BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-006
(NOT CONSOLIDATED)	
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005 (Filed July 1, 2015)
And Related Matters.	Application 15-07-007 Application 15-07-008

COMMENTS OF THE CLEAN COALITION ON PROPOSED DECISION ADOPTING STAFF PROPOSAL ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES

Kenneth Sahm White
Director, Economic & Policy Analysis
Clean Coalition
16 Palm Ct
Menlo Park, CA 94025
(831) 295 3734
sahm@clean-coalition.org

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I. INTRODUCTION

Pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the Clean Coalition respectfully submits these comments in response to the proposed *Decision Adopting Staff Proposal on Avoided Costs and Locational Granularity of Transmission and Distribution Deferral Values*, dated February 6, 2020.

II. DESCRIPTION OF THE PARTY

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 has been an active and consistent participant in both the Integration Capacity Analysis ("ICA") and Locational Net Benefits Analysis ("LNBA") working groups and an original advocate for distribution resource planning and processes. In addition, we have remained a leading intervenor in interconnection proceedings and an active participant in the Integrated Distributed Energy Resources ("IDER") proceeding that seek to utilize the ICA and LNBA results.

III. SUMMARY

- The Proposed Decision incorrectly defines "unspecified deferral value" as reflecting *unanticipated* grid needs. We request that the term "unanticipated" be replaced with "anticipated non-specific" in this instance to correct the misrepresentation and to clearly distinguish non-specific anticipated factors from unanticipated factors.
- We ask that the Proposed Decision be modified to find that a valuation of zero for "unspecified" avoided future transmission costs for SCE and SDG&E is not supported by the record, and order that the Commission shall establish a value accounting for the contribution of DER and associated operational profiles in reducing future transmission needs associated with each utility, to be completed in time for the next major update of the Avoided Cost Calculator in 2021.

IV. COMMENTS

The Clean Coalition appreciates the opportunity to submit these comments on the Proposed Decision ("PD"). We support the Commission's continued and evolving efforts in this proceeding to assess the impacts of DER and locational factors such that the benefits may be realized for ratepayers at large, individual customers, and communities.

1. Definition of unspecified deferral value

The PD incorrectly defines "unspecified deferral value" as reflecting "the concept that not all grid needs can be anticipated with perfect foresight, and some portion of those *unanticipated* grid needs could be satisfied by Distributed Energy Resources."[1] This is not correct. We request that the term "unanticipated" be replaced with "anticipated" in this instance to correct the misrepresentation.

[1] PD at 6 (emphasis added)

These unspecified needs are not "unanticipated", rather they are fully anticipated, but cannot be locationally specified with accuracy. We know that generic load growth will require commensurate grid investment, but it is challenging to specify the exact future need and location until the grid need is identified in the annual Grid Needs Assessment or Transmission Planning Process. Likewise, we know that DER can reduce the impact of such load growth and associated grid investment costs. The Staff Proposal states that "Unspecified deferral value seeks to calculate what the Distribution Deferral avoided costs would have been under the counterfactual load forecasts", including the "No New DER" case.[2] "Unspecified" refers to anticipated and quantifiable general needs and avoidable costs. In contrast, "unanticipated" refers to the risk of needs arising outside of forecast scenarios, and the value of hedging against this risk based on its scale and probability of occurrence. These are separate and distinct values. The forecast need for future transmission investment - beyond just those specific projects currently on the books - is entirely quantifiable, and this constitutes the unspecified but anticipated need and cost. Each DER profile will have a quantifiable contribution toward reducing these future needs, and avoiding their costs.

2. Valuation for unspecified transmission deferral

While we broadly support the methods and conclusions of the Revised Staff Proposal and the PD's adoption of its findings, we are deeply concerned about the failure of the Staff Proposal and PD to adopt either any valuation update for the very large reductions in general transmission expenditures that have been identified by the Clean Coalition and other parties, or establish a clear path and timeline to address this long deferred matter. While some value is currently incorporated in the Avoided Cost Calculator ("ACC") for PG&E, a default value of zero is used for the other utilities.

