BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Demand-Side Resources.	Rulemaking 14-10-003 (Filed October 2, 2014)

REPLY COMMENTS OF THE CLEAN COALITION ON MAJOR UPDATES TO THE AVOIDED COST CALCULATOR

Kenneth Sahm White
Economics & Policy Analysis Director

Clean Coalition
16 Palm Ct
Menlo Park, CA 94025
brian@clean-coalition.org
(708) 704-4598

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I. INTRODUCTION

Pursuant to Rule 13.1 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the schedule established in the December 12, 2019 Letter of Executive Director Stebbins modifying the procedural schedule, the Clean Coalition submits these reply comments on the Energy Division Staff Proposal for 2020 Avoided Cost Calculator Update.

Pursuant to Rule 11.6, the Administrative Law Judge granted by email to parties dated November 22, 2019, an extension of time to file comments and reply comments on the Staff Proposal and to file separately from the Opening and Reply Briefs.

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.

II. COMMENTS

a. GENERAL

The Clean Coalition supports many of the changes put forth in the staff report as well as opening comments made by parties, particularly the recommendations and data provided by CALSSA. The focus of these reply comments is limited the transmission component of the avoided cost calculator. Expressing the true value of transmission costs that can be avoided through the use of DER is a critical component of the cost-effectiveness of any sort of DER project.

While we support the goal noted by many parties of refining transmission values within the DRP proceeding (R.14-08-013), there is as yet no established plan or schedule for doing so. In the interim, the ACC should adopt a reasonable best estimated value, and update that value reflecting refinements whenever they are available from the DRP or other venues. Thus, the Avoided Cost Calculator ("ACC") should prioritize incorporating both short-term avoided costs and long-term avoided costs to reflect the fundamental reality that if all growth in peak demand was served locally, then no additional transmission capacity would be required for this purpose.

Likewise, if RPS and other policy drivers were met with DER then no new policy driven transmission investment would be required. The same holds true for reliability investments. Economic investments should be determined by the total resource cost, including the contribution to transmission infrastructure capacity and losses.

Additionally, the cost of owning, operating, and maintaining transmission greatly exceeds the initial capital investment and must be fully accounted for when comparing alternatives. Lifetime costs, including return on equity, burden the ratepayer with roughly five-fold the capital costs reflected in many transmission planning and non-wires alternative assessments, and we strongly support the work to incorporate these costs in the ACC.

Lastly, it is important to recognize that existing transmission capacity is a constrained resource, and where DER frees up capacity or avoids use that would otherwise occur, that capacity can used for transmission services that would otherwise have required new investment transmission capacity - and that new investment is avoided. The ACC must account for these avoided costs.

b. Replies

In their Opening Brief the Public Advocates Office ("PAO") and others argue that the Commission Should Adopt a Zero Value for Avoided Distribution Costs in the ACC.[1]

PAO states that the best available estimate of avoided transmission costs is zero and there is no clear record evidence at this time showing that DERs are capable of actually deferring transmission costs.[2] This is simply false - parties including the Clean Coalition have provided information previously in both this proceeding and referenced related filings in the DRP proceeding, as referenced below. We have also directly addressed each of the four categories of drivers for transmission investment, demonstrating that DER is more than capable of mitigating all four. Transmission is not an energy resource; it is a means of delivering services between energy resources and customers. DER are energy resources located near customers, thereby reducing the need for transmission to deliver those services from the energy resources to the customers.

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. The value of zero is known with certainty to be wrong and to under value the typical contribution of DER. It is the responsibility of the Commission to adopt an estimated value the best practical alignment with actual value, and as such that value must not be zero.

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

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[1] Public Advocates Opening Brief at 19-23
[2] ibid at 20

changes in local area load forecasts strongly influenced by energy efficiency programs and increasing levels of residential, rooftop solar generation.[3] 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 regarding avoided transmission value is fundamentally flawed needs further refinement. While we support consistent methodologies across proceedings as a goal, known errors must be acknowledged and reasonably accounted for in each proceeding and not be propagate erroneous valuation leading to decisions resulting in major unwarranted costs to ratepayers. While we support the goal of refining transmission values within the DRP proceeding (R.14-08-013), there is no established plan or schedule for doing so at this time. In the interim, the ACC should adopt a reasonable best estimated value, and update that value reflecting refinements whenever they are available from the DRP or other venues.

