines or bulk generators fail, then fault detection services are handled on the transmission grid. Distribution grid faults however, can and are handled through distribution level monitoring and modeling resources. Thus, it is unclear how fault detection could be thought of as a transmission service. Where the faults are transmission faults, those charges should be applied to transmission connected energy that depends on the transmission grid for delivery.

Black start capability (distributed resources only): As with fault detection and control, how black start can be conceived of as a service provided by the transmission grid is entirely unclear. Since black start services by definition are only needed during area-wide outages in which the grid cannot provide power, they are by definition NOT provided by the transmission grid, because it is the failure of the transmission grid that necessitates black start services in the first place.

In fact, black start services are only needed by resources that are unable to provide their own energy without the grid. Since PV and storage can provide their own black start capabilities and play a critical role in restarting or maintaining power in the face of transmission failures, suggesting that DER need the transmission grid to provide black start services fails to understand the nature of these technologies. The reality is that black start services are almost exclusively needed by transmission connected fossil fuel resources, and frequently these are provided by on-site solar emergency microgrids.

Reserves (proportional): Generally, reserves are provided by both transmission-connected and distributed resources. Furthermore, reserves are called into service regardless of whether it is local or remote resources that have failed. When outages occur, the ability to provide reliability services depend on the location and capabilities of the resource, not where it is connected. Indeed, as we have seen in the context of the Moorpark subarea, frequently distributed resources are more reliable simply because they are located closer to load and not subject ot transmission constraints that may prevent transmission-connected resources from providing reliability services. Thus, as with frequency regulation and voltage support, if anything reliability services are better provided by distributed resources, fatally undermining any assertion that such "backup power" is a specifically transmission-connected generator service.

Back-up power option (transmission): Although not listed by CAISO, several stakeholders have pointed to "back-up" power as a service provided by the transmission grid. In fact, this is the only listed service that can be properly characterized as a transmission-level service. This is also the only service that is an existence benefit rather than a use benefit,[3] because it has value whether or not it is ever used, much like resilience benefits of DER to deal with outages of the transmission grid.

As an existence benefit, the valuation of stand-by power is more similar to an insurance service or an option that has independent value even if never called on. Similar to those financial products, the value of the stand-by power option depends on the expectation value of the option. That is, the value should be related to the probability the option is called and the value or lost value that would be incurred if the option were not called. Since the probability of DER is quite low (and by some measures lower than the failure of the transmission grid), the value of the option is similarly going to be fairly low, even if it is not zero.

Empirically, the stand-by option value could be estimated either by a generalized failure rate and lost value of outage to yield an expectation value, or it could be estimated by reference to other energy option products that provide an option for access to energy in return for some payment.

[3] Energy balancing, frequency management, and voltage support all depend on the joint effect of ALL energy dispatched by the grid and so is not separable from energy usage. Should all DER withdraw from generation and remove 5% of the grid energy, the impact is similar to the loss of any other 5% of generation, subject to locational effects. Thus, transmission-connected generation is no more a "but for" cause of system performance than DG is. In this sense, these are in no way transmission-specific services.

c. ***Benefits-based TAC structure and Valuation of services***

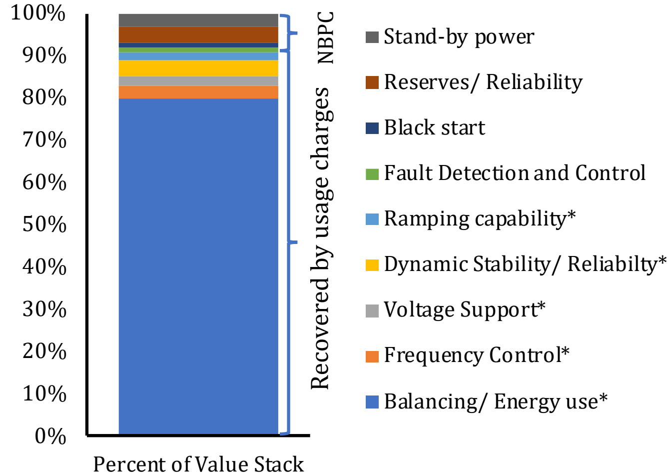
This structure suggests a per customer non-bypassable charge component be added to account for existence benefits.

Reviewing the various benefits provided by the energy system reveals that most are provided by transmission-connected generation proportional to their usage overall.