We believe the PD's intention is conceptually reasonable for further developing methods and estimation of "unspecified" distribution deferral value in the ACC Update process, however the schedule for this raises real concern. The ACC considers major updates only every other

[2] Administrative Law Judge's Ruling Confirming Use of Recommendations from Rulemaking 14-08-013 and Introducing Staff Proposal for Major Updates To Avoided Cost Calculator, November 11, 2019, at Attachment A: Energy Division Staff Proposal for 2020 Avoided Cost Calculator Update section 5.1.2 & 5.2 - Distribution Deferral Background, at 34-35

year, and as this was just completed in the Integrated Distributed Energy Resources Rulemaking (R.) 14-10-003, ratepayers will have to wait an additional two years before a method for accounting for these avoided costs will even be available for use across the gamut of proceedings that rely upon the ACC to determine the most cost effective programs, procurement and investments. A delay of six years from the start of this proceeding to implement the goals of AB 327 seems unwarranted, and even then the PD only states that the Commission "may" continue to consider this issue with regard to the value of DER in avoiding transmission costs.[3]

We remind the Commission that DER have already resulted in billions of dollars of avoided new transmission infrastructure, saving ratepayers tens of billions in costs when properly accounting for the associated Transmission Revenue Requirements borne by ratepayers, including the lifetime operation and maintenance of these facilities, and the annual return on equity charges received by the profit-oriented transmission owners. Continued failure to account for the impact of DER on future transmission investments is in contradiction to goals AB 327 and misdirects planning across major utilities and in CAISO's Transmission Planning Process ("TPP"). The TPP relies on forecasted growth in demand on the transmission system to meet customer load, to deliver energy from new renewable resources, and to maximize economic access and dispatch of resources. If the role of DER in reducing the need for additional transmission investment to meet these goals is not accurately accounted for and valued, then the development of DER will be depressed -- especially with regard to the operational profiles and locations where it would be projected to offer the greatest benefit to ratepayers.

The Commission knows that local distributed energy resources can contribute to meeting all types of needs at both the local and system level, and that local needs can be met either through local resources, or through added transmission infrastructure to deliver non-local energy supplies, the only question is which portfolio serves ratepayer's requirements at the lowest total cost. These considerations are even more important as the state grapples with critical concerns over local grid resilience and continuity of service in emergency conditions, and is investing heavily in addressing these at the distribution level. To the degree that the need for added transmission infrastructure is reduced when TPP modeling employs forecasts with higher specific DER profile scenarios, these avoided costs <u>must</u> be attributed to those DER and factored into

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[3] Proposed Decision at 1

associated planning and programs. To continue to assign a value of zero is simply and categorically wrong, and it is wrong on the order of billions of dollars. Moreover, it is blatantly inconsistent to have adopted a system wide avoided transmission value for PG&E and not adopt a value for SCE and SDG&E -- there are understandable reasons for why this discrepancy has occurred in the history of the development of the ACC, but it is far less defensible for it to continue.

It is important not to confuse certainty and granularity - unspecified deferral is less locationally granular, but not less certain. Certainty of unspecified deferral increases as granularity decreases. It is easier to use DER growth to avoid future transmission needs than distribution needs. For example, the NP15 transmission area may have a high certainty of increasing capacity need, and this could in turn be met with high probability by DER throughout that region in line with its Peak Capacity Factor. Conversely, DIDF may specify a specific need at a specific location, but with lower certainty of the need forecast or of the ability to procure DER to defer it (we acknowledge however that installed DER offer great opportunity to employ changes in operational profiles to quickly meet evolving distribution needs through tariff driven or dynamic inverter or load modification).

