BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 14-07-002 (Filed July 10, 2014)
And Related Matter.	Application 16-07-015

INFORMAL COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION, THE CALIFORNIA SOLAR & STORAGE ASSOCIATION, AND VOTE SOLAR ON DRAFT NEM 2.0 STUDY PLAN

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December 20, 2019

**INFORMAL COMMENTS OF
THE SOLAR ENERGY INDUSTRIES ASSOCIATION,
THE CALIFORNIA SOLAR & STORAGE ASSOCIATION,
AND VOTE SOLAR ON DRAFT NEM 2.0 STUDY PLAN**

The Solar Energy Industries Association ("SEIA"), the California Solar & Storage Association ("CALSSA"), and Vote Solar appreciate the opportunity to provide these written comments on the draft research plan ("Draft Plan") for a study to evaluate California's net energy metering successor tariff which was approved in Decision ("D.") 16-01-044 ("NEM 2.0") and which has been in effect for the state's investor-owned utilities (IOUs) since 2016 or 2017. The consultant Itron, with feedback from Energy Division ("ED") staff, has prepared the Draft Plan for the NEM 2.0 evaluation. SEIA, CALSSA, and Vote Solar participated in the December 6, 2019 workshop on the Draft Plan, and we hope that these written comments can document more specifically the comments that we made at the workshop. In particular, the NEM 2.0 program has been implemented at a time of significant and rapid change in both the design of retail electric rates in California and the tools that the Commission uses to assess the costs and benefits of distributed energy resources ("DERs") such as the distributed solar systems that are the focus of the NEM 2.0 program. If the NEM 2.0 evaluation is to be useful and balanced, it must take into account this rapidly changing landscape. We also provide some of the specific feedback on the Draft Plan that ED has asked interested parties to provide.

I. INTRODUCTION

The Draft Plan has the following key elements:

- Define the NEM 2.0 population
- Cost-effectiveness analysis
- Cost-of-service analysis

SEIA, CALSSA, and Vote Solar provide comments below on each of these elements.

II. DEFINING THE NEM 2.0 POPULATION

Itron and ED staff have asked parties for feedback on the key characteristics that should be used to form groupings, or bins, of NEM 2.0 customers. There are two key characteristics that define the economics of NEM 2.0 service for a customer that installs a behind-the-meter ("BTM") solar or wind system under NEM 2.0: (1) the rate schedule under which the customer takes service, and (2) whether the customer's rate schedule and time-of-use periods ("TOU") are grandfathered, and if they are, for what duration and under what structure. Both of these dimensions are complex: first, utility rate designs have been changing (and proliferating in number) over the last several years as the IOUs have moved to implement default TOU rates for residential customers and to change to new TOU periods with a much later (4p to 9p) peak period and new definitions for the summer and winter seasons. Thus, NEM 2.0 customers take service under a variety of different rate schedules.

Moreover, the migration of NEM 2.0 customers to evening-peaking TOU rates has only just begun, and is ongoing. While SDG&E's rates with the 4p to 9p peak have been in place since 2018, SCE's similar rates just became available March 1, 2019. PG&E's rates with the later peak period became available November 1, 2019, but are not mandatory for another year. Thus, the staff and Itron should recognize and consider that, if this analysis focuses on NEM 2.0 systems in 2018 or 2019, there will be many systems that will be captured in the analysis that are not TOU-grandfathered, are not yet receiving evening-peaking price signals, but that will transition to TOU rates with the 4p to 9p peak in the near future.

Second, many NEM 2.0 customers qualify for "grandfathered" TOU rates. D. 16-01-044, at page 93, adopted grandfathering provisions for residential customers that moved to TOU rate designs as the result of installing solar or wind generation under NEM 2.0:

> … a NEM successor tariff [i.e. NEM 2.0] residential customer who takes any TOU rate (including a TOU pilot rate) prior to the implementation of default residential TOU rates has the option to stay on that TOU rate for a period of five years from the date the customer commences the TOU rate.[1]

Further, in D. 17-01-006, the Commission also established guidelines for limited "grandfathering" of then-existing TOU periods (i.e. the legacy TOU periods prior to the switch to new TOU periods with the 4p to 9p peak period) for non-residential solar customers.[2] We note that the cut-off dates for eligibility for this grandfathering differ based on the type of customer. Specifically, the Commission adopted a grandfathering measure whereby eligible existing behind-the-meter (BTM) non-residential solar customers would retain their legacy TOU periods, but not rate levels, for a period of ten years from their individual interconnection dates (i.e., original Permission to Operate [PTO] dates). The Commission adopted two cut-off dates for customers to file initial interconnection applications to be eligibile for such grandfathering of TOU periods, one for private entities and a later one for public agencies. Both cut-off dates occurred in 2017; thus, many non-residential NEM 2.0 customers are not on grandfathered TOU rates. Since D. 17-01-006 was issued, the IOUs have established, in recent rate case decisions, a set of grandfathered retail rates applicable to the customers who qualified for grandfathering.

As a result, we believe that the customer's rate schedule and grandfathering status are the key characteristics that should be used to group NEM 2.0 customers. We do not support combining customers with significantly different rates that have the same TOU periods into one bin, as suggested in the Draft Plan, because those rates may differ greatly from each other and result in substantially different customer savings. Instead, we encourage Itron to use as bins all rate schedules, including grandfathered rates, that have significant loads and numbers of NEM

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1 D.16-01-44, at p. 93.

2 D.17-01-006, at pp. 57-65.

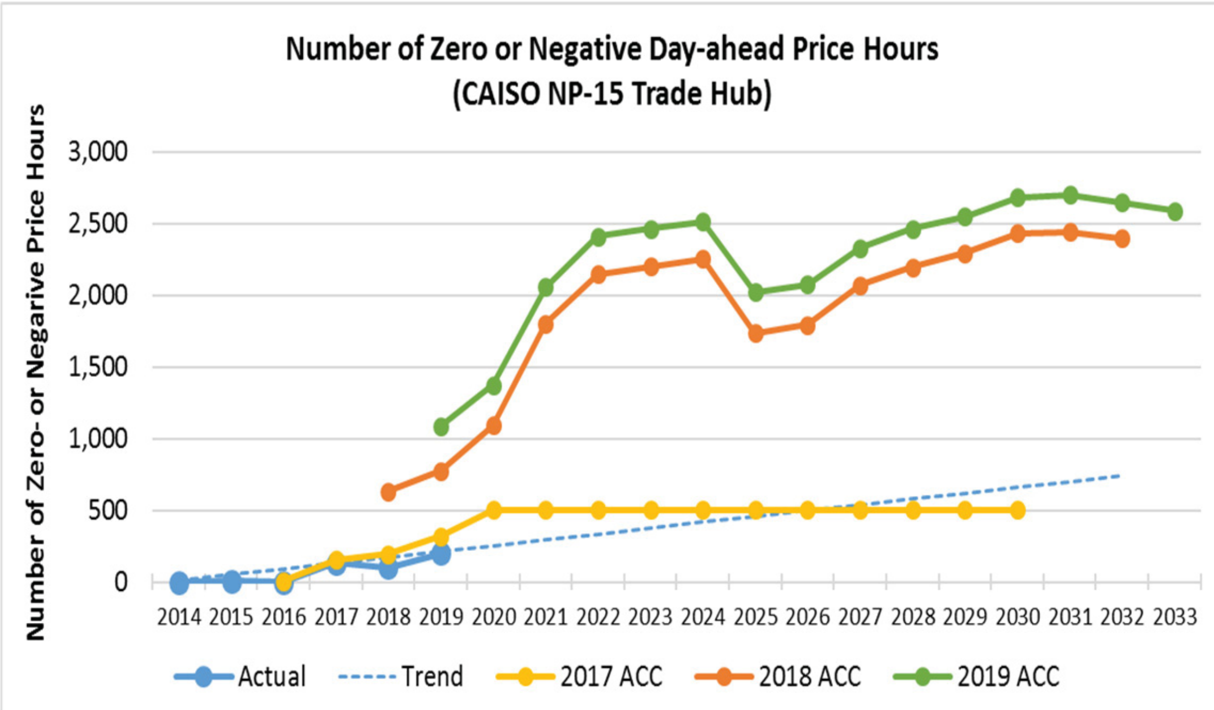
customers. This will ensure that important groups of NEM customers are not excluded from the analysis.

III. COST-EFFECTIVENESS ANALYSIS

Benefits. Itron proposes to analyze the cost-effectiveness of NEM 2.0 using, for the benefits (avoided costs), "the most recent publicly available version of the CPUC Avoided Cost Calculator" ("ACC"). This version is the 2019 ACC. SEIA, CALSSA, and Vote Solar cannot emphasize enough how problematic it would be to use the 2019 ACC to calculate avoided costs in any year after the first year of the forecast (2019).

We will discuss in detail just one of the issues with the 2019 ACC – the hourly avoided energy costs used in the 2019 ACC. The Commission developed an extensive record this fall in the IDER proceeding, R. 14-10-003, on the severe problems with the hourly energy price shapes used in the 2019 ACC. We attach the SEIA/Vote Solar testimony in R. 14-10-003 (Attachment A) – see Section II.B, pages 6 to 17 for a full discussion of this issue. In essence, the 2019 ACC starts with an hourly price shape of avoided energy costs in 2019 that is based on the actual profile of CAISO day-ahead (DA) market prices in the prior year (2018). The actual 2018 CAISO price profile is fine as a starting point. However, the 2019 ACC then adjusts this profile in future years using an inaccurate adjustment that assumes an unrealistic build-out of utility-scale, solar-only generation from 2019-2022. The result is that the current ACC assumes that, by 2022, 28% of the hours in the CAISO DA market will have zero or below-zero prices, which is far more than indicated by the recent trend in the number of zero or below-zero prices (thus far in 2019, 2% of hours have had prices of zero or below). See Figure 1 from the testimony, reproduced below. As shown in the figure, this problem also existed in the 2018 ACC, but less so in the 2017 ACC.

Figure 1: *Actual and ACC-forecasted Zero Price Hours in NP-15*



The three IOUs have agreed that the 2019 ACC's hourly profiles of avoided energy prices result in "unrealistic future energy cost shapes."[3] In fact, the key parties to R. 14-10-003 reached a stipulation that the 2020 ACC should use production cost modeling ("PCM") to determine the hourly shape of future avoided energy costs, thus completely replacing the method used in the 2019 ACC.[4] The ED's proposal for major changes in the ACC (the "Staff Report"), issued November 20, 2019 in R. 14-10-003, also supports the use of PCM.[5]

The result of the 2019 ACC model's assumed price shapes is to significantly devalue solar energy in all future years after 2018. For example, the extremely low mid-day prices forecasted for 2023 in the ACC model result in a solar-weighted annual average price in 2023

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[3] Joint IOU testimony in R. 14-10-003, at p. 2-6.

[4] See R. 14-10-003, Exhibit JPS-02: the parties agreed to "accept use of IRP production cost modeling to determine the hourly marginal energy prices used in the ACC."

[5] See Staff Report, at pp. 17-24.

that is 59% lower than using the CEC's 2023 time-dependent valuation ("TDV") production cost modeling (i.e. $9 per MWh instead of $21 per MWh) which ED staff recently distributed to the parties to R. 14-10-003. This is despite the fact that the baseload average prices for 2023 in the 2019 ACC model are only 8% lower than in the CEC TDV production cost model for 2023.

As a result, SEIA, CALSSA, and Vote Solar recommend that any use of the 2019 ACC should be limited to using an hourly profile of avoided energy costs that is based on 2018 actual CAISO hourly prices. Practically, this would limit the use of the 2019 ACC to just the first-year costs and benefits (2019), with no lifecycle analysis that includes years after 2019.

SEIA, CALSSA, and Vote Solar would prefer that the cost-effectiveness of NEM 2.0 systems is assessed on a lifecycle basis, that is, over the 25- to 30-year life of a solar system. An analysis of just the first year of costs and benefits would be at best indicative but not conclusive. For NEM 2.0 systems installed in the 2017 - 2019 time frame, a lifecycle analysis necessarily involves a projection of costs and benefits at least 23 years into the future. This requires the use of the long-term forecast of avoided costs such as is contained in the ACC. However, at this point in time, it makes little sense to use the long-term forecast in the 2019 ACC that the parties to R. 14-10-003 all recognize is flawed and that the Commission will be overhauling in the first six months of 2020. The Staff is well aware of the issues with the 2019 ACC that have led to the development of an extensive record in R. 14-10-003; indeed, ED staff has made a substantial and constructive contribution to the needed major changes to the ACC through its 54-page November 20 Staff Report, which proposes changes in both methodology and values for every element of the ACC. SEIA, CALSSA, and Vote Solar urge Itron and the staff not to base the cost-effectiveness element of this study on the flawed 2019 ACC. To the extent that the 2019 ACC is used, it should be limited to indicative analyses of first-year costs and benefits.

Bill Savings / Lost Revenues. Under the standard cost-effectiveness tests, the bill savings from NEM 2.0 systems are a benefit in the Participant Test and a cost in the RIM test. Care needs to be taken in calculating bill savings, with consideration given to the rate the customer was on before installing solar. For example, it is likely that most NEM 2.0 residential customers were on the old inclining-block, usage-tiered rate before installing solar, and would not have moved to a TOU rate absent the NEM 2.0 requirement to use a TOU rate. This needs to be considered in bill savings calculations. The bill savings calculations also need to account carefully for rate design features like the $10 per month residential minimum bill, which can result in customers with solar systems that supply a large portion of their annual usage paying $120 per year even if their annual net bill would be much lower absent the minimum bill.

Other Costs and Benefits. Itron noted that it "will also request data on other integration costs associated with NEM 2.0." We assume that this is meant as a request to the IOUs. In fairness, we would ask Itron to seek such data from other stakeholders as well. For example, SEIA, CALSSA, and Vote Solar would like Itron to consider the attached analysis of the trend in integration costs in the CAISO market and among other WECC utilities with growing solar and wind penetrations, which was presented recently in a case before the North Carolina Utilities Commission.[6] This analysis shows that ancillary service costs on the CAISO system have not increased since 2006, as a percentage of wholesale market costs, despite the major increase in the penetration of solar and wind resources on the CAISO system over this period. Studies done by other western utilities show declining costs to integrate solar and wind resources, per MWh of renewable output, as the growing penetrations of solar and wind resources make available more

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6 *Direct Testimony of R. Thomas Beach on behalf of North Carolina Sustainable Energy Association* (dated and submitted to the North Carolina Utilities Commission in Docket No. E-100, Sub 158). Appended hereto as Attachment B. See especially pages 6-16.

gas-fired resources that can compete to provide ancillary services, and as system operators "learn by doing" to integrate these new resources more efficiently through innovations such as the western Energy Imbalance Market.

We note that Itron is proposing to work with the utilities to acquire program costs associated with implementing the NEM 2.0 tariff. This data should be consistent with the cost reported by the IOUs in their annual advice letter filings of NEM costs. The most recent of these filings are PG&E AL 5640-E, SCE AL 4074-E, and SDG&E AL 3426-E. The utilities also should report the offsetting revenues from the NEM interconnection fees implemented pursuant to D, 16-01-044 as well as the interconnection and upgrade costs contributed by NEM customers themselves.

Itron also asks "are there other integration costs that should be considered in the cost effectiveness analysis?" SEIA, CALSSA, and Vote Solar ask Itron to consider not just other integration costs, but also – for the study to be balanced – other benefits of net metered systems. A number of these additional benefits are discussed and quantified in Section III of the SEIA / Vote Solar testimony in R. 14-10-003:

- Avoided fuel price volatility
- Avoided methane leakage
- Reliability and resiliency benefits from DER systems that include storage
- Grid services from certain DERs

All NEM 2.0 systems provide the first two of these benefits, by displacing natural gas use, and these benefits have been quantified. We recognize that only the small subset of existing NEM 2.0 systems that include storage will be able to provide reliability and resiliency benefits, but these benefits should be included given their emerging importance in a world with frequent Public Safety Power Shutoffs. We also acknowledge that further work is needed to implement and to quantify many of the benefits of the variety of grid services, but at least a qualitative discussion of these emerging benefits would be useful to readers and policymakers.

IV. COST-OF-SERVICE ANALYSIS

SEIA, CALSSA, and Vote Solar caution Itron and ED staff that conducting a balanced cost-of-service study is not just a matter of "work[ing] closely with PG&E, SCE, and SDG&E to leverage information from their General Rate Cases (GRC)…." This is because recent GRC Phase 2 cases have not adopted a well-defined cost-of-service model for each IOU, nor have these cases even adopted specific marginal costs for each IOU. Instead, these cases have been resolved through Commission approval of "black box" rate settlements that, by their explicit terms, cannot be used as precedents for other purposes. Most of the adopted rates in these cases are based on settlements that cannot be traced exactly to the marginal costs proposed by any one party to the case, including the utility's original proposal. Further, these "black box" deals do not adopt specific marginal cost values, for either rate design or cost allocation.[7] Given the importance of time-of-use rates, significant attention and negotiation also has occurred in recent Phase 2 cases concerning how marginal costs are allocated to the hours of the year; again, multiple allocations were proposed, considered, and negotiated to produce the final settled rates. SEIA participates actively in GRC Phase 2 negotiations, and will object strongly to any cost-of-service analysis that is based narrowly on a utility's <u>filed</u> marginal costs or hourly allocators, because other parties also proposed different marginal costs and hourly allocators, and many of the settled & approved rates are <u>not</u> based strictly on the utility's filed values. Further, care

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[7] See, for example, D. 18-08-013 in PG&E's last GRC Phase 2, at pp. 24-27: "Thus the MC/RA [Marginal Cost / Revenue Allocation] settlement, and our approval of it, does not reflect the approval of, or acceptance of, any of the settling parties' marginal cost proposals" (p. 27). Also, D. 18-11-027 in SCE's last GRC Phase 2, at p. 16: "The marginal costs used by the MC/RA settlement, while not subject to full Commission review, are apparently within the range of values proposed by the parties, and are therefore reasonable in light of the whole record."

needs to be taken to ensure that this study does not reveal the details of settlement negotiations that the parties to the most recent Phase 2 cases expected to remain confidential.

That said, there are ways to construct a reasonable cost-of-service study from recent GRC Phase 2 data. Some marginal costs and hourly allocations were uncontested; in other cases, the values used were made public in the settlements. Finally, reasonable values can be derived from the mid-points of the range of positions that parties took in the record of the Phase 2 cases. SEIA and Vote Solar have discussed how such middle-ground values can be selected in Sections II.E.2 and II.E.3 of our testimony in R. 14-10-003. We are also willing to work cooperatively with the utilities, Itron, and staff to develop a set of agreed-upon cost-of-service parameters that reflect the currently-adopted rates used by most NEM 2.0 customers and that respect the settlements in recent Phase 2 cases.

Finally, we recommend that Itron take particular care to define exactly what it means by the “gross” and “net” loads of NEM customers, as specified on page 9 of the Draft Research Plan. In particular, the a customer’s “gross” load could be either (1) its entire on-site use of electricity in end-use applications (i.e. its “pre-solar” load before adding solar) or (2) the load delivered from the utility to the customer, as recorded when the meter runs forward, on the channel of the meter that records deliveries from the utility system (also often called “delivered load”). In terms of the cost-of-service analysis, we assume that by “gross” load Itron means #2, delivered load, because the utility does not have any metered data on #1 and the utility only incurs costs to serve the loads to which it delivers power at the customer’s meter.[8] The utility does not incur costs to serve loads which the customer self-supplies behind the meter with its

[8] This issue arises because Slides 10 and 11 discuss developing “gross load shapes” as the customer’s total load before adding solar (i.e. #1). We urge Itron to refer to #1 as “pre-solar” loads and to #2 as “delivered” loads to eliminate confusion with multiple possible definitions for the word “gross.”

own generation; thus, any cost-of-service analysis should be based only on the delivered loads that the utility actually serves. Similarly, "net" load should be delivered loads (#2 above) less the power that the customer exports to the grid through the export channel of the customer's meter. It is also important to specify the time interval over which this netting occurs (i.e. monthly, daily, hourly, or instantaneous). NEM 2.0 is based on 15-minute netting for non-residential customers and hourly netting for residential customers, per D. 19-04-019. We ask staff and Itron to affirm this understanding of the definitions for "gross" and "net" loads in their response to these comments.

V. CONCLUSION

We appreciate this opportunity to provide Itron and ED staff with input on their Draft Plan for the NEM 2.0 evaluation. We would be happy to continue to work with Itron, staff, and other stakeholders to provide feedback on this study as it is performed, in the areas we have indicated above. Please do not hesitate to contact the persons listed on the title page to these comments.

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ATTACHMENT A

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 Distributed Energy Resources.	))))	Rulemaking 14-10-003 (Filed October 2, 2014)

Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association and Vote Solar

October 7, 2019

EXECUTIVE SUMMARY OF RECOMMENDATIONS

I. Introduction

This testimony presents the recommendations of Vote Solar (VS) and the Solar Energy Industries Association (SEIA) concerning needed major changes to the Commission's Avoided Cost Calculator (ACC). The ACC is used to assess the cost-effectiveness of distributed energy resources (DERs) in the service territories of the major California investor-owned utilities (IOUs). DERs are demand-side resources that customers install and use on their premises, including energy efficiency (EE), demand response (DR), renewable distributed generation (DG), and storage. These are preferred resources under California's resource planning policies.

II. Updates to the Current ACC

A. The ACC, Generally

The major changes to the ACC that VS/SEIA propose are based on the current structure for the ACC. The current ACC is based on assumptions that DERs avoid:

1. the energy and capacity costs of gas-fired electric generation,
2. marginal transmission and distribution costs as adopted in CPUC ratemaking cases, and
3. certain costs to meet the state's goals to reduce greenhouse gas emissions.

This testimony presents two types of major changes. The first are changes to the current ACC that are needed to resolve inaccuracies or inconsistencies in the calculator or to update the input assumptions used in the ACC. Section II of this testimony discusses these changes. The second set of changes, discussed in Section III, is the addition to the ACC of certain new benefits of DERs that the Commission should recognize and approve.

B. Avoided Energy Cost Price Shape

The ACC calculates avoided costs in all 8,760 hours of each of the years 2019-2048. As a result, an important part of the ACC is the allocation of monthly or annual avoided cost values to the hours of the day.

The current ACC starts with an hourly price shape of avoided energy costs that is based on the actual profile of CAISO day-ahead (DA) market prices in the prior year. VS/SEIA support this starting point. However, the ACC then adjusts this profile in future years using an inaccurate adjustment that assumes an unrealistic build-out of utility-scale, solar-only generation by 2022. The result is that the current ACC assumes that, by 2022, 28% of the hours in the CAISO DA market will have zero or below-zero prices, which is far more than indicated by the recent trend in zero or below-zero prices. The build-out of new solar-only generation on which this adjustment is premised is not happening, and the Commission is re-focusing near-term procurement on meeting capacity needs, perhaps with re-contracted gas-fired generation, or, hopefully, with clean resources. Meeting these needs with clean resources would include solar tightly coupled with storage that has a much different output profile and much higher capacity benefits than solar-only.

The current ACC's adjustments in the price shape also fail to provide future DERs with any equitable share of the benefit from the market price reductions that they will cause. VS/SEIA recommend that this benefit should be shared between other ratepayers and customers who install DERs, by returning to the past practice of using the actual market price shape for the most recent calendar year, without adjustment in future years. Ratepayers will benefit as this actual shape changes over time, while the value of DERs installed in the near future will not be depressed by market changes that the DERs themselves produce or that result from uncertain and possibly inaccurate projections of resources added in the more distant future.

C. Natural Gas Forecast Issues

There are several needed changes to the natural gas forecast used in the ACC.

First, the forecast should assume that gas transportation rates in California will continue to increase at far above the rate of inflation. This is based on several recent studies of how natural gas rates in California will evolve given increasing costs (to improve safety) and declining throughput (to meet goals for reductions in carbon emissions).

Second, the gas commodity forecast should be based 100% on gas forward market prices for the first two years, then transition over the next five years to an average of long-term fundamentals forecasts. This would replace the current forecast's 100% reliance on forward prices for the first seven years. It is only in the first two years that the forward market is deep, liquid, and conveys the most information; the volumes and open interest in the market decline sharply thereafter. As a result, the weight placed on forward market prices also should drop starting in year three.

I recommend the calculation of separate avoided energy costs for northern (PG&E) and southern (SCE/SDG&E) California. The ACC does this today, but uses a statewide burnertip gas price that no gas-fired electric generation (EG) plant in the state actually faces. There can be significant differences between the burnertip gas costs in northern versus southern California, which result in different long-term economics for gas-fired generation in the two regions. For the northern California avoided energy cost, I recommend the use of the average of the two northern California EG burnertip prices, one for EG plants connected to the PG&E local transmission system, the other for EG plants connected to PG&E's backbone pipelines.

D. Other Minor Changes

VS / SEIA recommend several other minor changes to the ACC. The first is to use only two years of forward electric prices in the ACC, consistent with the above recommendation for the ACC's gas forecast. This change has little impact on the ACC results.

The second recommendation is to increase the energy loss factors slightly, to capture the short-run congestion costs that the IOUs incur, as reflected in the difference between IOU-specific default load aggregation point (DLAP) prices and trade hub (NP15/SP15) prices.

E. Avoided T&D Costs

Avoided CAISO Transmission Costs. The current ACC includes a small avoided cost for high-voltage CAISO transmission for PG&E, but no similar avoided cost for SCE or SDG&E. This inconsistency needs to be remedied, and avoided CAISO transmission costs calculated and included in the ACC for all three IOUs.

DERs clearly reduce peak demands on the CAISO system – they lower end-use loads (EE and DR), shift energy use in time (storage), or supply power behind the customer's meter (DG). The CAISO itself has recognized repeatedly, in three consecutive transmission plans (covering 2016-2019), that the recent growth of DERs has reduced the state's peak demand forecasts. These lower load forecasts have had a major impact on the need for many of the projects in the CAISO's plans, contributing to the cancellation, delay, or downsizing of over $2 billion in transmission investments in these plans.

