Thematic Question Matrix:

Clean Coalition Responses, Review Transmission Access Charge Structure Stakeholder Process.

October 25, 2017

TED MECHANICS and TAC RATE IMPLICATIONS		
Party	Question	Answer
AREM 29	More explanation is required to understand the proposal and how it would be applied including how the TAC is calculated and billed by the CAISO, how you propose the TAC to be incorporated in Transmission Owner tariffs or otherwise recovered by the load-serving PTOs, and how the full transmission revenue requirement would be recovered and billed down to the level of the retail customers. For example, your TED proposal would simply change the billing determinant for TAC, which would result in a higher rate and cost shifts among PTOs, but as previously noted, these slides also seem to indicate additional changes to the current mechanism for billing and collecting TAC and the transmission revenue requirement, which have not been described in your proposal.	Please see our presentation of September 25, 2017, and Oct 13 response to CAISO questions which provide greater clarity. Several key points include: 1) The current TRR calculation and CAISO HV TAC collection systems would remain unchanged. 2) PTOS will need to propose additional changes to the FERC approved retail delivery rates to properly reflect these adjustments in the billing process. The total amount billed to ratepayers will not change. 3) Additional comparable tariff changes will be required in the PTO LV TAC determinant basis, and These changes would also need to be made if any changes are made in the current volumetric or demand basis for customer charges applied to each customer class.

SDGE 1	Assume a Utility Distribution Company (UDC) provides distribution service to its customers through two 230/12 kV transformers, where the low side of each transformer connects to separate distribution circuits. Assume the real power flow across one transformer during the relevant TAC settlement period is 100 MWh from the 230 kV side to the 12 kV side. Assume the real power flow across the other transformer is 10 MWh from the 12 kV side to the 230 kV side. In this example would the Transmission Energy Downflow (TED) for the UDC be 100 MW or 90 MW?	100 MW. The TED is gross downflow only, so that back flow is not deducted. Any backflow to the transmission system will be captured as downflow at some other T-D interface where that energy is used to serve local loads.
SDGE 2	Assume an LSE within a UDC service area has two end-use customers. If the metered end-use consumption for one customer during the relevant TAC settlement period is 1 MWh and the metered end-use consumption for the other customer is -3 MWh (because of rooftop solar), would the LSE's Customer Energy Downflow (CED) be 1 MWh or -2 MWh?	Actually, not enough information is given. The downflow of the first customer is 1 MWh, but the second gross customer down flow would have to be summed over those periods when the customer as importing energy from the grid. If the BTM generation was greater than load throughout the period, then the LSE would have a CED of 1MWH. If the second customer exported 4 MWH but used 1 MWH when not exporting the LSE would have a CED of 2 MWH. CED is one way downflow of energy to the customer (gross downflow not net of exports). This is the same as the "Gross Load" defined by the CAISO tariff as gross measurement of end use customer load at the meter (excluding unmetered loads behind the customer meter that are reduced by real-time BTM generation). This is the current basis for TAC This is distinct from the net customer load of NEM customers, for which the metered NEM exports onto the distribution system are credited against their gross consumption. As defined by CAISO tariff, the Distribution Operator (utility) is responsible for reporting the gross load and is assessed TAC on this total. Per prior CPUC Decisions, these are By-passable Charges for NEM customers, who only pay T&D costs in proportion to their net metered load.