Service	Type	Charge within TAC
Balancing/ Energy	Proportional	Volumetric
Frequency regulation	Proportional	None/ separately charged
Dynamic stability	Proportional	Volumetric
Reserve/reliability	Proportional	Volumetric
Ramping	Proportional	Volumetric
Voltage regulation	Local	None or volumetric
Black start	Local	None
Fault detection	Local	None
Back-up option	Transmission	Non-bypassable per customer charge

Assigning the proportion of TRR to be recovered from use-based or non-bypassable charges is again an empirical issue. However, most if not all of these services actually have markets to compensate generators for providing these services. Thus, the relative value of each is a matter of comparing the total billing for each service category to the total spent on all energy services, including the delivery of energy. Since the total generation charges in the state for the moment exceed all payments for ancillary services and back-up power options, the large majority of TRR recovery would logically be recovered through use based volumetric charges. As a simplifying matter, the non-bypassable component may be too trivial to be worth including, especially if concerns about LSEs avoiding transmission contributions are dealt with through the use of a seniority-based cost allocation to new users of existing infrastructure as suggested above.

Figure 2: Illustration of structure of hybrid TAC structure.



Here, the same value stack is assigned to allocate costs based on volumetric-based charges (e.g., volumetric rates, demand charges or other charges derived from use patterns) and a non-bypassable per customer fee (labeled "NBPC")

d. ***TED-based TAC would remove the existing cost shift from customers of UDCs that have avoided transmission system usage.***

For those services which are proportional to use of the transmission system, Transmission Energy Downflow is unequivocally a superior basis for transmission access charges. In fact, the Customer Energy Downflow shifts costs onto the customers of UDCs which procure some proportion of their energy from DER. Since those DER also provide a range of services to the grid as a whole, the customers of UDCs that do not pay for their proportional transmission use are free riders on the UDCs that procure DG.

CASE 5: A benefits-based evaluation of TAC structure.

Consider two UDCs, both with 50 GWh of customer usage. UDC 1 relies entirely on transmission resources, while UDC 2 receives 10 GWh from DG. Here, assume that 80% of the value of the benefits from transmission use are proportional to transmission use and energy delivery. The non-proportional benefit accrues to both UDCs equally. Here, we use an arbitrary rate of $100 total benefit value per MWh.

CASE 5: Benefits-based	UDC 1 Load	UDC 2 Load
Customer Load	50 GWh	50 GWh
DG procurement	0 GWh	-10 GWH DG reduction
Transmission Load	50 GWh	40 GWh
Total Transmission flow	**90 GWh**	
Total CED	**100 GWh**	
Proportional Value (MWh x $100/MWh)	$5,000,000	$4,000,000
Non-Proportional Value	$1,125,000	$1,125,000
Total Transmission Benefit Value	$6,125,000	$5,125,000
Total Transmission-Proportional value	**$9,000,000**	
Total Transmission non-proportional value	**$2,2500,000**	
Total Transmission value	**$11,250,000**	
Relative proportion of transmission benefit	54.4%	45.5%
Cost Assignment (CED)	50% (50 GWh/100GWh)	50% (50GWh/190 GWh)
Relative Cost shift	+9%	-9%
Proportional (TED) Transmission Responsibility	55.6% (50 GWh of 90 GWh) ($5,000,000)	44.4% (40 GWh of 90 GWh) ($4,000,000)
+20% non-bypassable component	$1,125,000	$1,125,000
Overall responsibility	54.4%	45.5%

Here, CED imposes almost a 10% cost shift that penalizes the customers of the UDCs doing the most to alleviate transmission congestion.

By adjusting the TED-based TAC to include a non-bypassable component, the TED-based TAC can match the benefits here. In this example, because this includes a non-bypassable component, this structure would mean that a UDC that met all their load with DG would still be responsible for 10% of the total charges (half of the 20% non-bypassable component in this example. Also, even without the non-bypassable charge component, because the proportional component is greater than 50% of the total the TED proportional cost allocation of 55.6%/44.4% is closer to the actual 54.4%/45.6% benefit division, than the 50%/50% division implied by the CED. Thus, even by itself, the TED-based TAC would be better aligned with the assigning costs to beneficiaries.

3. **Basis 3: TED-based TAC is less distorting to economic efficiency than CED-based TAC.**
   a. ***CED-based TAC results in failure to send any price signal for delivery costs means that delivery assets will be over-consumed.***

As the Clean Coalition has repeatedly demonstrated, the inability to differentiate between generation sources in terms of delivery costs means that more expensive resources are procured than is economically efficient. As a simple matter, society bears the real costs of both generation and delivery infrastructure. if resources that incur lower combined generation and delivery costs are made to appear artificially expensive, then more expensive resources will be procured at the expense of resources that are in fact cheaper in real terms. This constitutes a distortion of the market for energy.

