Stakeholder Comments Template

Transmission Access Charge Options Issue Paper

Submitted by	Company	Date Submitted
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The Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of distributed energy resources ("DER")—such as local renewables, advanced inverters, demand response, and energy storage—and we establish market mechanisms that realize the full potential of integrating these solutions. The Clean Coalition also collaborates with utilities and municipalities to create near-term deployment opportunities that prove the technical and financial viability of local renewables and other DER.

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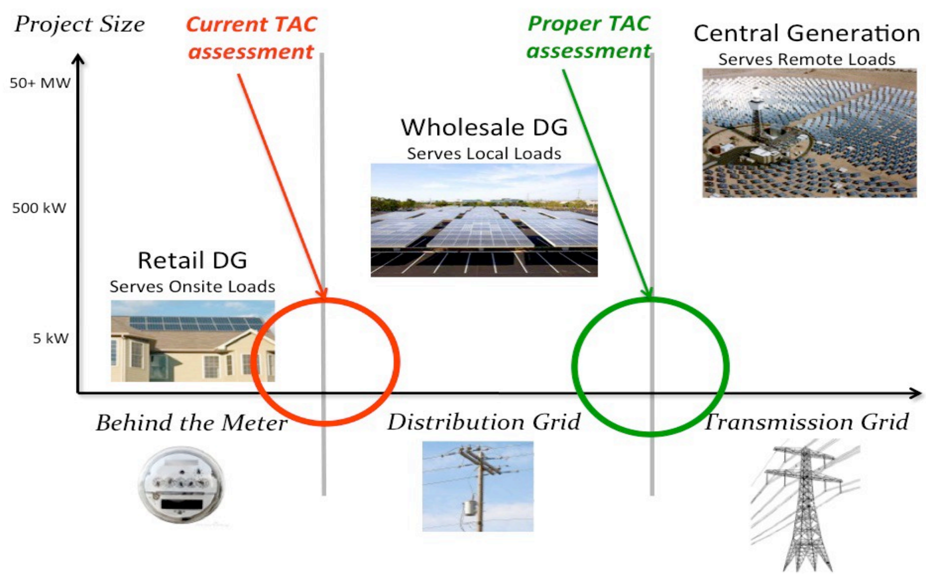
Responses to Questions

Additional background information appended to bottom of this stakeholder template in support of the Clean Coalition's responses to specific questions.

1. One theme emphasized in the issue paper and in FERC orders is the importance of aligning transmission cost allocation with the distribution of benefits. Please offer your suggestions for how best to achieve good cost-benefit alignment and explain the reasoning for your suggestions.

Regardless of how we calculate the distribution of benefits from transmission services - whether benefits equally shared ("postage stamp rate") or are differentially shared by sub-regions ("license plate rate"), a Transmission Access Charge (TAC) is assessed in proportion to load on the assumption that load is an reasonable basis to allocate costs associated with the benefits received. However, *this raises an important question of how to calculate the load upon which the benefits and costs are apportioned*. With current combined HV and LV TAC rates at $17.46/MWh in PG&E territory, and a 20 year levelized impact of approximately $30/MWh on loads subject to TAC, this has very significant consequences for the siting and development of renewable generation and the demand for transmission.

Under current CAISO tariff language, TACs are assessed against most utilities based on the gross customer load of that utility instead of the portion of load served by transmission resources (i.e., as measured at the transmission interface). This has the impact of assessing transmission costs on loads served by local distributed renewable resources without the use of the transmission system as if that energy were utilizing the transmission system, as illustrated below.



Determining the optimal mix of grid infrastructure and other resources for ratepayers requires transparency in costs and benefits. As a potent economic signal, the allocation of TAC should reflect these costs and benefits. As a result of the current misalignment of TAC assessment, local renewable generation is not credited with the full avoided-cost value it can offer, development of local renewables is depressed, and demand for addition transmission is exacerbated.

This was not a factor 15 years ago when nearly all load was served via transmission, but as the state pursues aggressive renewable generation targets, and is developing comprehensive new Distribution Resource Planning and investment - based upon net ratepayer benefit calculations - correctly aligning TAC assessments with transmission usage will have a major impact on both planning and procurement.