AREM 17	SLIDE 15: This proposed calculation for a "HV TAC Rate" using TED would increase the level of the TAC charged to the load-serving PTOs. Do you propose any other changes in how TAC would be applied to or recovered from PTOs or other entities?	While the rate would increase, the basis (TED) would decrease, such that the total TRR collected would initially be unchanged. Although the TAC charged to any individual Distribution Operator (DO) may go up or may go down depending on whether the DO/LSE had procured more or less DG than average, the current difference between LSE's is within ~1%. To the degree that additional DG reduces TRR growth in future years, TAC rates will be lower than they would be otherwise for all DO/LSEs For additional elements, please see our presentation of September 25 and our comments of October 13th
AREM 18	SLIDE 15 Your slide does not address the "LV TAC," which is referred to in Slides 3, 14 and 42. Are you proposing any changes to the current way in which the LV TAC is calculated, applied or collected?	The CAISO process only addresses the tariff for the HV TAC. However, we will seek to work with the CPUC and IOUs to change the LV TAC to conform with the structure of the HV TAC.
COST ALLOCATION CORRECTION		
AREM 21	SLIDE 16 and 21: As the CAISO indicated in Slides 20 and 21 of its August 29th presentation, the TEDTAC proposal would be expected to shift costs. Please explain your view of how costs would shift under your proposal.	The TED-based TAC would correct the existing cost shift between LSE's that does not account for transmission impacts associated with remote sourcing of energy to serve load. This cost shift discourages procurement that reduces transmission impacts. Overall, the corrections would be only among LSEs and would amount to under 1% changes in the total TAC charged, depending on how far over or under the statewide average DG procurement a particular IOU is. Please see our presentation of September 25th for greater detail
TAC COST ALLOCATION DISTORTIONS		
ORA 1	Please provide the DER impact analysis on existing transmission costs.	There is no significant impact on existing costs. The total TRR remains the same. Existing costs would be covered much as they are now. Existing load that is served by transmission-connected generation would continue to be served by that generation, and the charges based on transmission flows serving existing load would continue to cover the costs of the existing infrastructure. Slide 25 refers to the growth of total transmission costs in **future** years, which results from new transmission costs. These future costs would be reduced as the need for new transmission is reduced. O&M represents more than 50% of total future costs, and O&M for new facilities will be reduced as new transmission build is reduced.

ORA 4	Please explain how the load served by DER would continue to pay for existing transmission costs in the TAC-fix analysis. During the Clean Coalition presentation discussion, Clean Coalition staff stated that load served by DER would continue to pay for existing transmission costs that could not be avoided with DER. A. Confirm that load served by DER would pay for existing transmission capital costs. If so, please provide the method used to determine the existing transmission capital costs that load served by DER would pay. B. Provide the methodology or formula used in the TAC-Fix analysis to determine the existing transmission operating and maintenance costs that load served by DER would continue to pay. C. Provide the assumptions and/or analysis that support these cost recovery methods or formula.	Loads will be served by a combination of transmission sourced and DER sourced wholesale energy. All load will continue to pay delivery charges, including their share of TAC. These charges are uniform across of an LSE's customers. The total TAC is recovered from all user energy on the same per kWh rate for their customer class. The TED-based TAC is not charged to load, but to LSEs, who pay proportional to how much of their energy is sourced from transmission-connected sources and how much is sourced from distribution-connected wholesale and NEM export generation. A. As noted, the costs of existing transmission capital costs are socialized across all customers, whether or not they also procure some energy from DER. The question is whether this should be proportionate to the quantity of energy received from the transmission system by the LSE serving those customers. B. Please see our presentation of September 25th, and the posted excel model used for the calculations. Available at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=21F0889F-3A84-4622-8F09-E8653BF3D02C C. Please see our presentation of September 25th, and the posted excel model used for the calculations.
AREM 6	Please explain how DG output is "subject to transmission fees?"	Currently, DG energy procured by LSEs is charged the same transmission fees that transmission-sourced energy pays. Since there is no differential charge, the different impacts on transmission grid usage are not reflected in procurement decisions
AREM 7	Please explain your view that customers with installed DG do not use the transmission system.	Actually, that is not our view. Our view is that DG-connected generation does not use the transmission grid to deliver energy to customers within the same local distribution area. Delivery of energy is the primary function of the transmission system and defines its location and capacity.
AREM 8	Please explain how the current TAC "subsidizes remote generation."	Because the costs of transmission use are applied to both transmission connected energy (which uses the transmission grid to deliver energy to customers) and to distribution-connected generation (which does not), the fees charged on DG energy lowers the costs applied to remote energy, effectively subsidizing the transmission grid used by remote generators to reach customers.
AREM 9	Your slide shows a "TAC assessment" applied to generation – both remote and DG. Please explain how the current TAC is assessed on generation.	TAC is charged on the energy delivered to customers and passing through their meters, regardless of whether that energy used the transmission grid to reach customers or not.