At a more nuanced level, modeling by the Market Surveillance Committee has confirmed that for transmission investments that are variable and can be deferred by Distributed Generation, the TED-based measure is more economically efficient.

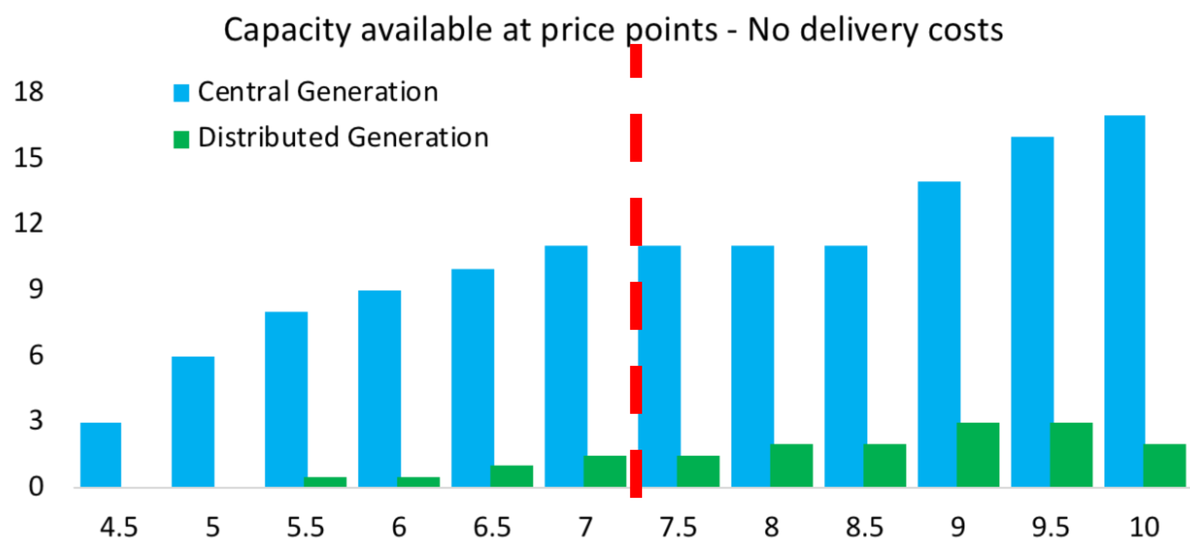
Overall, there are two key economic distortions that result from a CED-based TAC and therefore higher overall ratepayer costs because of the market inefficiency: 1) over procurement of resources that have higher real costs in terms of delivery and generation and 2) overinvestment in transmission.

b. CED results in procurement of higher total cost resources by ignoring the differences in true delivery costs.

As a basic issue, evaluating procurement bids based on combined generation and delivery costs when there are real differences leads to lower overall costs.

Case 6: CED distorts the market and raises overall costs.

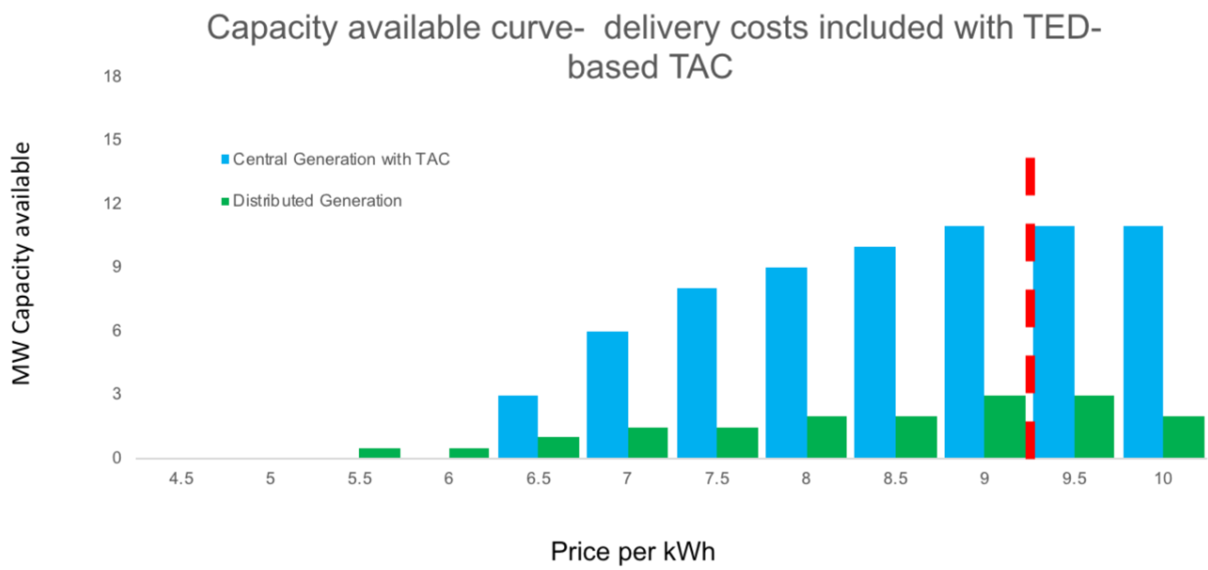
Consider an LSE engaging in a RFO under the CED TAC structure that does not differentiate between delivery costs and therefore is ignored. Here, the LSE is selecting the lowest cost 50 MW of capacity. In this numerical example, the LSE selects bids up to 7 cents/ kWh. Of course, all bids also result in 2 cents/KWh TAC charge, for an average price of 8.125 cents per kWh.