Despite its own explicit recognition of how DERs contribute to avoiding high-voltage transmission costs, the CAISO has not supported any value in the ACC other than zero for the avoided costs for CAISO transmission. From a longer-term perspective, it is inconceivable that DERs have not saved the state a dime in unspecified high-voltage transmission costs, given that (1) California has successfully promoted the use of energy efficiency and demand response resources to keep per capita energy use constant for the last forty years and (2) the state has incentivized customers to install over 8 GW of behind-the-meter solar on one million rooftops. Yet the CAISO is arguing in R. 14-08-013 that, going forward, DERs have no value in avoiding future transmission investments except for certain limited use of DERs as "non-wires alternatives" to defer specific, near-term transmission projects. None of the arguments that the CAISO or other parties have made opposing long-term avoided transmission costs withstand scrutiny. This Commission needs to act in either this case or R. 14-08-013 to adopt an avoided CAISO transmission cost to be used to evaluate DERs in California.

I present two methods to determine avoided CAISO transmission costs for use in the ACC. The first approach is to calculate avoided CAISO transmission costs for each IOU using the same methods that the utilities have used for many years to calculate long-run marginal distribution costs in CPUC ratemaking cases. I present avoided transmission costs for PG&E and SCE using this approach. The second method is simply to use the CAISO's Transmission Access Charge (TAC) as the proxy for avoided CAISO transmission costs, in recognition that costs are allocated to the TAC based on a utility's metered load, which DERs clearly reduce. Either approach would be acceptable to VS/SEIA.

Avoided subtransmission, substation, and distribution costs. There may be a continued need for the ACC to use marginal subtransmission, substation, and distribution costs from the record in GRC Phase 2 proceedings. The costs used in the ACC should use the best available marginal cost information from the most recent GRC Phase 2 cases that the Commission has decided. This is important to ensure close alignment between the avoided costs used in the ACC and the marginal costs used to set current retail rates – after all, the primary purpose of DERs is to avoid purchases of retail power. In addition, the use of the record from recent Phase 2 cases provides a level of prior Commission review of the values used in the ACC. If a marginal cost value was adopted explicitly in the Commission decision for general use, or if a value proposed by the utility was not opposed, that value should be used. If a "black box" settlement that the Commission approves in a GRC Phase 2 case does not adopt a specific marginal cost value for general use, I recommend that the Commission select for use in the ACC a representative, mid-range value from the range of marginal costs proposed in the Phase 2 case.

I have applied this approach to the decisions, adopted settlements and evidentiary records in the most recent GRC Phase 2 cases, and recommend marginal subtransmission, substation, and distribution costs to use in the ACC.

Allocation of avoided T&D costs to hours. The parties to recent GRC Phase 2 cases have devoted significant effort to examining how marginal subtransmission, substation, and distribution costs should be allocated across the hours of the year, and in several of these cases have reached settlements on these allocators. These allocations are based on the use of data on loads on the subtransmission and distribution systems that were not available when the ACC was developed but have become available in recent years. These allocators are superior to the ACC's use of hourly temperature data in climate zones as a proxy for these loads.

I present recommendations for the specific allocators that should be used in the ACC for each IOU's avoided T&D costs.

III. New Benefits of DERs

The Commission should recognize and approve certain new benefits of DERs, as presented in this section.

A. Avoided Fuel Price Volatility

DERs displace the marginal use of natural gas to generate power, and thus reduce ratepayers' exposure to volatile fossil fuel prices. This hedging benefit can be quantified using a method that Clean Power Research developed for the Maine Public Utilities Commission. This approach recognizes that the value of the hedge that a renewable resource provides is equal to the cost that the utility would have to incur to fix upfront the costs for the natural gas that it would have burned but for the load reductions or clean power production from DERs. I have calculated this hedging benefit by applying the Maine PUC method to the gas commodity forecast that I propose for use in the ACC.

B. Avoided Methane Leakage

Recent studies have increased the estimates for the amount of methane that leaks from the gas pipeline and storage infrastructure, due to improved accounting for low-probability, high-consequence leaks such as the 2015-2016 well failure at the Aliso Canyon storage field. I concur with E3's presentation at the August 30 workshop that the leakage of high global warming potential (GWP) gases such as methane needs to be included in cost effectiveness evaluations of various DERs. This includes the methane leakage (estimated by E3 at 1.9%) that occurs upstream from gas-fired EG plants in California. The simplest way to include the climate impacts of methane leakage in the ACC is to increase the avoided cap and trade costs by 47.5% (1.9% leakage times methane's 25 GWP = 0.475).

C. Reliability and Resiliency Benefits of Storage and Solar + Storage

DERs that include storage can provide an assured back-up supply of electricity, improving the reliability and resiliency of the electric system. I distinguish reliability from resiliency: reliability focuses on minimizing the normal, shorter-duration outages caused by weather or equipment failures; resiliency is the ability to maintain service during less-frequent, higher-consequence "black sky" events of longer duration and larger extent. Storage-based DERs can improve both reliability and resiliency, and this testimony quantifies both benefits. The value of reliability -- about $300 per year per customer – is based on the reliability metrics that the IOUs file with this Commission and on value of service studies widely used by the IOUs. I calculate a value of resiliency from the costs of fossil-fuel-based backup power systems that can provide a basic level of electric service during a prolonged interruption; this resiliency value is $87 per kW-year for residential customers and $106 per kW-year for non-residential.

D. Grid Services

"Grid services" covers a range of new benefits on the electric system, mostly focusing on distribution system benefits. I describe and document how a number of important grid services are being valued or can be valued. These include:

- Dispatchable capacity
- Ancillary services
- Voltage support
- Thermal capacity on the distribution system
- Life extension of distribution equipment
- Conservation voltage reduction

The first two of these services are being deployed and have well-established ways to value them. The next four will require additional actions by the Commission and the utilities to be realized. In this testimony I ask the Commission to be proactive and to recognize, first, that these services are being deployed or may be developed in the near future and, second, that the ACC should be modified to be ready to include these services, or should be modified promptly when they are implemented.

IV. Summary of Proposed ACC Changes

Table ES-1 summarizes the specific major changes and additions that Vote Solar and SEIA propose to make in the ACC. Please refer to the testimony for the detailed justification for each change or addition.

Table ES-1: *Proposed Changes to the ACC*

Issue	Proposed Change		
	PG&E	**SCE**	**SDG&E**
Avoided energy price shapes	Use actual, recorded CAISO market heat rates from 2018 for the day-ahead and real-time NP15 and SP15 price shapes.		
Avoided capacity price shape	Use 2020 RECAP LOLEs.		
Use of DLAPs	Increase energy loss factors by the ratio of historical DLAP and trade-hub prices.		
Natural gas forecast	1. Use 2 years of forward market prices, then transition over 5 years to the average of EIA and CEC IEPR forecasts. 2. Intrastate nominal rate escalation: 11%/year to 2025, 6%/year from 2026-2050.		
Burner-tip EG gas forecast used	Use separate EG burner-tip gas forecasts for (1) PG&E – NP15 and (2) SCE/SDG&E – SP15. Exclude the cap & trade component of EG rates, because the ACC includes that cost as a separate component.		
Avoided CAISO transmission	\$126 per kW-year in 2021	\$31 per kW-year in 2019	Use NERA regression like SCE
CAISO Transmission escalation	Use 4.4% per year, not general inflation.		
Avoided T&D (non-CAISO)	Based on GRC Phase 2 record (see Table 3)		
Allocation of avoided CAISO T	Use PCAF allocations based on CAISO hourly loads in 2018.		
Allocation of avoided D	Based on GRC Phase 2 record (see Table 4)		
	Distribution PCAFs, except flat adder for secondary D	Distribution PLRFs, except flat adder for grid-related	Distribution PCAFs
Electricity Forward Prices	Use NP15 or SP15 forward market prices, rather than an average. Use 2 years of forward market prices, rather than 7 years.		
NP15 or SP15 Modeling	Ensure that the model solves without a shortfall in CCGT costs.		
Avoided Natural Gas Volatility	Add hedging benefits from Table 5, based on DER measure life.		
Methane Leakage	Increase hourly levelized avoided cap and trade costs by 47%.		
Reliability and Resiliency	Reliability: \$300 per customer-year Resiliency: (1) Residential - \$87 per kW-year (2) Commercial - \$106 per kW-year		
Grid Services	Specific methodology for each service: • Dispatchable capacity (based on DR program valuation) • Ancillary services (based on CAISO A/S markets) • Voltage support • Thermal capacity on the distribution system • Life extension of distribution equipment • Conservation voltage reduction		

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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 Distributed Energy Resources.	))))	Rulemaking 14-10-003 (Filed October 2, 2014)

Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association and Vote Solar

I. INTRODUCTION

Q: Please state for the record your name, position, and business address.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in the attached *curriculum vitae* (CV), which is **Attachment RTB-1** to this testimony. As reflected in my CV, I have more than 35 years of experience on resource planning, rate design, and ratemaking issues for natural gas and electric utilities. I began my career in 1981 on the staff at the Commission, working on the implementation of PURPA, on the restructuring of California's natural gas industry, and as an advisor to three commissioners. Since leaving the Commission in 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted comments, studies, or reports on numerous occasions before this Commission as well as state regulatory commissions in many other states. My CV includes a list of the formal testimony that I have sponsored before this Commission and in other state regulatory proceedings concerning electric and gas utilities.

Q: Please describe more specifically your experience on avoided costs and issues related to the cost-effectiveness of renewable distributed generation (DG) and other types of distributed energy resources (DERs).

A: I have worked on issues concerning the calculation of avoided cost prices throughout my career, including sponsoring testimony on avoided cost issues in state regulatory proceedings in Oregon, California, Idaho, Montana, Nevada, New Hampshire, North Carolina, and Vermont. With respect to benefit-cost issues concerning renewable DG, I have sponsored testimony on net energy metering (NEM) and solar economics in California and ten other states. Since 2013 I have co-authored benefit-cost studies of NEM or solar DG in Arizona, Arkansas, California, Colorado, New Hampshire, and North Carolina. I also co-authored the chapter on Distributed Generation Policy in *America's Power Plan*, a report on emerging energy issues, which was released in 2013 and is designed to provide policymakers with tools (including rate design changes) to address key questions concerning distributed generation resources.[1] Finally, since 2007, I have sponsored testimony on rate design issues concerning solar DG in numerous General Rate Case (GRC) Phase 2 proceedings at this Commission involving all three of the major California investor-owned utilities (IOUs).

Q: On whose behalf are you testifying today?

A: I am appearing on behalf of Vote Solar (VS) and the Solar Energy Industries Association (SEIA).

[1] This report has been published in *The Electricity Journal*, Volume 26, Issue 8 (October 2013). It is also available at http://americaspowerplan.com/ .

Vote Solar is a non-profit, grassroots organization based in Oakland, California that works to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar is not a trade group and does not have corporate members. Vote Solar has more than 70,000 members throughout the United States, including many members in the IOU service territories in California.

SEIA is the national trade association of the United States solar industry. Through advocacy and education, SEIA and its 1,000 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy. SEIA's members have a strong interest in the adoption and implementation of innovative, forward-looking policies and programs that will accelerate the development of solar photovoltaic (PV) generation. The views contained in this testimony represent the position of SEIA as an organization, but not necessarily the views of any particular member with respect to any issue.

Q: What is the purpose of your testimony?

A: My testimony presents the recommendations of Vote Solar and SEIA (VS/SEIA) on major changes that the Commission should make to the current Avoided Cost Calculator (ACC). The ACC is a spreadsheet model used to calculate the benefits of programs that encourage the installation of a wide variety of DERs in the service territories of the major California IOUs. This includes energy efficiency (EE), demand response (DR), renewable DG, and storage resources – all of which are clean, preferred resources that state policy has long placed in the first two tiers of the state's loading order for new electric resources.[2]

Q: Do the changes to the ACC recommended in your testimony apply to the 2019 version of the ACC that the Commission adopted on August 1, 2019 in Resolution E-5014?

A: Yes.

Q: At the August 30, 2019 workshop on major changes to the ACC, the Commission's Energy Division and its consultant Energy & Environmental Economics (E3) presented a proposal for a new ACC that would be based on the RESOLVE model that is used for Integrated Resource Planning (IRP). Does your testimony address that proposal?

A: No, it does not address that proposal directly. It is my understanding that the proposal to base the ACC on the RESOLVE model will be addressed later in this docket through comments on a Staff Proposal that will be more detailed than the concept presented at the August 30 workshop.

Q: Nonetheless, do you expect that some of the changes and additions to the ACC that you propose in this testimony also may apply to a new ACC based on RESOLVE?

A: Yes. For example, the gas forecast that I propose in Section II.C should be used as an input assumption to RESOLVE. Further, the new ACC may need to include hourly avoided transmission and distribution values, such as the ones I recommend in Section II.E. In addition, all of the new benefits that I discuss in Section III should be included in whatever ACC emerges from this proceeding.

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[2] The state has maintained this "loading order" for new resources since 2003. See http://docs.cpuc.ca.gov/word_pdf/REPORT/51604.pdf. Decision 12-01-033, at pp. 17-22, has a more recent discussion of the loading order.

II. CHANGES TO THE EXISTING AVOIDED COST CALCULATOR

A. The Avoided Cost Calculator, Generally

Q: Please describe the structure of the current Avoided Cost Calculator.

A: The current ACC is an Excel spreadsheet model that calculates the hourly, long-run avoided costs for each of the IOUs and for each major climate zone for a 30-year period (2019-2048). The structure of the ACC assumes that the marginal resource to supply energy and generation capacity in the state is a natural gas-fired generator – a combined-cycle gas turbine (CCGT) for energy in all hours and a simple-cycle combustion turbine (CT) for peaking capacity. The ACC has used this structure based on a gas-fired marginal resource since the calculator was first developed in 2005.[3]

In the ACC, long-term avoided energy and capacity prices are determined in combination such that the marginal CT peaker and CCGT baseload units recover their average costs. The model determines an avoided cost price for generation capacity based on the residual capacity costs of a CT after considering the dispatch revenues which the CT receives from being dispatched in the California Independent System Operator's (CAISO) real-time (RT) energy market. The ACC performs a similar exercise for the CCGT unit, assuming that it receives energy revenue in the day-ahead (DA) market, and capacity revenues from the CT-based generation capacity price. The energy market prices are adjusted in an iterative fashion until the CCGT fully recovers its costs.

To the avoided energy and capacity costs of a marginal gas-fired resource, the ACC adds additional components for other benefits that DERs can provide. These additional components include the following avoided costs:

- **Line losses** based on the fact that DERs are customer-sited resources that reduce

[3] See Decision 05-04-024.

line losses both on the CAISO high-voltage grid and on the IOU's subtransmission and distribution systems.

- **Ancillary service costs** assuming that DERs will reduce loads on the CAISO system, and thus reduce the need for the ancillary services which the CAISO procures based on load.
- **Cap & trade costs** for reductions in greenhouse gas emissions, as priced in California's market for carbon emission allowances.
- **T&D costs** using the marginal subtransmission, substation, and distribution costs from recent IOU general rate case proceedings, on which retail rates in California are based.
- Avoided long-term costs to meet the state's carbon reduction and Renewable Portfolio Standard goals, in the form of a **Greenhouse Gas (GHG) Adder** that is incremental to the avoided cap & trade costs.

Notably, there is not an explicit component in the current ACC for avoided high-voltage transmission costs on the CAISO system, although the avoided transmission costs for one utility (PG&E) are based on CAISO-level costs.

The ACC calculates avoided costs in all 8,760 hours of each of the years 2019-2048. As a result, an important part of the ACC is the allocation of monthly or annual avoided cost values to the hours of the day. The current ACC uses a variety of approaches to derive the hourly shape of the various avoided cost components.

B. Hourly Shapes for Avoided Energy and Capacity Costs

1. Avoided energy cost price shapes

Q: How has the ACC converted the annual avoided energy cost into hourly values?

A: Before the 2016 ACC, the hourly shape for avoided energy costs was based on the actual hourly shape of CAISO market heat rates[4] (MHRs) in prior years.

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[4] The market heat rate in each hour is the CAISO day-ahead (DA) energy market price in that hour, less variable O&M costs and GHG allowance costs, divided by the burnertip gas cost for that day. Basing the

This approach changed in the ACC update in 2016. In the 2016 ACC, the recorded hourly shape of CAISO MHRs in 2015 was modified for the next five years (2016-2020), by adding an adjustment from the RPS Calculator model that modifies market heat rates in each hour using an assumed build-out of renewables in the first five years of the forecast.[5] This adjustment reduces MHRs as more renewables are added to the system. In addition, the RPS Calculator includes an "export adjustment" that sets the MHR (and thus the avoided energy price) equal to zero in hours with "exports," where exports are defined as occurring whenever the CAISO's load net of renewables, hydro, and nuclear resources is less than 25% of the available thermal generation. In the 2018 ACC, the renewable build-out used to make this MHR adjustment changed, to use the initial modeling for the Reference System Plan (RSP) adopted in February 2018 in the 2017 Integrated Resource Plan (IRP). In addition, in the 2018 ACC the adjustments to the MHRs were extended from five years (2016-2020) to 13 years (2018-2030).[6] As a result of the new assumption for the renewable build-out, the hourly shapes of avoided energy costs changed significantly from the 2017 ACC to the 2018 ACC, with far more zero-price hours in the 2018 ACC, especially in the years after 2020.

It is also important to note that, when the 2016 ACC began to make this yearly adjustment to the MHRs based on DA market prices, the ACC continued to use only one shape, in all years, for CAISO real-time (RT) prices – the prior year's actual CAISO real-

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price shape on hourly market heat rates instead of DA market prices removes the impact of varying natural gas prices.

5 See Energy and Environmental Economics, Inc. (E3), *Avoided Costs 2016 Interim Update* (dated August 1, 2016), at p. 3 (No. 8 of the "Methodology Enhancements"). The documentation states: "Include adjustments to the hourly energy price profile using the CPUC RPS Calculator to account for projected increases in renewable generation. RPS Calculator implied heat rate changes by month/hour are incorporated into the price shape for years 2016 through 2020, and adjustments after 2020 are held at the 2020 levels."

6 See E3, *Avoided Costs 2018 Update* (dated May 24, 2018), at p. 20 (section on "Hourly Shaping of Energy Costs"). See also Resolution E-4942, at p. 6.

time price shape. As noted above, the RT price shape is used in the ACC to determine the hours when the CT is dispatched.

Q: What issues do you have with how the ACC determines the hourly shape for avoided energy prices based on the CAISO DA market?

A: I have several:

- Today, the annual adjustment to the hourly price shape is highly inaccurate, for several reason
  - The RPS Calculator is no longer used for resource planning. The CPUC website notes that the RPS Calculator has been replaced by the IRP.[7]
  - The specific renewable build-out extracted from the 2017-2018 RSP, on which the adjustment is based, is now unlikely to materialize.
  - The adjustment does not replicate recent CAISO market results; for example, it clearly results in far too many zero-price hours.
- The adjustment to the price shape is conceptually wrong because it deprives DERs of credit for a benefit that they will provide to the system if they are deployed.
- It is speculative to penalize a DER that may be installed in the near future – and which will be evaluated using this year's ACC – based on an uncertain build-out of resources in years long after the DER will be on-line.

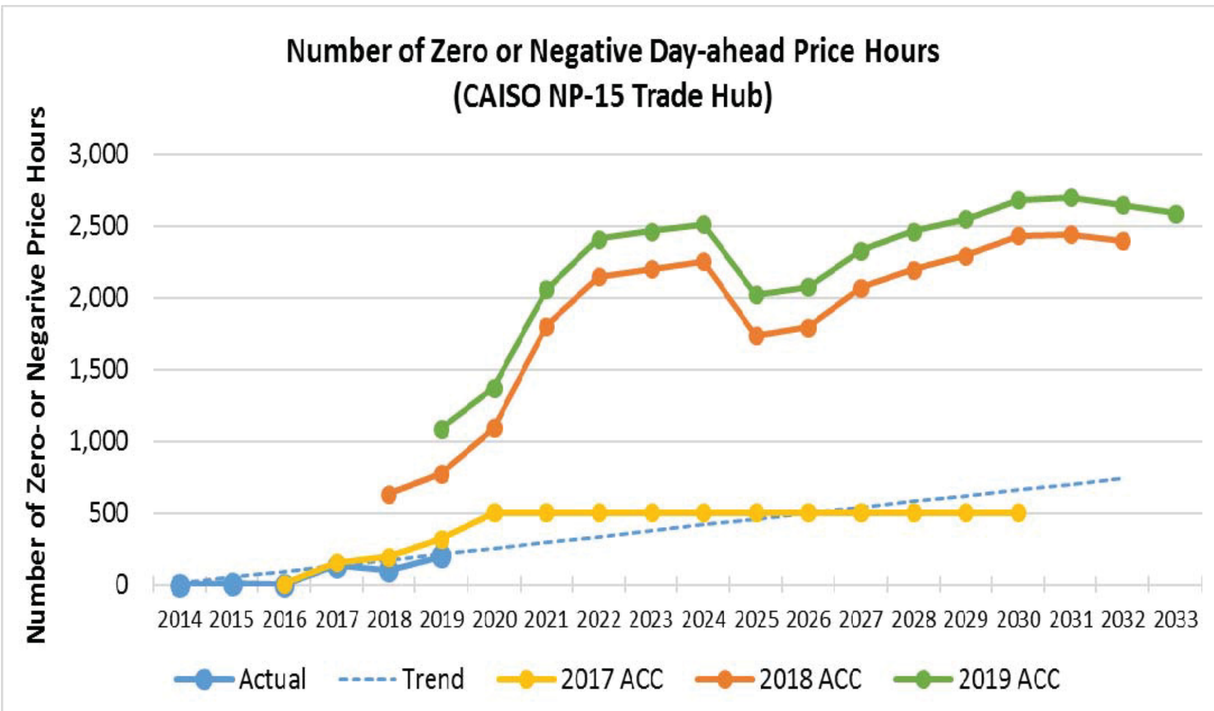
Q: What are your concerns with the accuracy of the adjustments to the avoided energy price shapes used in the 2018 and 2019 ACCs?

A: The adjustment to the energy price profiles used starting in the 2018 ACC has resulted in inaccurate and unrealistic price profiles.

- The adjustment produces far too many hours with zero prices. In the 2018 ACC, the price profile for 2018 forecasted 7% of hours with zero or lower prices, while in reality the actual CAISO DA market recorded less than 1% such hours in 2018.

For the first eight months of 2019, the 2019 ACC predicted 12% of hours with zero or lower prices, while in the CAISO DA market only 1.9% of hours have had zero or lower prices, even though hydro conditions in 2019 were much wetter than normal. **Figure 1** below shows the actual number of DA market hours with zero (or lower) prices in 2014-2019 (to date) compared to the forecasted number of zero-price hours for the same years from the 2017 through 2019 ACCs. Only the 2017 ACC has been close to accurate.

Figure 1: *Actual and ACC-forecasted Zero Price Hours in NP-15*

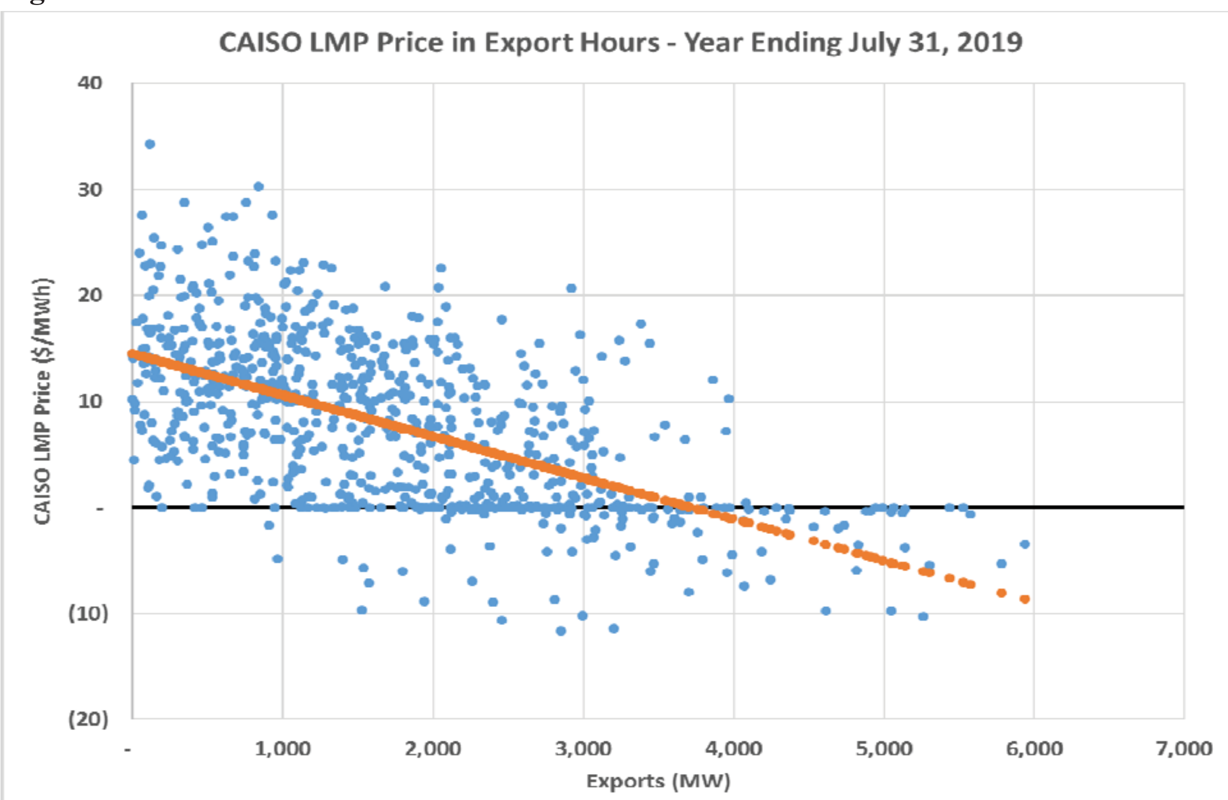


- Further, the profiles in the 2019 ACC predict that, by 2022, more than one-quarter (28%) of the hours in the CAISO market would have zero or below-zero prices, a result which I do not believe is realistic or sustainable. Such prolonged periods of time in which California would offer free power or would pay buyers to take power would quickly result in higher demands for CAISO generation, both within the CAISO and in other WECC markets. This market response would raise prices. The MHR adjustment in the ACC do not include such a market response.

[7] See https://www.cpuc.ca.gov/RPS_Calculator/.