AREM 10, 12	Your slide says the TAC "artificially increases" the cost of DER. Please explain.	Please see our presentation of Sept 25th for more detail. By charging for transmission delivery charges on DG energy for a system that is not used to deliver that energy, the transmission charges artificially inflate the delivered cost of energy from DG by inflating the delivery component. This added cost decreases the apparent value of DG procurement.
AREM 11	Your slide says the TAC "artificially increases" the cost of DER. Please explain.	Please see above
AREM 23	SLIDE 23: Please explain how TAC is an "avoided transmission cost."	Please see our presentation of September 25, 2017. To the extent DG is used to serve new load, new transmission build is not needed to serve load, so the cost is avoided, reducing the TRR and associated TAC.
AREM 24	SLIDE 23: Is this slide intending to show that transmission costs should be a factor considered in utility procurement? If so, please explain how procurement policy relates to your proposal to modify the calculation of TAC based on TED.	Yes. Procurement should reflect the full and accurate costs of generation and delivery. Otherwise, there will not be any incentive to reduce costs that do not result in a price signals. By applying TAC only to energy using the transmission grid, DG priced between the cost of remote generation and the cost ofr remote generation plus TAC would be competitive in the bidding process and be procured where is not currently where remote generation receives a subsidy charged to DG generation. If there is a difference in TAC associated with energy from difference procurement options, this difference will be reflected in LCBF or any other procurement cost comparison. Please see our presentation of September 25, 2017.
AREM 25	SLIDE 25: Is this slide intending to show that construction of new transmission can be avoided by DERs? If it is, how does that point relate to the TAC, which recovers the PTOs' embedded costs of the transmission system?	This slide demonstrates that new transmission projects have been cancelled based on DG deployment. Had these projects been built, they would also have become "embedded costs" and increase costs to ratepayers. DG prevented that from happening and lowered costs to ratepayers as a result.
AREM 26	SLIDE 32: Please explain this slide. What is the origin of the "savings" and how are the "savings" calculated?	Please see our presentation of September 25th and accompanying model. Available at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=21F0889F-3A84-4622-8F09-E8653BF3D02C
IMPLEMENTATION MECHANICS		
CLECA 5B	In addition, Clean Coalition at the August 29 stakeholder meeting stated that settlement data could be calculated from other data, not requiring revenue quality meters. Please provide an explanation of this alternative calculation and how it would be performed.	Insofar as customer meters, meters on transmission resources used to bill LSEs for energy, and meters on distribution grid connected resources used to bill LSEs for energy are all revenue quality, these could potentially be used to calculate energy crossing the transmission grid as an alternative to installing revenue quality meters at substations.

CLECA 5A	Does Clean Coalition know how many revenue quality meters would be needed for settlement purposes under its proposal and how many exist at the transmission-distribution interface?	We estimate no more than 10,000 such meters would be needed statewide, based on the number of substations.
AREM 1	Your proposal would require measurements at the interfaces between the High-Voltage (HV) transmission system and lower-voltage (LV) transmission system. How many such interfaces exist on the CAISO's system and do those interfaces have revenue-quality meters?	We have reconsidered this aspect of the proposal and believe that using T-D interface meters would be conceptually and logistically simpler to estimate.
AREM 2	You also note the need to measure transmission at the interfaces between the LV transmission system and the distribution system. How many such interfaces exist on the CAISO's system and do those interfaces have revenue-quality meters?	We estimate no more than 10,000 such meters would be needed statewide.
AREM 3	If revenue-quality meters are not in place, have you investigated the cost of installing them?	Yes. Our consultation with suppliers of such meters provided estimates that upgrades would cost $2,000 each for a total of $20 million capital cost statewide to install all meters. We welcome refinement to this figure.
AREM 4	Your proposal would require changes to the way meter data are collected and used in billing. Have you looked into additional system costs that would be required for modifying the CAISO's billing and metering systems, as well as those of the scheduling coordinators?	Depending on the structure that is ultimately adopted, we believe that the primary billing change would be the data used as the basis for charging TAC. The billing of customers would not necessarily change while LSEs would use the billing data they already receive for claiming credit for their DG energy procurement.
TAC-FIX AVOIDED TRANSMISSION COSTS MODEL AND PRINCIPLES		