We ask that the PD be modified to find that a valuation of zero for "unspecified" avoided future transmission costs for SCE and SDG&E is not supported by the record, and order that the Commission shall establish a value accounting for the contribution of DER and associated operational profiles in reducing future transmission needs associated with each utility, to be completed in time for the next major update of the ACC. This will reconcile the present inconsistency and support cost effective planning, procurement, and program development, including the wide range of important use cases identified in the PD.[4]

We regret that despite our repeated efforts, good faith attention by Energy Division staff and proposals by parties, this issue was not adequately addressed and prioritized in time to coordinate with the 2019 update schedule of the ACC in the Integrated Distributed Energy Resources Rulemaking (R.14-10-003), and seek assurance that this will be rectified well before the next update.

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[4] Table 1. Use Cases for Estimated Transmission & Distribution Deferral Value, including Integrated Resource Planning, Transmission Planning Process, NEM Tariffs, Distribution Investment Deferral Framework prioritization of candidate deferrals, Energy storage RFOs, Demand Response & Energy Efficiency program portfolios and budgets.

Background

We include below a brief summary of supporting information previously submitted in this proceeding.[5]

While precise estimation of future grid needs and the value of avoiding these as-yet-unrealized needs is inherently based on incomplete information it should not be considered speculative in a pejorative sense – the goal is to improve the accuracy of estimated value based on the available information, accounting for uncertainty.

It is most reasonable to assume that new additional grid needs will occur consistent with historical experience and forecasts, and that DER will be able to mitigate the probable future grid needs to a degree at least equal to their ability to meet existing needs.

In fact, DER have a proven record of eliminating the need for new transmission infrastructure investment, as CAISO has recognized. Growth in DER led to the cancellation of $2.6 billion in unneeded transmission projects in 2017-18 alone, due to changes in local area load forecasts strongly influenced by energy efficiency programs and increasing levels of residential, rooftop solar generation.[6] Ratepayers saved not just the $2.6 billion in initial capital costs but also tens of billions of dollars in future return on equity payments, operations and maintenance costs by the transmission owners. If the ACC or LNBA are not reflecting these actual savings, then the methodology needs further refinement.

We agree with using the peak capacity factor rating of each DER type, and this is already attempted in the ACC methodology and results. It is worth noting however that the purpose of the (avoided) transmission investment is critical to consider. Peak capacity is the driving factor for facilities built to meet capacity needs, but not for policy driven transmission investments; in these cases, other factors such as access to renewable resources may be the driving factor. Where transmission would have otherwise been built to deliver energy from large scale PV development, this may be avoided MW for MW with local distributed PV resources, after accounting for the relatively small differences in the two PV output profiles. In such cases,

[5] R.14-08-013 Clean Coalition Comments on Administrative Law Judge's Amended Ruling Requesting Comments on The Energy Division White Paper on Avoided Costs and Locational Granularity of Transmission and Distribution Deferral Values, June 21, 2019.

[6] CAISO 2017-18 Transmission Planning Process, www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf

Commission driven distributed PV and other DER growth directly reduces the future as-yet-unspecified transmission needs that would be required to meet the states RPS and GHG goals.

The primary limitation on the use of DER as an alternative to conventional utility investment is not technical but is the narrow time window created by the planning and procurement process. The Distribution Investment Deferral Framework ("DIDF") requires that an "alternative" to the planned investment must be deployed at a date sufficiently in advance of the projected need to allow time for the utility to still construct the planned conventional project if the DER alternative has not successfully mitigated the need in advance of that date. For this reason, projects planned for needs occurring within three years are generally excluded from consideration for deferral. When DER reduces future and as yet unspecified grid needs, this also eliminates the requirements for time to procure DER specifically to meet those needs, and the time required to allow for scheduling and construction of conventional solutions. As such, the ability of DER to mitigate future as yet unspecified grid needs and provide an alternative to projects that have not yet entered the planning phase is considerably greater than the opportunity for DER to address projects already within the planning phase, and should not be ignored.