- These profiles are the result of an assumption that CAISO market prices will equal zero (or less) in any hour when the CAISO is presumed to be exporting power because load net of renewables, hydro, and nuclear resources is less than 25% of total loads. We have performed a backcast for the year ending July 31, 2019 to examine whether CAISO DA prices were zero (or below zero) in the hours when load net of renewables, hydro, and nuclear resources was less than 25% of total load. The results of this analysis are shown in **Figure 2**, which shows that there were 781 such hours, but only 162 (21%) in which recorded CAISO DA prices were zero or lower. This shows that the static supply curve used in the MHR adjustment is not accurate. For example, the supply curve is limited only to California resources and does not model WECC-wide power flows or price impacts. Given the increasing integration of WECC markets through new market mechanisms such as the western Energy Imbalance Market, the *ad hoc* adjustment to MHRs from the RPS Calculator is clearly out of date and inaccurate.

Figure 2



Q: Has there been any significant discussion of the accuracy of this annual adjustment to the ACC's energy price profiles?

A: No. There was no discussion of the accuracy or future implications of this adjustment, either in the 2018 or 2019 documentation for the ACC or in Resolution E-4942, when this adjustment was changed to use a new renewable build-out that resulted in a major increase in the number of expected zero-price hours.[8]

Q: Does the assumed renewable build-out used to make the MHR adjustment in the 2018 and 2019 ACCs remain a reasonable assumption?

A: No. This renewable build-out is from the original RSP adopted in D. 18-02-018 as the first step in the 2017-2018 IRP. This plan assumed that the CAISO system will see 9.0 GW of new solar-only generation and 1.1 GW of new wind on-line by 2022.[9] When the Commission adopted the RSP in D. 18-02-018, it specifically declined to order the early procurement of the renewables in the plan, citing uncertainties resulting from the increasing market share of community choice aggregators (CCAs).[10] The Preferred System Plan (PSP) that the Commission ultimately adopted in D. 19-04-019 at the end of the 2017-2018 IRP process reduced this 2022 procurement somewhat, to 6 GW of solar and 1 GW of wind.[11] It now appears that the actual near-term procurement of renewables will be significantly less than the planned quantities in either the RSP or PSP. Near-term procurement has been complicated by the PG&E bankruptcy and possible credit downgrades to SCE and SDG&E, as well as by electric customers' increasing preference to purchase their generation from CCAs. The IOUs face financial constraints on making long-term commitments, and they are long on renewables to serve their declining market

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[8] Resolution E-4942, at page 6, characterized this change in the profiles of energy prices in the ACC to be one of several "minor corrections… made for consistency with the updated GHG adder." Given the major impact on the energy price shapes resulting from this modification (as discussed above), this change should not have been characterized as a "minor correction."

[9] See Decision 18-02-040, at p. 88 (Figure 5).

[10] *Ibid*., at pp. 98-101.

[11] See Decision 19-04-040, at p. 114 (Figure 2). I note that the change in future procurement in the PSP, compared to the RSP, does not appear to have been reflected in the 2019 ACC.

share of fully-bundled IOU customers. The CCAs are undertaking some of the near-term procurement of renewables specified in the 2017 RSP, but the CCAs' procurement of renewables by 2022 appears from recent data to be unlikely to reach the levels specified in the 2017 IRP.[12]

Moreover, the Commission has now opened a "procurement phase" of the 2017 IRP proceeding (R. 16-02-007) that is recommending near-term procurement to meet new concerns about the adequacy of available generating capacity starting in the summer of 2021. The ruling that initiated this new phase included a staff analysis that there is a need for 2,000 MW of system capacity to be on-line by August 1, 2021, plus a need for Southern California Edison (SCE) to re-contract another 500 MW.[13] SCE commented that the 2021 capacity need may be as high as 5,500 MW, and SCE and the CAISO both recommended that the Commission re-orient near-term procurement to include the extension of retirement dates for older, conventional steam generation units using once-through cooling with ocean water (OTC units).[14] In a proposed decision (PD) issued September 12, 2019 in R. 16-02-007, Administrative Law Judge (ALJ) Julie Fitch has recommended that southern California load serving entities (LSEs) procure 2,500 MW of new capacity resources over the 2021-2023 period (with 1,500 MW procured and on-line by the summer of 2021) and that the Commission support three-year extensions of the retirement dates for up to 3,750 MW of older gas-fired OTC units. Thus, much of this near-term procurement may be aging gas-fired generation.

[12] Recent CalCCA comments in R. 16-02-007 show that CCAs currently have contracted for 2,700 MW of new renewables (about 490 MW of firm capacity) to be on-line by 2023. See CalCCA July 22, 2019 comments in R. 16-02-007, at Appendices B and D.

[13] See "[Ruling] Initiating Procurement Track and Seeking Comment on Potential Reliability Issues" issued June 25, 2019 in R. 16-02-007. The staff analysis is attached to the Ruling.

[14] See comments of SCE and CAISO in the Procurement Track of R. 16-02-007, filed in response to the June 25 Ruling.

Q: Even if renewables provide a portion of this near-term capacity need, will the renewables that are procured be the solar-only resources assumed on-line by 2022 in the renewable build-out assumed in the ACC?

A: No. The need for firm capacity is likely to result in the procurement of solar plus storage resources that can offer significant amounts of firm capacity, not the solar-only capacity in the 2017-2018 RSP and PSP. The hourly profile of the output of solar plus storage plants are significantly different than the solar-only resources that were assumed in the MHR adjustment in the 2018 and 2019 ACCs, and much of the capacity of such plants could be dispatchable during the evening peak by the purchasing LSE or the CAISO.

Q: What do you conclude?

A: In this changing environment for near-term procurement, the renewable build-out that is the basis for the adjustments made to the avoided energy price shapes in the 2018 and 2019 ACCs is no longer reasonable or accurate.

Q: Do you agree conceptually with making adjustments to the avoided energy price shapes in the ACC in future years based on an assumed future build-out of renewable generation?

A: No, I do not. The adjustment appears intended to capture the impact that future resources with zero variable cost will have in reducing market-clearing energy prices in the CAISO market. I agree completely that renewable and efficiency resources have had the impact of reducing market prices – obviously we have seen such an impact over the last decade as the growing penetration of solar resources (on both sides of the meter) in California has reduced midday prices dramatically. The problem with including such "market price suppression" in future years in the ACC is that the reduction in market prices is <u>a benefit that will result from the same DERs that the ACC will be used to value</u>. The value of DERs should not be discounted for the fact that they will reduce future market prices. Instead, the Commission should resolve this issue in a way that equitably assigns to future DERs at least a share of the market price suppression benefit that their resources provide.

Q: Is this suppression or reduction of market prices widely recognized as a benefit that should be included in the avoided costs used to evaluate DERs?

A: Yes. The market price suppression benefit has been analyzed extensively in the New England ISO market, where it is called the Demand Reduction Induced Price Effect (DRIPE). DRIPE is included as a benefit of DERs in the region's biennial forecasts of avoided costs used for demand-side programs.[15] Oregon includes market price reduction as one component of its resource value of solar, based in part on a recommendation that E3 made to the Oregon commission.[16]

Q: Are there studies of market price suppression benefits in California?

A: Yes. Clean Power Research conducted a study in October 2015 on fuel hedging and market price suppression benefits of distributed solar in California, finding a 20-year levelized market price response benefit in the range of $30 per MWh (SCE and SDG&E) to $38 per MWh (PG&E).[17] In an August 2018 paper, UC Davis economists also found significant reductions in hourly CAISO energy prices due to increased solar output (e.g. a $20.40 per MWh decrease in CAISO midday real-time prices from 2012 to 2016).[18]

Q: Do the benefits of lower CAISO market prices extend beyond just the direct market purchases that LSEs make from the CAISO's markets?

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[15] See Chapter 7 of the report on *Avoided Energy Supply Costs in New England*, March 27, 2015, at https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf.

[16] See Oregon PUC Order 17-357, at pp. 2-3, which outlines the 11 elements of the Oregon RVOS, including market price response.

[17] Clean Power Research, "Quantifying the Fuel Price Hedge and Energy Market Price Benefits of California's Distributed Solar PV Fleet," (October 5, 2015), at p. 18, Table 9, hereafter "CPR CA Study."

[18] See Bushnell & Novan, "Setting with the Sun: The Impacts of Renewable Energy on Wholesale Power Markets" (August 2018), at https://ei.haas.berkeley.edu/research/papers/WP292.pdf.

A: Yes. Lower CAISO market prices also can reduce the cost of imported power that must compete with CAISO market prices as well as the cost of QF generation whose contracts are linked to CAISO market prices either directly or through short-run avoided cost (SRAC) prices. The result can be a "multiplier effect" on the market price suppression benefit.[19]

Q: Please explain why the MHR adjustment to the energy price shapes is unfair to DERs that may be evaluated using the ACC.

A: The 2019 ACC will be used to evaluate DER programs for the next year, until a revised 2020 ACC is adopted. It is unfair to evaluate DERs that will be added in the coming year (or soon thereafter) based on market price effects from renewable resources that might be added sometime between 2021 and 2030. As discussed above, there is significant uncertainty in the timing and composition of those future resources, as indicated by the change in direction in the new "procurement phase" of the IRP docket. Further, the IRP modeling focuses on the resources needed to meet 2030 carbon reduction goals, with far less attention to exactly when those resources will be procured and built.

Q: Does the renewable build-out on which the energy price shapes in the ACC are based represent the resources that you expect to see developed in the next decade?

A: No. Renewable procurement in the next decade is likely to focus on solar plus storage units that offer significant capacity and renewable integration benefits, not the large amounts of solar-only resources added in the 2017-2018 IRP modeling. In the DER market, the substantial change in rate design that the Commission adopted in all recent IOU GRC Phase 2 cases – specifically the new 4 p.m. to 9 p.m. statewide peak period – is going to drive new solar customers to include storage so that they can shift their solar

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[19] Although this multiplier is certainly greater than one, without specific information on LSEs' procurement activities and contractual arrangements, it is not easy to quantify nor is it straightforward to calculate how lower CAISO market prices impact a particular LSE. I can say that lower CAISO market prices will produce, in aggregate and on average, benefits to energy buyers in the state.

output into the valuable evening peak period.[20] Concerns with electric reliability and resiliency driven by recent wildfires, as well as the extended availability of SGIP incentives for behind-the-meter storage, will further drive adoption of solar plus storage resources.

Q: Based on the above discussion, what is your recommendation for the price shape that should be used for avoided energy costs in the ACC?

A: For all of the above reasons, I recommend using the actual MHR shapes for the most recent calendar year, i.e. 2018, without changes in future years based on an inaccurate adjustment to market heat rates and an uncertain trajectory of building out utility-scale resources.[21]

This resolution equitably shares the benefit of market price reductions between DER customers and other ratepayers. Other ratepayers will benefit because, as more resources with zero variable costs actually come on-line, market prices will decline (as they have in recent years) and this will be reflected in the prior year's actual MHR price shape that is used for the ACC. At the same time, the DERs that are evaluated with the ACC and that will come on-line in the near future will not see their benefits unfairly reduced by the impact that they themselves will have on the market, or by more speculative impacts from resources that may be added long after they are in place.

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[20] The 2017-2018 IRP modeling did not include the potential impacts of the 4 p.m. – 9 p.m. statewide TOU period. See Energy Division presentation of the proposed RSP (September 18, 2017), at Slide 136: "The IRP baseline case for DR does not reflect the rate designs currently contemplated for the planned 2019 default of residential customers onto TOU rates, or the later 4 p.m. – 9 p.m. peak window recommended by the CAISO…."

[21] From a technical perspective, this use of the 2018 price shapes in all years will also help ensure the model can solve reasonably and rapidly for all scenarios. For example, when calibrating for SCE/CZ10, the 2019 ACC model with the MHR adjustment is not able to determine price adjustments that result in zero cost shortfalls in the years 2022, 2023 and 2024. With 2018 price shape used in all years, this problem does not arise.

Finally, this recommendation is consistent with the ACC's use of a single real-time price shape in all years, with the shape taken from the prior year's actual real-time CAISO prices.

Q: If the Commission does adopt an adjustment to the price shape used for avoided energy costs in the ACC, how should the reasonableness of such an adjustment be judged?

A: First, it should replicate past changes in CAISO price shapes, when backcast to prior years. Second, any such adjustment should be based on the updated resource procurement to 2030 adopted in the next IRP cycle (2019-2020) and, given the inherent uncertainty in the exact timing of future resource deployment, should assume a steady trajectory of new resource development out to 2030. Finally, the adjustment should ensure that future DERs receive at least a share in the benefits of any reduction in market prices that they are assumed to cause.

2. Avoided generation capacity cost price shapes

Q: Do similar issues arise with the hourly shapes used in the ACC to allocate avoided generation capacity costs?

A: Yes. The ACC allocates avoided generation capacity costs using two capacity price shapes – one for 2020 and another for 2030 – derived from loss-of-load-expectations (LOLEs) calculated using the RECAP model. The years between 2020 and 2030 are interpolated; years after 2030 use the 2030 capacity price shape. The 2020 profile reflects the significant additions of solar to the CAISO system in recent years, with most of the capacity value allocated to a few weekday evenings in August and September. As discussed above, there is now significant uncertainty in whether the new resources identified in the 2017-2018 IRP will be added as specified in the RSP, particularly given the near-term capacity need that was not evident in the RSP. As discussed above, it is my expectation that renewable resources that provide significant capacity and integration benefits – such as solar paired with storage – will be added instead of the large amounts of solar and wind that the 2017-2018 RSP adds by 2022.

Consistent with the above discussion of energy price shapes, I recommend that the capacity price shape should use, for all years, the near-term 2020 RECAP profile of loss-of-load-expectations (LOLEs) without speculation on the resources that may be added between 2020 and 2030.

C. Natural Gas Forecast Issues

1. Increasing costs, declining throughput, skyrocketing pipeline rates

Q: Please discuss recent trends in the gas industry in California that are relevant to the natural gas forecast used in the ACC.

A: California's ambitious goals to reduce greenhouse gas emissions to 40% below 1990 levels by 2030, and to be carbon neutral by 2045, will have major impacts on California's natural gas system that only now are coming into focus. In particular, reaching the state's carbon reduction goals will result in a significant drop over time in natural gas use among all types of gas customers. Gas throughput on the PG&E and SoCalGas systems is already starting to decline, dropping by about 5% per year over the last five years, as shown in **Table 1**'s recorded data for 2013-2018 from the *2019 California Gas Report Supplement*.[22]

[22] Available at https://www.socalgas.com/regulatory/documents/cgr/2019_CGR_Supplement_7-1-19.pdf, see pages 12 to 16.

Table 1: *Recorded Statewide Gas Supply (MMcfd)*

Year	Throughput
2014	6,504
2015	6,399
2016	5,934
2017	5,862
2018	5,107
Average Annual Change	-5.9% per year

In recent years there have also been serious safety incidents on the California gas system – first, the 2010 San Bruno explosion of a PG&E gas transmission line that killed eight people and destroyed a neighborhood and, second, the 2015 well failure at SoCalGas' Aliso Canyon storage field that resulted in a major release of methane, with lengthy evacuations and adverse health impacts for nearby residents. As a result of San Bruno, the California gas utilities have made major investments in replacing and upgrading their gas transmission infrastructure. New regulations for gas storage fields after Aliso Canyon are likely to result in the decommissioning of some older storage fields and to raise future costs to store gas.[23] Largely driven by these safety-related investments, PG&E's adopted revenue requirement for its gas transmission and storage facilities has increased from $462 million in 2010[24] to the $1,580 million that the Commission just authorized for 2022 in its final decision in A. 17-12-009.[25] This is an average increase of 10.8% per year over 12 years.

Gas transportation rates paid by gas-fired electric generators (EGs) are calculated with the costs of the pipeline and storage infrastructure in the numerator and gas throughput in the denominator. With the numerator rising due to safety-related costs and the denominator decreasing as the result of programs to reduce carbon emissions, the

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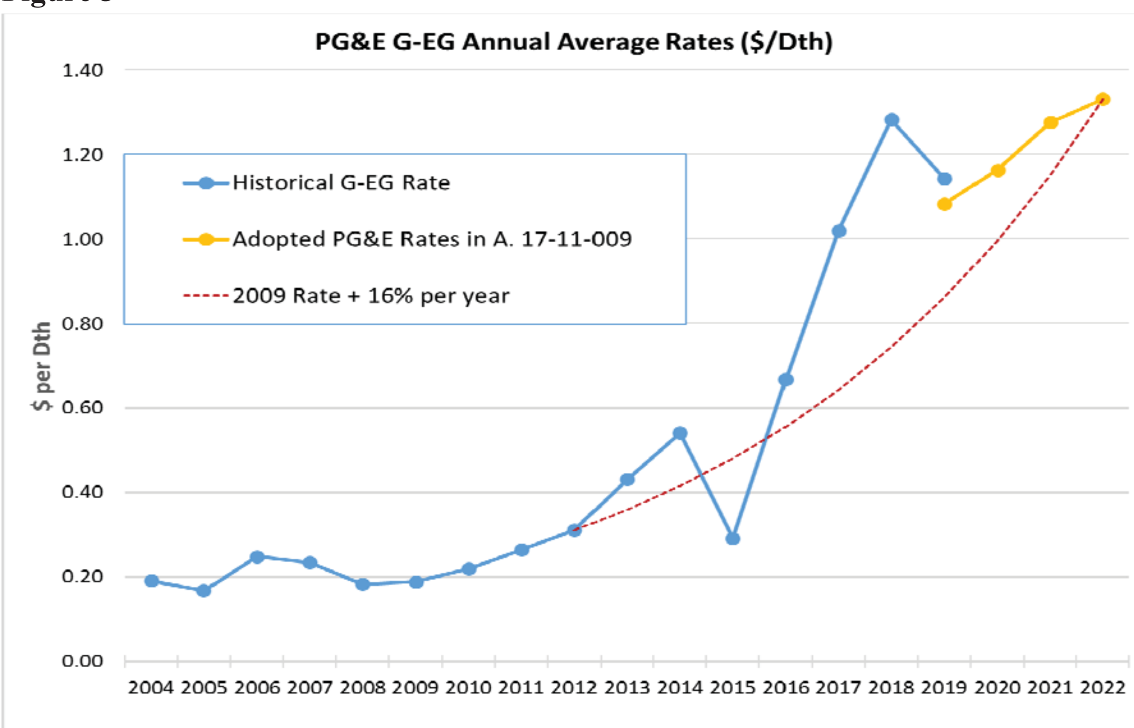
[23] See the Commission's recent approval of PG&E's plan to decommission two older storage fields, in the final decision in the PG&E Gas Transmission & Storage rate case, A. 17-11-009 (the final order is not yet available).

[24] See D. 11-04-031, at p. 16.

[25] Based on the agenda decision in A. 17-11-009, at Appendix E, Table 1.

result has been dramatic escalations over the last decade in the gas transportation rates paid by EG customers. For example, **Figure 3** shows PG&E's actual G-EG transportation rate from 2004 to 2018 (blue line), including the new G-EG rates just adopted in the final decision in the PG&E Gas Transmission & Storage rate case, A. 17-11-009 (yellow line).[26] The figure indicates that, during the 10-year period from 2009 to 2018, PG&E's G-EG rate escalated at an average rate of 25% per year. Over a somewhat longer 15-year period (2004 to 2018), the average escalation in the G-EG rate was 15% per year. The new rates for 2019-2022 just adopted in the PG&E GT&S rate case decision indicate that the escalation rate from 2009 to 2022 will average 16% per year (red dashes). Obviously, this rate escalation is roughly consistent with the 11% annual increase in revenue requirement (2010 to 2022) and the 6% annual decline in throughput (2014 to 2018) cited above.

Figure 3



[26] We note that these rates do not include certain additional charges, such as the municipal surcharge.

Q: Have there been any recent studies which indicate whether these sharp escalations in gas transportation rates in California are likely to continue?

A: Yes. There have been two significant recent studies on this topic.

E3 Gas Study for the CEC. At a California Energy Commission (CEC) workshop on June 6, 2019, E3 presented new work on the impact of California's carbon reduction goals on future natural gas rates in California, as part of a Public Interest Energy Research (PIER) grant.[27] The purpose of the study was to evaluate the implications of a low-carbon future in California for the customers of the natural gas system, including both economic and health impacts. This study reached the following major conclusions:

- Continuing to use fossil natural gas in buildings at today's levels of consumption will not meet the state's carbon reduction goals.
- Using renewable natural gas (RNG) to decarbonize buildings, by replacing fossil methane with RNG, would maintain gas throughput and could meet the state's climate goals, but would be an expensive strategy for the state.
- Building electrification is a lower-cost strategy to achieve the state's climate goals.
- Building electrification will further reduce gas throughput and raise rates for remaining gas customers, in addition to the expected declines in EG gas use due to electric sector programs such as the RPS.
- A gas transition strategy is needed to reduce the costs of the gas system and protect consumers from high future rates.
- Building electrification improves air quality and health outcomes in urban centers.[28]

E3's study projects continued sharp increases in the revenue requirements for the gas utilities of 5% real per year (i.e. above inflation) through 2025, due to continuing safety-

[27] E3, "Draft Results: Future of Natural Gas Distribution in California," presented at the CEC Staff Workshop for CEC PIER-16-011 on June 6, 2019. Hereafter, "E3 Gas Study." Available at https://ww2.energy.ca.gov/research/notices/2019-06-06_workshop/2019-06-06_Future_of_Gas_Distribution.pdf.

[28] E3 Gas Study, at Slides 6 and 15.

related investments, then increasing at 1% real thereafter through 2050. See **Figure 4** below, Slide 22 from the E3 Gas Study. At the same time, in the favored high building electrification case, overall throughput on the gas system declines at about 3.5% per year from 2020-2050, with EG throughput dropping at 5% per year in all scenarios. See **Figure 5**, which is Slide 16 from the E3 Gas Study.

Figure 4: *Slide 22 from the E3 Gas Study*

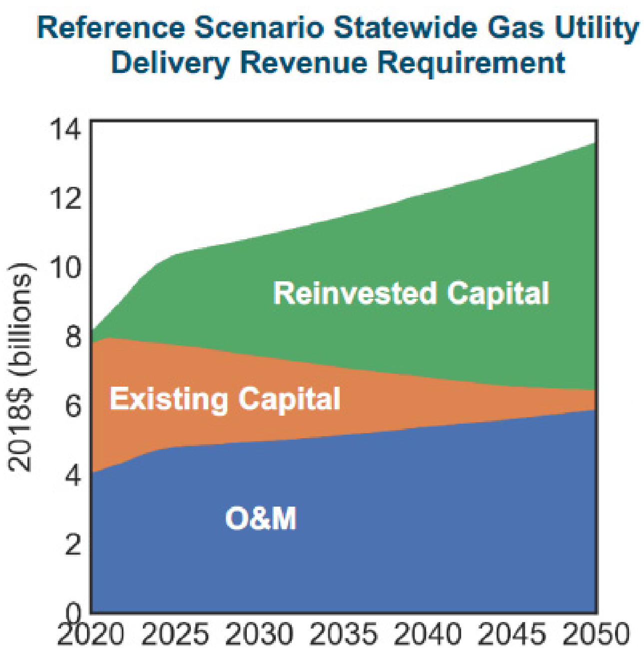
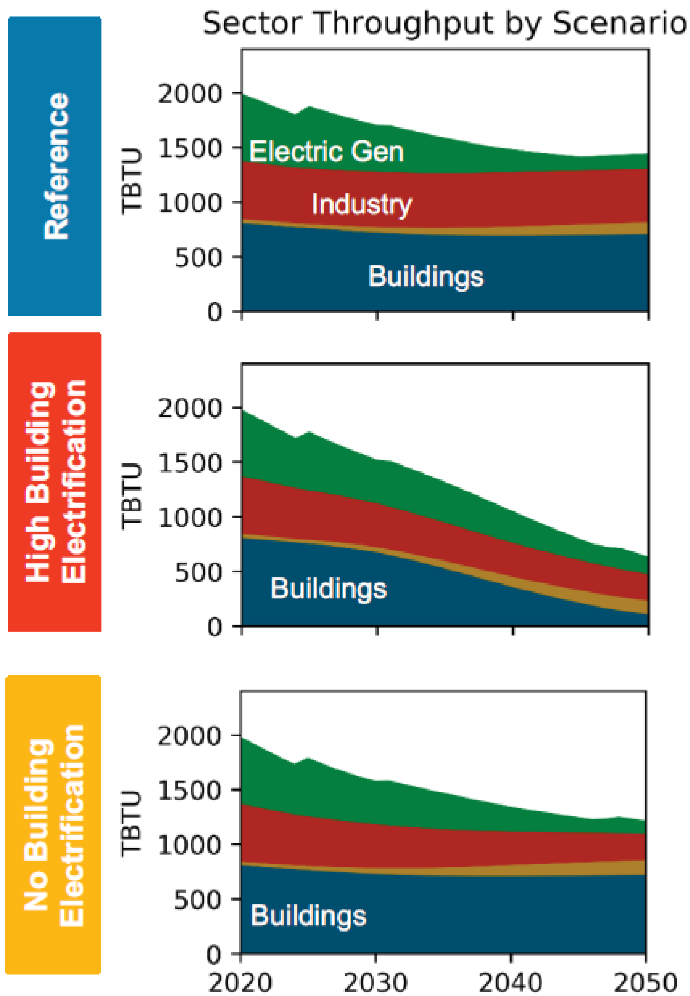


Figure 5: *Slide 16 from the E3 Gas Study*



Assuming that EG customers' share of the overall revenue requirement changes in proportion to their share of the overall throughput, the E3 results suggest a long-term real escalation in EG rates in excess of 10% per year through 2025 (continuing the trend since at least 2010) and 5% to 10% per year after 2025, unless steps are taken to reduce future gas system revenue requirements. The E3 study suggests a number of steps that could be taken (but have yet to be adopted) to mitigate future rate increases, including the accelerated depreciation or targeted retirement of gas assets.