ORA 2	Please provide the DER output assumption used for the TAC-Fix analysis. Clean Coalition's presentation states that DER output includes energy from wholesale DG and DERs as well as net energy metering exports. A. Provide the analysis used to determine the output from wholesale DG and DERs as well as net-metering exports in the TAC-Fix analysis.	Please see our September 25th presentation and accompanying model. We assume 50% of NEM energy enters the distribution system and is subsequently reflected in metered customer energy downflow, however this is a user modifiable variable in the model. Available at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=21F0889F-3A84-4622-8F09-E8653BF3D02C
ORA 3A	**Please describe the assumptions used to account for solar DER variability in the TAC-Fix analysis.** The Clean Coalition presentation illustrates that solar production can reduce a portion of the evening peak at reduced capacity, i.e. 46% is maximum capacity at 6 p.m. on September 10, 2016. However, this solar production may be greater in the summer months and reduced in the winter months. A. Explain how the TAC-Fix analysis accounts for variations in the production of solar during peak demand periods in the morning, afternoon, and evening and throughout the year.	The profile used for September 10, 2015 is based on the solar profile from that annual peak day to reflect contribution to peak capacity. System wide reductions in PV output are correlated with demand below annual peaks. Our model uses an average capacity factor to estimate annual production since TAC is based on the total MWhs delivered.
ORA 3B	Provide the assumed percent of DER output that serves morning, afternoon and evening peak load, excluding possible line losses, for all the DER types included in the TAC-Fix analysis.	This is beyond the scope of the detail of analysis needed to assess impacts of the proposal, as transmission investment is associated with annual peaks, not hourly peaks, although we note that CAISO does provide this data. It is worth noting that DG production avoids incurring transmission losses in delivery, and by reducing congestion on the transmission system also reduces losses realized on transmission sourced energy, which can exceed 7% during peak periods.

AREM 5	The TAC recovers the PTOs' costs of the existing transmission system under CAISO control. The TAC is charged to all load-serving PTOs for each unit of measured gross load. Please explain how a TAC calculated using "TED" instead of gross load would "result in major ratepayer savings in avoided transmission investment."	A TED-based TAC would allow transmission costs to be applied only to transmission sourced energy. In turn, this would increase the number of DG projects that would be competitive and procured. Increasing DG deployment would reduce the need for additional transmission investment to meet load growth. Reduced transmission investment translates directly into ratepayer savings in the future.
AREM 13	Is the "total TAC rate" the TAC set by the CAISO?	The total HV TAC is the rate set by CAISO. The total HV+LV TAC includes the LV rates established by each PTO/DO.
AREM 14	The current CAISO TAC is $0.0117/kWh. Your slide shows a TAC of $0.03/kWh "levelized over 20 years "after TAC Fix implementation." Please provide an explanation showing how you get from the current $0.0117/kWh TAC to what is shown on your slide.	This is based on the HV+LV TAC rate, using PG&E as the example Their current combined rate is ~1.9¢/kWh, which we project to increase up to nearly $0.05/kWh over 20 years (in 2017 dollars, extrapolating prior CAISO ten year forecasts, as shown in the presentation). The level cost over 20 years with a real growth rate of 5% a year would be approximately $0.03/kWh.
AREM 15	Please explain how your resulting $0.03/kWh TAC gets you to "12.4% of load met by local renewables after 20 years."	12.4% penetration is the 'Business As Usual" expected DG penetration based on PG&E estimates and current trends in TAC rates and application. (see citations in presentation to PG&E DRP report).
AREM 16	Slide 24 also compares the $0.03/kWh (levelized over 20 years) to *current* wholesale costs of energy. Please explain the point you are trying to make with this comparison	A 20-year contract would include a 20 year levelized cost in procurement evaluation. Procurement for renewable resources is typically based on long term fixed PPA rates (RPS, RAM, ReMAT and IEP contracts with POUs and CCAs), so these costs will remain constant over the period being evaluated. The relevant TAC rate is the levelized rate over the contract terms of the offers being compared, not the rate for just the first year of the contract.
AREM 19	SLIDE 16 and 21: Please explain how billing load-serving PTOs a "HV TAC Rate" calculated based on TED reduces future transmission investments?	Please see our presentation of September 25, 2017. TED-based TAC removes the penalty on DG, which makes DG more cost competitive. Increased DG deployment reduces the need for transmission investment.
AREM 20	SLIDE 16 and 21: Please explain how billing load-serving PTOs a "HV TAC Rate" calculated based on TED results in significant ratepayer savings?	See above