In the Issue Paper, CAISO staff note that the consideration of changes to the TAC structure is "driven mainly by a concern with how the regional rate might shift cost allocation between the load served by the ISO prior to a new PTO joining and the load that is served by the prospective new PTO once it becomes part of the ISO's regional service territory. For example, if the new PTO places a large amount of costly high-voltage transmission under ISO operational control, the ISO's existing customers likely would be concerned about a significant increase in the regional TAC rate, whereas if the new PTO's system has relatively low high-voltage system costs and new infrastructure investment, its own existing customers would have the analogous concern." This same concern applies with regard to investments in non-transmission alternatives (NTAs) by a PTO or any LSE subject to TAC rates, including the development of local distributed resources.

When allocating transmission costs between Service Territories and among the Load Serving Entities (LSEs) within each service territory, a factor that is appropriate to consider is the proportion of each LSEs load that is served through transmission.

In its current application of TAC (postage stamp rates and license plate rates) CAISO recognizes that benefits and costs are shared in proportion to load. However, under current practice, load is defined in such a way as to fail to account for the portion of load served locally within the distribution systems without reliance upon transmission capacity. There is a significant difference between a LSE that meets a substantial portion of its load through local resources in comparison to and LSE whose load is served entirely through transmission facilities.

The failure to account for load served by local non-transmission resources in current TAC assessment discourages development of distributed generation and other NTA. The ISO should consider this factor when developing the initial straw proposal and subsequent proposals later in this initiative.

The ISO has suggested consideration of an approach which would "break down the HV category by type of transmission project – reliability, policy or economic – and then assess which areas of the expanded ISO territory receive the benefits of each facility and allocate costs accordingly."

It is important to account for cost causation associated with the proportional level of demand each PTO places upon the ISO system. With the rapid development of distributed resources and their potential to reduce demand for transmission services, *the ISO's basis for TAC assessment upon each PTO should acknowledge and reflect the degree to which they have reduced their demand on transmission*. Doing so will both create appropriate economic signals to value distribution resources and conform with the FERC principles of allocating costs commensurate with benefits and not involuntarily allocating costs to those who do not benefit.

For example, Community Choice Aggregations and subscribers to California's Green Tariff Shared Renewables may select various local Community Renewable products that reduce or avoid use of transmission, yet are involuntarily allocated TAC costs by their PTO distribution operator. CCAs and GTSR programs are intended to allow indifference in cost to existing utility customers not participating in the CCA or GTSR; however, under current TAC allocation, a difference in proportional reliance upon local or remote resources transfers costs from one group to the other. Only by recognition in TAC of the PTO's proportional reliance on transmission can the PTO receive the appropriate adjustments in its TAC obligation and assign these to the LSEs and customer categories within its territory, avoiding cost transfers and preserving the principle of indifference. This same factor significantly impacts PTOs with NEM customers to the extent that Gross Load is not reduced by energy transferred to the distribution grid by these systems and subsequently reflected in the gross metered load of customers. As NEM is replaced by a successor tariff, the energy sent to the grid by these customers during any hour will be subject to TAC, reducing its value to the PTO and in turn to the customer receiving credit for their excess hourly production.

An approach more appropriately assessing TAC is to meter load at the point of transmission voltage step-down to distribution, and potentially between higher voltage and lower voltage transmission lines, as is currently allowed for metered sub-systems such as municipal utilities operating within a PTO service area. This provides a consistent basis for sharing transmission costs (assessment and allocation of TAC) while allowing different jurisdictions to apply their own basis for regional costs (LVTAC)

2. <u>Please comment on the factors the ISO has identified in section 5 of the issue paper as considerations for possible changes to the high-voltage TAC structure. Which factors do you consider most important and why? Identify any other factors you think should be considered and explain why.</u>

The eight factors identified are all important considerations, especially when the expansion of the ISO incorporates established systems and extends into other regulatory jurisdictions.

As discussed in response to questions 1, 4, & 7, the issue of differential benefits across LSEs is vitally important and the focus of our comments, and this applies also to the issues of project purpose and geographic scope.

The question of PTO use of transmission facilities may be a subset of the benefit criteria, however we believe it warrants consideration as a distinct additional factor – beyond the question of which zones or sub-regions benefit from existing transmission investment or new projects, is the question of **how that benefit is measured**.

Current practice relies upon the measurement of a PTOs "Gross Load" at the customer meter to apportion costs between utilities. This approach fails to reflect differences in ISO transmission cost causation associated with each utility's actual demand on, or use of, the transmission system. To the extent that costs are allocated in proportion to load, the measurement of load should occur at the interface between the utility and the ISO, i.e. at the substation. The current practice of assigning TAC based on a PTO's aggregate customer metered load treats the portion of these loads served by local resources as if that load was entirely dependent upon transmission service, ignoring the role of distributed energy resources (DER) in meeting customer load. To our knowledge, even PTO utility procured distribution resources that meet ISO local capacity requirements, and that do not back-feed into the transmission system, still do not currently offset any portion of that utility's transmission costs as reflected in TAC assessments.