Gridworks Gas Study. On September 19, Gridworks released a new study, *California's Gas System in Transition: Equitable, Affordable, Decarbonized and Smaller*.[29] This work focuses on the transition strategies that could be used to mitigate the rapidly-growing gas rates that will result from the steep decline in gas throughput that is likely to result from widespread building electrification. The Gridworks Study's participants reviewed and accepted the conclusion of the E3 Gas Study that a high building electrification scenario will be the least-cost way to meet the state's goals to reduce carbon emissions.[30] The study succinctly summarizes the challenge that the state faces with keeping future gas rates affordable:

> *The simple fact is that meeting California's GHG reduction goals, a statewide priority and absolute necessity to combat climate change, inevitably means a substantial decline in gas throughput in the state. At the same time that gas demand is projected to decline over time, the costs of operating a safe and reliable gas delivery system in California have been increasing.*[31]

The study shows that rates will increase significantly for all classes of gas customers, including EG plants, and that it is the remaining residential gas customers who will face the largest increases, unless the state adopts a comprehensive, carefully-planned set of mitigation measures. The report emphasizes that, as gas rates increase, this will only increase the incentive for residential customers to adopt electrification measures, further reducing gas throughput.[32] The Gridworks Study provides an in-depth discussion of a range of possible mitigation strategies that state policymakers could pursue to lower future rates for small customers, including accelerated depreciation, reduced investments and targeted retirements, securitization, and cost allocation and rate design changes for

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[29] Available at https://gridworks.org/initiatives/cagas-system-transition/, hereafter "Gridworks Study." This study was funded jointly by PG&E and the Energy Foundation, with technical input from E3. I participated in the Gridworks Study as part of a group of stakeholders that provided significant feedback during the course of the work.
[30] See Gridworks Study, at pp. 1 and 4-5.
[31] *Ibid*., at p. 1.
[32] *Ibid*., at pp. 1-2 and 9-10.

gas distribution costs. The Gridworks Study shows that these mitigations could have a significant impact to reduce the escalation in future rates for residential and other small customers, but would not have a major impact in reducing the escalation in EG rates.[33]

These important new studies inform the recommendations that I present below on future escalation rates for intrastate EG gas transportation rates in the gas forecast that should be used in the ACC.

2. Proposed natural gas burnertip price forecast

Q: Please describe the structure of the existing natural gas burnertip price forecast in the ACC.

A: The forecast was developed in a series of Commission decisions on the gas forecast used to project all-in CCGT costs for the market price referent (MPR) that was used for a number of years as a price benchmark for the RPS program. Here are the key elements of the ACC gas forecast:

- **Gas Commodity.** Seven years of forward market prices at the benchmark Henry Hub market, then a three-year transition after year 7 to the long-term Henry Hub fundamentals forecast from the most recent *Annual Energy Outlook* published by the Energy Information Administration (EIA).
- The price, or **"basis,"** differences between (1) the Henry Hub market and (2) California markets at the SoCal border and PG&E city-gate. The basis differences use seven years of forward market prices, then the differentials are kept constant in subsequent years at the average of the basis values for

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[33] The Gridworks Study acknowledges, at page 14, that the severe increases in residential rates could generate future pressure to shift costs from small customers to large users such as EG plants, further increasing EG rates. The Gridworks Study states that such a re-allocation of costs would need to be

the first seven years.

- **Intrastate transportation charges** to the EG burner-tip are based on the current tariffed SoCalGas or PG&E EG transportation rates downstream from either the SoCal border (for EG plants on the SoCalGas system) or the PG&E city-gate (for EG plants on the PG&E system), with a long-term rate escalation of just 2.2% (i.e. at inflation).[34]

Q: What are your primary concerns with this gas forecast?

A: My first concern is the assumption that future gas transportation rates in California will escalate at just the rate of general inflation. For the reasons discussed above – (1) increasing costs to meet new safety concerns and (2) declining throughput to meet carbon constraints – gas pipeline transportation rates within California for EG customers will escalate at far above inflation for the next 20 to 30 years, even if California is successful at implementing the comprehensive suite of rate mitigations outlined in the Gridworks Study. I recommend that the Commission assume that intrastate rates will increase at real escalation rates of 9% per year to 2025, then 4% thereafter to 2050 (in nominal terms, this would be 11% per year to 2025, then 6% per year thereafter). This recommendation is consistent with the EG rate scenarios in the Gridworks Study even with the best-case suite of mitigations that have yet to be adopted.[35]

Second, the existing forecast relies too heavily on forward prices. The forward market for seven years of natural gas at fixed prices is neither liquid nor broadly traded. The open interest in the NYMEX gas forward market is almost entirely in the first two

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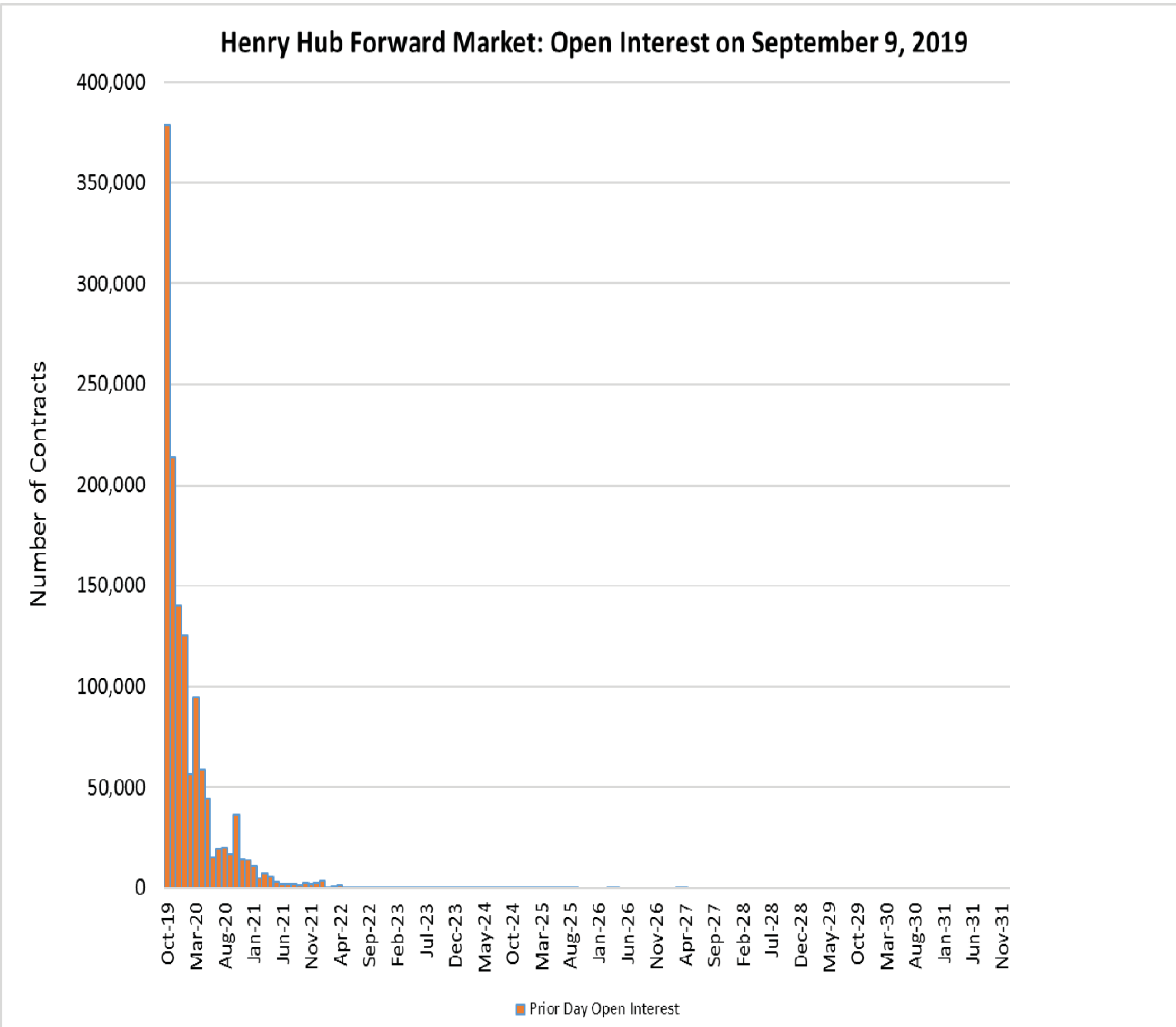
"carefully considered" given that it would increase electric rates and could shift carbon emissions to out-of-state EG plants.

[34] The MPR gas forecast includes the tariffed rates for EG transportation and for the municipal surcharge, plus a small adder of $0.08 per Dth for hedging transaction costs. The current MPR forecast incorrectly includes the component of EG rates that recovers GHG allowance costs from the California cap & trade market; the ACC includes a separate component for these costs. We have removed the cap & trade component of EG rates in order not to double-count this avoided cost.

[35] See, for example, Figure 9 on page 14 of the Gridworks Study.

years. For example, **Figure 6** shows the open interest[36] from the market on September 9, 2019. 99% of the open interest is in the first two years. Given the small and sporadic volumes traded after the second year, the reported prices after two years are less certain and convey less information than the initial two years that are heavily traded.

Figure 6



[36] "Open interest" indicates the number of outstanding forward market contracts that have not been settled. From the time the buyer or seller opens a forward contract until the counter-party closes it, that contract is "open." Open interest is an important measure of the activity and liquidity in a market.

Forward prices and fundamentals forecasts both have roles to play in a reasonable gas price forecast. Forward prices provide market-based information on short-term price trends, which are influenced strongly by current demand, by near-term expected demand, and by the current status of gas in physical storage. It make sense that short-term forward prices provide a reasonable forecast of short-term spot prices, in part because the two markets are clearly linked by the physical and economic ability to store gas from one season to the next. But I am not aware of substantial evidence that using as many as seven years of forward price data, including years that are thinly-traded, is superior to forecasts that examine the fundamentals of natural gas supply and demand. It is important to remember that forward prices represent the price at which parties are willing to contract for future supplies today, but not necessarily what the price for those future supplies will be tomorrow or when the fulfillment date for the forward contract is reached. Forward prices often track current prices, and it is a common observation that the magnitude of the forward price curve shifts up or down largely in parallel to changes in the current spot price.[37]

Fundamentals forecasts look at longer-term trends in the gas supply and demand balance in North America and the world market for liquified natural gas (LNG). For example, the *2019 AEO* forecast considers the impacts of both the growing demand for U.S.-produced natural gas in domestic and export markets as well as the growth in production from shale gas and gas associated with tight oil production.[38] EIA expects that increases in gas demand for electric generation will be driven by retirements of coal and nuclear capacity.[39] Fundamentals forecasts tend to be higher than forward market prices in falling markets (e.g. since 2010), but lag forward prices in rising markets (e.g. in the 2000s). For example, in 2009 researchers at the Lawrence Berkeley National noted that

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[37] For a graphic illustration of this using forward oil price curves, see Timera Energy, *The dangers of mixing forecasts and forward curves*, Chart 1, available at https://timera-energy.com/the-dangers-of-mixing-forecasts-and-forward-curves/.
[38] See *2019 AEO*, at pp. 73-76.

EIA's yearly *AEO* gas forecast had fallen below contemporaneous forward prices for nine years in a row.[40] Obviously, that trend has changed since 2010. These changing trends over time also are apparent in the EIA's own analysis of the accuracy of its past AEO forecasts.[41] I concur with the observations of a group of utilities, who commented on the importance of the fundamental factors that influence future gas prices in seeking to extend a gas hedging program in Florida:

> [The] increased dependence on natural gas means customers will have significant exposure to the uncertainties of natural gas prices if hedging were completely discontinued. While natural gas prices have trended downward in recent years, neither future gas prices nor the level of price volatility can be predicted with any certainty. Additionally, the recent downward trend in natural gas market prices cannot continue indefinitely. Factors such as production costs, weather, environmental regulations and exportation impact natural gas supply and demand, as well as natural gas price volatility.[42]

I propose a balanced forecast that uses forward market prices for the first two years, where the market is robust and deep, then transitions over the next five years to the average of a set of recent fundamentals forecasts.[43] This places a gradually declining emphasis (80% in Year 3, 60% in Year 4, and so on) on forward market prices, which reflects the declining volumes of trades and open interest in these out years.

The third change that I propose is to return to the use more than one long-term fundamentals-based forecast, to take advantage of more than one perspective on long-

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39 *Ibid*., at pp. 81-82.
40 Mark Bolinger and Ryan Wiser, *Comparison of AEO 2010 Natural Gas Price Forecast to NYMEX Futures Prices* (LBNL, January 2010), available at https://emp.lbl.gov/sites/all/files/update-memo-lbnl-53587.pdf.
41 See https://www.eia.gov/outlooks/aeo/retrospective/pdf/table_8a.pdf.
42 See *Joint Petition by Investor-Owned Utilities for Approval of Modifications to Risk Management Plans*, filed April 22, 2016 by Duke Energy Florida, Florida Power & Light, Gulf Power, and Tampa Electric in Florida Public Service Commission Docket No. 160096-EI, at ¶ 5.
43 I also propose to use the Henry Hub – California border basis differential from the forward market for the first two years, then hold this difference constant for the rest of the forecast.

term gas prices. Originally, the approved MPR gas forecast used the average of four fundamentals forecasts.[44] I would use at least two forecasts: (1) the CEC's IEPR gas forecast for the SoCal border market, and (2) for a national perspective, most recent EIA *AEO* forecast.

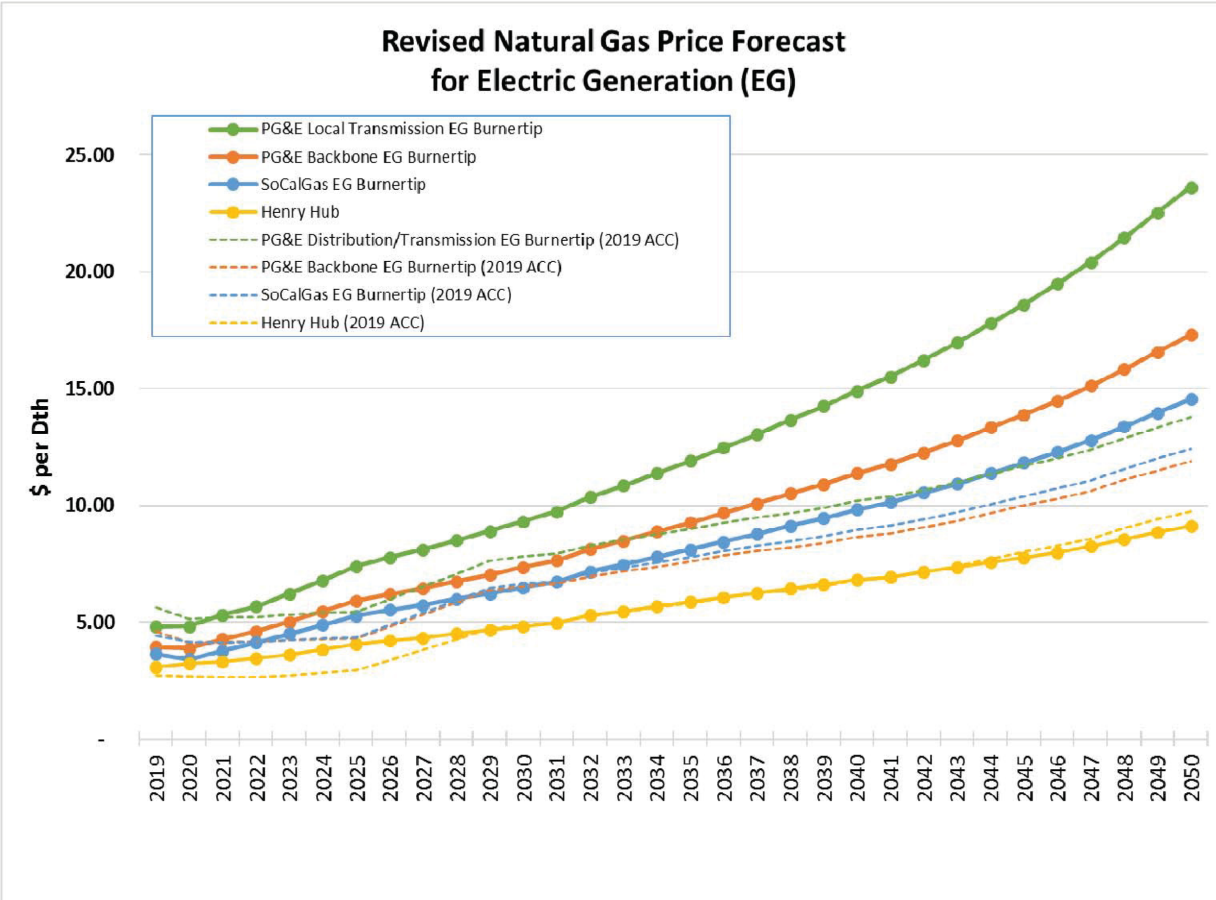
Fourth, PG&E's backbone transportation rates upstream from the PG&E City-gate market will be impacted by the significant increases in intrastate transportation rates. To ensure that the forecast fully captures the expected growth in PG&E backbone rates, I drive the forecast for the PG&E city-gate market under the assumption that city-gate price will reflect the SoCal border price plus the as-available transportation rate on the PG&E Baja backbone path. Over time, PG&E city-gate market prices have tracked the SoCal border price plus the as-available Baja path transportation rate.

Q: Please present the resulting burner-tip gas forecast for gas-fired EG plants.

A: The solid lines on **Figure 7** show the recommended gas forecasts for 2019-2048. For comparison, the dashed lines in the figure are the forecasts used in the 2019 ACC. **Attachment RTB-2** provides VS/SEIA's recommended gas forecasts in tabular form.

[44] See D. 04-06-015.

Figure 7



3. Choice of EG burnertip costs

Q: The ACC's burnertip gas forecast currently uses a simple average of three burnertip gas prices: (1) PG&E EGs connected to the local transmission system (Schedule EG-LT), (2) PG&E EGs connected to the backbone transmission system (Schedule EG-BB), and (3) EGs in southern California on the SoCalGas/SDG&E system (Schedule GT-5NC). Do you recommend a change in this practice?

A: Yes. I recommend the calculation of separate avoided energy costs for northern (PG&E) and southern (SCE/SDG&E) California. The ACC presently calculates an average statewide EG burnertip gas price by combining northern and southern California prices.

This statewide average burnertip gas price is not a price that any EG plant would ever face; an EG plant will face a price specific to its location in either northern or southern California. As a result, the southern California burnertip price should be used for the southern California avoided energy cost. For the northern California avoided energy cost, I recommend the use of the average of the two northern California burnertip prices. The PG&E G-EG-LT transportation rate to power plants served from the PG&E local transmission system is much higher than the G-EG-BB rate to plants that connect directly to the PG&E backbone system. As a matter of economics, one could assume that the higher-cost, local transmission EG plants are most likely to be on the margin, and thus that the burnertip cost of gas to these plants represents the marginal gas-fired unit. However, the majority (60% to 80%) of PG&E's EG gas throughput is to the backbone EG plants,[45] plus there is evidence that PG&E discounts the EG-LT rate to help the local transmission EG plants remain competitive in the market.[46] As a result, I have used the average of the two burner-tip gas prices in northern California.

D. Other Minor Changes

Q: Do you recommend any other minor changes to the avoided generation costs in the ACC?

A: Yes. First, consistent with my recommendation above to use just two years of forward gas market prices, I also recommend that the ACC should use no more than two years of forward electric prices. The electric forward market is even less transparent than the

[45] See Table 16C-3 of PG&E's testimony in the most recent GT&S Rate Case (A. 17-11-009), available at https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=430331. In 2016, about 60% of PG&E's market responsive electric generation demand was on the PG&E backbone system. PG&E forecasted the share of generation on the backbone system will grow to about 78% in the 2019 to 2022 rate case period. Decision 19-09-025 in A. 17-11-009 added 98 MDth/d to PG&E's 2019-2022 market sensitive EG throughput forecast, allocated between local transmission and backbone services based on the recorded division between these services in 2017.

Henry Hub gas forward market. The other Commission-approved use of electric forward market prices of which I am aware is for determining market heat rates for short-run avoided cost (SRAC) energy prices. SRAC pricing uses only one year of electric forward market prices for the NP-15 or SP-15 trade hubs.[47] In my experience working with the ACC, this change has little impact on the ACC results when the resource balance year feature of the ACC is set to the first year (i.e. 2019).

Second, one of the clear benefits of DG is that it allows the utility to avoid energy costs. The ACC calculates these avoided energy costs based on the hourly profiles of NP-15 or SP-15 CAISO trade-hub prices that would be paid to CT or CCGT generators. However, this does not capture the more specific locational value of energy in the CAISO's locational marginal pricing (LMP) market. Energy prices vary across the CAISO grid by location as a function of congestion costs and line losses, and these variations are captured in the LMP prices at 3,000 nodes across the CAISO grid. The LMP prices that DERs in the IOU load centers avoid are best represented by each IOU's default load aggregation point (DLAP) price, not by the trade hub prices. The loss factors used in the ACC appear to be based on energy losses from the generator to the customer, but do not appear to capture the congestion cost component of the difference between DLAP and trade hub prices. These congestion costs are the short-term costs of re-dispatching units on the CAISO system to avoid congestion on the CAISO grid, and are avoided by DERs located behind the meter. To estimate the locational value of DERs at avoiding congestion costs, we have examined the difference over the last year between the congestion costs in (1) CAISO trade hub prices (NP-15 and SP-15) and (2) the default load aggregation point (DLAP) prices for the three IOUs. We have added this difference to the energy loss factors used in the ACC for each IOU.

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[46] See the Rebuttal Testimony of R. Thomas Beach on behalf of Calpine in the GT&S rate case (A. 17-11-009), at pages 18-19, also available at https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=430331.

[47] See D. 07-09-040 and Resolution 4246.

Finally, the model solves sequentially for the avoided energy costs necessary for a CCGT to fully recover its costs, first for NP15 then for SP15. There is a problem with this sequential approach, because the NP15 CCGT may have a shortfall in its cost recovery after the SP15 energy prices have been computed such that the SP15 CCGT shortfall is zero. This is due to the use of a statewide capacity price which causes the SP15 results to impact the NP15 results, and vice versa. The ACC model acknowledges this feedback issue, noting that the "shortfall for PG&E will vary from zero because of the impact of SCE energy price calibration on the statewide average capacity revenues."[48] We have resolved this issue by modifying the ACC to calculate energy prices with zero shortfall for whichever market (NP15 or SP15) is being modeled in that run.

E. Avoided T&D Issues

Q: Please explain why you are addressing avoided transmission and distribution (T&D) issues for the ACC, when certain of these issues also are under consideration in R. 14-08-013.

A: At the August 30, 2019 workshop on major changes to the ACC, the Energy Division made clear that parties should present testimony in this docket on their proposed changes to the ACC related to avoided T&D – and in particular the issue of including avoided high-voltage CAISO transmission costs. The first section below addresses this issue. In addition, the current avoided T&D costs used in the ACC are taken from the record of marginal T&D costs proposed for use in CPUC ratemaking in recent GRC Phase 2 cases. There are proposals in R. 14-08-013 to continue to use these GRC Phase 2 marginal T&D costs in the ACC, perhaps supplemented for a five-year period by a new methodology based on the IOUs' Grid Needs Assessments that is also under consideration in that docket. Thus, it is likely to be necessary to update the current avoided T&D costs in the ACC to use the most recent and representative values from GRC Phase 2 cases. The

[48] See the ACC Market Dynamics tab, at cell B322.

second section presents recommendations for how to do this. Finally, annual avoided T&D costs must be allocated to the hours of the year. Recent IOU rate cases have addressed this issue, which is increasingly important given today's emphasis on time-varying rates. The third and final section discusses the hourly allocators for avoided T&D costs that should be used in the ACC.

1. Avoided CAISO transmission costs

Q: Does the current ACC include avoided costs associated with the CAISO's FERC-jurisdictional, high-voltage transmission system?

A: Yes, but only for PG&E. For PG&E, the ACC currently includes an avoided CAISO transmission cost value of $7.71 per kW-year. As I will explain below, this value is far too low, but at least it is not zero. In contrast, for SCE and SDG&E, the ACC does not include an avoided cost for CAISO transmission. Clearly, there is an inconsistency here that needs to be resolved.

Q: Why is it critical for the Commission to adopt a value in the ACC for avoided CAISO transmission costs?

A: A fundamental attribute of DERs is that they are installed on the customer's premises, behind the meter and interconnected to the IOU's distribution system. DERs such as energy efficiency and demand response reduce the end use of electricity, and thus clearly reduce loads on the CAISO system. To the extent that a DER such as behind-the-meter solar produces power, that generation is consumed either by the host customer, i.e. behind the meter, or is exported to the distribution system where it is consumed by the host's neighbors. In sum, at today's penetrations of DERs, the predominant impact of DER generation is to reduce the peak demand for electricity that must be served from the CAISO transmission grid.

Q: There are several recent examples of DERs serving as "non-wires alternatives" (NWAs) for specific CAISO transmission upgrades that would otherwise be needed in a particular local area.[49] Why don't the costs of these avoided upgrades serve as a measure of avoided CAISO transmission costs?

A: I agree with the Energy Division's careful distinction in R. 14-08-013 between "specified" and "unspecified" avoided T&D costs.[50] The CAISO is developing a process for evaluating NWAs, but only in certain specific locations, and the Commission has piloted a parallel process, the Distribution Investment Deferral Framework (DIDF), for using DERs to defer specific distribution upgrades. Both of these processes are relatively new, have had only limited success, and will likely be refined in the coming years as regulators gain experience in considering the use of DERs to replace specific planned T&D investments.

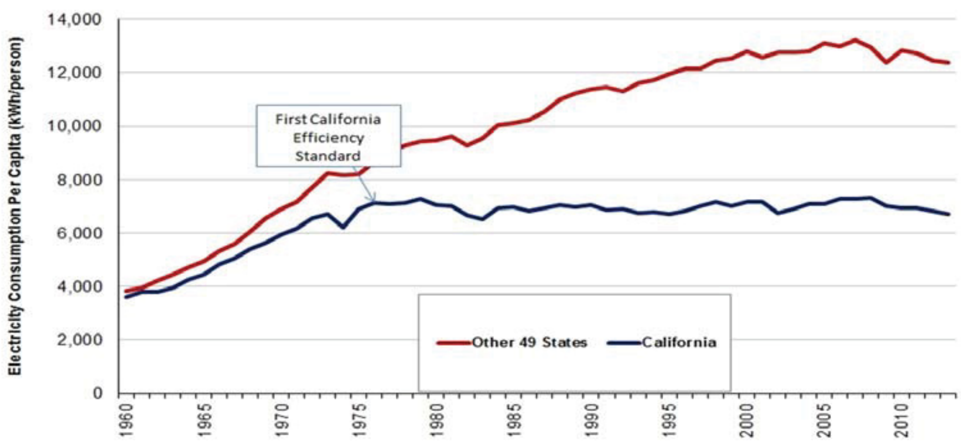
However, these "specified" avoided T&D costs will not capture all of the long-run T&D costs that DERs will avoid. California's distributed energy resources on the customer's side of the meter have been responsible for avoiding transmission and distribution resources for decades. The reduction in electricity demand can be seen in the famous Rosenfeld Curve (see **Figure 8** below), which shows that California has flattened its per capita electricity usage over the last four decades even as per capita electric consumption continued to grow in the rest of the United States. If California had followed the per capita demand trajectory of the rest of the U.S., electric demand in

[49] For example, the CAISO developed transmission alternatives to resolve capacity deficits in the western Los Angeles Basin resulting from the retirement of coastal OTC power plants and the SONGS nuclear units. These transmission investments provided cost benchmarks against which to evaluate generation alternatives in the western L.A. Basin local reliability area (LRA), including DERs and other preferred resources. PG&E and East Bay Clean Energy used a similar process to procure DERs as an alternative to the transmission upgrades that would be needed to replace a set of aging gas-fired peakers in downtown Oakland.