CLECA 3	Please provide the data and the calculations (with a working spreadsheet) for the $.052/kWh TAC rate in slide 44. This does not appear to match any figure in the Excel workbook provided.	Please see the Excel model attached to our presentation of September 25, 2017. This is based on the 5% real inflation projected for TAC rates.
CLECA 4	Please provide an explanation of the TRR total on Slide 43. Is this for PG&E only and missing three decimal places?	No, this is a hypothetical example designed to demonstrate the calculation and impacts of the TED-based TAC.
CLECA 9	Please explain Clean Coalition's definition of levelized cost and how it compares to the traditional definition.	Levelized cost is the average cost in current year dollars over the period under review. As renewable energy is commonly procured on a twenty-year contract which is or can be defined as a fixed rate PPA reflecting the levelized cost of the energy purchase, we similarly reflect the average the TAC rate in real (inflation adjusted) dollars, to represent the average TAC cost over the lifetime of the contract.
POLICY and RATEMAKING PRINCIPLES		
CLECA 8	Per slide 29, are all wholesale distributed generation and aggregated DG RPS-eligible?	All renewable wholesale DG (i.e. DG energy sold to an LSE) is RPS eligible. Fossil fueled DG would not be, however this is not a significant part of the market. Aggregation does not impact RPS eligibility, however DG behind the customer meter is calculated as reducing the RPS denominator rather than be credited to the RPS numerator as wholesale DG would be. As such, where wholesale DG has a 1:1 value, at a 50% RPS based BTM DG would have a 1:2 RPS value per MW.
LSE SETTLEMENT MECHANISM		
SDGE 3	If the CED for an LSE's end-use customers within a given UDC is 10 MWh during the relevant TAC settlement period, and the LSE has contracted to purchase 12 MWh of output from a distribution connected generator within the same UDC during the relevant TAC settlement period, is the LSE's share of TED 0 MWh or -2 MWh?	Presuming that the extra 2 MWh serve local load of another LSE in the distribution area, it would be -2MWH (e.g., the LSE is credited with avoiding its own TAC and 2 MWH of some other LSE's TAC). If the MWh backfeeds from the distribution area substation, then it's not credited as it does not avoid TED based TAC. This would only occur where local supply exceed total local load. (We address elsewhere how to determine if any portion of DG exceeds local load, and the differentiating existing local load service contracts from new generation that may exceed local load)

SDGE 4	Assume one LSE within a UDC service area has contracted to purchase 8 MWh of output from a distribution connected generator within the same UDC service area during the relevant TAC settlement period. Assume another LSE within the same UDC has contracted to purchase 2 MWh of output from the same distribution connected generator within the same UDC service area during the relevant TAC settlement period. How would the UDC know what portion of the output from the distribution connected generator was purchased bilaterally by the first LSE, what portion was purchased bilaterally by the second LSE and what portion may have been sold through the CAISO's wholesale markets and not subject to a bilateral contract? In other words, would all LSEs within a given UDC service area be obligated to provide the UDC with their bilateral contracts with distribution-connected generators? If so, would the UDC be obligated to interpret the bilateral contracts for purposes of determining what amounts of output from distribution-connected generators are to be associated with the different LSEs?	No. The scheduling coordinator would provide the data as to how much energy was dispatched, and the actual billing to each LSE would be the basis for the credit of the DG output. The LSE would need to provide evidence of the actual MWh procurement during the TAC settlement period to the UDC to claim a credit, regardless of contracted energy. There would be no reason for the LSE to provide, or for the UDC to review contracts. An LSE may forecast it's DG procurement eligible for TAC credit, and a UDC may wish to request this estimate.

SDGE 5	Slide 17 of Clean Coalition's August 29, 2017 presentation entitled "Transmission Access Charges (TAC) Structure, Use Transmission Energy Downflow (TED) as the TAC Billing Determinant" states that "LSE share of TED" is equal to "LSE CED – (LSE LV and DG output)". This calculation produces a MWh value for the relevant TAC settlement period. Is this MWh value intended to be (i) used to calculate each LSE's *percentage share* of the High Voltage (HV) Transmission Revenue Requirement (TRR) during the relevant TAC settlement period and, in turn, each LSE's TAC liability, or (ii) multiplied by the *$/MWh* HV TAC rate to calculate each LSE's TAC liability? SDG&E assumes it must be the former, because otherwise there would not be enough MWh against which to recover the entire HV TRR (because of distribution-connected generation and exports from NEM customers).	Yes, the proposal would base allocations on the percentage share. As SDGE notes, the percentage share approach guarantees that all TAC liabilities are covered. However, if the *$/MWh* TAC rate is based on TRR/TED, and TED = (CED – DG output), then the result should be the same. Note that LV generation credit was considered as an option, but the current Clean Coalition is proposal only for DG credit. Likewise, beyond the ISO HV TAC, we recommend a consistent approach for PTO's LV TAC.

