**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Consider Distributed Energy Resource Program Cost-Effectiveness Issues, Data Access and Use, and Equipment Performance Standards

Rulemaking 22-11-013
(Filed December 22, 2023)

COMMENTS OF LOCAL GOVERNMENT SUSTAINABLE ENERGY COALITION ON ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING PARTY COMMENTS ON FUNDING FOR AN AVOIDED TRANSMISSION AND DISTRIBUTION COST STUDY

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Introduction

The Local Government Sustainable Energy Coalition (LGSEC) is a statewide membership network that represents local government interests related to clean energy and climate resilience to regulatory agencies. LGSEC's coalition of more than 35 city, county, and regional governments represents nearly two-thirds of the state's electricity demand. In addition to policy advocacy, LGSEC members advance sustainable energy and climate solutions to meet California's decarbonization goals through knowledge exchanges, tailored learning opportunities, and statewide collaboration. Among other successes, LGSEC helped build the blueprint for California's energy strategy by providing lead support for the formation of Local Government Partnerships (LGPs), Regional Energy Networks (RENs), and Community Choice Aggregations (CCAs).

LGSEC's interest in this proceeding is largely based on its concern that grid modernization be affordable, equitable, and result in increased distributed energy resources (DER) access; cost-effective DER and dynamic rates be fostered; and future LG, CCA and REN programs be measured against properly calibrated metrics. The Avoided Cost Calculator (ACC) importantly influences the ability to achieve these goals; it must be based on economically sound consistent principles and accurate data.

350 Bay Area also reviewed and supports these comments.

In its Ruling in this proceeding, the California Public Utilities Commission (CPUC) provided parties with "…an opportunity to provide comments on whether the Commission should authorize $1.5 million dollars in ratepayer funding for an avoided T&D costs study."[1] LGSEC's recommends that the Commission *not* authorize this funding, unless at least two conditions are met:

(1) Money is set aside to support a technical advisory group (TAG) to assist with study oversight, composed of knowledgeable stakeholders, including representatives of local governments. The TAG should consist of at least five members, three to be nominated by non-investor-owned utility (IOU) parties to this proceeding, two by IOUs, with a chair selected by the participants. The TAG should also recruit observers engaged in other overlapping dockets, including R.22-007-005, focusing on dynamic rates, and California Energy Commission (CEC) staff engaged in developing load management standards. Up to $50,000 of study funds should be set aside to support the costs of TAG participation, including providing per diems as requested by members.

(2) The study includes proper methodologies and frameworks to examine avoided transmission and distribution costs, as adjudicated by the TAG. Identifying and calculating distribution marginal costs is especially complex, prompting the need for careful scrutiny by the TAG and other stakeholders to develop a proper methodological frame before a study is fully implemented. It would be a waste of ratepayer funds, or

[1] *ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING PARTY COMMENTS ON FUNDING FOR AN AVOIDED TRANSMISSION AND DISTRIBUTION COST STUDY*, Page 4.

worse, create misleading pathways that exacerbate ongoing affordability challenges, to conduct a study that does not adequately reflect state-of-the-art knowledge, data, and perspectives.

The remainder of these comments focuses on further elucidating (2), since (1) is relatively straightforward.

Properly Determining Transmission and Distribution Marginal and Avoided Costs

The following framework and underlying principles should be incorporated into study design.

Three principles for calculating marginal costs

Determining marginal and calculating avoided costs for an electricity system properly begins with four key principles. First, marginal and average costs are interictally intertwined and mathematically related. This relationship cannot be ignored. Second, marginal costs for all components—generation, transmission, and distribution—should be calculated using the same basis for customers and usage. Third, transmission costs are driven by additions of generation, not increased customer loads. Fourth, marginal costs will not accurately reflect ratepayer costs if the relationship between initial capital cost and lifetime ratepayer impact is not explicitly described and calculated; capital costs typically represent 20% of ratepayer costs,[2] with 80% of associated ratepayer costs realized in operation, maintenance, financing and return on equity.

[2] In constant value/real dollars.