CASE 7: Same distribution of bids under the TED-based TAC.

Here, the parameters are exactly the same as in Case 6, except under a TED-based TAC. Bids for transmission-connected resources face different TAC charges so the costs of delivery are included in bid evaluation. Thus, the TAC charges are added into the generation price to compare all-in total costs. Here, the clearing price is therefore higher at

9 cents/kWh. however, the total average cost is lower than in the first case at 7.8 cents/kWH.



As a result, not only does the LSE face lower overall costs, but also procures roughly double the amount of DG.

Thus, accounting for the differential costs of transmission delivery between local and remote resources results in both lower costs and increased procurement of DG.

c. CED-based TAC therefore results in over-procurement of remote generation results in over-investment in transmission.

As a theoretical matter, where DG is undervalued, the deferral or avoidance value of DG cannot be realized. Without deferral and avoidance of infrastructure investment, more investment will be made than is optimal. The Market Surveillance Committee model presented by Prof. Ben Hobbs, confirmed that to the extent that DG can "displace bulk generation, then ... the result would be enough savings in network costs to yield a net cost savings from the proposed [TED-based] TAC system."[4] Since it is abundantly clear that

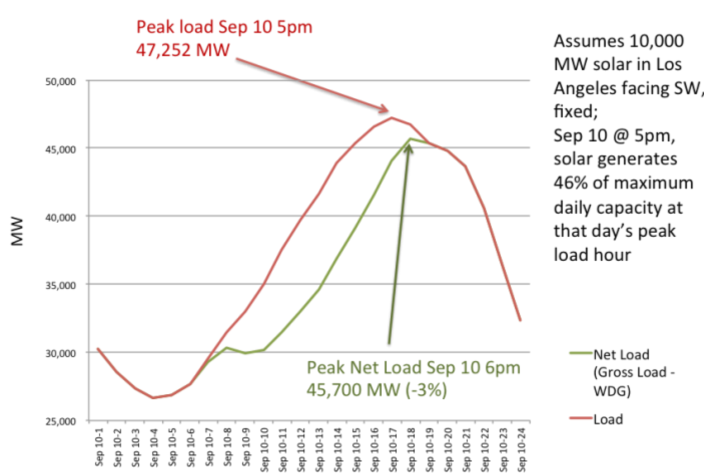
[4] B. Hobbs, Some Simple Economics of TAC Allocation to Distributed Front-of-Meter Generation, MEMO (DRAFT)
at

neither distribution costs nor transmission costs are fixed, this is the only modelled case that is relevant to the analysis of the TAC.

Clearly, a fundamental point is that DG can and does displace transmission investment and has since the beginning of CAISO. As noted above, CAISO's own transmission process plans for transmission load only once customer load met by DG has been subtracted. More critically, DG has the capability to replace transmission investment in each of the four primary drivers of transmission investment:

1. Thermal capacity, or increases in peak demand
2. Policy-driven goals
3. Economic drivers (to access cheaper energy)
4. Reliability needs

Peak Demand: DG's contribution in reducing peak demand has already reduced costs associated with the existing transmission system, and continues to do so. At system peak, every MW generated on the distribution system that meets local demand directly reduces peak demand on the transmissions system. As demonstrated in our model of the impact of moving 10,000 MW of solar to the distribution grid would reduce peak transmission flows and move these later (See Figure 5). With the deployment of co-located storage, DG increasingly become capable of addressing peaks outside of the solar window.



Ultimately peak transmission capacity is determined entirely by the peak transmission energy flow from remote generation. Anything that reduces the need for LSEs to procure remote resources to meet local load will reduce peak transmission flows, whether or not that peak load is reduced by energy efficiency, demand response, customer load shifting, energy storage, or distributed generation. Thus, any of these load modifiers will reduce the need for transmission investment, as CAISO recognizes in the planning process. However, of these load modifiers, DG is the only one that is subject to TAC charges.