3. <u>The examples in section 7 illustrate the idea of using a simple voltage-level criterion for deciding which facilities would be paid for by which sub-regions of the combined BAA. Please comment on the merits of the voltage-based approach and explain the reasoning for your comments.</u>

No comment at this time

4. <u>Please comment on the merits of using the type of transmission facility – reliability, economic, or public policy – as a criterion for cost allocation, and explain the reasoning for your comments.</u>

The different purposes of under which transmission investments are made may reflect distinctly different benefits and beneficiaries. For example, economically driven projects may reduce costs evenly across LSEs, while reliability projects may be driven by load growth that is specific to one or more sub-regions, in which case there is an argument in favor of allocating costs proportional to cost causation – a utility effectively employing energy efficiency measures to limit load growth should not also limit load growth should not also see its TAC payments subsidize a separate utility's transmission focused approach to addressing demand. This will be especially important if the ISO expands to include utilities in other states operating under business models benefiting from load growth.

Public policy is a major factor for the ISO, with 76% of planned transmission investment driven by California's 33% Renewable Portfolio Standard. SB 350 will raise the contribution of renewables to 50% by 2030 and will result in major additional transmission investment if current cost allocation practices are not reformed. Under a regional expansion, utilities joining the ISO from regions beyond California may not benefit from state specific public policy driven investments in proportion to their load. Likewise, utilities within the existing ISO may take different strategies in meeting RPS or other policy mandates, and may differentially benefit from investments. For example, a utility or CCA may prefer to procure more local distributed resources and invest in distribution level upgrades to support this; however, development of these resources will be discouraged if the procuring agencies will also have to pay for the choice of others to rely upon remote transmission dependent resources. Spreading the costs of increased reliance on transmission resources across all PTOs without regard to the division of benefits invites excess use of these resources, consuming available capacity and creating an artificial demand for additional transmission capacity, akin to the classic 'tragedy of the commons'.

As the new Distribution Resource Plans rely heavily upon net ratepayer benefits determinations, the ratepayer benefits achieved by local resources will be greatly reduced if development of local capacity is not reflected in reduced TAC assessments.

5. Please comment on the merits of using the in-service date as a criterion for cost allocation; e.g., whether and how cost allocation should differ for transmission facilities that are in service at the time a new PTO joins versus transmission facilities that are energized after a new PTO joins.

No comment at this time

6. Please comment on using the planning process as a criterion for cost allocation; i.e., whether and how cost allocation should differ for transmission facilities that are approved under a comprehensive planning process that includes the existing ISO PTOs as well as a new PTO, versus transmission facilities that were approved under separate planning processes.

No comment at this time

7. The examples in section 7 illustrate the idea of using two "sub-regional" TAC rates that apply, respectively, to the existing ISO BAA and to a new PTO's service territory. Please comment on the merits of this approach and explain the reasoning for your comments.

The ISO has noted in section 2 (p5) that courts have rejected "postage stamp" rates based on load ratio where there are significant regional differences in the benefits realized by transmission facilities, in line with the cost allocation principles FERC specified in Order 1000. On this basis, it is appropriate to evaluate whether a new PTO's service territory and its associated transmission facilities are substantially distinct from the ISO's existing BAA, and to allocate costs proportional to benefits before dividing by load ratio.

8. Please offer any other comments or suggestions on this initiative.

The Clean Coalition appreciates the opportunity to comment on the Transmission Access Charge Options Issue Paper and looks forward to further engagement to address these topics.

