Stakeholder Comments Template

Submitted by	Company	Date Submitted
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Please use this template to provide your written comments on the stakeholder initiative:

"Review Transmission Access Charge Structure"

Submit comments to InitiativeComments@CAISO.com

Comments are due July 26, 2017 by 5:00pm

The Issue Paper posted on June 30, 2017 and the presentations discussed during the July 12, 2017 stakeholder meeting can be found on http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx.

Please use this template to provide your written comments on the issue paper topics listed below and any additional comments that you wish to provide.

1. Suggested modifications or additions to proposed scope of initiative.

The issue paper proposed two main topics for the scope of this initiative. If you want to suggest modifications or additions to the proposed scope, please explain how your proposed changes would fit with and be supportive of the two main topics.

Comments:

CALSEIA generally agrees that the two main topics presented in the paper regarding TAC structure issues are appropriate for the scope of the initiative, but we recommend that the first issue should be re-framed as follows: "Whether there is sufficient public policy justification to continue the practice of collecting transmission charges from LSEs on energy that has been generated and consumed without travelling over the transmission system."

For the most part, CAISO's current method of TAC assessment is based on usage of the transmission system, and CAISO does not attempt to collect TAC charges on energy efficiency, conservation, or other means by which customers may reduce reliance on the transmission grid. Distributed generation that uses the distribution system, but not the transmission system, appears to be the exception to this principle, and there does not appear to be any rationale to support it. Thus, the focus of the first TAC structural issue should be whether any such rationale exists.

CALSEIA agrees that it is appropriate to evaluate the second TAC structure issue – whether it is appropriate to use instantaneous demand instead of or in addition to energy consumption in assessment of and collection of TAC charges. In addressing this question, it would be helpful to expand the scope of the initiative to determine the relative contributions of load and instantaneous demand at the transmission/distribution interface on transmission investment. Such an evaluation could use regression analysis to analyze recent data on load, demand and transmission investment.

Furthermore, we suggest that the scope should be streamlined to remove the questions in Section 5.3 that seek to specifically quantify the impact of DERs on transmission costs, since:

1) Empirical evidence already exists showing that distributed resources can defer or replace the need for new transmission investments, saving ratepayers hundreds of millions of dollars;
2) The CPUC already has a process underway to determine a specific avoided transmission cost value for DERs, so a separate CAISO initiative seeking to answer the same question is duplicative and wasteful of parties' scarce resources. CAISO should coordinate with the CPUC process rather than conducting a separate one that risks arriving at a contradictory conclusion;
3) Using avoided transmission cost of DERs as a means to determine the TAC point of collection is not a useful exercise, because different DERs (including solar PV, storage, combined heat and power, fuel cells, etc.) will have different transmission avoided cost values, and those values will change depending on penetration levels and location. By contrast, TAC assessment is a "one-size-fits-all" means of assigning value that cannot account for the wide degree of variation in transmission avoided cost.
4) As mentioned in Section 3.3.1, "Courts have not required FERC to allocate costs with exact precision," so it is not necessary for CAISO to arrive at an exact value for transmission avoided cost of DERs in order to re-configure how transmission charges are assessed and collected. All that is necessary is a general recognition that DERs can

reduce the need for transmission investment in order to apply sound ratemaking principles that allocate resources efficiently.

To be clear, CALSEIA is not suggesting that the avoided transmission cost of DERs should not be evaluated at all. Indeed, CALSEIA is an active participant in the CPUC's Locational Net Benefits Analysis Working Group, which is addressing this very question. CALSEIA simply requests that CAISO consolidate its efforts on this question with the work that is ongoing at the CPUC to streamline the work of the parties who are interested in this issue and to avoid the risk of the two separate initiatives coming to two different conclusions on the same question.

Trying to design a basis for TAC allocation around a specific avoided cost value for DERs is simply not possible, due to wide degree of variation in technology, usage and location. The general correlation between DERs and reduced transmission cost is sufficient to justify sound rate design around the principle that transmission charges should not be collected on energy that does not travel over transmission lines.