[50] See the Energy Division's *White Paper on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values*, attached to a ruling dated June 5, 2019 in R. 14-08-013, esp. Table 5.

California would be more than 50% higher today.[51]

Figure 8: *the Rosenfeld Curve*



This accomplishment has allowed California to avoid major investments in transmission and distribution infrastructure, including significant investments that have never appeared in the utility planning process as a result of the lower demand trajectory. This illustrates the challenge in assessing the "counterfactual," long-run avoided investment and capacity-related costs associated with long-lived resources such as DERs.

Finally, it is clearly important to avoid any double-counting of avoided T&D costs. Thus, any method used to calculate unspecified avoided T&D costs should be careful not to use the costs for any specified T&D upgrades that are deferred through the use of NWAs or DIDF.

Q: What evidence is there that DERs avoid unspecified CAISO transmission costs?

A: There is abundant data in the last three approved CAISO transmission plans (covering

[51] See A. Rosenfeld, D. Poskanser, *A Graph Is Worth a Thousand Gigawatt-Hours: How California Came to Lead the United States in Energy Efficiency*, available at https://eta.lbl.gov/sites/all/files/related-files/innovations-fall09-poskanzer.pdf, esp. p. 73, also https://www.nrdc.org/experts/sierra-martinez/california-leads-nation-energy-efficiency-part-2-myth-busting-naysayers.

from 2016 to 2019) which document more than $3 billion in previously-approved CAISO transmission costs that have been cancelled, delayed, or downsized as a result of lower load forecasts – load forecasts which the CAISO acknowledges have dropped in significant part as a result of the growth in DER deployment. The permanent reduction in CAISO-level transmission costs in these three plans exceeds $2 billion. Each of the three plans explains these lower load forecasts are the result, in significant part, of DER adoption. For example, the first page from the *2017-2018 CAISO Transmission Plan* states:

> *<u>Consistently declining load forecasts</u> across the entire forecast period – especially for the one-in-ten peak load forecasts affected by weather normalization processes – has led to the third year of re-evaluation of previously-approved upgrades. This year's re-evaluation effort has been the most comprehensive to date, and also entailed not just reviewing and canceling previously-approved projects, but also re-scoping projects to more effectively and efficiently meet needs. <u>The downward pressure on peak demand load growth and energy consumption was compounded by higher than anticipated development of behind-the-meter solar photovoltaic generation.</u> Behind-the-meter solar has reduced the summer peak loads traditionally occurring in mid-day in many parts of the state and shifted them towards the unaffected load levels occurring later in the day when solar production has dropped off.*[52]

Very similar language appears on the first pages of the 2016-2017 and 2018-2019 CAISO Transmission Plans.

The following figure and tables show how the growth in DERs contributed to lowering the 1-day-in-10-year peak demand forecasts that the CAISO used in these transmission plans. In **Figure 9**, the black lines are actual recorded demands. The yellow lines show the 2014 CEC demand forecast prior to the last three CAISO transmission plans. The blue lines show the 2017 CEC demand forecast used for the

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[52] *2017-2018 CAISO Transmission Plan*, at p. 1 (emphasis added).

2018-2019 transmission plan, three plans after the 2014 forecast.[53] The solid lines are the final net peak demand from end-users; the dashed lines show what demand would be absent self-generation (including solar PV) and demand response resources. The orange lines in the figure show the 2009 CEC demand forecast, because some parties to R. 14-08-013 have asserted that the drop in the demand forecast from 2009-2014 also could have contributed to the cancellation or delay in projects approved as far back in time as 2009.

The difference between the dashed and solid lines of the same color in Figure 1 shows the impact of DERs such as solar PV and DR plus other onsite self-generation. Clearly, the increase from 2014 to 2017 in the amount of peak demands expected to be supplied using onsite generation or DR has had a major impact on the forecasted CAISO peak demands. The figure also shows lower overall demands in successive 2014 and 2017 forecasts (dashed lines); this lower overall demand reflects, in part, the impact of another type of DER (energy efficiency).

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[53] These demand forecasts are from Form 1.4 of the CEC's California Energy Demand (CED) forecasts of "mid" case peak demand. Form 1.4 for the CED 2017 forecast is available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=222323&DocumentContentId=28716. For the earlier CEC forecast before the last three CAISO planning cycles, we used the CEDU 2014 forecast. See https://www.energyarchive.ca.gov/2014_energypolicy/documents/demand_forecast_sf/Mid_Case/STATEWIDE_Mid.xlsx.

Figure 9:

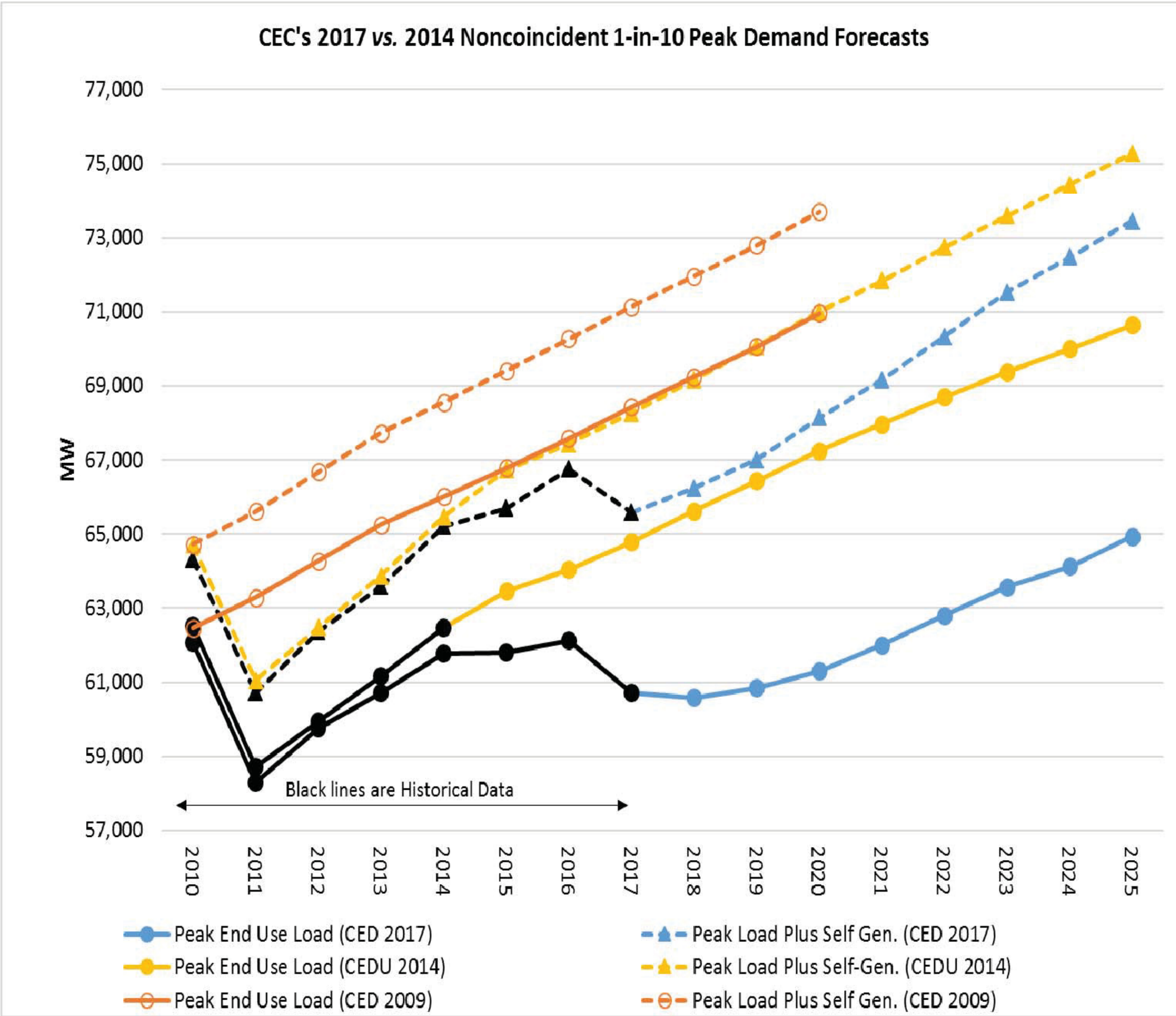

Table 2 below adds up the cumulative $2.0 billion reduction in CAISO transmission investments over the last three CAISO transmission plans, by the most recent year in which each canceled or downsized project was expected to come on-line. The table also shows the change over these three planning cycles in the CEC's one-in-ten net end-use demand forecast (from **Figure 9**), and calculates an implied avoided CAISO transmission cost of $49 per kW-year based on the reduction in transmission investments driven, in substantial part, by the cumulative change in

demand from 2014 to 2017. Even if one uses the cumulative change in demand from 2009 to 2017, the avoided CAISO transmission cost only drops to $30 per kW-year.[54]

Table 2: *Avoided Costs of CAISO Transmission Investments*

	Saved Costs of Cancelled/Downsized Transmission Projects ($Millions)					**Change in 1-in-10 Peak Load (GW)**			**Avoided Cost**	
Year	2016-17 CAISO TPP	2017-18 CAISO TPP	2018-19 CAISO TPP	3-year Total	Cumulative	2018-19 TPP (CED 2017)	2015-16 TPP (CEDU 2014)	Change	$/kW	$/kW-year*
2017	$8		$42	$49	$49	60.7	64.8	4.1	**12**	**2**
2018	$0	$7	$225	$232	$281	60.6	65.6	5.0	**56**	**7**
2019	$85	$83	$95	$263	$544	60.8	66.4	5.6	**97**	**12**
2020	$8	$329	$0	$337	$881	61.3	67.3	6.0	**148**	**18**
2021	$33	$670	$48	$751	$1,631	62.0	68.0	6.0	**274**	**32**
2022	$90	$87	$0	$177	$1,808	62.8	68.7	5.9	**306**	**36**
2023	$15	$141	$0	$156	$1,964	63.6	69.4	5.8	**339**	**40**
2024	$0	$136	$85	$221	$2,185	64.1	70.0	5.9	**371**	**43**
2025	$0	$135		$135	$2,320	64.9	70.6	5.9	**394**	**46**
2026	$25	$125		$150	$2,470			5.9	**420**	**49**

* Assumes 11% RECC factor, $1.10/kW-year transmission O&M, and a 3.8% general plant loader.

The calculations in Table 2 show the significance and approximate magnitude of avoided unspecified CAISO transmission costs. Avoided costs are often difficult to determine because, by definition, they are counterfactual costs that are not incurred. The acknowledged costs saved from the cancelled or downsized projects in the CAISO transmission plans are the best possible evidence of avoided costs – documented projects that were actively planned by the utilities, often for many years, but that were cancelled or downsized as the result of a demonstrable reduction in demand driven, in major part, by DERs, and so recognized by the planners themselves.

[54] The recent CAISO transmission plans also cite the completion of the cycle of renewable development needed to meet the 33% by 2020 Renewable Portfolio Standard (RPS) goal and an end to the reliability-related projects related to the retirement of SONGS and coastal power plants. Our detailed review of the cancelled and downscaled projects shows that only a small portion of the reduction in investments was due to these other two factors.

The growth of DERs reduces the peak demand forecast, and, as stated by the CAISO itself, the lower peak demand forecast in turn results in cancellations, delays, or re-sizing of transmission projects. DERs avoid CAISO transmission costs only to the extent that they reduce peak demands. The avoided CAISO transmission costs that I calculate apply not just to DERs, but to any technology or practice that reduces the peak demand that electric customers place on the CAISO system.[55]

Q: How do you propose to calculate avoided CAISO transmission costs?

A: The Commission should consider two possible approaches.

Option 1 - Calculate the long-run marginal capacity costs for CAISO transmission for each utility. The first option I propose would result in a distinct avoided CAISO transmission cost for each IOU, based on each IOU's specific marginal costs for CAISO-level transmission.

Electric rates in California have been based on long-run marginal costs since the 1980s. As a result, for about three decades the utilities regulated by this Commission have been calculating long-run marginal capacity costs for distribution. The well-established and long-used methods for calculating marginal distribution capacity costs also can be used to calculate the marginal CAISO-level transmission costs of each IOU. I discuss below how to apply these methods to the IOUs, and present specific calculations for SCE and PG&E.

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[55] A number of parties to R. 14-08-013 have mischaracterized SEIA's position, asserting that SEIA is arguing that DERs are <u>solely</u> responsible for the reduction in costs in these three CAISO transmission plans. See, for example, R. 14-08-013, *Reply Comments of the CAISO* (August 23, 2019), at p. 3. SEIA's filings and analysis presented in R. 14-08-013 have been clear that DERs are only <u>partially</u> responsible for the CAISO transmission cost reductions. See, for example, R. 14-08-013, *Comments of the Solar Energy Industries Association on Energy Division White Paper on Avoided Transmission and Distribution Costs* (filed June 21, 2019), at pp. 13, 15. 16, 17, and 21.

Option 2 -- Use the CAISO's Systemwide Transmission Access Charge. A second, simpler approach is to use the CAISO's current systemwide Transmission Access Charge (TAC) rate of $12.59 per MWh as the measure for 2019 of the CAISO transmission costs that are avoided by all DERs that reduce metered retail loads.[56] The postage-stamp TAC rate applies to all participating utilities and covers the costs for the highest-voltage (above 200 kV) transmission facilities. The utilities on the CAISO system are allocated the costs of the high-voltage CAISO system through the TAC rate, which is based on each utility's metered retail load (in kWh).[57] Many DERs reduce the utility's metered load:

- EE and DR resources allow customers to use less power from the grid;
- DG serves on-site loads, also reducing the amount of power taken from the grid; and
- when a DG project exports power, the meter runs backward, also reducing metered loads.[58]

Thus, DERs lower the utility's metered loads and allow the utility to avoid the allocation of TAC costs to it in future years. Further, the recent CAISO systemwide marginal costs of $49 per kW-year, as presented in Table 2 above, correspond to an avoided cost of about $12 per MWh.[59] As a result, on the margin, the current TAC rate of $12.59 per MWh represents a reasonable proxy for the amount saved when a DER reduces that utility's load by one kWh. This is a conservative (i.e. low) metric, as it does not consider avoided costs for the lower-voltage CAISO-controlled facilities that are specific to each IOU.

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[56] The 2019 TAC Rate of $12.5924 per MWh is available at https://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffectiveJun01_2019_RevisedJul10_2019.pdf.

[57] This metered load is what is referred to as Gross Load in the CAISO Tariff, Appendix A. See CAISO, *How Transmission Cost Recovery Through the Transmission Access Charge Works Today: Background White Paper* (April 12, 2017), at page 1, footnote 1. Available at http://www.caiso.com/Documents/BackgroundWhitePaper-ReviewTransmissionAccessChargeStructure.pdf.

[58] Even with smart meters that can record exports directly, these exports are consumed on the local distribution system by other customers, thus unloading the high-voltage transmission system.

[59] Based on the CAISO's 2017 system load factor of 48%. $49,020 per MW-yr / (0.48*8760 hours/yr) = $11.69 per MWh.

Q: Your first recommendation is to calculate avoided CAISO transmission costs using the same methods that the IOUs use to calculate marginal distribution costs. How do SCE and SDG&E calculate marginal distribution capacity costs in their GRC Phase 2s?

A: Both utilities use the well-established National Economic Research Associates (NERA) regression method to determine their long-run marginal distribution capacity costs that vary with changes in load.[60] The NERA regression model fits incremental distribution investment costs to peak load growth, using at least 15 years of data to capture the utility's long-term marginal costs for capacity. The slope of the resulting regression line provides an estimate of the marginal cost of distribution investments associated with changes in peak demand. The NERA methodology typically uses ten or fifteen years of historical expenditures on distribution investments and system peak loads, as reported in FERC Form 1, and, if available, a five-year forecast of future expenditures and expected load growth.

SEIA has presented two calculations of SCE's marginal CAISO transmission costs using the NERA regression method at the December 2018 and July 2019 workshops.[61] The second calculation removed the past costs of transmission built to access RPS resources, and calculated a marginal CAISO transmission cost of **$31 per kW-year**. The regression used to calculate this value is shown in **Figure 10**.[62] I recommend the use in the ACC of this marginal CAISO transmission cost for SCE. The

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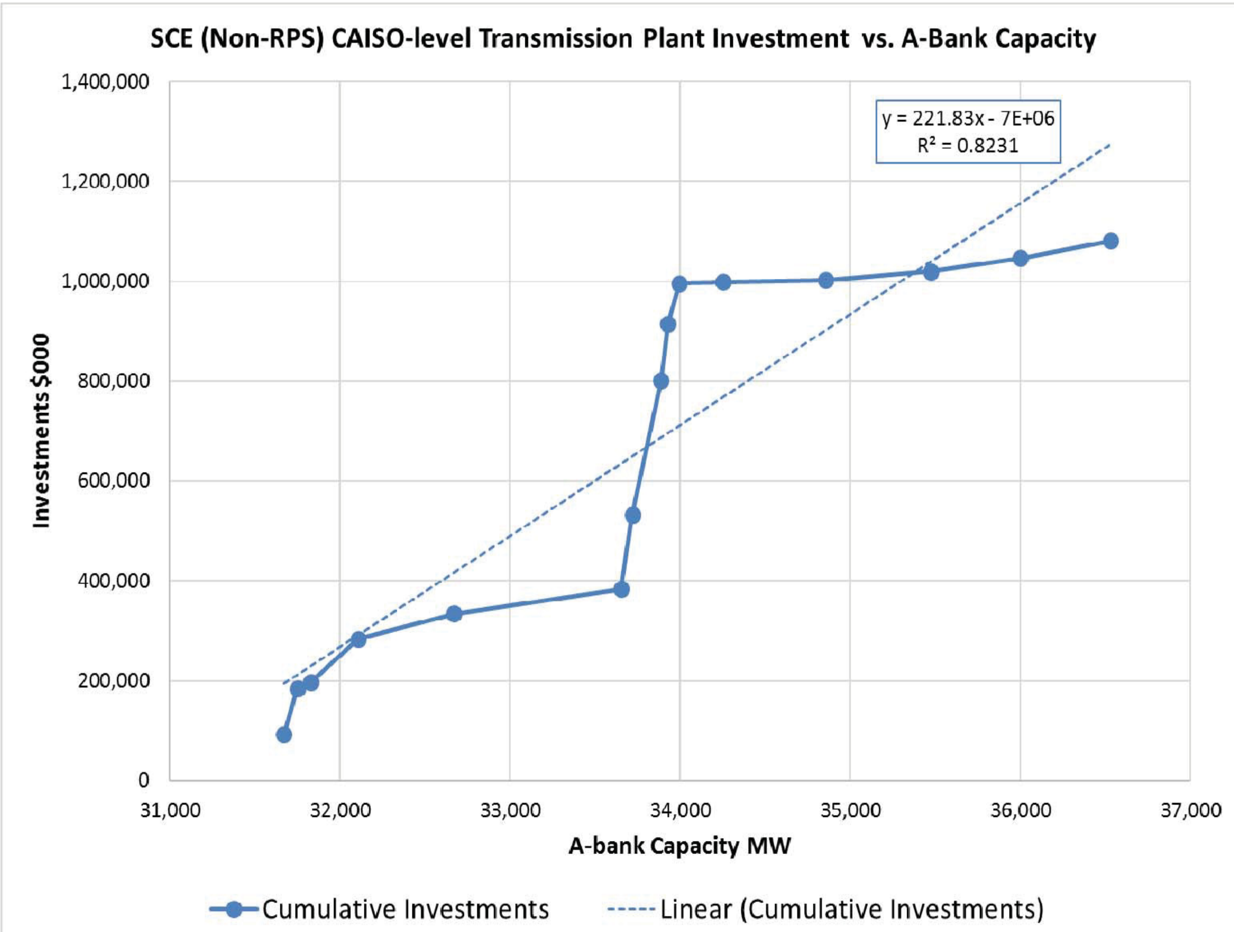
[60] For a detailed explanation of this approach, see Southern California Edison's recent testimony in CPUC Docket A. 17-06-001, Exhibit SCE-02, at pp. 36-38, available at http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/F40D6AEFD8622526882581CB007FC097/$FILE/A1706030-%20SCE-02A-2018%20GRC%20Ph2-Various-Errata%20Marginal%20Cost%20and%20Sales%20Forecast.pdf.

[61] These calculations use data that SCE provided in response to a discovery request in its most recent GRC Phase 2 case (A. 17-06-030).

[62] The regression slope is $222 per kW in 2018 dollars. I apply a 2.2% inflation adjustment to 2019 dollars and SCE's 7.3% general plant loader, then multiply by SCE's real economic carrying charge of 9.94%. Then I add $6.85 per kW-year in O&M costs for a total of $31.02 per kW-year.

Commission should direct SDG&E to use the same NERA regression method, following the approach used for SCE.

Figure 10



Q: Please discuss the issues that you have identified with PG&E's avoided CAISO transmission costs now used in the ACC for that utility.

A: There are four important defects in the value of $7.71 per kW-year used in the 2019 ACC for PG&E's avoided CAISO transmission costs.

First, PG&E's number is taken from a settlement in PG&E's last GRC Phase 2 case (A 16-06-013) in which the parties agreed to use this figure for very limited purposes associated with two specific rate schedules. This value was not adopted for general use for other purposes such as the ACC, in other dockets. SEIA was a party to A. 16-06-013 and would have opposed the settlement vigorously if it knew that these marginal cost numbers that were specified for limited purposes in A. 16-06-013 could be cherry-picked for use for completely unrelated purposes in other dockets. The Commission will discourage greatly the ability of parties to settle complex matters such as GRC Phase 2 cases, if it uses numbers from settlements in those dockets in ways that the parties to those cases clearly did not intend the numbers to be used.

Second, the marginal cost for CAISO transmission that PG&E proposed in its testimony was $11.48 per kW-year.[63] The first step in PG&E's calculation of this value was to remove about 75% of the projects in PG&E's current transmission plan on the grounds that these projects are not deferrable by changes in customer demands. PG&E assumed that just 29 out of 118 (i.e. 25%) of planned projects are deferrable by changes in demand. This resulted in PG&E categorizing as deferrable just $849 million out of $5.1 billion in project costs (17%). PG&E's criteria for a project being non-deferrable include:

1. Projects needed to meet regulatory, contractual or safety requirements.
2. Projects that improve system efficiency, such as those that reduce Local Capacity Adequacy Requirements or cost-effectively reduce customer outage time.
3. Projects that address a greater than 10 percent capacity deficiency.[64]

These criteria are not appropriate for removing investments completely from the calculation of long-term avoided CAISO transmission costs, especially for the use case of

[63] See A. 16-06-013, Exhibit PG&E-9, Chapters 3 and 4, hereafter, "PG&E Testimony."
[64] A. 16-06-013, PG&E Testimony, Chapter 3, at p. 3-3.

evaluating long-lived DER assets. The utilities and the CAISO often categorize transmission projects based on the principal reason for the project, such as:

- **Load growth** – serving peak demand
- **Reliability** – addressing N-1 or N-1-1 contingencies in high load hours
- **Economic** – relieving congestion, which typically occurs in high-demand hours
- **Policy-driven** – to meet RPS needs based on MWh goals

However, the transmission system is a network, and an addition that is made principally for one reason (for example, reliability) also will increase the system capacity to serve load growth, as a secondary benefit. In addition, the first three of the above types of transmission projects (peak load growth, reliability, and economics) are directly or closely tied to peak demands on the grid, and all types of additions to the networked grid (including capacity to access new RPS resources) may contribute to serving peak demands. Further, renewable generation from DERs, or reduced load from demand response or energy efficiency measures, contribute equally with RPS generation (which may require new transmission) to meeting the state's long-term carbon reduction goals. As a result, the long-term avoided or deferred transmission costs associated with DERs should be calculated considering all investments in transmission.

Third, PG&E's removal of projects that address greater than a 10 percent capacity deficiency is inappropriate in a calculation of long-run marginal or avoided transmission costs. This criterion accounts for many of the projects removed from PG&E's plan. For example, in addition to the 29 projects that PG&E determined can be deferred by a 5% to 10% demand reduction, there were 50 projects to resolve a capacity deficiency which PG&E categorized as non-deferrable – presumably these all addressed capacity deficits above 10%. Thus, the 10% limitation appears to have excluded from PG&E's long-run marginal cost of transmission 63% (i.e. 50 out of 79) of projects designed to address capacity deficiencies. Figure 9 above show that there has been a 9% reduction in expected peak CAISO demands in just three years, which has precipitated the CAISO's major recent $2 billion pruning of planned transmission projects. Thus, clearly there can be demand reductions in excess of 10% over relatively few years, driven in significant part by DER development, that can defer projects addressing capacity deficiencies greater than 10%. It is particularly inappropriate to apply PG&E's 10% criteria to a calculation of <u>long-term</u> unspecified transmission deferral value for DERs that can have economic lives of 25 years or more. These unspecified transmission deferral values will be used in the ACC to determine the life-cycle benefits from procuring such long-lived DER assets.

Fourth, PG&E's calculation is based only on projects scheduled to be online in 2020 and 2021 – i.e. only on projects with on-line dates within the forecast period for PG&E's last GRC Phase 2.[65] If one extends PG&E's calculation to include projects with online dates out to 2024, this single change increases PG&E's calculated marginal CAISO transmission cost from $11.48 per kW-year to about $30 per kW-year. Again, the Commission should use the full set of forecasted transmission investment data in order to capture avoided or deferred costs over a long-run period that corresponds to the economic life of many DERs.