Marginal costs must mathematically sum to average and total costs

Average costs equal the sum of marginal costs. Or inversely, marginal cost equals the incremental change in average costs when adding a unit of demand or supply. The two concepts are interlinked; one must speak of one when speaking of the other.

Figure 1 below shows the relationship between marginal and average costs. Importantly, it is not mathematically possible to have rising average costs (the orange dashed line) when marginal costs are below average costs; marginal costs must be greater than average costs (as shown with the thicker red line.) An assertion that transmission or distribution marginal costs are less than the average costs of transmission or distribution given that average costs are rising is mathematically incorrect.

Figure 1

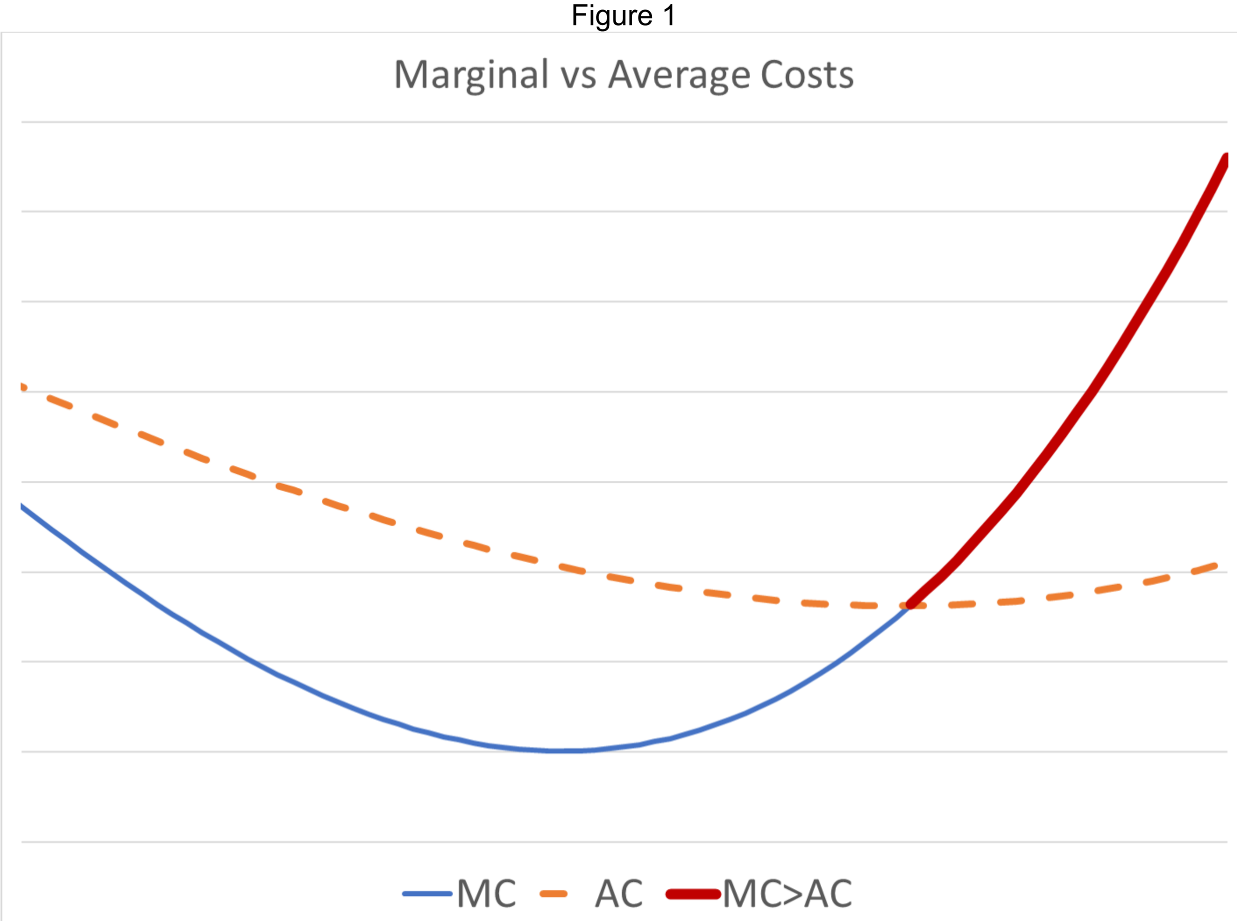
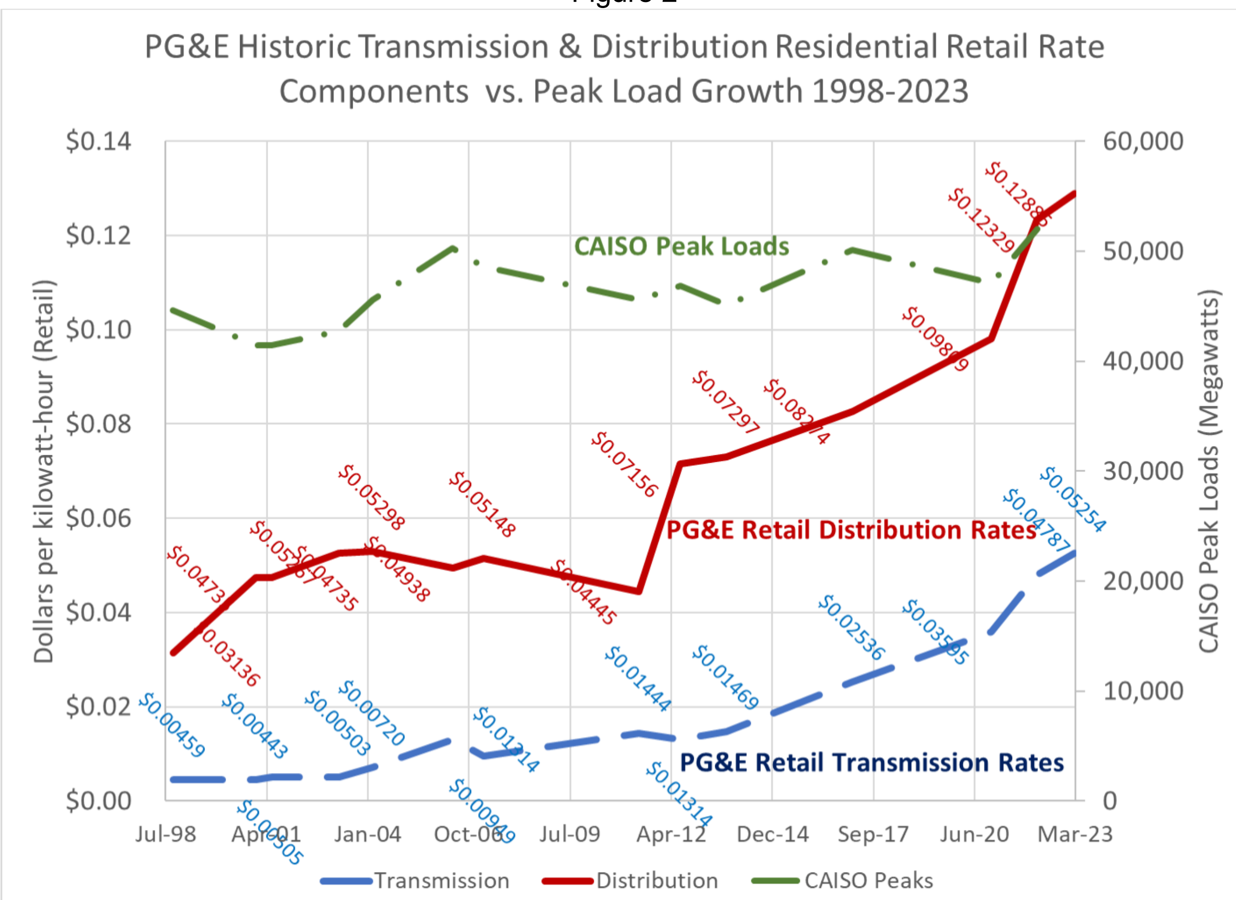


Figure 2, based on Pacific Gas and Electric Company's (PG&E) historic retail transmission and distribution charges, illustrates increases in average transmission and distribution costs.[3] PG&E's transmission charges have risen five-fold over the last 25 years. Distribution has gone up four-fold. **The only mathematical way for this to occur when load is flat or rising is for marginal costs to be above average costs**.