2. Structure of transmission cost recovery in other ISOs/RTOs.

Please comment on any lessons learned or observations from the other ISO/RTO approaches that you think will be useful to the present initiative.

Comments:

CALSEIA observes that there are a wide variety of methods for allocating transmission charges, and that there does not appear to be consensus around the optimal means of doing so. As the report acknowledges, ratemaking is not an exact science, and often tries to satisfy multiple objectives. Nevertheless, the intent of all of the existing methods of assigning transmission charges appears to be to collect revenue on the basis of usage of the transmission system, either on a per-kWh basis or on the basis of demand, consistent with the principle of cost-causation.

As CAISO's paper makes clear, there is no ISO that assigns TAC charges on a fixed basis unrelated to the usage of the transmission system. There is good reason for this. The ability of customers to avoid fixed infrastructure costs by reducing their use of the system is a feature of sound ratemaking, which satisfies the Bonbright principles of fairness, efficient use of resources, and avoidance of waste. Ultimately, good rate design should send price signals to consumers that there is a cost to infrastructure, which will incent prudent use of the system and ultimately lead to lower costs in the long run.

3. Today's volumetric TAC rate structure.

Do you think it is appropriate to retain today's volumetric TAC rate structure ($ per MWh of internal load or exports) going forward? If so, please explain why. If not, please indicate what type of change you think is preferable and why that change would be appropriate.

Comments:

CALSEIA does not believe that it is appropriate to retain the feature of CAISO's rate structure that assigns transmission costs to LSEs for energy that has not travelled over the transmission system. Changing TAC assessment from end-use metered load (EUML) to the transmission-energy down-flow (TED) would be entirely consistent with the current "pay-as-you-use" approach CAISO has taken in assigning transmission charges to date, but it would simply account for the recent emergence of DERs that can provide customers with energy that does not travel across transmission lines.

Once the TAC is assessed at the TED, a second question is whether it should be assessed on the basis of energy, demand, or some combination of the two. This is an important question, and analysis is needed to determine the extent to which transmission costs are driven by peak demand versus energy consumption. If certain transmission costs are driven largely by peak demand, then shifting to a demand-based TAC assessment at the TED could send appropriate price signals to LSEs to deploy DERs (such as energy storage) that reduce peak demand on the transmission grid, thereby reducing future transmission costs.

4. Impact of distributed generation (DG) output on costs associated with the existing transmission system.

Do you think DG energy production reduces costs associated with the existing transmission system? Please explain the nature of any such cost reduction and suggest how the impact could be measured. Do the MWh and MVAR output of DG provide good measures of transmission costs avoided or reduced by DG output? Please explain your logic.

Comments:

It is a well-established fact that high loads on transmission and distribution system equipment can lead to excessive thermal loading that can cause transformers and other equipment to wear out prematurely.[1] It is also well established that energy generation serving load downstream of transmission and distribution equipment can reduce stress on transformers and other transmission and distribution equipment, extending the life of that equipment.[2]

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[1] McNary, Sharon. "Transformer behind DWP blackout had been set for replacement," KPCC Environment and Science, July 10, 2017. The Los Angeles Department of Water and Power cited excessive electricity demand as the cause of a fire that destroyed a transformer and caused widespread power loss.

[2] "The Value of Grid-Support Photovoltaics to Substation Transformers," Hoff and Shugar, Pacific Energy Group and Pacific Gas & Electric (PG&E), 1993. In 1993, PG&E attempted to quantify the value of distributed solar PV to a substation transformer. PG&E's paper found that "a 0.50 MW PV plant reduced the Kerman Substation transformer's hottest-spot temperature by 4 °C on a peak day in 1993." This temperature reduction "converted to an allowable load increase of 4.6 percent or 0.46 MW on peak and a transformer upgrade deferral value of $398,000, assuming that the transformer needed upgrading and there was an annual load growth of 1 percent."