SDGE 6	When there are multiple LSEs within the same UDC service area, Clean Coalition offers two proposals for allocating TAC between the LSEs. Slide 40 of Clean Coalition's August 29, 2017 presentation describes an "Overcollect + Refund Method." Under this method the UDC would collect from all LSEs an amount of money equal to each LSE's CED (MWh) during the relevant TAC settlement period times the HV TAC rate ($/MWh). It appears the method would then have the UDC calculate the "overcollection" for each LSE by multiplying (a) the HV TAC rate, times (b) the sum of (i) Low Voltage (LV) generator output purchased by the LSE, (ii) Wholesale Distribution Generation (WDG) output purchased by the LSE, and (iii) Net Energy Metering (NEM) exports by the LSE's end-use customers. The UDC then refunds to each LSE, the LSE's respective "overcollection." a. Slide 40 suggests that the amount of "LV output" purchased from a generator by a particular LSE during the relevant TAC settlement period would be provided to the UDC by the "scheduling coordinators reporting to the UDC." Does this method contemplate a change in the CAISO tariff that would compel scheduling coordinators to report generator meter data to the UDC? b. Where the "LV output" of a particular generator is being sold to multiple LSEs within the same UDC distribution service area, how would the UDC know how much output to associate with the different LSEs? Would the UDC be required to interpret bilateral purchase	After consultation with stakeholders, the Clean Coalition strongly favors the overcollection and refund method. • SDG&E's comment does include one erroneous assumption however. The UDC collections come from ratepayers through billed delivery charges on CED based on the TED-based TAC rates. This would result in an overcollection relative to the total TAC charges. This overcollection is then refunded to the LSEs for ratepayer benefit. Also, after consultation, the Clean Coalition favors basing HV TAC on the T-D TED, not the HV-LV TED, since the flows across the HV-LV interface are quite complex. (Likewise, we recommend a consistent approach for PTO's LV TAC, but that is beyond CAISO tariff scope.) a. Yes, the scheduling coordinator data would be important for claiming credit for DG. However, the LSEs rather than the scheduling coordinators could be responsible for reporting this data (presuming they wish to be credited for their DG procurement) b. No, the LSE would report their billing for energy from the generator. Ultimately, the generator is paid for output, and the LSE paying for the energy gets credit. c. The collection can be guaranteed to match the TRR exactly by prioritizing those payments. As noted above, SDG&E's calculations appear to be somewhat different. First, CAISO issues bills to the UDC for all T-D TED, which should equal the TRR given how the TAC rate is calculated. Second, the UDC then bills customers at the TAC rate, resulting an overcollection. Third, the UDC pays the TAC bill from CAISO out of those collected funds. What remains is the overcollection. Fourth, the overcollection is distributed among the LSEs proportional to the DG+NEM gross exports procured within its territory. Since this is done on a proportional basis, rather than a rate basis, the total of all refunds is guaranteed to equal the overcollection. Since the total overcollection is what remains after the TAC bills are paid to cover the TRR, the TAC exactly covers the TRR. Note that if not all DG is claimed for credit, the overcollection is distributed proportional to the DG output that is claimed by LSEs for credit.

	power contracts to make these determinations? c. Assuming (i) the HV TED excludes real power flows where the flow direction is from a below 200 kV bus to an above 200 kV bus, (ii) there are generators on the lower voltage systems whose real power output is not contractually sold to LSEs within the UDC, and (iii) real power losses on the lower voltage systems are not accounted for, how does the "Overcollect + Refund Method" ensure the UDC collects from LSEs the exact amount of the HV TRR? Said differently, the HV TAC rate ($/MWh) is calculated by dividing the HV TRR ($) by the HV TED (MWh). So unless the calculation of the "overcollection" ends up accounting for exactly the same volume as the HV TED, the net amount of dollars collected from LSEs within the UDC service area after issuing the overcollection rebate, will be different than the HV TRR. (SDG&E created an example that implemented SDG&E's understanding of the "Overcollect + Refund Method" and was unable to reach a result where the net amount of dollars collected from LSEs was equal to the HV TRR.)	