I have re-run PG&E's marginal transmission cost calculation from its last GRC Phase 2 case with two changed assumptions: (1) assuming that capacity projects addressing more than a 10% deficiency are deferrable in the long-run and (2) including the full set of PG&E's planned transmission projects out to 2024. These two simple and justifiable changes to PG&E's model of its marginal CAISO transmission costs increases PG&E's unspecified avoided transmission costs substantially, to **$126 per kW-year** in 2021. This is the value for avoided CAISO transmission that should be used in the ACC for PG&E.[66] PG&E's unspecified avoided transmission costs are significantly higher than SCE's (as presented above and at the earlier workshops); this is consistent with the

[65] A. 16-06-013, PG&E workpapers for Exhibit PG&E-9, Chapters 3 and 4.

[66] $126 per kW-year is the value for 2021. This should be escalated, or de-escalated to other years starting in 2019, based on the escalation rate discussed below.

fact that most of the $2 billion in cancelled/avoided CAISO transmission costs in the three recent CAISO Transmission Plans were in PG&E's service territory.

Q: Your proposal above for IOU-specific avoided CAISO transmission costs does not include CAISO transmission costs to access RPS resources. Can DERs avoid RPS-related transmission costs?

A: Yes. DERs can avoid RPS-related cost in several ways. First, DERs reduce the retail loads on which the state's RPS loads are based. Second, and more directly, DERs reduce GHG emissions, and thus lower the amount of utility-scale RPS resources that must be procured going forward to meet the state's carbon reduction goals. Historically, CAISO-level transmission costs built to access RPS resources have been significant: for example, to meet the state's 33% by 2020 RPS goal, SCE has stated that it will incur $6.4 billion in transmission costs to access about 25,000 GWh per year of annual RPS generation (based on SCE's 2012-2016 annual bundled sales of about 75,000 GWh per year).[67] If one annualizes these capital costs with a real economic carrying charge, then adds O&M, the resulting cost is about $30 per MWh. Going forward, future transmission costs to access RPS resources are supposed to be included in the GHG Planning Price calculated by the RESOLVE model. However, RESOLVE apparently found that there were no additional transmission costs needed to deliver the 12.3 GW of new utility-scale renewable and storage resources selected in the 2017-2018 RSP to meet the 2030 carbon emission goal of 42 million tonnes, and thus currently there are no avoided RPS transmission costs included in the current GHG Planning Price in the ACC.[68] Given the significant RPS transmission investments that have been required in the past, I am skeptical that California could reach its ambitious RPS and GHG goals without significant future

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[67] See the Commission's 2016 RPS report to the Legislature, at p. 9 (for transmission costs), available at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Pub%20Util%20913.3%20Report%20-%20Final%20-%20Print%20-%20Revised.pdf; also, SCE's 2017 RPS Compliance Report, filed in R. 15-02-020 (January 17, 2018), at Appendix D (for 2012-2016 bundled sales).

transmission investments, particularly in a "No DER" case assuming no future DER deployment.

Q: What escalation rate would you use to escalate current avoided CAISO transmission costs to future years?

A: The CAISO maintains a model to estimate the future expected increases in the TAC rate. I recommend escalating current avoided CAISO transmission costs at this forecasted growth for the TAC rate, which is 4.4% per year based on the CAISO's presentation of its model results for 2019 through 2025 on May 17, 2019.[69] I note that this represents a lower rate of growth than in the past, given that the CAISO postage-stamp TAC rate increased by over 10% per year from 2012 to 2019.[70]

2. Avoided subtransmission, substation, and distribution costs

Q: What avoided costs for the IOU's subtransmission, substation, and distribution facilities are presently used in the ACC?

A: The ACC currently uses marginal subtransmission, substation, and distribution costs sourced from recent IOU general rate case (GRC) Phase 2 proceedings. As discussed below, there are issues with whether the most representative values are selected.

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[68] See Energy Division presentation of the proposed RSP (September 18, 2017), at Slide 54: "All new renewable resources are located in areas that are not expected to require delivery network upgrades."

[69] See CAISO, *Transmission Program Impact on High Voltage TAC Estimating Model – 2018-2019 TPP Version* (May 17, 2019), at Slide 6, available at http://www.caiso.com/Documents/Presentation-2018-2019TransmissionAccessChargeForecastModel-May17_2019.pdf#search=2018%2D2019%20Transmission%20Access%20Charge%20Forecast%20Model.

[70] The 2019 CAISO TAC rate is almost double what it was in 2012, increasing from $6.39 per MWh in 2012 to $12.59 per MWh in 2019. See CAISO, *Transmission Access Charge Structure Enhancements: Draft Final Proposal* (September 17, 2018), at Table 2.

Q: Avoided unspecified distribution costs that could be used in the ACC are under consideration in R. 14-08-013. What are the principal recommendations in that case?

A: The Energy Division has proposed a new method for calculating avoided unspecified distribution costs based on the costs presented in the IOUs' five-year grid needs assessments (GNAs). It is unclear whether this new approach will be adopted, whether it will be ready for use this year in the ACC, or whether it will apply beyond the five-year period covered by the GNAs. SEIA has recommended the continued use of marginal distribution costs from recent IOU GRC Phase 2 proceedings, if the new approach is not adopted or not ready.[71] SEIA has also recommended that, even if the new Energy Division approach is adopted, the long-run marginal distribution costs from GRC Phase 2 proceedings should be used for years after the initial five-year period covered by the GNAs. Thus, there is likely to be a continued need for the ACC to select marginal distribution costs from the record in GRC Phase 2 proceedings.

Q: Please discuss how the marginal subtransmission, substation, and distribution costs used in the ACC, as needed, should be selected from the records of GRC Phase 2 proceedings.

A: Generally, the avoided subtransmission, substation, and distribution costs used in the ACC should use the best available marginal cost information from the most recent GRC Phase 2 cases that the Commission has decided. This will ensure, first, close alignment between the avoided costs used in the ACC and the marginal costs used to set current retail rates, and, second, a level of prior Commission review. Alignment with the marginal costs used to set retail rates is particularly important given that a primary impact of DERs is to reduce retail loads served by the utility. I do not support the occasional past practice of using marginal costs proposed in the utility's <u>testimony</u> in GRC Phase 2 cases, because the other parties to GRC Phase 2 cases often recommend marginal costs

[71] See SEIA's June 21, 2019 comments in R. 14-08-013, at page 11.

that differ from the utility's proposal, and the utility proposals often are not adopted explicitly by the Commission for general use. I also oppose cherry-picking marginal cost values for use in the ACC from settlements that adopted those values for strictly limited purposes that do not include the ACC; as discussed above, there is one example of such cherry-picking in the 2019 ACC – PG&E's avoided costs for transmission.

Here are how marginal distribution costs in GRC Phase 2 cases should be selected:

1. If the Commission decision specifically adopts a marginal cost value for general use (or approves a settlement that recommends a specific marginal cost value for general use), that value should be used in the ACC.
2. Many recent GRC Phase 2 cases have been resolved by settlement without adopting specific marginal cost values for general use. In such cases:
    a. If a marginal cost value proposed by the utility was not opposed, that value should be used.
    b. If the settlement does not adopt a specific marginal cost value for general use, the range of marginal costs proposed in the case provides the best available information on the marginal costs used to set current rates. In this case, VS/SEIA recommend selecting a representative, mid-range value from the range of marginal costs proposed in the Phase 2 case.[72]

I have applied this approach to the decisions, adopted settlements and evidentiary records in the most recent GRC Phase 2 cases to recommend marginal subtransmission, substation, and distribution costs to use in the ACC. I provide in **Table 3** below both the values used in the 2019 ACC and VS/SEIA's recommendations for how to update them based on the decisions and records in recent GRC Phase 2 cases.

[72] I am not proposing that the Commission seek information from settling parties on exactly what numbers formed the basis for a particular settlement. I am recommending that the Commission examine the range of positions on marginal costs that were submitted by the utility and parties that represent a broad and significant group of customers. This should be workable given that relatively few parties present detailed marginal cost proposals in GRC Phase 2 cases. The Commission also should retain the flexibility to exclude from the range proposals that are clear outliers or that represent a narrow interest.

Table 3

<table>
<tr><th>Utility</th><th>2019 ACC Assumption</th><th>Vote Solar / SEIA Recommendation</th></tr>
<tr><td>SCE</td><td>From SCE's 2017 GRC Phase 2 (A. 17-06-030) testimony: $40.00/kW-yr for subtransmission, $25.00/kW-yr for substation, and $102.90/kW-year for distribution.[73] The 2019 ACC does not divide these marginal distribution costs into "peak" and "grid" functions, as SCE proposed in A. 17-06-030.</td><td>Parties to A. 17-06-030 did not contest the level of SCE's marginal distribution costs, but there were differences in how to allocate them to the different functions of the distribution system. I propose to use the allocation of SCE marginal subtransmission and distribution costs from the Revenue Allocation settlement adopted in D.18-11-027 in A. 17-06-030.[74]

SCE now separates its marginal T&D costs between substations and circuits and between peak and grid functions. The next section discusses how to incorporate the grid-related marginal costs into the ACC.

<table>
<tr><th colspan="3">Allocation of SCE Marginal T&D Costs</th></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td><u>Function</u></td><td><u>Peak</u></td><td><u>Grid</u></td></tr>
<tr><td></td><td>$/kW-yr</i></td><td><i>$/kW-yr</td></tr>
<tr><td>Substations (A-Bank)</td><td>$ 31.17</td><td></td></tr>
<tr><td>Sub-transmission Circuits</td><td>$ 1.75</td><td>$ 7.02</td></tr>
<tr><td>Substations (B-Bank)</td><td>$ 25.03</td><td></td></tr>
<tr><td>Distribution circuits</td><td>$ 26.78</td><td>$ 76.21</td></tr>
<tr><td>Total</td><td>$ 84.73</td><td>$ 83.23</td></tr>
<tr><td>Share</td><td>50%</td><td>50%</td></tr>
</table>
</td></tr>
</table>

[73] From SCE's errata testimony in the 2017 GRC Phase 2 (A. 17-06-030), SCE-02A Table I-14, which may be found at: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/F40D6AEFD8622526882581CB007FC097/$FILE/A1706030-%20SCE-02A-2018%20GRC%20Ph2-Various-Errata%20Marginal%20Cost%20and%20Sales%20Forecast.pdf.

[74] See D.18-11-027, at pp. 13-14.

<table>
<tr><th>Utility</th><th>2019 ACC Assumption</th><th>Vote Solar / SEIA Recommendation</th></tr>
<tr><td>PG&E</td><td>Uses marginal primary distribution costs that were included in Attachment 1 to the Revenue Allocation / Marginal Cost settlement agreement in PG&E's 2016 GRC Phase 2 (A. 16-06-013) solely for the limited purposes of (1) setting customer-specific contract rates under Schedule E-31 and (2) analyzing contribution to margin for customers taking service under Schedule EDR.[75]</td><td>Use mid-range values for marginal distribution costs by division presented in the record of the most recent PG&E GRC Phase 2 (A. 16-06-013). In recognition of the settlement on marginal costs adopted in D. 18-08-013 in this case, use representative systemwide values of $63.56 per kW-yr for marginal primary distribution costs and $3.80 per kW-yr for secondary distribution, as summarized below.[76] Parties did not oppose how PG&E allocates marginal distribution capacity costs across its divisions.

<table>
<tr><th colspan="3">PG&E Marginal Distribution Capacity Costs</th></tr>
<tr><td></td><td colspan="2">System Average MDCC</td></tr>
<tr><td><u>Party</u></td><td>Primary</td><td>Secondary</td></tr>
<tr><td></td><td>$/kW-yr</i></td><td><i>$/kW-yr</td></tr>
<tr><td>PG&E</td><td>$ 39.43</td><td>$ 1.25</td></tr>
<tr><td>CalPA (then ORA)</td><td>$ 67.53</td><td>$ 4.81</td></tr>
<tr><td>CLECA</td><td>$ 83.71</td><td>$ 5.34</td></tr>
<tr><td>Average</td><td>$ 63.56</td><td>$ 3.80</td></tr>
</table></td></tr>
<tr><td>SDG&E</td><td>The ACC uses $22.05 per kW-yr for substation and $77.97 per kW-yr for local distribution as proposed by SDG&E in its testimony in the 2015 SDG&E GRC Phase 2.[77]</td><td>In A. 15-04-012, ORA recommended higher marginal distribution capacity costs ($29.06 per kW-yr for substation and $104.57 per kW-yr for local distribution). In recognition of the black-box settlement in this case, VS/SEIA propose to use a 50/50 mix of the SDG&E and ORA marginal substation and local distribution costs, i.e. $25.56 per kW-yr for substation and $91.27 per kW-yr for local distribution.</td></tr>
</table>

[75] This settlement is at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M202/K235/202235606.PDF. This attachment is specifically labeled “Agreed Marginal Costs to be Used Solely for Schedule E-31 and Schedule EDR Purposes.”

[76] See PG&E Testimony, Exh. PG&E-9, Volume 1, Chapter 6, Table 6-1; ORA Testimony, Exh. ORA-1, Chapter 4, Table 4-1; CLECA Testimony, Exh. CLECA-1, Table 6, p. 63.

[77] See A. 15-04-012, SDG&E Testimony [Saxe], Attachment A at https://www.sdge.com/sites/default/files/Saxe%2520Clean%2520w_Attachments.pdf, for SDG&E’s proposed $22.05/kW-year substation and $77.97/kWh-year local distribution marginal cost values.

Q: Are there new developments concerning the derivation of marginal T&D costs in recent GRC Phase 2 cases that should inform the ACC?

A: Yes. The Commission should recognize that, with the advent of default time-of-use rates for all customers and with the major change to a 4 p.m. to 9 p.m. peak period, parties have devoted significant effort in recent GRC Phase 2 cases to examining the time dependence of marginal subtransmission and distribution costs. This includes a closer look at what portions of marginal costs are driven by peak demands at the circuit, substation, or system levels and what portion is incurred based on the customer's individual use of the grid. Thus, in SCE's last GRC Phase 2, its marginal distribution costs were separated into "peak" and "grid" components, as shown in Table 3 above. The "peak" component are those distribution costs that are driven by peak period demands, while the "grid" component is based on the customer's individual use of the grid in any hour. Both of these components are marginal or avoided costs, and both should be included in the ACC. As specified in the next section, the "grid" component should be allocated on an equal cents per kWh basis across all hours, because it includes the portion of marginal distribution costs that are not time-dependent.

Similarly, a small portion of PG&E's marginal costs, for secondary distribution facilities, are not time-dependent and are not included in the ACC. These marginal costs should be allocated on an equal cents per kWh basis across all hours, as this is how these marginal costs are recovered from the smaller residential and small commercial customers predominantly served from the lower-voltage secondary distribution system.

3. Allocation of avoided T&D costs to hours

Q: The ACC calculates avoided costs for all 8,760 hours of the year. As a result, allocators must be chosen to allocate avoided T&D costs across the hours. Are there

new developments concerning how marginal or avoided T&D costs should be allocated across the hours of the year in the ACC?

A: Yes. The parties to recent GRC Phase 2 cases also have devoted significant effort to examining how marginal subtransmission and distribution costs should be allocated across the hours of the year, and in several of these cases have agreed on how these marginal costs should be allocated to hours in the rate designs that use the new 4 p.m. to 9 p.m. peak period. These allocations are based on the use of data on loads on the subtransmission and distribution systems that were not available when the ACC was developed but have become available in recent years. I submit that these approaches using actual subtransmission and distribution system loads are superior to the ACC's use of temperatures in climate zones as a proxy for these loads.

I recommend the same approach to choosing these allocators that I propose above for choosing marginal/avoided T&D costs:

1. If the Commission decision specifically adopts a marginal cost allocation (or approves a settlement that recommends a specific marginal cost allocation for general use), that allocation should be used in the ACC.
2. Many recent GRC Phase 2 cases have been resolved by settlement without adopting specific marginal cost allocations. In such cases:
    a. If a marginal cost allocation proposed by the utility was not opposed, that allocation should be used.
    b. If the settlement does not adopt a specific marginal cost allocation for general use, the range of allocators proposed provides the best available information on the allocation used to set current rates. In this case, VS/SEIA recommend using a set of allocators that represents mid-range compromise among the range of allocators proposed in the Phase 2 case.

Table 4 presents my recommended allocators for avoided T&D costs.

Table 4

Utility	2019 ACC Assumption	Vote Solar / SEIA Recommendation
SCE	Peak Capacity Allocation Factors (PCAFs) based on expected 2020 and 2030 distribution loads	**Peak-related:** Use 50/50 compromise of ORA and SCE Peak Load Reduction Factors (PLRFs) from 2018 GRC Phase 2 record. The rate design settlements adopted in D. 18-11-027 used settled sets of PLRFs (combinations of the SCE and ORA PLRFs) to allocate peak-related marginal distribution costs, except for TOU-8 Option E rates that used 100% ORA PLRFs. SEIA can provide the ORA and SCE PLRF profiles. **Grid-related:** Allocate equally across all hours, consistent with SCE's residential and small commercial rate design adopted in D. 18-11-027.
PG&E	PCAFs based on expected 2020 and 2030 distribution loads.	**Marginal primary distribution costs:** PG&E's distribution PCAFs as filed in A. 16-06-013 (which generally were supported by other parties). **Marginal secondary distribution costs:** Allocate equally across all hours, consistent with PG&E's residential and small commercial rate design adopted in D. 18-08-013.
SDG&E	PCAFs based on expected 2020 and 2030 distribution loads.	In the record of A. 15-04-012, SEIA provided **PCAFs based on actual 2015 SDG&E substation load data**. This allocation of marginal distribution costs was uncontested (see D. 17-08-030, at p. 21).

Q: How would you allocate avoided CAISO transmission costs to the hours of the year?

A: Obviously, this allocation is not an issue in CPUC rate cases, because CAISO-level transmission costs are FERC jurisdictional. In conjunction with my first recommendation to calculate IOU-specific CAISO transmission costs, I would propose to allocate these avoided costs to hours using, for each IOU, a set of peak capacity allocation factors (PCAFs) calculated from each IOU's most recent calendar year of actual loads on the CAISO system. These PCAFS are readily determined from CAISO load data, and are based on all hours with loads at or above 90% of the peak hour load. **Figure 11** below shows a 12x24 heat map of the PCAF allocation for PG&E based on 2018 CAISO-level loads, using a PCAF allocation of all hourly loads that are within 10% of the CAISO system peak load for PG&E in 2018. Similar allocations are readily available for SCE and SDG&E.

Figure 11: *CAISO Transmission PCAFs for PG&E*

Hr\Mo	1	2	3	4	5	6	7	8	9	10	11	12	Total
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
8	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
9	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
10	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
11	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	0.9%	0.0%	0.0%	0.0%	0.0%	3%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.7%	3.8%	0.0%	0.0%	0.0%	0.0%	12%
17	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.0%	7.4%	0.0%	0.0%	0.0%	0.0%	21%
18	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	18.4%	10.0%	0.0%	0.0%	0.0%	0.0%	29%
19	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	15.6%	7.2%	0.0%	0.0%	0.0%	0.0%	23%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.7%	3.6%	0.0%	0.0%	0.0%	0.0%	11%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.6%	0.0%	0.0%	0.0%	0.0%	1%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0%
Total	0%	0%	0%	0%	0%	1%	66%	33%	0%	0%	0%	0%	100%

If the Commission adopts my second alternative to use the CAISO TAC, these costs should be allocated equally across all hours, as the TAC is set based on the metered (kWh) loads of each utility. I note that this is how CAISO transmission costs are recovered in the retail rates today for the residential and small commercial customers of the IOUs.

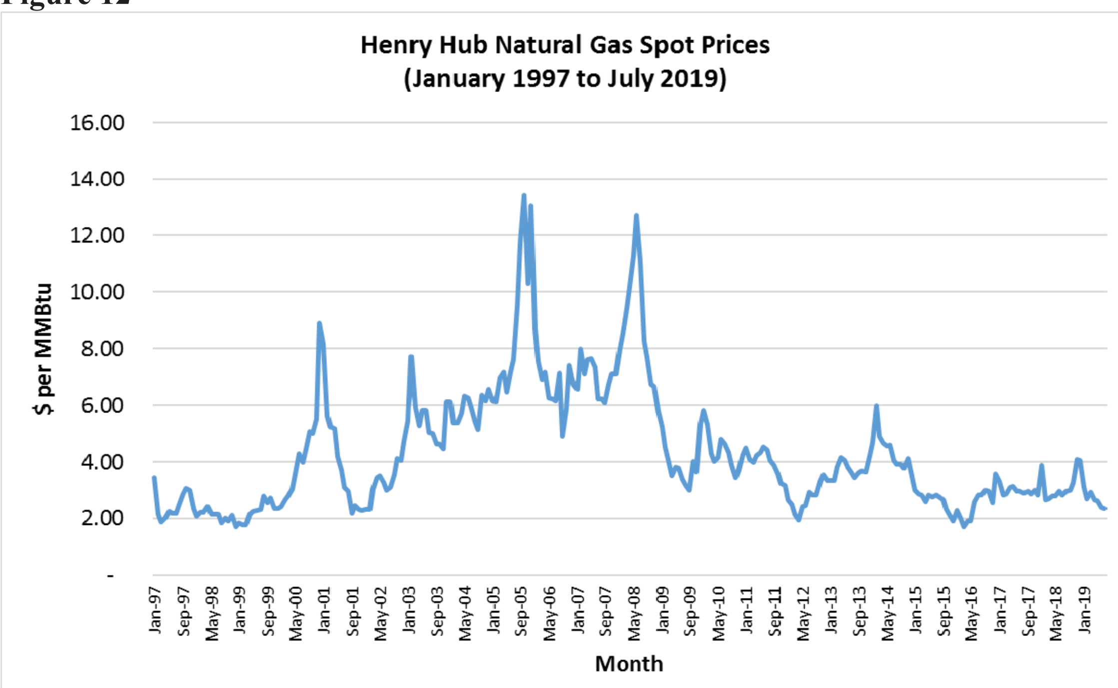
III. NEW BENEFITS TO BE ADDED TO THE CALCULATOR

A. Avoided Fuel Price Volatility

Q: Why do DERs provide value as a fuel price hedge?

A: Our forecast of future natural gas prices is a single smooth curve with no abrupt changes (see Figure 7, above). In reality, the actual natural gas market exposes consumers to periodic price spikes. Such spikes have occurred regularly over the last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 12** below.[78] In addition, the path of future prices has significant uncertainty. This volatility imposes a cost on consumers. DERs hedge against this volatility, by reducing the use of natural gas as the marginal fuel to produce electricity. This benefit can be quantified.

Figure 12



78 Source for Figure 7: Chicago Mercantile Exchange data.

Renewable generation also hedges against other types of market dislocations or generation scarcity such as was experienced throughout the West during the California energy crisis of 2000-2001 or as has occurred periodically during drought conditions in the U.S. that reduce hydroelectric output and curtail generation due to the lack of water for cooling. Renewables provide this hedge by reducing the amount of power that must be purchased at volatile short-run market prices.[79]

Q: The California utilities conduct risk management programs that include hedging their exposure to gas and electric market price fluctuations using a variety of forward market instruments. Please explain how the hedge provided by renewable DG resources is different than these existing hedging programs.

A: Existing utility hedging programs are designed primarily to reduce the near-term volatility of their short-term fuel and purchased power expenses. Generally, these programs focus on reducing volatility only in the next one to three years, as the forward markets are most liquid in the near-term and there are substantial transaction costs associated with long-term hedges in financial markets. However, utilities regularly engage in long-term hedging through their resource portfolios, and some utilities are careful to evaluate their overall risk position as including both their short- and long-term positions in both natural gas and power. For example, PacifiCorp's discussion of its hedging program in its 2015 IRP emphasized how its long position in the power market functions as a hedge against its short position in natural gas, and concludes that "[t]his has the effect of reducing the amount of natural gas hedging that the Company would

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[79] For example, in 2014 - 2015, California was fortunate that a period of rapid growth in its solar fleet occurred during a multi-year drought; in 2014, for example, the rapidly increasing output of solar projects in California covered 83% of the reduction in hydroelectric output due to the drought. This is based on Energy Information Administration data for 2014, as reported in Stephen Lacey, *As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap: New solar generation made up for four-fifths of California's lost hydro production in 2014* (Greentech Media, March 31, 2015). Available at http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-renewable-energy-provider-in-california.

otherwise pursue."[80] This is exactly the hedge represented by renewable DG resources whose output decreases the utility's exposure to price volatility in gas and electric markets. In addition, other observers have noted that long-term, fixed-price contracts for renewable generation provide utilities with a means not available in the financial markets to hedge their long-term exposure to gas and power markets, and thus could replace a portion of their current budgets for risk management.[81]

Q: Are you aware of methods to quantify the value of renewable DG in avoiding the uncertainty and volatility in natural gas prices?

A: Yes. Several studies have quantified the long-term hedge value of renewable generation. In 2013, Public Service of Colorado estimated that the long-term (20-year) hedging benefits of distributed solar resources on its system to be $6.60 per MWh.[82] This study used the cost of options contracts in the gas futures market to calculate the hedging benefit.

More recently, the consultant Clean Power Research developed another approach to calculating the hedge value of renewables, as part of the Maine Public Utilities Commission's *Maine Distributed Solar Valuation Study*, released in 2015.[83] This method recognizes that natural gas prices are the primary driver of marginal energy costs, and

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[80] 2015 PacifiCorp Integrated Resource Plan, at pp. 246-247. See https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2015-irp/PacifiCorp_2015IRP-Vol1-MainDocument.pdf.

[81] Lisa Huber, *Utility-scale Wind and Natural Gas Volatility: Unlocking the Hedge Value of Wind for Utilities and Their Customers* (Rocky Mountain Institute [RMI], July 2012), at pg. 15, available at http://www.rmi.org/Knowledge-Center/Library/2012-07_WindNaturalGasVolatility.

[82] Xcel Energy Services, *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System: Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223* (May 2013), at pp. 6 and 43, and Table 1.

[83] See Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015); hereafter, "Maine Solar DG Valuation Study." Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

calculates the additional costs to fix the fuel costs of a marginal gas-fired generator for a 25-year period, compared to purchasing gas on an "as you go" basis. To fix fuel costs for a long-term period, the money to purchase fuel in the future must be set aside today in risk-free investments. This results in higher costs because this money could otherwise be deployed to earn a higher return (assumed to be the utility's weighted average cost of capital) if it was available to be used for alternative investments. These incremental costs are what the utility who owns marginal gas generation (or who purchases such power) would have to spend to obtain the same hedging benefit that it can obtain from an identical renewable resource whose fuel costs are zero, thus eliminating the uncertainty and volatility in future fuel costs for the 25-year life of the renewable generation. These additional costs are substantial when one considers the alternative uses to which one can put the money that must be set aside upfront to fix the cost of natural gas for 25 years.