Figure 2



This phenomenon must be accounted for in the proposed study. Calculations of avoided transmission or distribution costs using a marginal cost methodology necessitates that avoided

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[3] The underlying data reflects *only* infrastructure construction and maintenance costs; all nonbypassable, public goods and policy costs are excluded. IOU/CAISO transmission revenue requirements and retail transmission and distribution charges also include approved return on equity, between 8 and 12% annually, a significant rate component.

costs approach the average cost of service. Any divergence requires a rigorous mathematical analysis showing the specific factors that cause average rates to rise above marginal costs. The current Avoided Cost Calculator and supporting documentation fail to provide any such examination.

Marginal costs for all system components must use the same calculation bases

Marginal cost principles for generation are perhaps the best understood of the three system components, in large part because generation is not integrated into a network and is easily separable. In the 1990s the Federal Energy Regulatory Commission's (FERC) Order 888 launched electricity generation market reformation based on a fundamental premise of neoclassical economics: that market prices in competitive markets reflect short-run marginal costs and that short-run marginal costs will converge with long-run marginal costs over time. Long-run marginal costs in turn will provide sufficient return on investment to incent new resource additions.

Independent System Operators (ISO), such as California ISO (CAISO), were established to transparently provide market prices based on this understanding of marginal costs as a means foster efficient resource investment and operation. The California Public Utilities Commission relies on the CAISO market price as the largest component of its marginal generation cost calculation, implicitly endorsing these FERC principles.

Yet, importantly, generation marginal cost is not solely related to the addition of "new" load or customers. As shown in Figure 2 above, CAISO's peak load has been essentially stagnant since 2006.[4] This lack of load growth means that the marginal generation cost has been entirely attributable to maintaining service for existing loads and customers. This can be seen further when considering how generation costs are impacted by adding renewables to replace fossil

[4] Energy loads for the IOUs have been similarly stagnant and even falling as the load factor has decreased.

generation, and batteries to replace combustion turbines. These investments are for substituting existing plants that serve existing loads.

As previously discussed, marginal costs for all components—generation, transmission and distribution—should be calculated using the same basis for customers and usage. Following the Commission-adjudicated approach for generation, transmission and distribution marginal costs must be computed taking into account replacements to continue service to existing loads and customers. Focusing solely on additions for new customers ignores a component of marginal costs that are included in generation marginal costs, leading to an "apples to oranges" assessment among components.

Transmission marginal costs are driven by generation additions

Generation is added to meet increased loads, transmission is enhanced to convey that generation to substations.[5] Extra transmission is rarely motivated by load growth without associated incremental generation capacity. The incremental cost of new transmission is determined by installation of new generation capacity, as transmission delivers power to substations before it is distributed to customers. For this reason, marginal transmission costs must be attributed to generation, not customer load. This has potentially important implications to DER, which may avoid the transmission system entirely, or reduce the need for centralized generation conveyed through the transmission system.

Again, Figure 2 shows that CAISO peak loads have been stagnant for the past two decades, yet transmission costs have soared. During the period a substantial amount of renewable generation, wind and solar, has been built to displace existing fossil fueled power. Most of that

[5] CAISO also initiates "market driven" transmission investments to access lower priced generation resources, and "reliability driven" ventures to address pathway constraints and risks of loss of load service capacity.

renewable power is delivered from remote areas in rural California and other states. The costs for those transmission projects have been large, with further transmission reinforcement added within load centers to distribute the new power to substations. For this reason, marginal transmission costs should be calculated based on the addition of generation resources, not on load changes.[6]

Two methods for calculating transmission marginal costs using these principles

Using transmission rate filings to determine marginal costs

When load reduction measures, such as energy efficiency and solar rooftop, displace utility generation, particularly during gross peak load periods,[7] it also supplants the need for associated transmission that interconnects the plant and transmits power to the local grid. Because power plants compete with one another for transmission grid space, bulk power generation reduction opens the grid to send power from other plants to other customers.