While it is clear that DERs reduce costs associated with the existing transmission system, CALSEIA does not believe it is necessary or practical to quantify the exact degree to which those costs are reduced as a prerequisite for changing the basis for TAC assessment. As CAISO has noted, neither FERC nor the courts have required that allocation of costs be determined with exact precision. Given that exact precision is not possible, in allocating costs adherence to general principles such as fairness and cost causation are the best that policy makers can achieve. The simple fact that DERs reduce the cost of the transmission system is enough to justify a ratemaking structure that incentivizes LSEs to deploy DERs.

As to the question of whether MW or MVAR output provide a better measure of transmission costs reduced by DG output, this is likely to be addressed in the CPUC's transmission avoided cost sub-group of the Locational Net Benefits Analysis Working Group. It would not be practical for CAISO to attempt to design collection of TAC charges using specific values correlating MW and MVAR output with transmission avoided cost. The reason is that these specific avoided cost values are likely to vary depending on technology, operational characteristics and location – but TAC collection must by its nature be a "one-size-fits-all" approach that cannot account for these differences. Given the imprecise nature of ratemaking it is sufficient to simply recognize that DERs reduce transmission costs, rather than attempting to arrive at specific values for the purposes of TAC collection.

5. Potential shifting of costs for existing transmission infrastructure.

If the TAC rules are revised so that TAC charges are reduced or eliminated for load offset by DG output, and there is no reduction in the regional transmission revenue requirements that must be recovered for the existing transmission infrastructure, there will be an increase in the overall regional TAC rate that presumably will be paid by other load. How should this initiative take into account this or other potential cost shifts in considering changes to TAC structure?

Comments:

It is important to note that any change in rate design will lead to some entities paying more and some paying less in the short term, assuming the revenue requirement is fixed. If a given rate structure is not appropriately reflective of cost-causation, and a change is made that makes it more reflective of cost-causation, it is not appropriate to frame that change as a "cost-shift." Rather, it would be a change in rate design that makes recovery of costs more reflective of which entities drive those costs. This change in cost responsibility to reflect an entity's usage of the electric grid can act as a "price signal" encouraging consumers to reduce their use of the system, which ultimately lowers system costs for all users.

Another way "cost-shifting" is sometimes viewed is the result of ratemaking mechanisms that allow consumers to pay for the existing system on the basis of their usage of that system, rather than collecting a fixed amount from each consumer regardless of usage. This design has been viewed as resulting in a shifting of costs for existing infrastructure between customers who reduce their usage and those that do not. For decades, however, economists studying rate design

have rejected the notion that fixed infrastructure costs must be collected equally from all users of the grid via fixed charges – which is the only way to truly eliminate shifting of existing infrastructure costs among ratepayers.[3] Economists recognize that while many costs are fixed in the short run, nearly all costs are variable in the long-run, and changes in customer usage of the grid can have profound impacts on those costs. Thus, attempts to eliminate cost-shifting by collecting costs in a way that cannot be avoided through reduction of use would lead to the perverse outcome of higher total system costs.

CAISO's current method of collecting the TAC – through EUML – allows LSEs and their customers to reduce their share of existing infrastructure costs by numerous means that reduce metered energy consumption, such as energy efficiency and conservation. LSEs that implement aggressive energy efficiency programs are able to reduce their share of the TAC, which presumably changes the cost responsibility assigned to LSEs that have not implemented such aggressive programs. This is not a negative outcome, since energy efficiency ultimately leads to fewer power lines and power plants, reducing the total cost to supply power to California citizens. It is also a fair outcome, since all LSEs have an equal opportunity to deploy energy efficiency and reduce consumption. The same is true of generation resources sited on the distribution grid or that export power from behind the customer meter.

6. Potential for DG and other DER to avoid future transmission costs.

The issue paper and the July 12 presentation identified a number of considerations that the transmission planning process examines in determining the need for transmission upgrades or additions. Recognizing that we are still at an early stage in this initiative, please provide your initial thoughts on the value of DG and other DER in reducing future transmission needs.