For example, Micro-grids are proven distribution level systems capable of meeting all the electrical needs within a defined area, even doing so "islanded" in complete separation from other distribution or transmission grids. It is objectively clear that where needs have already been met by DER, this DER has resulted in avoiding having these needs ever enter into consideration in either the distribution planning process ("DPP") or the transmission planning process ("TPP").

Likewise, the Long Island Power Authority (LIPA) identified a high locational value and offered a 7¢/kWh premium to 40 MW of appropriately sited solar DG facilities to encourage locational capacity sufficient to avoid $84,000,000 in new transmission costs that would otherwise be incurred, resulting in a net ratepayer savings of $60,000,000.[7] This was a recognized need. However, if a comparable quantity of DER had already been deployed in this area, the "need" for new transmission capacity would not have arisen. The quantity and location

[7] Uncontested Testimony of Kenneth Sahm White: *CLEAN COALITION REBUTTAL TESTIMONY REGARDING PACIFIC GAS AND ELECTRIC COMPANY'S AND SAN DIEGO GAS AND ELECTRIC COMPANY'S APPLICATIONS TO ESTABLISH GREEN TARIFF SHARED RENEWABLES PROGRAMS* January 10, 2014; CPUC Proceeding A.12-01-008 and A.12-04-020, at 2.

of the DER would have been the same, and the same new transmission capacity would have been equally avoided regardless of whether the DER were deployed before or after the capacity shortfall potential was recognized. If DER mitigates load service requirements such that the limits of existing infrastructure capacity will not be reached within the planning cycle, the value is no less than if it provides the same mitigation after a mitigation project is triggered.

The Commission remains correct in recognizing that future as-yet-unplanned-for needs have value, also correct in recognizing that there is uncertainty in forecasts, and consequently in seeking to apply a probabilistic analysis of future needs, and in utilizing a "no DER growth" scenario as a basis of comparison for determining the impact of forecast growth in DER. It is precisely these impacts, both positive and negative, which the Commission is appropriately seeking to capture through a benefits assessment, with the added component of locational variation in the LNBA.

As noted in prior uncontested testimony,[8] deploying DER that displace transmission-sourced energy during peak demand periods avoids the need to increase transmission capacity, which preempts the need for future infrastructure investment planning.

Similarly, a May 2012 study by Southern California Edison found that transmission upgrade costs for their share of the Governor's goal of 12,000 MW of distributed generation could be reduced by over $2 billion from the trajectory scenario. As illustrated in Figure 1 the lower costs were associated with the "guided case" where 70 percent of projects would be located in urban areas, and the higher costs were associated with the "unguided case" where 70 percent of projects would be located in rural areas.[9]