PAO identifies some potential for issues with the Staff Proposal that should be addressed regarding geographic granularity. However, it is important not to confuse certainty and granularity - for transmission deferral the location is less 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.[4]

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.

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

[4] Clean Coalition Comments on the Energy Division White Paper on Avoided Costs and Locational Granularity of Transmission and Distribution Deferral Values, June 21, 2019 at 2

[Although installed DER offer great opportunity to employ changes in operational profiles to quickly meet evolving distribution needs through dynamic inverter or load modification]

PAO raises misleading concerns when they state that

> "A method with a high level of geographical granularity could result in double counting or gaming. Depending on the granularity of the location used, the avoided transmission cost could simultaneously count deferral value from long-run specified, short-run unspecified, and long-run unspecified projects. A high level of granularity could allow DER providers to game the ACC by selecting a sub-LAP with high costs even if the DER is in a different sub-LAP or it is not yet known where the DER will be deployed (as would often be the case for energy efficiency and demand response programs)."[5]

It should be clear that simultaneously counting deferral value from long-run specified, short-run unspecified, and long-run unspecified projects is not necessarily double counting, but instead counting each the contribution toward avoiding each of these separate cost categories. While it is important to review the potential for overlap and ensure that double counting does not occur, reducing local transmission loads associated with a specified project can certainly also reduce system level loads that contribute to as-yet unspecified projects. Likewise, the concern regarding gaming of the system appears to be founded on a false premise, as we are aware of no proposal from Energy Division staff or parties to allow DER providers to select "a sub-LAP with high costs even if the DER is in a different sub-LAP". We should always guard against gaming, but it stands to reason that the ACC would apply to the sub-LAP in which the project is actually located, or a weighted average of the applicable sub-LAPs targeted if the location or distribution of DER cannot be determined in advance.

We support using the peak capacity factor rating of each DER type, and ideally hourly performance profiles such as adopted for the Integration Capacity Assessment

[5] Public Advocates Opening Brief at 22

methodology, 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. For example, where transmission would have otherwise been built to deliver energy from large scale PV development, <u>this may be avoided MW for MW with local distributed PV resources</u>, after accounting for the relatively small differences in the two PV output profiles. In such cases, 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. <u>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")</u>.

As a further example, the Long Island Power Authority (LIPA) had planned a specific transmission project to meet an identified need, and thereby determined a high locational value for DER. LIPA 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.[6] This was a recognized specified 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 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,[7] 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.