These reductions are not only theoretical, but California has seen real reductions in peak demand from DG and cancelled or deferred projects because of DG. For example, in PG&E's 2015 Distribution Resources Planning (DRP) report, the utility estimated that DER reduced their 2014 annual peak load by 2,742 MW (13.5%), with local PV generation being the second largest component. This rose to 3,695 MW by 2016 (17.3%), of which generation accounted for 1,273 MW after adjusting for effective capacity during the peak hour.

Policy goals: As stakeholders have noted, a substantial portion of transmission investment has been driven by RPS and the need to connect to renewable generation. However, since DG PV contributes to RPS targets every bit as much as remote solar, DG offsets RPS-related investment at least on a 1:1 basis. For example, ReMAT program procurement of 750 MW of wholesale DG is RPS-eligible and is already included in IOU RPS procurement planning. This reduced the need throughout the past decade for new remote renewable generation and any transmission that would have otherwise been planned and built to access new resources required to meet RPS targets. DG resources have not been more heavily utilized in the RPS in part because the TAC distorts the market by failing to correctly attribute transmission costs to the remote generation that justified those investments in the first place.

Economic drivers: DG reduces transmission costs associated with economic drivers based on its correlated generation profile and location. DG reduces economic drivers in three distinct ways. First, DG can be the most economically advantageous resources, but ones that do not need expensive transmission to access. This means DG supplants bulk generation directly. Second, DG frees up transmission capacity, so that the benefits of the existing transmission grid can flow to other LSEs without needing to build more infrastructure. DG frees up transmission capacity, so that other economically advantageous transmission-connected projects can be accessed without substantial additional investment. Third, DG can reduce the marginal costs of energy by reducing congestion and line losses. Taken together, these factors reduce both past need for economic-driven investment and free current capacity to meet emerging needs and economic opportunity.

Reliability drivers: DG has proven reductions in transmission costs associated with reliability needs as well.

Varied DER can address local reliability needs while simultaneously avoiding new transmission investment. For example, in one report, researchers confirmed that battery energy storage systems could provide frequency and voltage stability services (along with other energy services) to the grid. CAISO's own research has demonstrated that batteries can replace the need for transmission lines into the Moorpark subarea. If designed as co-located solar and storage, DG represents a direct alternative to building transmission for reliability needs. Furthermore, real world deployments in geographically bounded areas, such as Kaua'i, have demonstrated that photovoltaic solar plus storage can cost effectively meet the full suite of reliability needs.

d. *How much transmission spending can be avoided is an empirical question.*

The Clean Coalition has provided data and direct examples to demonstrate that DG can, does, and has reduced transmission investments. While other stakeholders have conjectured that this is not accurate, no solid evidence has been presented to support these statements.

Ultimately, this is a critical question that must be resolved, and determining how much DG can avoid or control transmission investment requires empirical analysis. Evidence from CAISO and SDG&E have suggested that peak-driven investment alone accounts for 25% to 40% of transmission investment. Adding in investment from the other drivers suggests that a majority of transmission investment is deferrable.

Resolving this fundamental question can be addressed in part by looking at new investment from the four drivers relative to the total TRR. Alternatively, CAISO could conduct a sensitivity analysis by running the TPP models under different projected levels of DG in order to evaluate the relationship between increased DG and transmission needs.

It is tremendously important that if CAISO is going to make decisions that could cost Californians tens of billions of dollars that it do so based upon substantial evidence. As CAISO itself said in the Straw Proposal, "Linkages between policies and transmission cost incurrence and benefit should be sufficiently demonstrated." We entirely agree, but point out that CAISO has not as yet developed a body of evidence with which to evaluate what proportion of transmission investment is avoidable, and how that relates to the level of DG that may come online.

4. **Regardless of the basis for analyzing the TAC structure, TED is clearly superior to CED across most realistic or likely scenarios.**

TED-based TAC structures perform better on matching historical costs to customers who drove those costs, on matching cost allocation to the current beneficiaries, and would drive better incentives for a clean energy economy. No matter which of the three frameworks is adopted, the TED-based TAC is simply a better rate design.

IV. Ratemaking Principles emphasize that costs should follow benefits

a. FERC Order No. 1000 clearly gives preference to allocating costs based on the beneficiaries of the transmission system, not the historical customer demand.

CAISO's emphasis on evaluating the cost allocation primarily on the basis of past cost causation without consideration of the present beneficiaries runs squarely counter to the direction of FERC, current practice, and CAISO's own statements.