Comments:

The fact that DG and other DERs reduce future transmission needs has been well established and is supported by significant empirical evidence. Over the past few years in California, there have been several cases of multi-million dollar transmission projects that had been planned but were cancelled as a result of load reduction specifically resulting from rooftop solar. For example, growth of distributed solar PV in the Fresno region has delayed or eliminated the need for a new 230 kV transmission line project, putting the planned project on hold, saving ratepayers between $115 million and $145 million.[4]

In another example of DG and other DERs reducing future transmission needs, PG&E credited load reduction from rooftop solar and energy efficiency when it cancelled nearly $200 million of planned transmission upgrades in CAISO's 2015-2016 Transmission Plan. In remarks to the CAISO board, PG&E Director of ISO relations Eric Eisenman pointed to flattened load

[3] For example, see Borenstein, "What's so Great about Fixed Charges?" Energy Institute at Haas, November 3, 2014. https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges.

[4] Sheeran, Tim. "Solar growth puts Fresno high-voltage line on hold," Fresno Bee. December 20, 2016.

forecast from a combination of energy efficiency and rooftop solar as the reason for the cancelled projects.

In November 2016, CAISO reported that 16 transmission upgrade projects in the northern regional transmission area had been deferred or cancelled due to reduced load forecasts, which include load reduction from DG.[5]

It is important to note that the examples cited above – representing hundreds of millions of dollars in ratepayer savings realized just in the past two years alone – represents only the savings from cancelled projects that had previously been planned and does not consider projects that were never planned to begin with because DG and other DERs became part of the load forecast.

7. Benefits of DERs to the transmission system.

The issue paper and the July 12 discussion identified potential benefits DERs could provide to the transmission system. What are your initial thoughts about which DER benefits are most valuable and how to quantify their value?

Comments:

It is well established that DERs provide significant value to transmission ratepayers in terms of avoided costs. The question of how to specifically quantify the benefits is a complex topic that is currently being addressed in the CPUC's transmission avoided cost sub-group of the LNBA Working Group. CAISO should address this question through participation in the CPUC's Working Group so that all of the interested parties can provide input and the agencies can arrive at conclusions that factor in all of the relevant information. To address the question in a separate process creates redundant work, strains parties' resources and risks arriving at conflicting conclusions.

Moreover, it is not necessary for the CAISO to arrive at a specific avoided cost value for DERs in order to make a determination about collection of transmission charges. The well-established positive correlation between DER deployment and avoided transmission cost is sufficient to justify a rate design that allows LSEs to reduce TAC charges by reducing generation that must travel over the transmission system to serve load.

Ratemaking mechanisms that incent participants to reduce their use of the system have long been considered good public policy, since they ultimately result in lower costs for all ratepayers. Because ratemaking must be applied system-wide and cannot take into account the differences among various DG technologies and locations, attempting to specifically quantify the avoided cost values of all DERs in this process is unnecessary. A positive correlation between reduced use of the transmission system and reduce transmission costs is sufficient for CAISO to

[5] Jeff Billinton, CAISO, "Review of Approved Projects – North Area," November 16, 2016 presentation at the 2016-2017 Transmission Planning Process Stakeholder Meeting.

establish a TAC collection method that recovers transmission costs on the basis of each LSE's use of the transmission system.

8. Other Comments

Please provide any additional comments not covered in the topics listed above.

Comments:

As noted above, attempting to establish a specific avoided cost value for DERs would be duplicative of other work and unnecessary to consideration of TAC allocation. However, CALSEIA does believe it would be helpful for CAISO to consider whether peak load or overall usage most accurately reflects the drivers of specific types of transmission costs. A determination of the extent to which certain costs are driven by peak demand compared with total energy consumption would help CAISO determine whether the TAC should continue to be collected on a volumetric energy basis or whether a demand-based collection, or some combination of the two, would be most appropriate.

The data necessary to make this determination likely resides at CAISO and the utilities, rather than with any of the non-utility intervenors in this proceeding. Using this data, CAISO could perform regression analysis to illuminate the degree to which demand and energy consumption, respectively, contribute to transmission costs. As a next step, CALSEIA recommends that CAISO consider how to conduct an assessment on this question to help parties determine whether instantaneous demand should be a factor in how the TAC is allocated and collected.