One way to value that displaced transmission is through FERC filed rates. For example, PJM has a market in financial transmission rights (FTR) that values relieving the congestion on the grid in the short term. American Electric Power (AEP) files network service rates yearly with PJM and FERC. Table 1 recounts those rates on a per megawatt-year basis.[8] The rate more than doubled between 2018 to 2021, with average annual increases of 26%.

Table 1 – AEP Transmission Rates 2018-2021

Year	Network service rate per MW-year	Percent Increase
2018	$24,822.32	

[6] Especially when load has not been changing historically.

[7] Metered loads do not reflect "behind the meter" uses that may be either reduced through energy efficiency or served by distributed energy resources. Using metered loads instead of gross loads leads to an underestimate of the value of these resources. That said, CAISO's definition of "Gross Load" is the metered customer load, not net metered load, or total customer load including customer self-generation. It will be important for the study to distinguish between the various definitions of Gross Load used by each agency or in different contexts.

[8] AEP, FERC Docket No ER17-405 and Docket No ER17-406.

2019	$31,173.04	25.6%
2020	$41,759.82	34.0%
2021	$49,798.97	19.3%
Avg.		26.1%

Based on the addition of 22,907 megawatts of generation capacity in PJM over the period[9] the incremental transmission cost was $196,000 per megawatt-year, or nearly four times the current AEP transmission rate. This incremental cost represents the long-term value of displaced transmission, equal to about $37 per megawatt-hour.[10]

Using FERC Form 1 data to calculate transmission marginal costs

The value of displacing transmission requirements can be determined from the utilities' FERC Form 1 filings, accounting for new power plant capacity from California Energy Commission data. Table 2 summarizes the calculation of this incremental cost. Transmission investment additions were collected from the FERC Form 1 filings for 2017 to 2020.[11] The Wholesale Base Total Revenue Requirements submitted to FERC were obtained for the three utilities for the same period. The average fixed charge rate[12] for the Wholesale Base Total Revenue Requirements was 12.1% over that year. That fixed charge rate is applied to the average of the transmission additions to determine the average incremental revenue requirements for new transmission for the period.

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[9] Monitoring Analytics. (2020). *2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022 Delivery Years*. The Independent Market Monitor for PJM. Retrieved from https://www.monitoringanalytics.com/Reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf.

[10] This value is in line with recent retail transmission rates (TAC) established annually by CAISO for PG&E and other IOUs, but substantially lower than long term 20 year levelized TAC projections.

[11] FERC Form 1 for Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric, Years 2017-2020, p. 206.

[12] Or capital recovery factor.

The plant capacity installed in California from 2017 to 2020 is calculated from the CEC's "Annual Generation – Plant Unit".[13] This metric is conservative, leading to an underestimate of marginal cost, because (1) it includes the entire state while CAISO serves only 80% of California's load, with the three IOUs serving a subset of that; and (2) the list of "new" plants includes a number of repowered natural gas plants at sites with already existing transmission. A more refined analysis, which should be conducted in the study, would find an even higher incremental transmission cost.

Based on this analysis, the appropriate marginal transmission cost is $171.17 per kilowatt-year. Applying the average CAISO load factor of 52%, the marginal cost equals $37.54 per megawatt-hour—quite similar to the calculation for PJM marginal cost.[14] This amount should be used to calculate the net benefits for customer investments which avoid the need for additional transmission investment by providing local resources rather than remote bulk generation.

Table 2 – CAISO Transmission Costs – 2017-2020

Average Additions	$2,379,513,874
Average Incremental RRQ	$287,104,235
Average Added kW/Year	1,677,325
Incremental $/kW-Yr	$171.17
Incremental $/MWH	$37.54

[13] CEC, "Annual Generation – Plant Unit," https://ww2.energy.ca.gov/almanac/electricity_data/web_qfer/Annual_Generation-Plant_Unit_cms.php, retrieved June 2021.