Q: Have you applied either of these methods to calculate the value for the California utilities of avoiding fuel price volatility?

A: Yes. I applied the approach developed in the Maine Solar DG Valuation Study to my recommended gas commodity forecast for the SoCal border, using U.S. Treasuries (at current yields) as the risk-free investments, the IOU's weighted average cost of capital, and a representative CCGT heat rate of 7,000 Btu per kWh. The result is the levelized hedge values shown in **Table 5** below for various economic lives for DERs ranging from 5 to 30 years. These numbers are comparable to those calculated by Clean Power Research itself for the California market, in the 2015 study referenced above.[84]

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[84] CPR CA Study, at p. 13, Table 6, referenced in footnote 17 above.

Table 5: *Avoided Fuel Price Volatility*

DER life *(years)*	Hedge Value *($ per MWh)*
5	2.60
10	6.90
15	12.00
20	17.80
25	24.20
30	31.20

Q: These numbers appear to be substantial, especially for longer DER lives. Please comment on the magnitude of this benefit.

A: It is important to recognize that the market volatility and disruptions against which DERs hedge do not occur often, but, when they do occur, the impacts on consumers who rely on those markets can be substantial. In the California market, the prominent instances of such volatility over the last 20 years include (1) the 2000-2001 energy crisis, (2) the closure of the San Onofre nuclear plant in 2013 after its replacement steam generators failed, (3) natural gas price spikes after hurricanes such as Katrina and Rita in 2005, and (4) the high southern California market prices experienced in 2018 due to constraints on the Southern California Gas system related to pipeline outages and the Aliso Canyon incident. DERs provide a significant benefit for energy consumers by reducing their exposure to this market volatility and its resultant costs.

B. Avoided Leakage of High GWP Gases

Q: At the August 30 workshop, E3 presented a proposal to incorporate into cost-effectiveness evaluations consideration of the impacts of the leakage of gases with high global warming potential (High GWP), including methane.[85] Do Vote Solar and SEIA support this proposal?

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[85] E3, "HFC/High GWP Gasses" (August 30, 2019 workshop presentation in this docket).

A: Yes. Although the leakage to the atmosphere of High GWP gases has a smaller impact on the climate than emissions of carbon dioxide from the combustion of fossil fuels, the impacts of High GWP gases are not insignificant and, within California, are regulated comprehensively by the California Air Resources Board (CARB). E3's analysis shows that the impacts of the leakage of High GWP gases need to be considered in comparing the GHG emissions from various DER technologies, because this leakage has a significant impact on the relative climate impacts of various technologies that either burn a gas like methane or that use a High GWP gas as a heat transfer fluid (such as electric heat pumps). I also agree with E3 that, in order to do an "apples-to-apples" comparison among DERs that considers High GWP gases, it is vital to include in DER cost-effectiveness analyses the leakage of methane from the natural gas system. This not only includes the leakage associated with producing and transporting natural gas used in buildings, but also the natural gas burned in power plants. I agree with E3 that 1.9% methane emissions from the upstream portion of the gas system is a reasonable figure and in line with the latest research.[86] In prior comments in this docket, SEIA has recommended the use of 2% leakage for natural gas burned at power plants, based on a review of the recent academic literature that has emphasized the need to account for low-frequency, high-emitting events such as the Aliso Canyon leak in 2015-2016.[87] The straightforward way to include the real climate impacts of methane leakage into the ACC is to increase the assumed avoided cap & trade allowance costs by 47.5% (1.9% leakage times methane's 25 GWP = 0.475). I recommend that this important change should be incorporated into the ACC to represent fully and accurately the carbon emissions of gas-fired electric generation.

[86] Given that California imports 90% of its natural gas, the CARB's in-state methane emission figure of 0.68% of consumption is too low. E3 proposes a 2.4% leakage rate (1.9% upstream, 0.5% at the meter) as the appropriate value to reflect all GHG emissions associated with the natural gas produced in, imported into, and burned in California. See E3 High GWP Study, at Slide 9. I recommend assuming that there is negligible leakage from the gas laterals and meters at EG plants, and thus propose the use of the 1.9% upstream leakage rate as the appropriate rate for natural gas burned in power plants.

[87] See "Comments of SEIA on Staff Proposal Recommending a Societal Cost Test", filed in R. 14-10-003 on March 23, 2017, at Attachment 1.

C. Reliability and Resiliency Benefits of DERs

Q: Solar + storage units can provide a customer with a backup source of electricity. What are the benefits of this assured backup?

A: Renewable DG paired with on-site storage can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad benefits as a way to maintain functions related to safety, human welfare, and economic activity during grid outages. Obviously, this benefit has assumed increased importance in California given the heightened concerns with wildfires and the Public Safety Power Shutoff programs now in place for all of the IOUs.

Recently, the literature on mitigating power system interruptions has distinguished between **reliability** and **resiliency** benefits. In this discussion, "reliability" refers to the ability of an electric system to maintain service in the face of normal challenges to continuous operations, while "resiliency" emphasizes the ability to respond to and recover from low-frequency, high-consequence, "dark sky" events that may last longer in time and affect a larger area.[88]

Q: Can DERs that combine a renewable generation source (such as solar) with on-site storage provide both reliability and resiliency benefits?

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[88] For example, a recent report to the National Association of Regulatory Utility Commissioners (NARUC) discusses the distinction as follows, drawing on a 2016 report from the Electric Power Research Institute (EPRI):

> A major distinction between resilience and reliability is the scale and duration of the power interruptions contemplated. Reliability focuses on preventing disruptions that are "more common, local, and smaller in scale and scope," whereas resilience "addresses high-impact events, the consequences of which can be geographically and temporally widespread."

See Converge Strategies for NARUC, *The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices* (April 2019), at p. 8 (hereafter "NARUC Study"), citing Electric Power Research Institute, *Electric Power System Resiliency: Challenges and*

A: Yes. The storage provides the assurance of immediate, reliable power if the grid goes down, while the on-site generation is available to re-fill the storage to maintain a level of resilient service for critical loads through an extended interruption.

1. Valuing reliability

Q: Are their widely-used metrics to value reliability?

A: Yes. The three California IOUs file annual reliability reports with the Commission that report their annual number of outages per customer (SAIFI) and annual minutes of interruption, both as total (SAIDI) and per customer (CAIDI). As shown in **Table 6** below, over the last ten years, IOU customers have averaged about 2 hours per year (115 minutes, to be exact) of power interruptions.[89] Most of these interruptions are the result of outages on the distribution system, most often weather-related. This does not include so-called "major events," typically major storms or wildfire events, which are defined as producing outage indices that exceed what is normally expected.

Q: How do you put a dollar value on the cost to customers of power interruptions?

A: Utilities typically use "contingent valuation" approaches to assess how much customers value reliability, in dollars per minute of avoided interruptions. These "value of service" studies use customer surveys to determine how much customers are willing to pay to avoid short-duration interruptions, generally shorter than 24 hours.[90] The California IOUs have used these value of service studies in recent GRCs to justify the cost-effectiveness of various grid modernization efforts which, the IOUs believe, will result in certain increases in reliability. The middle column of Table 6 shows these values of

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Opportunities (2016), at p. 45. The NARUC Study is available at https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198.

[89] Based on the SAIDI statistics that the IOUs file in their annual reliability reports, which are available at http://www.cpuc.ca.gov/PUC/energy/ElectricSR/Reliability/annualreports/2014.htm .

reliable service, expressed as dollars per minute of customer interruption. Multiplying these values of service by the average minutes of interruption each year yields the annual reliability value per customer – about $300 per year – to be gained by a solar plus storage system that can eliminate short-duration interruptions.

Table 6: *Value of Reliability for California IOUs*

Utility	**2009-2018 CAIDI** *(minutes per year)*	**Value of Service**[91] *($ per minute)*	**Value of Uninterrupted Service** *($ per year)*
PG&E	118	$2.91	$343
SCE	111	$2.32	$257
SDG&E	117	$2.62	$307
Average	115	$2.62	$301

The value of service studies typically find that commercial customers place much higher value on uninterrupted electric service than do residential users.[92] The reliability values shown in Table 6 can be re-cast to separate the values for residential and commercial customers, as shown in **Table 7**, which uses another convenient source for the value of service estimates.[93] This disaggregation can be used if the distribution of solar + storage systems between the residential and commercial markets differs from the distribution of these types of customers across the system as a whole.

90 See, for example, NARUC Study, at p. 17 and 21-22. Also, M. Sullivan et al., *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States* (January 2015, Nexant for LBNL), hereafter "Nexant Study." Available at https://certs.lbl.gov/sites/all/files/lbnl-6941e.pdf.

91 The value of service estimates are from A. 19-06-001 (SCE GRC Phase 1), *Direct Testimony of Curt Volkmann on behalf of SEIA and VS* (May 2, 1017), at p. 22, citing SCE's testimony. For SDG&E, I use the average of the PG&E and SCE values.

92 For example, see Nexant Study, at Table ES-1.

93 Nexant and LBNL have developed an easy-to-use Interruption Cost Estimate (ICE) calculator, available at https://icecalculator.com/home, that includes value of service estimates for different types of customers. When the ICE calculator is run for a large California electric utility with customer counts and reliability indices similar to PG&E and SCE, the reliability value per type of customer is as shown in Table 7.

Table 7: *Value of Reliability by Type of Customer*

Customer Type	Value of Uninterrupted Service *(2019 $ per year)*
Residential	$ 6.54
Small C&I	$ 969
Medium and Large C&I	$ 11,666
All Customers	$ 331

2. Valuing resiliency

Q: How would you value the resiliency benefits of solar + storage systems?

A: To maintain a basic level of electric service during an extended grid outage requires some form of on-site back-up generation. As a result, one approach that has been used – most prominently by the U.S. military – to value resiliency is to use the capital costs of this back-up generation, plus the added operating and environmental costs during an extended outage. This is a "revealed preference" method based on the costs of a "defensive behavior" to mitigate the impacts of an extended interruption.[94] For example, if there is an extended power outage after a natural disaster, the sale and use of portable gasoline-powered generators will proliferate among residential customers who are trying to maintain a basic level of electric service on their premises.

To calculate a value for residential resiliency, we have sampled the costs for portable inverter electric generators from 2.5 kW to 5.5 kW in size that are compliant with CARB emission requirements for California. We sampled inverter generators because they are quieter to operate (but not as quiet as a battery), and noise is a significant environmental impact of these units (especially when a whole community is using them). The average cost of these units is about $472 per kW, to which must be added sales tax, fuel storage costs, and the installation of a manual transfer switch to feed the critical circuits in the home. These units are expensive to run, require fuel that must

[94] See NARUC Study, at p. 17.

be stored or replenished, and even the models that meet the voluntary CARB standards produce significant emissions of criteria air pollutants and carbon dioxide. I priced these additional impacts assuming use of these generators for one 7-day interruption in a 10-year period. The total cost for such a system to provide 3.5 kW of residential resiliency is $3,030, or $87 per kW-year over the 10 years, as summarized in **Table 8**.

Table 8: *Components of Residential Resiliency Value*

Component	Cost	Notes
Generator	$472 / kW	1.8 to 5.5 kW units
	$1,650	Assuming a 3.5 kW generator
CA Sales Tax	$140	At 8.5%
Transfer Switch	$600	Manual switch & installation
Fuel Storage	$300	Fuel containers and annual rotation
Excess Energy Costs	$60	Electricity costs above $0.25/kWh
Air Impacts	$280	NOx, PM2.5, GHG Planning Price[95]
Total	$3,030	Total for the 3.4 kW unit
	$87 per kW-year	Assuming one 7-day interruption per decade

In my opinion, this is a conservative (low) value, as it does not consider other downsides from small portable fossil generators, including the 70 annual deaths in the U.S. from carbon monoxide poisoning associated with the use of these units[96] and the limited fuel

[95] I have estimated the air emissions for portable gasoline generators assuming emissions of NOx and PM2.5 at the CARB voluntary compliance standard for these small engines, although many small generators on the market do not comply with these standards. To value the heath impacts of emissions of criteria pollutants (NOx and PM2.5), I used the values provided in the white paper that I authored with Alison Seel of the Sierra Club, *Non-Energy Benefits of Distributed Generation* (August 3, 2015), which is in the record for this docket as Attachment 2 to SEIA's comments filed March 23, 2017 on the staff proposal recommending a societal cost test. For the GHG costs, I used the average 2018-2030 GHG Planning Price less $20 per ton for the cap & trade value of GHG emissions from gasoline, which I assume to be included in the $4 per gallon cost of gasoline.

[96] See U.S. Consumer Product Safety Commission, "Incidents, Deaths, and In-Depth Investigations Associated with Non-Fire Carbon Monoxide from Engine-Driven Generators and Other Engine-Driven Tools, 2005-2016," at p. 5, available at https://www.cpsc.gov/s3fs-public/Non-Fire-Carbon-Monoxide-from-Engine-Driven-Generators-2005-2016-June%202017.pdf?FL5ZFHu050hLH_NGRwJtpM2EE4JHeveV.

capacity that may result in significant risks from the transportation, handling, or storage of fuel.[97]

The resiliency value for commercial customers appears to be similar, with one study of resiliency options for the U.S. military using an assumed cost of $80 to $85 per kW-year for the 20-year cost to protect a kW of load using individual diesel generation units for typical buildings on a military site.[98] The National Renewable Energy Laboratory (NREL) has a similar study of diesel generator backup costs that assumes a capital cost of about $70 per kW-year plus $35 per kW-year for ongoing maintenance.[99] These costs may be low for diesel gensets that meet strict California air emission regulations. I assume that the cost of diesel fuel will be roughly equal the California retail electric rates ($0.20 per kWh) that the diesel generation replaces, and I calculate air emission costs of $1 per kW-year assuming one 7-day outage per decade, based on current CARB standards for stationary diesel units. The total resiliency value is thus $106 per kW-year ($70/kW-yr for capital, $35/kW-yr for maintenance, and $1/kW-year for air emissions).

Q: How would these reliability and resiliency values be incorporated into the ACC spreadsheet model?

A: These benefits would be annual values, escalating with inflation. The reliability benefit would apply to storage or solar + storage systems; the resiliency benefit would apply to solar + storage systems. The reliability value is a dollar per system value, while the resiliency value in dollars per kW-year is based on the kW discharge capacity of the battery system.

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[97] These generators typically have fuel tanks large enough for no more than two days of operation at five to eight hours per day.

[98] NARUC Study, at pp. 26-27, citing Marqusee, J., Schultz, C., and Robyn, D., *Power Begins at Home: Assured Energy for U.S. Military Bases* (2017), commissioned by The Pew Charitable Trusts.

[99] S. Ericson and D. Olis, *A Comparison of Fuel Choice for Backup Generators* (NREL, March 2019), at pp. 20-21 and 25-27.

Q: Please discuss the use of these reliability and resiliency benefits in the context of the Commission's cost-effectiveness tests?

A: These are clearly benefits that accrue to the electric system as a whole and to the consumers who install a DER system that provides these benefits. Thus, they should be benefits in the Total Resource Cost, Societal Cost, and Participant Cost tests. I would also argue that the widespread adoption of such systems has broader benefits for all ratepayers, especially the resiliency benefit. In a "black sky" event that interrupts the grid for a prolonged period, even if I have not installed such a system myself, I will be better off if several of my neighbors, the local fire station, or the emergency shelter at the nearby school have assured backup supplies of electricity. Thus, I would include the resiliency benefit in the Ratepayer Impact Measure test.

D. Grid Services

Q: Can DERs provide grid services?

A: Yes. "Grid services" covers a range of new benefits on the distribution system. I describe, document, and discuss below a number of important grid services that are being implemented, piloted, or studied in various initiatives in the U.S.:

- **Dispatchable capacity.** Solar plus storage units can be dispatched by the utility or grid operator to provide a controllable source of peaking capacity. Capacity services may be dispatched in real time or utilized in a more passive manner where capacity is permanently scheduled for delivery within specified hours to achieve planning goals and system needs. This allows solar plus storage units to provide similar capacity benefits as demand response programs, with the difference that the storage unit may export some of its energy to the grid if its output exceeds the customer's use at the time of the utility call. As an example, Green Mountain Power has funded a portion of the cost for a number of residential customers to install Tesla storage units, provided the Vermont utility has rights to dispatch the units for a limited number of hours each year. Green Mountain has demonstrated that this dispatch not only provides generation capacity and avoids very high energy costs on peak days, but also allows it to avoid high-voltage transmission costs from ISO-New England (ISO-NE) that are allocated based on the utility's coincident peak demand.[100] There are similar initiatives underway in other northeastern states.[101] Sunrun has a 20 MW capacity contract directly with ISO-NE;[102] in California, Sunrun announced a small capacity contract to use aggregated solar + storage to provide capacity to East Bay Clean Energy in West Oakland.[103] There is also the potential for DERs to provide significant "shift" demand response resources, where loads are shifted from one part of the day to another.[104]

- **Ancillary services.** Wholesale, in-front-of-the-meter battery storage units on the CAISO system already are providing ancillary services such as regulation in the CAISO markets.[105] It is possible that aggregated distributed BTM storage also could provide similar services, presumably valued at the relevant CAISO market prices.

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[100] See https://granitegeek.concordmonitor.com/2018/07/23/using-customer-batteries-as-a-power-source-saved-vt-utility-500k/.
[101] See https://www.utilitydive.com/news/northeastern-utilities-aim-to-crush-and-flatten-system-peaks-as-ders-boos/562944/.
[102] See https://www.utilitydive.com/news/residential-solarstorage-breaks-new-ground-as-sunrun-wins-iso-ne-capacity/547966/. Also https://www.globenewswire.com/news-release/2019/02/07/1712238/0/en/ISO-New-England-Awards-Sunrun-Landmark-Wholesale-Capacity-Contract.html.
[103] See https://www.greentechmedia.com/articles/read/east-bay-power-purchaser-signs-distributed-capacity-contract-with-sunrun#gs.4hy6ag.
[104] See Lawrence Berkeley National Laboratory, *Final Report on Phase 2 Results: 2025 California Demand Response Potential Study* (2017). Available at: http://www.cpuc.ca.gov/General.aspx?id=10622.
[105] The daily output of these units can be seen at http://www.caiso.com/TodaysOutlook/Pages/supply.aspx under "Batteries trend." Days where this storage cycles many times between charging and discharging indicate that the storage is being operated to provide regulation or other ancillary services.

- **Voltage support.** Smart inverters can provide voltage support on distribution circuits, either with fixed settings or with settings that are controlled dynamically by the utility. The Commission has required the activation of several advanced features on smart inverters (Volt Var and Volt Watt modes) that provide voltage support on the distribution system. When the Commission did so, it recognized that there remained an issue, raised by DG parties, of compensation for this grid service. The Commission noted that this could be adjudicated in ongoing cases including this IDER docket and the interconnection proceeding, R. 17-07-007.[106] The Commission has not yet acted in this proceeding or R. 17-07-007 to review such compensation.

- **Providing additional thermal capacity on distribution systems.** Analyses of the impacts of DERs on distribution circuits and substations tends to focus on DER impacts on coincident peak loads, that is, on just a few hours when loads on the circuit or substation peak. However, the capacity of distribution circuits is limited less by the coincident peak load than by the cumulative thermal demand (i.e. the build-up of heat over the course of the day) in key equipment such as transformers, conductors, and voltage regulation devices. As a result, output from solar DERs over the course of the day can increase the thermal capacity of a distribution system, even if that output is not completely coincident with the distribution system's peak. Analysis of this effect for a sample of distribution circuits in New York indicates that the capacity contribution of DERs on a distribution circuit may be one-third higher when based on thermal capacity

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[106] See Resolution E-4898, at pp. 9-10: "The Commission may consider the development of compensation mechanisms [for these advanced functions] in open proceedings, and the study of these functions will assist in determining appropriate levels and mechanisms for compensation if compensation is found to be warranted… Activation of Functions 5 and 6 is a reasonable part of utilizing smart inverter functionality to benefit the grid and ratepayers."

compared to the contribution based on coincident peak output.[107] Such analyses could increase the assumptions in the ACC for the amount of T&D capacity that DERs are able to avoid.

- **Extending the life of distribution system equipment.** In addition to the benefit of avoiding investments that would otherwise be needed to increase distribution system capacity to meet load growth, DERs also can provide the benefit of extending the life of existing distribution system equipment. For example, a PG&E study found that a 500 kW solar PV system on a distribution circuit extended the life of a substation transformer by 4.6 years, at a cost savings to ratepayers of $398,000.[108] While this benefit may vary from circuit to circuit depending on the age of equipment, the ratepayer benefits can be significant enough that they should be included in the ACC.

- **Conservation voltage reduction (CVR).** Smart inverters can take the place of other voltage-regulating distribution equipment to provide energy and emission savings from planned reductions in the voltage on a distribution circuit. This grid service can allow a reduction in circuit voltages of up to 4%, with energy savings for all customers on the circuit that can range from $0.01 to $0.028 per kWh of solar output.[109] CVR schemes require utility planning and the coordination of the smart inverters on the circuit to ensure that the savings are realized.

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[107] The thermal capacity provided by DERs on distribution circuits is discussed in a paper from Solar City Grid Engineering, "Enhancing Methodologies for Valuing Transmission and Distribution Capacity," filed October 7, 2016 in Public Utilities Commission of Nevada Docket No. 16-06006 as Exhibit RH-4 to the Prefiled Direct Testimony of Ryan Hanley, hereafter "Hanley Testimony."

[108] "The Value of Grid-Support Photovoltaics to Substation Transformers," by T. Hoff of Pacific Energy Group and D.S. Shugar, PG&E. Available at https://www.cleanpower.com/wp-content/uploads/2012/02/047_ValuePVTransformerSupport.pdf. Another paper on the broader distribution system benefits of this project is at https://www.osti.gov/biblio/93996.

Q: These various grid services clearly are in different stages of development and deployment. Please comment on how this should impact the ACC.

A: These services also are in different stages of development in terms of how readily they can be valued. The point of presenting these services proactively in this testimony is to request the Commission to recognize, first, that these services are being deployed or may be developed in the near future and, second, that the ACC should be modified to be ready to include these services, or should be modified promptly, when they are implemented.

The first two grid services are being deployed or will be deployed in the near future, and they clearly have established starting points for valuation. Dispatchable capacity can be valued using existing demand response tariffs as starting points, and the CAISO has well-developed markets for ancillary services. As a result, the ACC can be readily adapted to calculate the benefits of these services, as needed to evaluate their cost-effectiveness. Further, there is also the potential to combine these services in multiple use applications that will expand hosting capacity to accommodate EV adoption, electrification, and the enhanced operational flexibility of the power system.

The remaining services will require further action by the Commission (to evaluate compensation for voltage support), additional data or analysis provided by the IOUs (for a quantification of thermal capacity effects or life extension benefits), or a program coordinated by a utility (for conservation voltage reduction). If and when these developments occur, the necessary changes to the ACC should be made promptly, and forecasted as needed, so that the value of these services is recognized in the ACC, even if such changes are outside of the biennial schedule for major ACC updates adopted in D. 19-05-019. The range of grid services that DERs can provide is changing rapidly, and the ACC needs to evolve equally quickly so that it does not become a barrier to the deployment of new and valuable benefits for California's electric system.

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[109] See Solar City Grid Engineering, "Energy Efficiency Enabled by Distributed Solar PV via

Q: Does this conclude your testimony in this case?

A: Yes, it does.

Conservation Voltage Reduction," attached to Hanley Testimony as Exhibit RH-5.

Attachment RTB-1

CV of R. Thomas Beach

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

- *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

- *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

- *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

- *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

- *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

- *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

- *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

- *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

- *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

- *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

- *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

- *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

- *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony on behalf of the **Joint Solar Parties** (R. 14-07-002 — September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

85. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 15-04-012—July 5, 2016)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

86. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 16-09-003 — April 28, 2017)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

87. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 17-06-030 — March 23, 2018)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).

   - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*

2. Prepared Surrebuttal and Responsive Testimony on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).

   - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

3. Direct Testimony on behalf of the **Solar Energy Industries Association** (Docket No. E-01345A-16-0036, February 3, 2017).

4. Direct and Surrebuttal Testimony on behalf of **The Alliance for Solar Choice and the Energy Freedom Coalition of America** (Docket Nos. E-01933A-15-0239 (TEP), E-01933A-15-0322 (TEP), and E-04204A-15-0142 (UNSE) – May 17 and September 29, 2017).

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009). https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).

   - *Development of a community solar program for Xcel Energy.*

3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).

   - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).

   - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

2. a. Direct Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — December 22, 2017)
   b. Rebuttal Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — January 26, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)

   - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

1. Prepared Direct Testimony on behalf of **Vote Solar** (Case No. U-18419—January 12, 2018)

2. Prepared Rebuttal Testimony on behalf of the **Environmental Law and Policy Center, the Ecology Center, the Solar energy Industries Association, Vote Solar, and the Union of Concerned Scientists** (Case No. U-18419 — February 2, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

    - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39, October 14 and November 9, 2016).

    - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

    - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

4. a. Prepared Direct Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
   b. Prepared Direct Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).

c. Prepared Rebuttal Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).

- *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).

   - *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011) http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443
June 20, 2104:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

3. Direct Testimony on Behalf of the **Oregon Solar Energy Industries Association** (UM 1910,01911, and 1912 — March 16, 2018).