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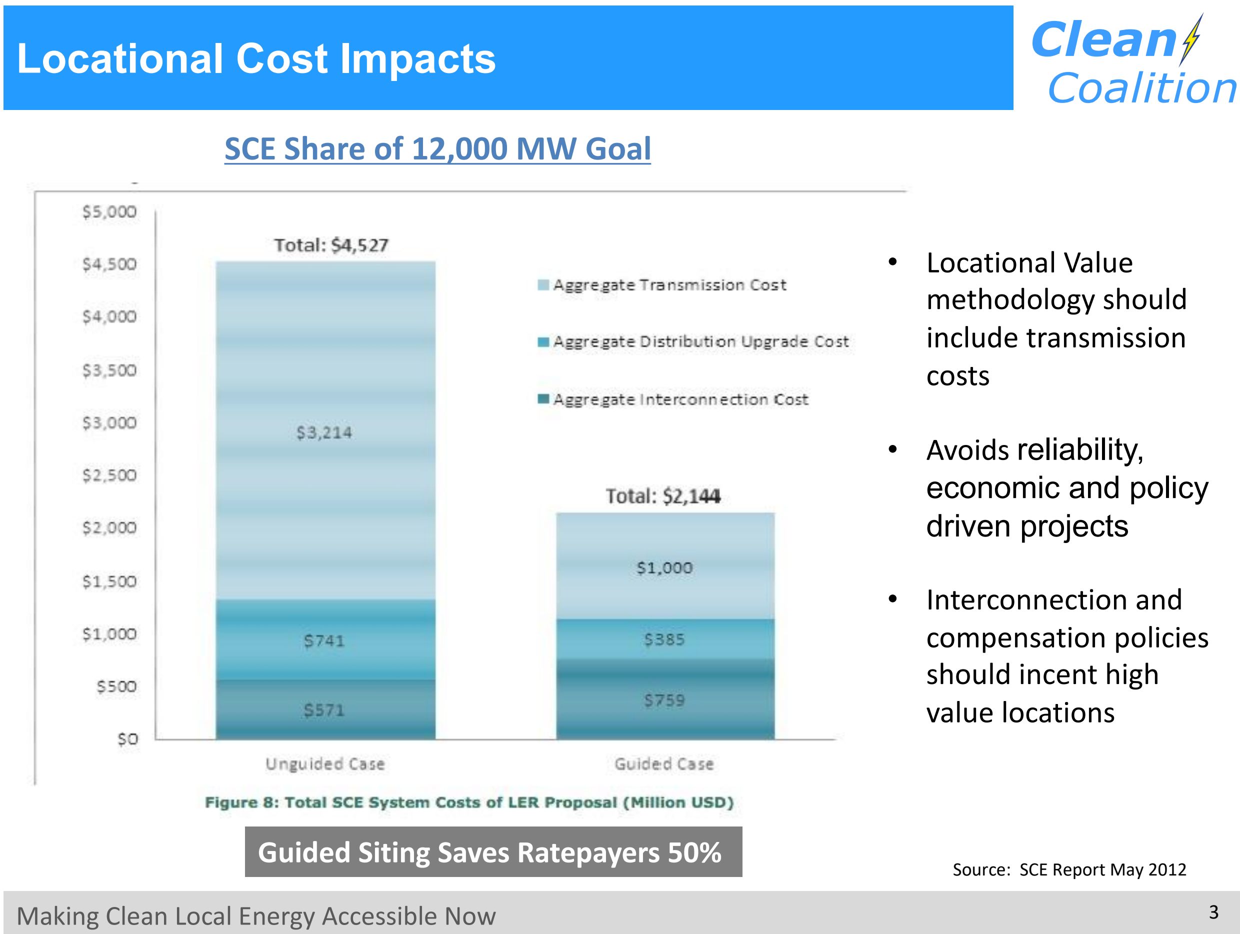
[6] Uncontested Testimony of Kenneth Sahm White: *CLEAN COALITION REBUTTAL TESTIMONY REGARDING PACIFIC GAS AND ELECTRIC COMPANY'S AND SAN DIEGO GAS AND ELECTRIC COMPANY'S APPLICATIONS TO ESTABLISH GREEN TARIFF SHARED RENEWABLES PROGRAMS* January 10, 2014; CPUC Proceeding A.12-01-008 and A.12-04-020, at 2.
[7] ibid at 5-7.

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.[8]

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

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

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.

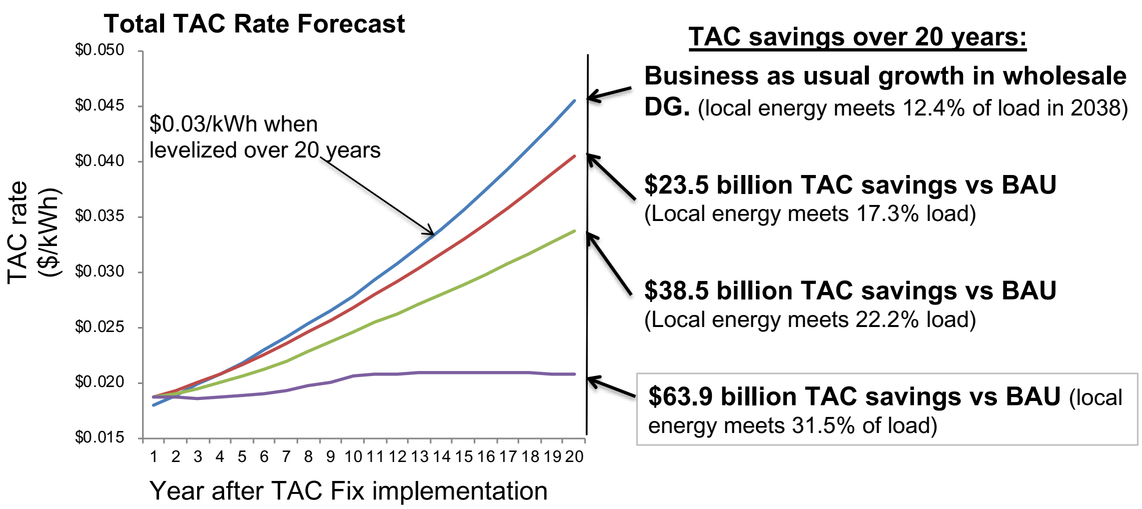
As demonstrated in the attached *Figure 2: Projected Total PG&E Transmission Access Charges: Accounting for Investments Not-yet-planned, Relative to DER Growth Scenarios,*[9] if we forecast the continued addition of new transmission projects beyond the current planning period, even utilizing CAISO's 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.