[14] If the load factor for solar (~25%) or wind (~45%) is used instead, this marginal cost will increase. While dedicated transmission extensions to solar and wind will have lower capacity factors, co-located storage will increase capacity factors, and main transmission lines will be used to access multiple types of resources as needed to meet demand, including interstate imports and exports.

Distribution marginal costs should reflect full changes in revenue requirements

Identifying and calculating distribution marginal costs is more complex than doing so for either generation or transmission. Distribution marginal costs conventionally are calculated based on a "bottom up" summation of identified projects for added customers and load and new developments. Unfortunately, this method excludes the marginal costs of continued service to existing customers, an element that is included in generation marginal costs. The network effect within the distribution grid that allows for shifting deliveries depending on system conditions further complicates this calculation. Simply summing "new" investment and dividing that over "new" load will provide a misleading result and be inconsistent with proper methodological approaches oriented towards generation and transmission costs.

As previously discussed, and shown in Figure 2, distribution retail rates have been rising rapidly in PG&E's service area, as well as for San Diego Gas and Electric (SDG&E), though less so for Southern California Edison (SCE), implying that the distribution marginal costs are significant. An important factor in rising distribution costs may be the historic IOU mis forecasting of load growth.

Figure 3 shows a collection of forecasts used by Southern California Edison in its General Rate Cases (GRC) through 2018, along with the CEC's Integrated Energy Policy Report (IEPR) forecasts. Filing dates range from 2006 to 2018. The CEC's IEPR forecast and actual SCE loads are shown in the blue line in the central part of the chart; those have been largely flat since 2006. Yet SCE continued to project rising growth to justify added distribution investment, which turned out to be incorrect.[15] Given that load was stagnant, incremental costs per kilowatt-hour rose rapidly for SCE, and as discussed below, PG&E.

[15] The Agricultural Energy Consumers Association tracked these forecast errors in testimony filed in both the SCE and PG&E GRCs starting with 2009.