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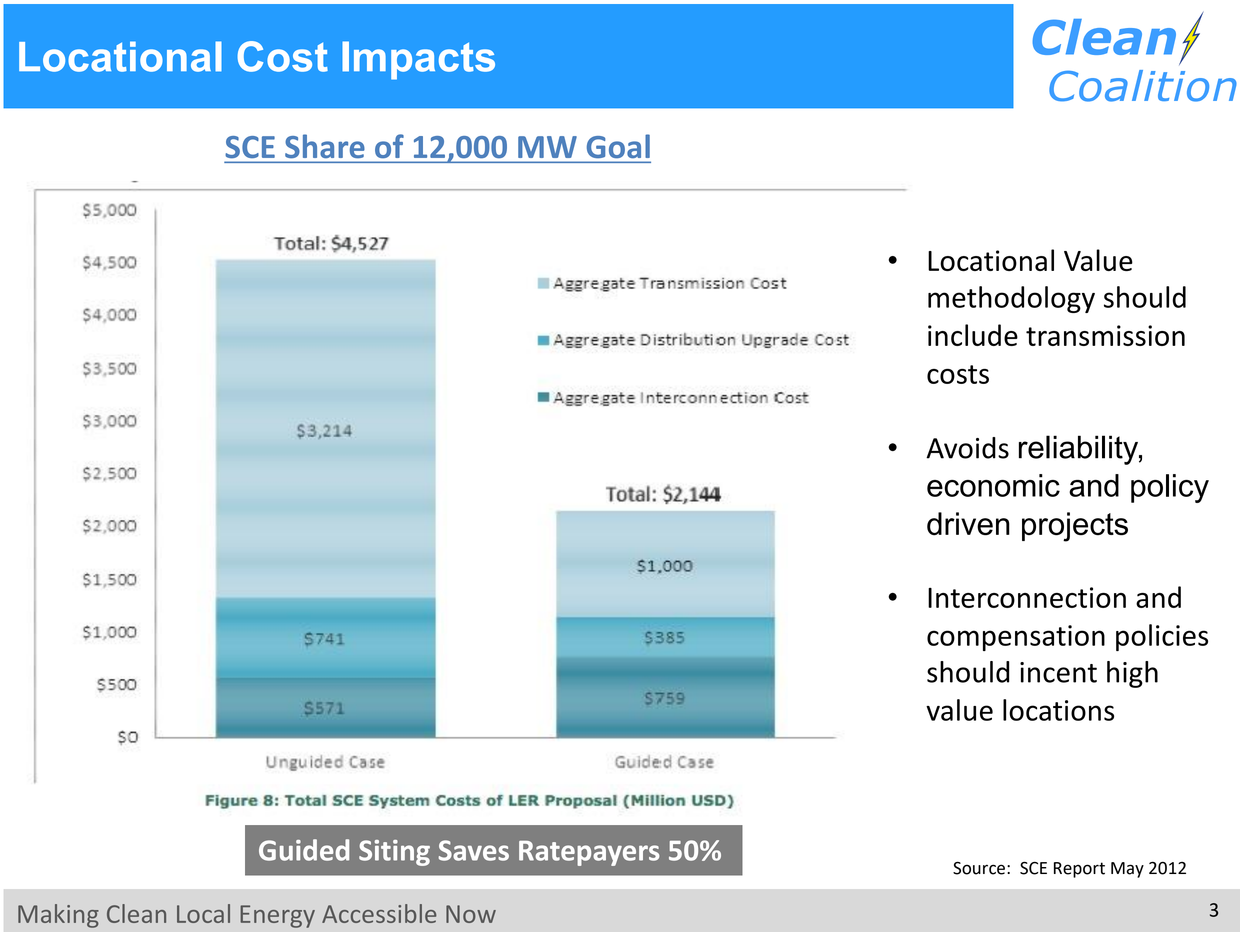
[8] ibid at 5-7.

[9] The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System, SCE, May 2012.

Figure 1: Locational Integration Cost Factors for Distributed Generation



Recognizing such location driven differences in costs and benefits of DER growth are again precisely the purpose of LNBA. In this instance we clearly see that there would be major transmission and distribution infrastructure cost savings if forecast DER growth occurred where there was greater capacity to accommodate that growth. However, since specific infrastructure projects for either scenario had not yet been planned, and LNBA methodology that only considered planned projects would fail to reflect the very cost differential predicted by the utility planners.

Failing to account for unspecified projects that have not yet been planned, or the value of DER mitigations relative to the ratepayer costs that would otherwise occur in the absence of these mitigations, provides a false and unrealistically low projection of future costs and savings. The staff's proposed methodology and examples, while recognizing the potential to avoid unspecified future needs, appears to conclude that the avoided transmission value is negligible, in contrast to the examples offered here and previously by parties.