Additional background information is provided below in support of above responses:

Issue: Transmission cost is allocated based on electricity use rather than use of the transmission system

The Low Voltage Access Charge and the High Voltage Access Charge are assessed by CAISO against Transmission Users based on Gross Load. Gross Load is defined in the CAISO tariff to include substantially all load served, as distinct from load served by the transmission system.[1]

The CAISO tariff does exclude from Gross Load served by wheeled power, certain station power load, and certain customer-sited generation.[2] However, these exclusions do not apply to the load served by typical wholesale distributed generation facilities, because such resources are not necessarily customer sited, and generally serve more than two properties. Likewise, energy even temporarily to the grid by net energy metered (NEM) customers is assessed TAC when production is higher than momentary on-site load, because exported NEM energy is consumed by other utility customers with the energy passing through customer meters to serve those loads. Accordingly, such load is included in Gross Load even if none of the energy from the locally-sited generation uses the transmission system. In other words, CAISO's definition of Gross Load allocates the cost of transmission investments based on total *electricity consumption* in a Transmission User's service territory, rather than based on a Transmission User's *usage of the transmission system*. This facet of California's transmission cost allocation scheme is of concern to the Clean Coalition because it partially conceals the benefit of siting generation close to loads, resulting in increased demand for addition transmission resources that may be largely avoidable.

Proposed solution: Allocate TAC based on usage of the transmission system instead of "Gross

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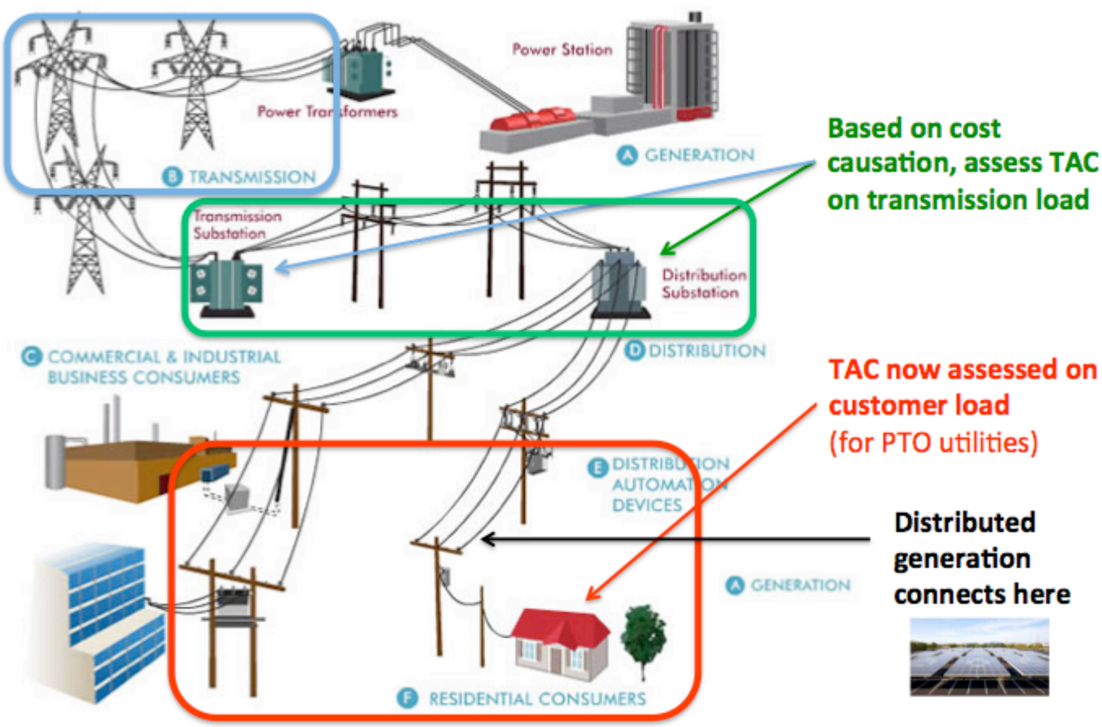
[1] Cal. Indep. Sys. Operator Corp, Fifth Replacement Electronic Tariff, App. A: Master Definition Supplement (June 2015), *available at* https://www.caiso.com/Documents/ConformedTariff_

> [2] Gross Load shall exclude (1) Load with respect to which the Wheeling Access Charge is payable, (2) Load that is exempt from the Access Charge pursuant to Section 4.1, Appendix I of the ISO Tariff,[2] and (3) the portion of the load of an individual retail customer of a Utility Distribution Company, Small Utility Distribution Company or MSS Operator that is served by a Generating Unit that: (a) is located on the customer's site or provides service to the customer's site through over-the-fence arrangements as authorized by Section 218 of the California Public Utilities Code; (b) is a qualifying small power production facility or qualifying cogeneration facility, as those terms are defined in the FERC's regulations implementing Section 201 of the Public Utility Regulatory Policies Act of 1978; and (c) secures Standby Service from the Participating TO under terms approved by a Local Regulatory Authority or FERC, as applicable, or can be curtailed concurrently with an Outage of the Generating Unit serving the Load.