Figure 3

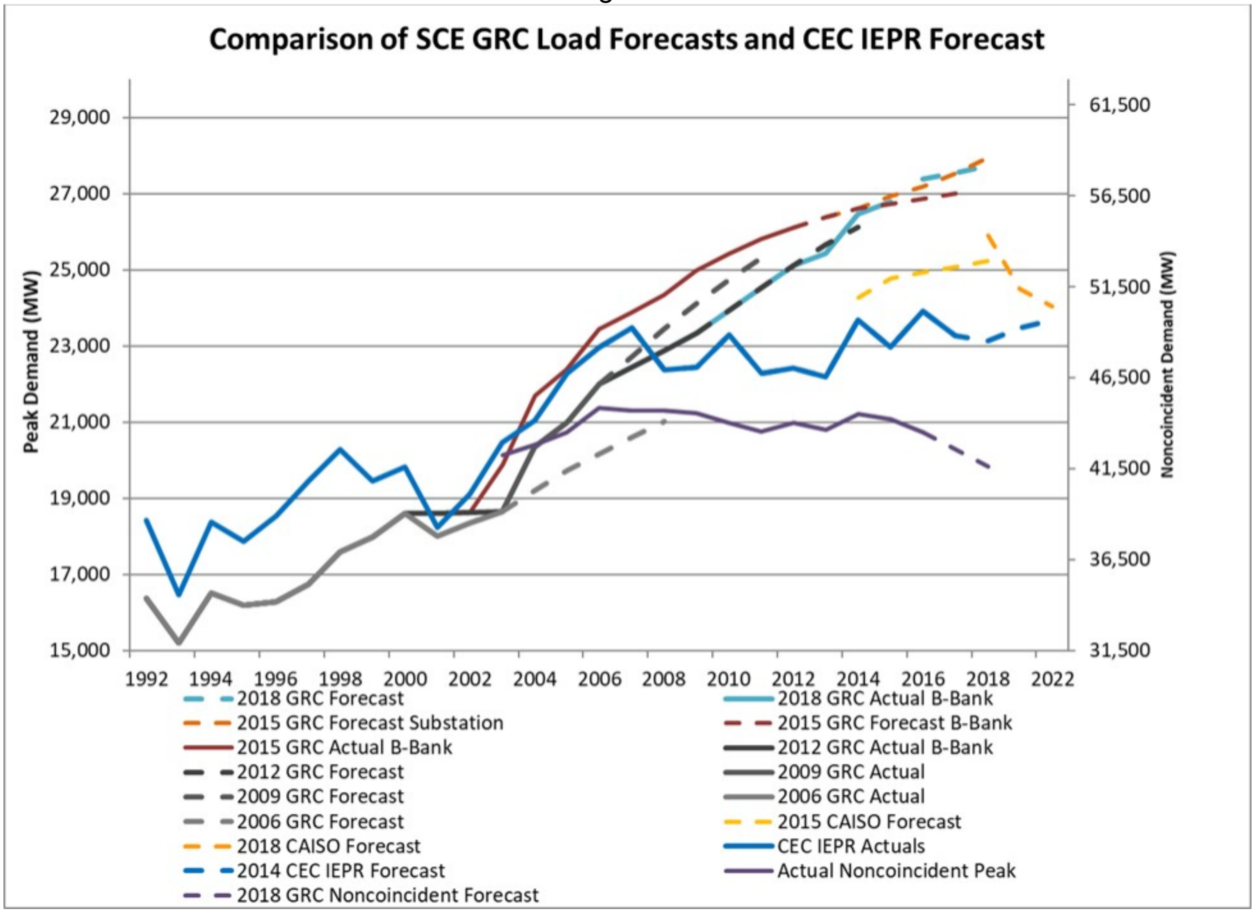
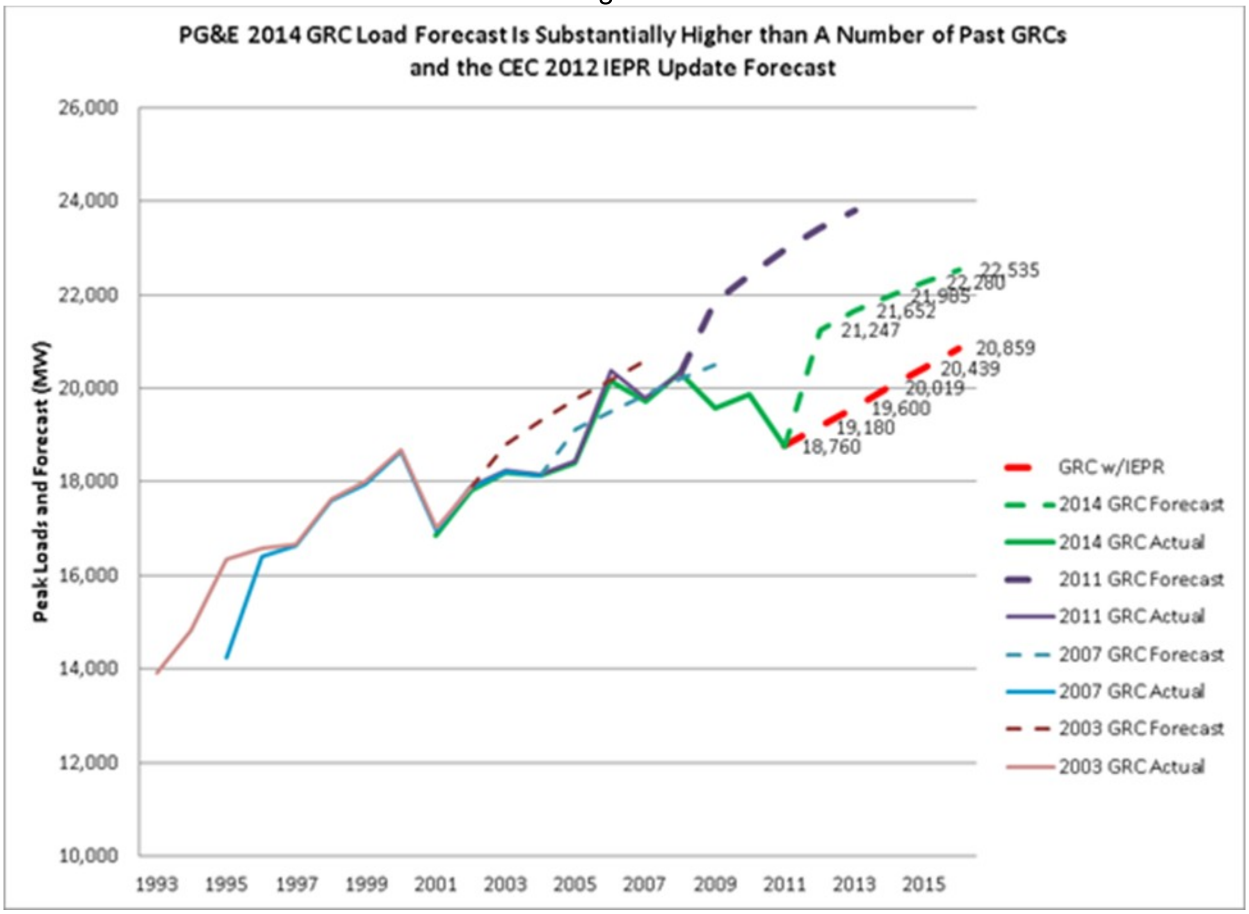