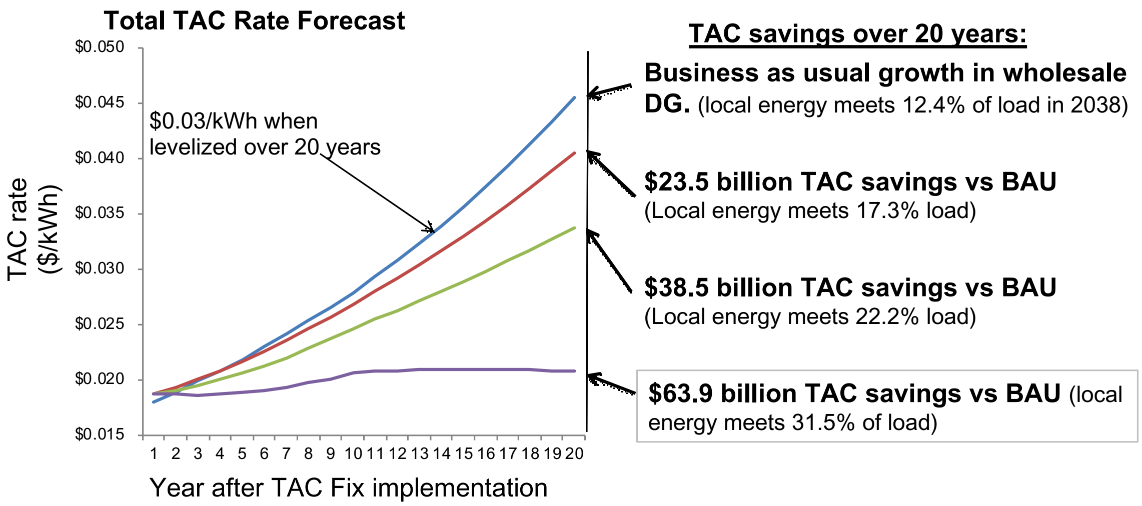
As demonstrated in the attached *Figure 2: Projected Total PG&E Transmission Access Charges: Accounting for Investments Not-yet-planned, Relative to DER Growth Scenarios,*[10] if we forecast the continued addition of new transmission projects beyond the current planning period, even utilizing CAISO's lower projected average future estimate of 7% nominal escalation (5% real) over the next 20 years, the transmission charges, and associated ratepayer costs, do not actually level off, but continue to climb. Increased deployment of DER mitigations would result in major savings that must be recognized.

Figure 2: Projected Total PG&E Transmission Access Charges: Accounting for Investments Not-yet-planned, Relative to DER Growth Scenario

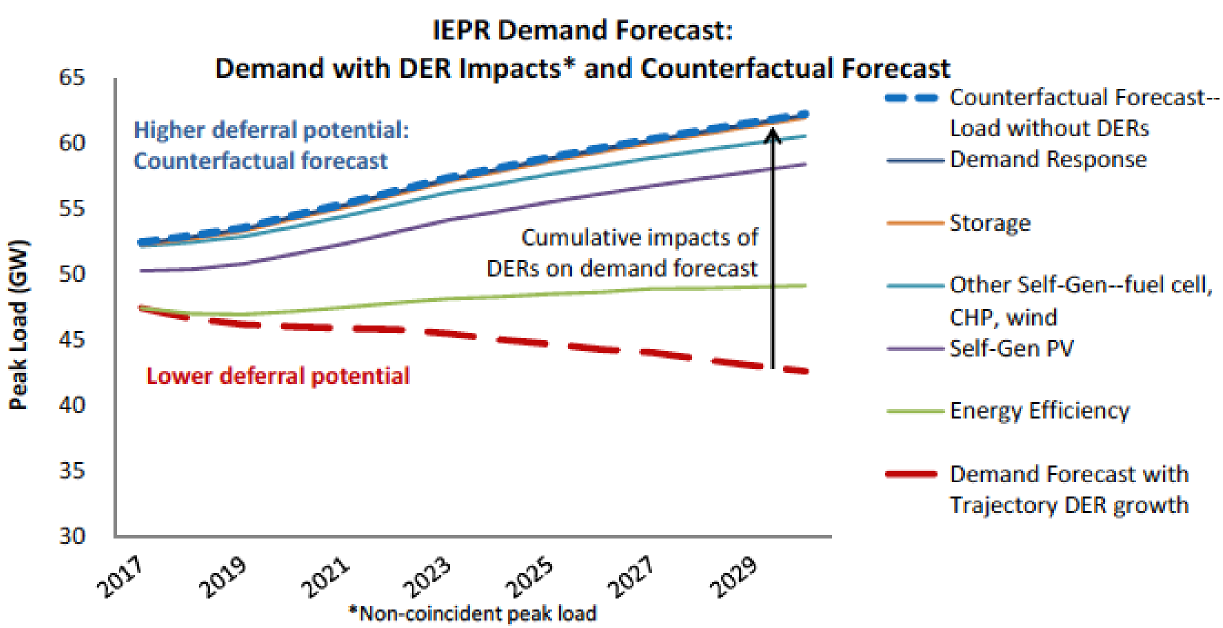
Cumulative Total TAC payments to CAISO ($ in billions)	Year 1	Year 20	Change	Change	Notes
Business As Usual (BAU)	$3.3	$135.8	$-	-	
Post-TAC fix Scenario 0: BAU with new billing determinant	$3.3	$128.4	$(7.5)	-6%	Change versus BAU
Post-TAC fix Scenario 1: Total DG added per year 1.5x of BAU	$3.3	$112.4	$(23.5)	-17%	Change versus BAU
Post-TAC fix Scenario 2: Total DG added per year 2x of BAU	$3.3	$97.4	$(38.5)	-28%	Change versus BAU
Post-TAC fix Scenario 3: Total DG added per year 3x of BAU	$3.3	$71.9	$(63.9)	-47%	Change versus BAU