In Order no. 1000, FERC emphasizes that cost causation turns on the analysis of the benefits of transmission infrastructure and not on only 'who the system was built for." Without the focus on beneficiaries, "cost allocation methods used by public utility transmission providers may fail to account for the benefits associated with new transmission facilities and, thus, result in rates that are not just and reasonable or are unduly discriminatory or preferential."[5] In rejecting a purely backward-looking approach based on transmission planning, FERC "affirmatively require[es] costs of transmission facilities to be allocated to beneficiaries…" in FERC Order no. 1000.[6,7] Thus, "the cost causation principle provides that costs should be allocated to those who cause them to be incurred and those that otherwise benefit from them."[8] Cost allocation should "ensure that beneficiaries of service provided by specific transmission facilities bear the costs of those benefits regardless of their contractual relationship with the owner of those transmission facilities."[9]

The "beneficiaries pay" principle is particularly important to developing a defensible tariff because the failure to assign costs to current beneficiaries risks creating free rider issues. Thus, FERC expressly directed that transmission cost allocation follow the beneficiaries, whether or not they are planned for, because otherwise "the Commission could not address free rider problems associated with new transmission investment" [10].

Courts have similarly endorsed "[FERC's] system-wide benefits analysis [as meeting] the requirements of the cost causation principle, that is, to compare 'the costs assessed against a party to the burdens imposed or benefits drawn by that party.'"[11] Thus, FERC's position that costs should be assigned to the beneficiaries or users of transmission assets is exceptionally well supported.

Furthermore, FERC acknowledges that these beneficiaries can and do change over time. In fact, the beneficiaries include those customers realizing a benefit "either at present or in a likely future scenario,"[12] which implies that benefits are not expected to remain fixed or for cost allocation to be set in stone at the time of project approval. Indeed, in

---

[5] FERC Order no. 1000, Paragraph 495.
[6] FERC Order no. 1000, paragraph 507.
[7] We note that in the Issue Paper, CAISO cited to a 1994 policy statement, which has been superseded by FERC Order no. 890, which in turn has been superseded by FERC Order no. 1000. Furthermore, the straw proposal cites a FERC decision from 1997 as being consistent with FERC Order No. 1000, even though FERC Order No. 1000 was not issued until
[8] FERC Order no 1000, Paragraph 535.
[9] FERC Order no. 1000, Paragraph 539.
[10] FERC Order no 1000, Paragraph 535.
[11] FERC Order No. 1000, paragraph 508, citing *Midwest ISO Transmission Owners v. FERC,* 373 F.3d 1361. (D.C. Cir. 2004).
[12] FERC Order No. 1000, Paragraph 544.

crafting the rule, FERC was well aware that careful evaluation of the beneficiaries was necessary, "given that the benefits and beneficiaries of a particular project may change over time, particularly in the case of a large project that provides regional and interregional benefits."[13]

b. *Cost allocation should also consider the incentives and efficiencies created by the tariff.*

CAISO is also remiss in rejecting consideration of the impacts of its tariff structure on California ratepayers based on a legally misguided notion that the tariff should be primarily focused on "fair" cost allocation, while giving short shrift to the economic inefficiencies CAISO's tariff introduces into the energy market.

First, economic efficiency is a key ratemaking principle under FERC's 1994 Policy Statement, as recognized in the issue paper. The Bonbright principles also recommend that rate design "discouraging wasteful use of service while promoting all justified types and amounts of use…." In fact, CAISO recognizes that "[i]n the Transmission Pricing Policy Statement, the Commission stated that this means that transmission pricing should promote good decision-making and foster efficient expansion of transmission capacity, efficient location of new generation and load, efficient use of existing transmission facilities, including the efficient allocation of constrained capacity through appropriate market clearing mechanisms, and efficient dispatch of existing generation."[14]

c. *Cost allocation balances theoretical precision with practical efficacy for the parties subject to the charges*

Finally, a lack of perfect alignment with all theoretical cost drivers or the existence of potential corner cases is not a justification for retaining an existing structure that performs worse under virtually all reasonably foreseeable possibilities. FERC emphasizes that rate-making does not require exacting precision. "[W]hile the cost causation principle requires that the costs allocated to a beneficiary be at least roughly commensurate with the benefits

[13] FERC Order No. 100, paragraph 509.
[14] CAISO Issue paper, FN 7.

that are expected to accrue to it, the D.C. Circuit has explained that cost causation 'does not require exacting precision in a ratemaking agency's allocation decisions.'"[15]
Choosing between alternative rate structures is not although there may be corner cases that the tariff does not perfectly capture, this is not a justification for retaining a worse rate design. In the stakeholder process, objections that particular instances are not perfectly captured have been used by stakeholders to suggest that no reform should be conducted. However, ultimately where one design is better under all or most circumstances, that design should be chosen.