Figure 4 shows a similar chart for PG&E filed in its 2014 GRC. A comparable pattern emerges, with the utility's forecasts deviating upward from the historic pattern of stagnant or even declining loads. Both charts represent planning assumptions developed prior to any significant adjustments for wildfire risk mitigation.

Figure 4



Some of the rise in distribution costs may be attributable to wildfire risk management investments, which are not responsive to load growth so much as altered distribution investment patterns, which, if captured correctly in cost methodologies could better illuminate the value of DERs. However, most of the rate increases predate actual investment in such mitigation measures.[16]

Comparing incremental revenue requirements for distribution accounts in the FERC Form 1 with the marginal cost-based revenue requirements in the utilities' GRC workpapers reveals large differences. The incremental revenue requirements from marginal cost-based

[16] Prospective undergrounding programs will significantly speed the pace of distribution rate increases, an emerging trend that could be at least partially ameliorated through more cost-effective alternatives, including establishing DER-based microgrids in rural areas that enable customers to ride through public safety power shutoffs (PSPS) with no interruptions of service. "Prepared Direct Testimony of Richard McCann, Ph.D. on Behalf of the California Farm Bureau Federation," PG&E 2023 General Rate Case, A. 21-06-021, June 13, 2022; and "Direct Testimony of Richard McCann, Ph.D. And Steven J. Moss, MPP on Behalf of Small Business Utility Advocates," SDG&E 2024 General Rate Case, A. 22-05-016, March 27, 2023.

revenue requirements do not match actual incremental increases, typically falling short significantly.

These results violate the first principle, that marginal and average costs are interictally intertwined and mathematically related; it cannot be ignored that the sum of marginal costs must equal total costs over time. Distribution marginal cost estimates should be calibrated to the total revenue requirement increment as reported in FERC Form 1. How to do this properly is a non-trivial question, which needs to be resolved and embedded into the study frame.

Customer investments in metered load reductions should be reflected in marginal cost calculations

Distributed solar generation installed under California's net energy metering programs appears to have mitigated and even eliminated load and demand growth in areas with established customers.[17] Similarly, prosumers likely displaced investment in distribution assets. These potential benefits need to be examined in the study.

Respectfully submitted,

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[17] "The changes were mainly due to changes in local area load forecasts, and strongly influenced by energy efficiency programs and increasing levels of residential, rooftop solar generation." See https://www.caiso.com/Documents/BoardApproves2017-18TransmissionPlan_CRRRuleChanges.pdf