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

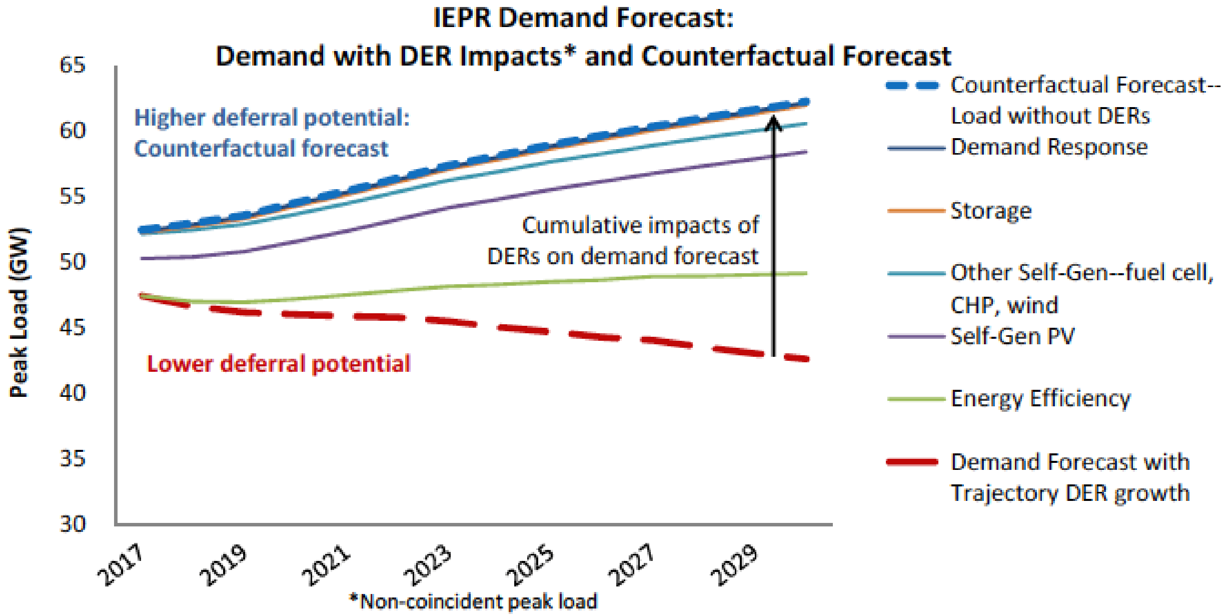
Figure 2: Projected Total PG&E Transmission Access Charges: Accounting for Investments Not-yet-planned, Relative to DER Growth Scenario

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



While these values are only indicative and subject to variation based on input assumptions, they align with the IEPR Demand Forecast which 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

I. CONCLUSION

The Clean Coalition appreciates the opportunity to submit these reply comments in response to the Ruling, Staff Proposal and party comments, and regarding the value of DER in avoided unspecified future transmission in particular. 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.

Respectfully submitted,

Kenneth Sahm White
Director, Economic & Policy Analysis
Clean Coalition

Dated: December 30, 2019

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 December 30, 2019, 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