V. Rate Design must be based on substantial evidence

At this stage, we urge CAISO to give credence only to statements and positions that have substantial evidentiary support. It is an axiom of California administrative decision-making that the agency must support findings with substantial evidence and those findings must support the conclusion reached. In order to meet this standard, decision makers "must set forth findings to bridge the analytic gap between the raw evidence and ultimate decision or order."[16] Furthermore, generally such findings are to be "supported by substantial evidence in light of the whole record."[17]

Although CAISO has given substantial weight to "disagreements," conjecture, or assertions in this process, it is fundamentally important to reasoned decision-making that CAISO rely on substantial evidence, which means ""more than a mere scintilla. It means such relevant evidence as a reasonable mind might accept as adequate to support a conclusion."[18] In at least one body of California administrative law, [a]rgument, speculation, unsubstantiated opinion or narrative, [or] evidence which is clearly erroneous or inaccurate... does not constitute substantial evidence."[19] While these standards may not directly apply here, the principle that decision-making should rely on facts to support conclusions which in turn support the ultimate decision.

---

[15] FERC Order No. 1000, Paragraph 504, citing MISO Transmission Owners, 373 F.3d 1361 at 1371.
[16] *Topanga Assn. for a Scenic Comm'ty v. County of Los Angeles* (1974) 11 Cal. 3d 506, 514.
[17] Cal. Code Civ. Proc. § 1094.5(c)
[18] *Richardson v. Perales*, 402 U.S. 389, 401 (1971)
[19] 14 Cal. Code Regs. § 15384

a. Distributed Generation can and does displace bulk generation, leading to reduced need for transmission.

The actual factual evidence presented in this proceeding, both in terms of modeling and actual evidence shows that distributed generation can and does displace bulk generation and reduce, defer, or eliminate the need for transmission. The Clean Coalition has presented analyses of how DG displaces bulk generation to reduce the need for transmission and provided several examples of DG eliminating the need for specific transmission projects which have been actual cancelled. Furthermore, CAISO and other stakeholders have conceded that the CAISO's own Transmission Planning Process is predicated on the fact that DG reduces the need for transmission planning. In CAISO's own TPP, the amount of load planned for is reduced by the amount of DG available. At this stage, although stakeholders have "disagreed" and stated their opinion that DG may not reduce the need for transmission investment or may do so in complex ways, none have yet adduced evidence showing where increases in DG have not reduced peak flows or met other needs that drive investment. The Clean Coalition has produced extensive modeling to show the relative scale of avoided transmission and provided open access to the model for others to improve or disprove. Yet, given both ample time to produce evidence and to develop better models and analyses, no other stakeholders have done so. Therefore, we suggest that a single well-supported position should have greater credence than a dozen unsubstantiated and unsupported views.

b. Distributed Generation will be stimulated by Transmission Charges that reflect differences in real delivery costs.

Similarly, The Clean Coalition has produced evidence to demonstrate how changes in the procurement would allow for efficient procurement and secure benefits resulting from increased DG deployment. Although the precise degree of response depends on many factors, the mechanism and process of stimulation has been demonstrated.

In particular, the stakeholders with familiarity with IOU procurement have agreed that the Least Cost Best Fit methodology is already structured to take into account differences in transmission charges if there were any. While LCBF accounts for differences in the necessary inter-tie costs from generator to transmission grid, the wider implications for cost growth are not. This alone would at least promote such procurement as the IOUs engage in to place DG and remote generation on equal footing.

c. *Changes to CAISO's TAC structure are necessary, but not entirely sufficient to control TAC cost growth.*

The change in the point of measurement should be made, even if only some of the procurement in the state would be immediately affected. CAISO argues that because a change in the TAC tariff is not sufficient to change all procurement in the state, it should not be undertaken at all.

However, as a regulatory matter it is important that CAISO take this step for two reasons. First, for IOUs using the LCBF methodology, the change in the HV-TAC would propagate into existing procurement methodologies. Thus, contrary to CAISO's assertions, other actions would be needed to ensure that the price signals reach the IOU procurement offices.