Load"

Clean Coalition proposes that Access Charges be consistently allocated based on load actually served by the transmission system, as measured at the interconnection of the CAISO transmission system with local distribution systems, rather than on total load served within. <u>This approach is already available to Public Utilities that have not entered into PTO agreements with CAISO, and should be extended to all Load Serving Entities</u>. Where appropriate, this approach may also be applied to the high voltage to low voltage transmission substations recognizing a PTO utility's discrete use of resources within the sub-region, as illustrated below.



This adjustment in TAC load assessment will send a significant price signal to the utilities that recognizes avoided transmission load costs and fairly allocates charges to cost contributors. If this proposed policy change is implemented, the resulting increased selection of a wholesale distributed generation over remote generation options will decrease the need for additional transmission capacity, and consequently reduce the future costs for all ratepayers to be recovered through TAC.

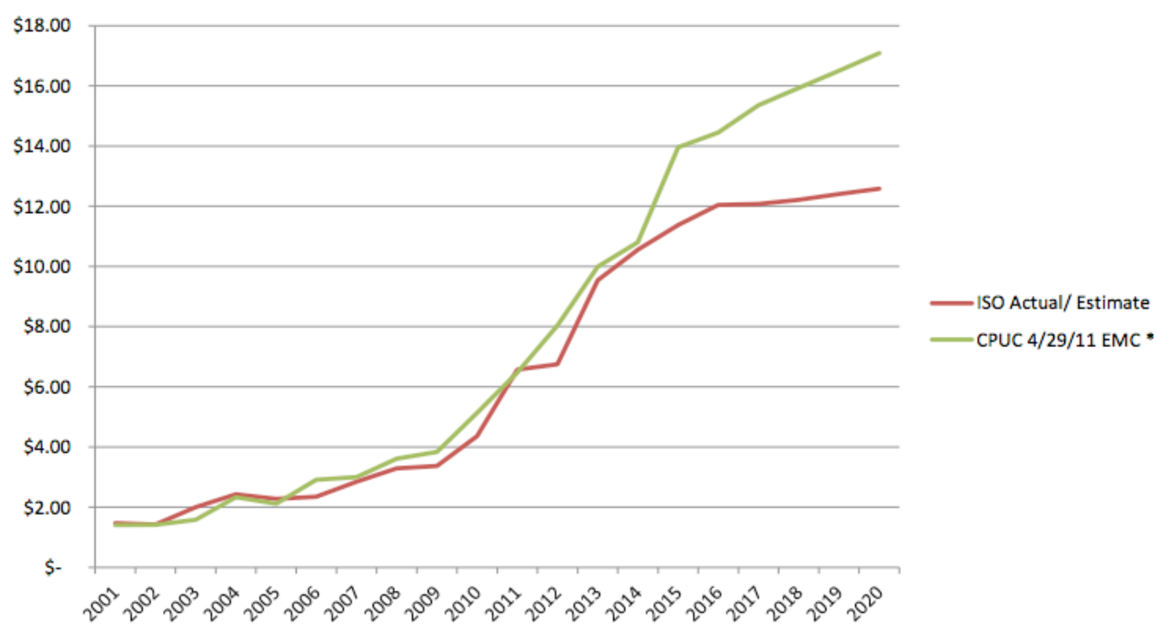
Transmission Access Charges, Current Rates and Trends

Transmission related costs of delivering energy from remote generation are often combined into costs that are charged by the transmission operators. In California, these costs are called Transmission Access Charges.[3] This is a flat "postage stamp" fee for every kWh delivered to the distribution system from the transmission grid. TACs should be avoided on energy that is delivered directly to the distribution system to serve loads on the same substation.

The High Voltage TAC currently is charged at $9.78/MWh and is consistent throughout the CAISO system. The Low Voltage TAC applies to the CAISO operated portion of systems within each individual utility service territory. For PG&E the use rate charged is currently $7.68/MWh, resulting in a total charge of $17.46/MWh (1.75¢/kWh). While the threshold definition of sub-transmission voltage and ISO operation varies between utilities, comparable cost allocation occurs either through ISO charges or internal utility accounting.