CAISO peak load after additional WDG versus baseline (MW)	2016	2017	2018	2019	2020
Post-TAC fix Scenario 0: BAU with new billing determinant	49,243	49,392	49,542	49,692	49,843
Business As Usual (BAU)	49,243	49,392	49,542	49,692	49,843
Post-TAC fix Scenario 1: Total DG added per year 1.5x of BAU	49,243	49,200	49,185	49,187	49,191
Post-TAC fix Scenario 2: Total DG added per year 2x of BAU	49,243	49,008	48,827	48,682	48,539
Post-TAC fix Scenario 3: Total DG added per year 3x of BAU	49,243	48,823	48,334	47,891	47,450

[10] Clean Coalition Transmission Access Charge Impact Model, available at: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx



While these values are only indicative and subject to variation based on input assumptions, they align with the IEPR Demand Forecast clearly indicates that DER are projected to have a very significant effect on peak load over the next decade, as shown in slide 9 of the Energy Division at the Dec 20, 2018 workshop. Energy Efficiency and distribution level PV in particular contribute to mitigating peak load growth that would otherwise occur, and the associated transmission and generation costs.



Forecast simplified for illustrative purposes. Actual counterfactual forecast must be adjusted for Codes and Standards and peak shift, and impact of EVs is included in forecast but not shown on this chart

V. Conclusion

The Clean Coalition appreciates the opportunity to submit these comments in response to the Proposed Decision. We have challenged the conclusion of the White Paper and Staff Proposal regarding the negligible value of DER in avoiding unspecified future transmission infrastructure investment, yet our concerns have not been addressed. We support the Commission's continued and evolving efforts in this proceeding to assess the impacts of DER and locational factors such that the benefits may be realized for ratepayers at large, individual customers, and communities. We request modification of the Proposed Decision as described in support of this goal.

Respectfully submitted,

Kenneth Sahm White
Director, Economic & Policy Analysis
Clean Coalition

Dated: February 26, 2020

VERIFICATION

I, Kenneth Sahm White am the representative for the Clean Coalition for this proceeding. I am authorized to make this verification on the organization's behalf. The statements in the foregoing document are true of my own knowledge, except for those matters that are stated on information and belief, and as to those matters, I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on February 26, 2020, at Santa Cruz, California

Kenneth Sahm White
Director Economic & Policy Analysis
Clean Coalition
16 Palm Ct.
Menlo Park, CA 94025
831.295.3734
sahm@clean-coalition.org