Second, for those LSEs that do not use LCBF or fall squarely within the utility commission's jurisdiction, it is critical to ensure that they receive some compensation for their efforts. However, without the funding that this proposal would free up, there is no clear source of the extra funds needed to fund this program. Given the regulatory challenges in regulating CCA procurement directly, it is critical to provide a market incentive to reward LSEs for the avoided costs associated with DG procurement. Without the reform of TAC at the CAISO, making the necessary changes in the IOU tariffs and providing a financial mechanism becomes exceptionally difficult, while having CAISO either adopt a change in the TAC or do so provisionally conditional on corresponding changes in the IOU tariffs would make those corresponding changes vastly more likely to occur. Thus, if CAISO agrees in principle that the TED-based TAC is superior, it is critical that CAISO take some concrete action to signal that agreement and to prevent CAISO from having to revise the TAC again in future if the IOUs make the corresponding changes with CAISO reforms. Setting CAISO up to have to engage in a fourth stakeholder process to revise TAC again in the coming months would be a dubious use of staff time.

VI. Outstanding Factual issues

Throughout this stakeholder process several critical factual questions have been raised that absolutely need to be addressed before findings supported by substantial evidence can be made.

1) <u>How much transmission investment can be deferred through increased DG deployment?</u>

The Clean Coalition presented extensive studies of how DG can reduce transmission investment over the next 20 years, but various stakeholders have questioned those results without supplying any evidence in rebuttal. We urge CAISO to do a study using the TPP methodologies to evaluate a) how much additional transmission would have been required over the last 20 years if there had been no DG deployed in the state and b) how much transmission spending would be reduced under high, medium and low levels of customer load growth and high, medium and low levels of DG deployment. This level of modeling can provide critical insight into this fundament factual question.

2) <u>How are various ancillary services compensated and passed on to ratepayers?</u>

CAISO has raised issues of the various services provided “by the transmission grid” but several of those services are actually separately compensated. For example, frequency regulation is subject to a separate market, and other services such as voltage support are folded into other mechanisms. Providing clarity to stakeholders regarding how these services are currently compensated will give key insight into which services are to be compensated under TAC.

3) <u>How much is spent in total on ancillary services relative to total spending on energy generation?</u>

CAISO has raised issues of the various services provided “by the transmission grid” but developed no quantitative or qualitative estimate of how important those services are relative to the value of energy delivery. It would appear that while those values are not zero, neither are they a substantial fraction of the total value of services delivered by the grid.

4) <u>What proportion of transmission projects have been driven by various market drivers?</u>

The role of DG in avoiding growth from all four cited drivers is clear, but better data regarding the relative importance of each driver would be valuable.

5) <u>What is the proportion of the TRR represents transmission build, operations and maintenance, or other components of the TAC?</u>

These data would shed additional light on how much transmission spending is fixed and how much is variable and potentially responsive to changes in energy flows.

6) <u>What are the actual projections of customer load growth and transmission load growth from various sources and under various conditions?</u>

Several stakeholders have opined that transmission load will not be growing in future, but without any supporting evidence of analysis to bolster that claim. Given that there are various factors such as EV growth and fuel switching that could drive substantial growth in customer and transmission load growth, it is important to get clarity on what projections exist and CAISO considers reliable. Since this is a critical question to resolve to craft a rate design that can meet the needs of California customers, it would be remiss without some clarity on these projections.

VII. Revisions to the proposal to use the TED-based TAC.

Through various conversations with stakeholders and CAISO staff, several critical additional elements could and perhaps should be incorporated into a change of location of measuring transmission use as TED. These are:

1) Incorporate a seniority-based backstop provision to allocate stranded assets. As discussed above, in the profoundly unlikely event that freed transmission assets can find no users, assign the costs to those for whom the investment was intended. This mechanism would essentially allocate declines in total system load to LSEs or UDCs

depending on the amount of avoided cost they'd engaged in in order to ensure that the costs of stranded assets cannot be avoided through aggressive DG deployment. We anticipate that with population growth, fuel switching, and EVs this is extremely unlikely. However, it would be prudent to incorporate a backstop mechanism in case load declines occur.

2) Incorporate a non-bypassable per customer component of the TAC as a hybrid charge. This would reflect the benefits that are unrealized through use of the transmission grid. This proportion can be estimated either through standard options pricing methods or by comparing the market value of services relative to all electricity spending, although given the relative spending on energy delivery services relative to all ancillary services, the bulk of TAC would be charged as proportional to transmission use. HOwever, this would ensure that even a UDC or LSE that opts for a 100% DG portfolio would not see its TAC go entirely to zero to reflect the ongoing reliance on the transmission grid.

VIII. Conclusions

Ultimately, the TED-based TAC remains the better rate design based on FERC Order No. 1000 principles, regardless of the basis of analysis. However, as various stakeholders have identified, there some refinements of the basic design to account for non-use proportional benefits and the potential for stranded assets that should be included. We look forward to continuing the factual and analytic process of establishing a robust and well-founded approach.