TAC rates have increased at an annualized rate exceeding 15% since 2005 as new transmission dependent generation has been approved, and new transmission capacity is far more costly than maintaining existing capacity. CAISO mid value estimates for the rate of increase in TAC charges will be substantially less than the recent trend and prior CPUC estimates, as illustrated below, however these do not take into consideration the SB 350's newly adopted 50% renewable standard for 2030. Utilizing CAISOs current projected average future estimate of 7% nominal escalation (5% real) over the next 20 years, the levelized current value of avoidable TAC charges applicable to a 20 year DG PPA is 3¢/kWh.

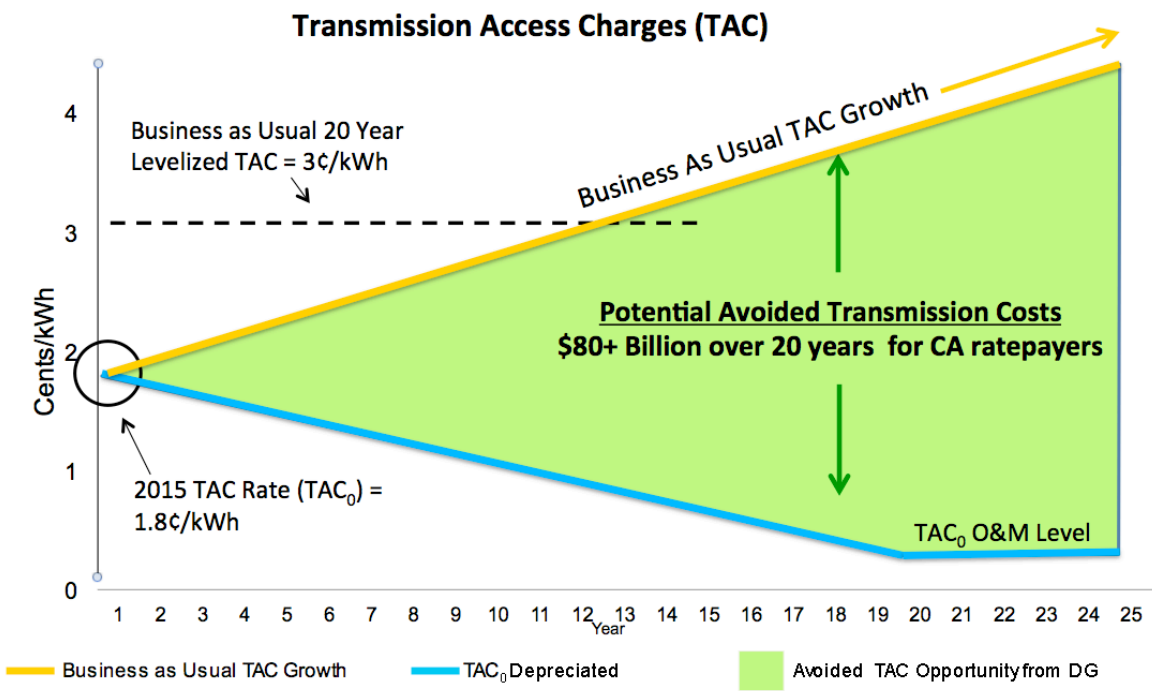
Historical and Projected High Voltage Transmission Access Charges ($/MWh)



Source: CAISO 2012[4]

[3] Cal. Indep. Sys. Operator Corp, Fifth Replacement Electronic Tariff § 26.1 (June 2015), *available at* https://www.caiso.com/Documents/ConformedTariff_Jun12_2015.pdf.

Deploying distributed generation projects that displace transmission sourced energy during peak demand periods avoids the need to increase transmission capacity, which allows existing transmission investments to depreciate and preempts future investments in transmission—both of which reduce future TAC rates, as reflected in the diagram below.



Source: Clean Coalition 2015

The orange "Business as Usual" line represents the expected growth in TACs as more investment is made in the transmission system to accommodate additional remote generation. The blue line represents the decrease in TACs that is possible if that net new additional remote generation was entirely replaced with distributed resources. The down ramp is based on a 40-year average depreciation schedule for TACs-related assets like transmission lines. Thus, the green wedge represents the potential cost savings achieved with distributed resources and continued operation of existing transmission capacity.

Reduced demand on transmission will reduce or defer the need for additional investment to expand transmission capacity, slowing the growth in TAC rates that is driven by the need to recoup new investment costs. Reducing the need for new investment in transmission will reduce charges across the board for all energy utilizing the system.

[4] http://www.caiso.com/Documents/BriefingLong-TermForecastTransmissionAccessCharge-Memo-Nov2012.pdf.