SDGE 7	When there are multiple LSEs within the same UDC service area, Clean Coalition offers two proposals for allocating TAC between the LSEs. Slide 41 of Clean Coalition's August 29, 2017 presentation describes a "Proportional Collection Method." Under this method the UDC would divide the "LSE TAC liability" ($) for each LSE by the "LSE CED" (MWh) for each LSE to create an "LSE-specific TAC rate." ($/MWh). a. What is the purpose for calculating an "LSE-specific TAC rate" if the methodology requires, as an input, the "LSE TAC liability?" Isn't the "LSE TAC liability" the desired outcome to begin with? b. Once the "LSE-specific TAC rate" is calculated, how is it used to determine each LSE's TAC liability?	This process would be employed only if the overcollection and refund method cannot be adopted for whatever reason. This represents an alternative to the overcollection and refund method. Here the TED due to CAISO for the HV TAC is allocated among LSEs based on their CED minus DG credits. That total allocation is divided by their CED to calculate the TAC component of delivery charges charged to customers. In this approach, LSE DG credit is reflected in the LSE-specific TAC rates charged to their customers as transmission (delivery) fees, accounting for the TAC liability associated with each LSE, and no overcollection or refund would occur.
CLECA 6	Please explain precisely, step by step, how the process proposed on slides 40 and 41 would change the current process for 1) determining the TAC and WAC rates, 2) determining the transmission charges paid by retail customers of each PTO-UDC, and 3) determining the transmission charges paid by customers of different LSEs in the PTO-UDC's service territory.	Please see above, and our presentation of September 25th.
CLECA 7	How would the proposal address ESPs, which do not have a service territory?	ESPs DG credit would be proportional for their DG sourced energy (excluding backfeed) within each UDC, just as other LSEs are.

AREM 22	SLIDE 17: This slide discusses allocating the “TAC liability” to LSEs, but the CAISO currently does not bill TAC to the LSEs. Is it your intention to change the current mechanism used for billing TAC to one that would require the CAISO to bill the TAC to LSEs? If so, please explain the details of this proposal. For example, how would the CAISO measure an LSE’s “use” or “TED” for CCAs or ESPs?	We do not believe that the LSEs have an appetite to take on direct billing from CAISO, and this would not be necessary as we have proposed the overcollection and refund method and an alternative LSE specific rate for UDCs to bill to customers, as discussed above.
AREM 27	BACKUP SLIDE 39: You state that the UDCs will “apportion” TAC costs to LSEs. This is not the current mechanism in place for billing or collecting TAC. Under the current mechanism for recovering the embedded costs of the transmission system, the CAISO bills TAC to loadserving PTOs for each unit of measured gross load. The load-serving PTOs recover the costs of their Transmission Revenue Requirements (including adjusted costs associated with TAC) through their Transmission Owners tariffs from their wholesale and retail customers (bundled, CCA and direct access). Is it your intention to change this current mechanism for recovering the embedded costs of the transmission system?	As described above, our preferred approach would be for UDCs to allocate credit to LSEs for DG (including gross NEM exports). As an alternative, the PTO UDCs could charge LSE specific delivery charges to customers.
AREM 28	BACKUP SLIDE 39: If it is, please provide the details of your proposal, including whether additional revenue quality meters will be needed and the required changes to the meter data collection and billing systems of the CAISO, scheduling coordinators, and LSEs (IOUs, ESPs, and CCAs).	We anticipate that revenue quality meters will be needed at the T-D interfaces. We would anticipate that the UDCs will need to develop a rebate mechanism, but otherwise our proposal is designed require no changes to the CAISO billing process (other than the switch to the TED billing determinant), and to minimize the changes to the UDC billing processes.
MISCELLANEOUS DATA REQUESTS		

CLECA 1	Please provide data and calculations (via a working spreadsheet) supporting the claim on slide 29 that O&M costs increase the cost of new transmission by 5 times, as well as the source of the data.	Please see the Excel model accompanying our September 25th presentation which identifies and incorporates initial capital investment and all associated ratepayer costs reflected in the TRR related to that investment over its lifespan.
CLECA 2	Please provide support for the claim that RETI 2.0 indicates the need to build $5 billion of new transmission to meet the 50% RPS requirement by 2030.	Please see transmission build estimates in http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214835_20161216T110654_Renewable_Energy_Transmission_Initiative_20.pdf