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)
   https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony on behalf of the **Solar Energy Industries Association** (SEIA) (Docket No. 44941 – December 11, 2015)

   - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

    - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)
http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

Attachment RTB-2

Recommended Natural Gas Forecast

Summary of Revised Natural Gas Price Forecast

Color Key:	Forwards	*Interpolated*	Fundamental

	Henry Hub					SoCalGas -- for SCE and SDG&E						PG&E								
Year	Forward Market	EIA AEO 2019	IEPR 2019	Average Long-term	Blended Forecast	Forward Market	Forward Market Basis	Blended SoCal	GT-5NC Rate	Franchise Fee	Burnertip SoCal MPR	Forward Market	Baja Path	Basis Forecast	Blended Citygate	G-EG Backbone Rate	G-EG All Others Rate	Franchise Fee	Burnertip PG&E BB	Burnertip PG&E LT
2019	2.73	3.09	3.09	3.09	2.73	2.93	0.20	2.93	0.67	0.04	**3.63**	3.67	0.74	0.94	3.67	0.23	1.10	0.04	**3.94**	**4.81**
2020	2.70	3.22	3.26	3.24	2.70	2.63	-0.07	2.63	0.74	0.04	**3.41**	3.62	0.98	0.91	3.62	0.23	1.18	0.04	**3.88**	**4.84**
2021		3.20	3.43	3.32	*2.97*		-0.07	*2.90*	0.82	0.04	**3.77**		1.11	1.04	*4.02*	0.23	1.26	0.04	**4.28**	**5.32**
2022		3.28	3.64	3.46	*3.24*		-0.07	*3.17*	0.91	0.04	**4.13**		1.15	1.08	*4.33*	0.23	1.31	0.04	**4.60**	**5.68**
2023		3.49	3.76	3.63	*3.52*		-0.07	*3.45*	1.01	0.05	**4.51**		1.28	1.21	*4.73*	0.25	1.45	0.05	**5.03**	**6.22**
2024		3.77	3.88	3.82	*3.79*		-0.07	*3.72*	1.12	0.05	**4.89**		1.42	1.35	*5.14*	0.28	1.61	0.05	**5.47**	**6.80**
2025		4.11	4.00	4.06	4.06		-0.07	3.99	1.25	0.06	**5.29**		1.58	1.51	5.56	0.31	1.79	0.06	**5.93**	**7.41**
2026		4.29	4.13	4.21	4.21		-0.07	4.14	1.32	0.06	**5.52**		1.67	1.60	5.81	0.33	1.89	0.06	**6.20**	**7.77**
2027		4.41	4.27	4.34	4.34		-0.07	4.27	1.40	0.06	**5.73**		1.77	1.70	6.05	0.35	2.01	0.06	**6.46**	**8.11**
2028		4.61	4.42	4.51	4.51		-0.07	4.44	1.48	0.06	**5.99**		1.88	1.81	6.32	0.37	2.13	0.06	**6.76**	**8.51**
2029		4.73	4.59	4.66	4.66		-0.07	4.59	1.57	0.07	**6.23**		1.99	1.92	6.58	0.39	2.25	0.07	**7.04**	**8.90**
2030		4.88	4.78	4.83	4.83		-0.07	4.76	1.67	0.07	**6.50**		2.11	2.04	6.87	0.42	2.39	0.07	**7.36**	**9.33**
2031		4.97	4.96	4.96	4.96		-0.07	4.89	1.77	0.07	**6.73**		2.24	2.17	7.13	0.44	2.53	0.07	**7.64**	**9.74**
2032		5.26	5.32	5.29	5.29		-0.07	5.22	1.87	0.08	**7.17**		2.37	2.30	7.60	0.47	2.68	0.08	**8.14**	**10.36**
2033		5.46	5.50	5.48	5.48		-0.07	5.41	1.99	0.08	**7.47**		2.51	2.44	7.92	0.50	2.85	0.08	**8.50**	**10.85**
2034		5.64	5.72	5.68	5.68		-0.07	5.61	2.11	0.08	**7.80**		2.67	2.60	8.28	0.53	3.02	0.08	**8.89**	**11.38**
2035		5.82	5.92	5.87	5.87		-0.07	5.80	2.23	0.09	**8.12**		2.83	2.76	8.63	0.56	3.20	0.09	**9.27**	**11.91**
2036		6.06	6.09	6.08	6.08		-0.07	6.01	2.37	0.09	**8.46**		2.99	2.92	9.00	0.59	3.39	0.09	**9.68**	**12.48**
2037		6.23	6.28	6.25	6.25		-0.07	6.18	2.51	0.09	**8.78**		3.17	3.10	9.36	0.63	3.59	0.09	**10.07**	**13.04**
2038		6.38	6.54	6.46	6.46		-0.07	6.39	2.66	0.10	**9.14**		3.36	3.29	9.75	0.66	3.81	0.10	**10.51**	**13.66**
2039		6.55	6.68	6.61	6.61		-0.07	6.54	2.82	0.10	**9.46**		3.57	3.50	10.11	0.70	4.04	0.10	**10.91**	**14.25**
2040		6.79	6.85	6.82	6.82		-0.07	6.75	2.99	0.10	**9.84**		3.78	3.71	10.53	0.75	4.28	0.10	**11.38**	**14.91**
2041		6.92	6.96	6.94	6.94		-0.07	6.87	3.17	0.10	**10.14**		4.01	3.94	10.88	0.79	4.54	0.10	**11.78**	**15.52**
2042		7.14	7.15	7.15	7.15		-0.07	7.08	3.36	0.11	**10.54**		4.25	4.18	11.32	0.84	4.81	0.11	**12.27**	**16.24**
2043		7.40	7.26	7.33	7.33		-0.07	7.26	3.56	0.11	**10.93**		4.50	4.43	11.77	0.89	5.10	0.11	**12.77**	**16.98**
2044		7.71	7.44	7.57	7.57		-0.07	7.50	3.77	0.12	**11.39**		4.77	4.70	12.27	0.94	5.40	0.12	**13.33**	**17.79**
2045		8.01	7.55	7.78	7.78		-0.07	7.71	4.00	0.12	**11.82**		5.06	4.99	12.77	1.00	5.73	0.12	**13.89**	**18.61**
2046		8.27	7.72	8.00	8.00		-0.07	7.93	4.24	0.13	**12.29**		5.36	5.29	13.29	1.06	6.07	0.13	**14.48**	**19.49**
2047		8.58	7.91	8.25	8.25		-0.07	8.18	4.49	0.13	**12.80**		5.68	5.61	13.86	1.12	6.43	0.13	**15.12**	**20.43**
2048		9.01	8.08	8.55	8.55		-0.07	8.48	4.76	0.14	**13.37**		6.03	5.96	14.50	1.19	6.82	0.14	**15.83**	**21.46**
2049		9.40	8.29	8.84	8.84		-0.07	8.77	5.05	0.14	**13.96**		6.39	6.32	15.16	1.26	7.23	0.14	**16.57**	**22.53**
2050		9.76	8.48	9.12	9.12		-0.07	9.05	5.35	0.15	**14.55**		6.77	6.70	15.82	1.34	7.66	0.15	**17.31**	**23.63**

ATTACHMENT B

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158

In the Matter of:	**)**
Biennial Determination of Avoided	**)**
Cost Rates for Electric Utility	**)**
Purchases from Qualifying Facilities –	**)**
2018	**)**

DIRECT TESTIMONY OF
R. THOMAS BEACH
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE, AND EMPLOYER.

A. My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q. PLEASE STATE YOUR EDUCATIONAL AND OCCUPATIONAL EXPERIENCE.

A. My experience and qualifications are described in my *curriculum vitae*, attached here to as **Exhibit 1**. As reflected in my CV, I have more than 35 years of experience in the natural gas and electricity industries. I began my career in 1981 on the staff at the California Public Utilities Commission ("CPUC"), working on the implementation of the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). Since 1989, I have had a private consulting practice on energy issues and have testified on numerous occasions before state regulatory commissions in eighteen states. My CV includes a list of the testimony that I have sponsored in various state regulatory proceedings concerning electric and gas utilities.

Q. PLEASE DESCRIBE MORE SPECIFICALLY YOUR EXPERIENCE ON AVOIDED COST ISSUES, PARTICULARLY AS THEY APPLY TO RENEWABLE AND DISTRIBUTED GENERATION PROJECTS.

A. In addition to working on the initial implementation of PURPA while on the staff at the CPUC, in private practice I have represented the full range of qualifying facility ("QF") technologies – both renewable small power producers as well as gas-fired cogeneration QFs – on avoided cost pricing issues before the utilities commissions in California, Oregon, Nevada, Montana, and North Carolina (in Docket No. E-100, Sub 140). With respect to the renewable generation issues under consideration in this case, I have testified on solar economics in Arizona, California, Colorado, Idaho, Massachusetts, Minnesota, New Hampshire, New Mexico, Oregon, and Virginia. Since 2013, I have co-authored cost-benefit studies of distributed solar generation ("DSG") in Arizona, Arkansas, California, New Hampshire, and North Carolina.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of North Carolina Sustainable Energy Association ("NCSEA"), an intervenor in this proceeding.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE IN FRONT OF THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes, I have. I testified for NCSEA in 2014 in Docket No. E-100, Sub 140, including preparing direct, response, and rebuttal testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present NCSEA's position on a specific set of issues in this docket, as identified in the Commission's *Order Scheduling Evidentiary Hearing and Establishing Procedural Schedule* (Hearing Order) in this docket, issued April 24, 2019. The direct testimony and exhibits of the North Carolina utilities on these issues was filed on May 21, 2019. Finally, on May 21, 2019 Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP"), and the

North Carolina Utilities Commission – Public Staff ("Public Staff") filed a *Stipulation of Partial Settlement Regarding Solar Integration Services Charge* ("Integration Stipulation"). This testimony will address the following issues in the Hearing Order:

c. Duke's Quantification of Ancillary Services Cost of Integrating QF Solar;

d. Duke's Proposed Solar Integration Charge "Average Cost" Rate Design and Biennial Update;

e. Dominion's Proposed Re-Dispatch Charge; and

f. NCSEA's and Public Staff's Proposals Related to Differing Ancillary Services Costs for Innovative QFs.

All of these issues are related to the costs of integrating higher amounts of solar generation into the systems of the North Carolina utilities. Finally, I will comment on the Integration Stipulation between DEC/DEP and the Public Staff.

Q. HAVE YOU PREVIOUSLY SUBMITTED INFORMATION AND ANALYSIS FOR THE RECORD IN THIS DOCKET?

A. Yes. On February 12, 2019 NCSEA submitted its initial comments in this docket, which included as Attachment 2 an affidavit that I prepared with a report (Report) on certain avoided cost issues under review in this case.

Q. WHAT INFORMATION DID YOU REVIEW IN PREPARING THIS TESTIMONY?

A. I have reviewed the North Carolina utilities' filings in this docket proposing their avoided cost rates to become effective in 2019, including the direct testimony and exhibits filed on May 21, 2019. I have also reviewed elements of their workpapers as well as their responses to certain discovery requests propounded by NCSEA and other parties, as documented in my Report and its workpapers. I also used additional documents and studies as listed in my Report and in this testimony, as well as the results of analyses performed by me or by my staff under my direction. That analytic work is discussed in my Report and available in my workpapers.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. This testimony provides the Commission with a broader context in which to evaluate the proposals of the utilities to adopt integration charges that would be subtracted from the avoided cost rates paid to future QFs on their systems. The integration cost study that DEC and DEP submitted, for example, shows increasing integration costs per MWh of solar output, as solar penetration increases. However, the actual experience of system operators in states, such as California, with higher penetrations of solar than North Carolina do not substantiate the results of the DEC/DEP study, which is based on a simulation and not actual experience. This testimony presents data on the actual ancillary service costs experienced by the California Independent System Operator (CAISO), which shows that ancillary service costs have not changed over a period in which the amount of wind and solar resources integrated by the CAISO has increased nine-fold. Similarly, I discuss several traditional vertically-integrated utilities that each have performed a series of wind and solar integration studies as the penetration of these resources on their systems has grown, with successive studies showing declining integration costs per MWh of renewable output.

The broader context of actual experience with solar integration is that system operators and utilities in the U.S. are "learning by doing," and developing ways to integrate large amounts of wind and solar generation without increasing ancillary service costs. These techniques can include improved solar forecasting, better use of real-time data from solar facilities, and greater cooperation with neighboring utilities, including the trading of imbalances within the hour through new market mechanisms such as the Energy Imbalance Market ("EIM") that has been so successful in the western U.S. Further, as the penetration of renewables with zero variable costs increases, the impact is to unload marginal gas-fired resources that become available to provide ancillary services, increasing the supply and reducing the costs for such services.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. My primary recommendation is that the Commission should not adopt the integration charges proposed by DEC, DEP, and Virginia Electric and Power Company d/b/a Dominion Energy North Carolina ("DENC"). Any costs to integrate the growing penetration of solar resources in North Carolina will be offset by other benefits of these new resources that the utilities have not recognized, including lower market prices and avoided transmission and distribution capacity costs, as discussed in more detail in my previously-submitted Report. Instead of implementing an integration charge, the Commission should direct the utilities under its jurisdiction that operate balancing areas in North Carolina to study the benefits of forming an EIM with the nearby PJM Interconnection.

If the Commission does adopt an integration charge, existing and committed QFs should be exempt from the charge, and the charge should be capped at no more than what the Commission determines to be the average integration cost for this tranche of solar studied. This would recognize the experience that actual integration costs per MWh of solar output do not appear to increase with solar penetration, if the system operator takes proactive steps to minimize integration costs. Finally, if an integration charge is adopted, I support the direction of one provision of the stipulation on integration cost issues that the Public Staff and DEC/DEP filed on May 21, 2019 – the provision that would not apply an integration charge to any QF that materially reduces the need for additional ancillary services by using physical energy storage, contractual dispatch capabilities, or other innovative mechanisms. I recommend that the Commission provide more specific details on qualifying for this exemption so that prospective QFs understand the additional investment or operating constraints that will be required to qualify.

II. INTEGRATION ISSUES

Q. ALL OF THE ISSUES CITED ABOVE CONCERN THE INTEGRATION COST ANALYSES SUBMITTED BY DED/DEP AND DNCP. PLEASE EXPLAIN YOUR PERSPECTIVE ON THE INTEGRATION COST ISSUE.

A. My Report did not address the technical details of the utilities' integration cost studies. Instead, I focused on the broader contexts for these studies. North Carolina obviously is not the only state in the U.S. with a rapidly-growing penetration of renewable resources. As a result, there is a growing body of evidence on both the benefits and costs of integrating new renewables, as utilities and system operators have "learned by doing" in integrating growing fleets of wind and solar resources and as there is more evidence on the market impacts of these new resources with zero variable costs. The utilities' integration studies at best only examine one aspect of integrating solar resources – the impact on the utilities' ancillary service costs – and even then, the results are not consistent with the actual experience of utilities elsewhere in the U.S. that also are integrating large amounts of solar resources. In addition, as my Report emphasizes, the Commission also needs to consider the benefits of integrating distributed solar generation that are not included in avoided cost rates. The Astrapé study for DEC/DEP fails to quantify or consider these benefits. These benefits include:

- **Lower market prices.** It is widely acknowledged that the growth of zero-variable-cost renewables, plus lower natural gas prices, has resulted in a broad reduction in electric market prices that has undermined the economics of baseload coal and nuclear resources.[1] Avoided cost rates have declined steadily in North Carolina for the last three years, due in significant part to lower natural gas and electric market prices. The studies cited in my Report indicate that the current penetration of renewables

[1] In https://ei.haas.berkeley.edu/research/papers/WP292.pdf, James Bushnell and Kevin Novan of the University of California at Davis find that renewable investment in California has been responsible for the majority of price declines in the California Independent System Operator's (CAISO) energy market over the last five years. Similarly, Lawrence Berkeley National Laboratory (LBNL) researchers have identified significant impacts on wholesale market prices from increasing penetration of renewables; see, http://eta-publications.lbl.gov/sites/default/files/report_pdf_0.pdf. MIT's Paul Joskow has also written about the impacts of rapid wind and solar penetration on wholesale markets, and the resulting challenges of retaining existing generators through market incentives alone; see https://economics.mit.edu/files/16650.

could easily account for a 4% reduction in energy market prices in the state, which would substantially offset the proposed solar integration charge.[2]

- **Avoided transmission and distribution capacity costs**, as discussed at length in Section III.C of my Report.

These benefits will more than offset any integration costs.

A. Learning by Doing

Q. PLEASE DISCUSS WHY THE UTILITIES' STUDIES ARE INCONSISTENT WITH THE ACTUAL OBSERVED COSTS OF INTEGRATING A HIGH PENETRATION OF SOLAR RESOURCES.

A. The DEC/DEP study from Astrape is based entirely on production cost simulations of each utility's individual control area, adding must-take solar generation to each utility's existing portfolios of on-system resources. The utilities have not introduced evidence of what their actual ancillary service costs are today or of how those costs have been impacted, if at all, by the growing amounts of solar generation on their systems. These simulation studies do not consider ways in which the utilities may adapt their system operations to minimize the cost of integrating solar generation – steps that can include improved solar forecasting, better use of real-time data from solar facilities, and greater cooperation with neighboring utilities (including the greater trading of imbalances within the hour). In fact, nothing that

[2] A 4% reduction in energy market prices in the range of $30 to $40 per MWh would substantially reduce or eliminate the integration costs proposed by DEC ($1.10 per MWh) and DEP ($2.39 per MWh). Four percent is the level of the market price suppression benefit of solar calculated from studies in the market of the New England Independent System Operator, as discussed on page 19, footnotes 36 and 37, of my Report.

Duke has provided in this proceeding exhibits its own efforts to mitigate intermittency issues on the grid, and, instead, pushes the entirety of the cause and the proposed solution onto future QF developers.

Nor do the utility studies recognize or consider that the changes in the avoided cost rate design that may result from this proceeding – shifting the peak avoided costs into late summer afternoons and winter mornings – will result in an increased use of solar tracking systems and storage. The addition of these technologies will reduce the variability of solar output and allow a significant portion of solar output to be dispatched into the time-of-use periods when power is most valuable to the system. The Commission should not adopt integration cost studies premised on an erroneous assumption that the solar to be built in the future in North Carolina will resemble the solar that has been installed to date.

Q. CAN YOU PROVIDE EVIDENCE OF A STATE WITH A LARGE PENETRATION OF SOLAR RESOURCES THAT HAS NOT EXPERIENCED SIGNIFICANT INTEGRATION COSTS?

A. Yes. Today, California has 20,000 MW of installed solar on the grid of the California Independent System Operator (CAISO) plus 6,700 MW of wind. Of the 20,000 MW of solar on the CAISO system, 12,000 MW are wholesale, utility-scale projects and 8,000 MW are behind-the-meter solar installed by almost one million utility customers.[3] The recent annual peak demands on the CAISO grid have been

[3] See, http://www.caiso.com/informed/Pages/CleanGrid/default.aspx. The data on behind-the-meter solar is from https://www.californiadgstats.ca.gov/.

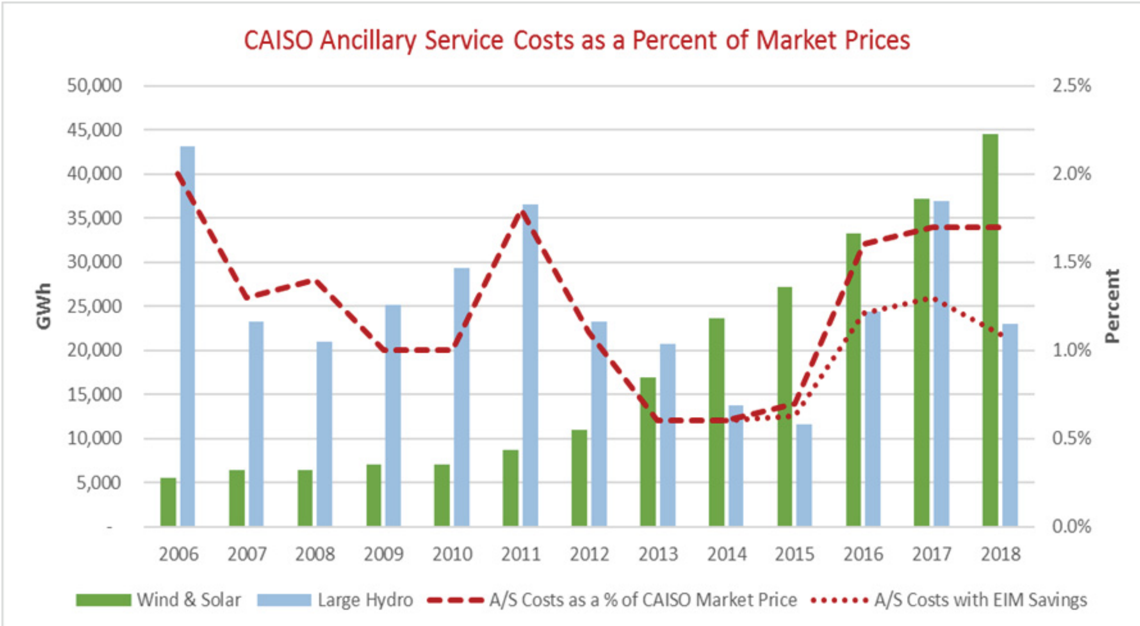
in the range of 46,000 to 50,000 MW.[4] Wind and solar now supply about one-quarter (25%) of the electricity on the CAISO system.[5] This is a much higher penetration of wind and solar than exists in North Carolina today or than has been modeled for North Carolina in any of the scenarios examined in this case.[6] The CAISO has integrated this high penetration of wind and solar resources without a discernable increase in its costs for ancillary services, which it obtains from a market for those services. **Figure 1** below shows the history of ancillary service costs on the CAISO system from 2006-2018 (red dashed line), expressed as a percentage of the CAISO energy market costs in each year. The figure also shows the growth of wholesale wind and solar generation in California (green bars); these resources have increased nine-fold (from about 5,000 GWh/year in 2006 to 45,000 GWh per year in 2018).[7] Ancillary service costs for the CAISO have fluctuated between 0.5% to 2.0% of CAISO energy market costs over this period.[8] The primary cause for these fluctuations has been the availability of large hydro resources (blue bars). Ancillary service costs increase in wet years when hydro generation is abundant (such as 2011 and 2017), because hydro resources are

[4] See, http://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf.
[5] This includes about 19% of the wholesale generation and 6% of loads served by on-site solar.
[6] The DEC/DEP Astapé study modeled a maximum of 3,020 MW of solar on DEC and 4,610 MW of solar on DEP, for a total of 7,630 MW on a system with a coincident peak of about 32,000 MW. See DEC/DEP Direct Testimony (Wintermantel), at Figure 2. This is similar to the penetration of wholesale solar on the CAISO system today, but the CAISO also integrates 8,000 MW of grid-connected, behind-the-meter solar.
[7] From the California Energy Commission's website with power source data for California: https://www.energy.ca.gov/almanac/electricity_data/total_system_power.html. Note that this is wholesale generation, and does not include the generation from on-site, behind-the-meter solar, which supplied approximately 15,000 GWh per year of load in 2018.
[8] Data on ancillary service costs as a percentage of CAISO energy market costs is from the CAISO's *Annual Report on Market Issues and Performance* over this period. These reports can be accessed on the CAISO website at http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx.

operated to produce energy rather than to supply ancillary services. In dry years, when hydro production is low, the hydro operators participate more actively in the ancillary services market because that is the best way to maximize the revenue from the limited water stored behind the dams. As a result, in those years ancillary service costs fall, as shown by the low ancillary service costs during the recent drought years of 2014-2015. Thus, as Figure 1 shows, ancillary service costs are strongly correlated with hydro conditions.

However, there has not been a discernable trend toward higher ancillary service costs despite the glaring fact that wind and solar generation *has grown by a factor of nine*. The dotted red line in Figure 1 for 2014-2018 shows the CAISO's ancillary service costs in these years including the CAISO's share of the intra-hour savings in balancing costs from the western Energy Imbalance Market ("EIM"). The EIM savings have reduced significantly the CAISO's costs to operate the California grid, even as the penetration of wind and solar has reached new highs and continues to grow.

Figure 1



Including the EIM savings, the CAISO's ancillary service costs over the last five years have averaged 1.0% of energy market costs; this is below the long-term average (2006-2018) of 1.2% of energy market costs. Thus, there is no evidence that the high penetration of wind and solar resources that the CAISO system has integrated in recent years has increased ancillary service costs. Although the California Public Utilities Commission began a process to develop wind and solar integration charges, it has not seen the need to complete that process and permanently adopt such charges.[9]

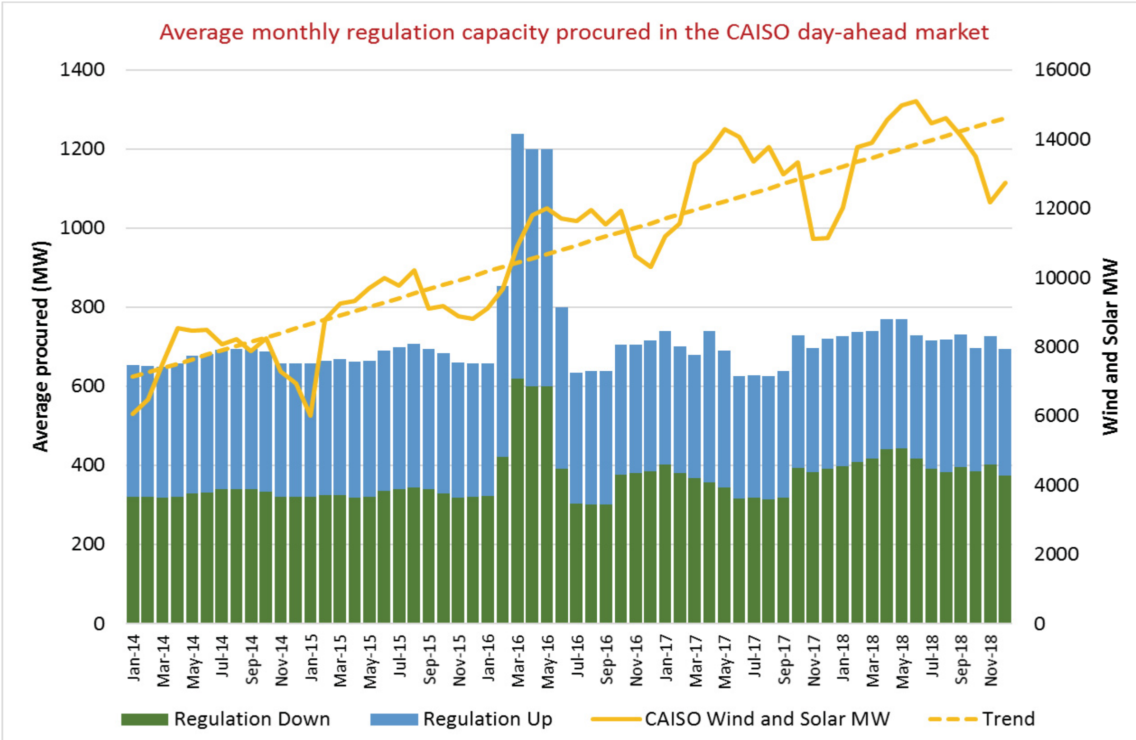
In early 2006, the CAISO increased the amount of regulation that it purchases, from 300-400 MW to 600 MW (in both directions), due to a concern

[9] The California commission has had a series of rulemaking proceedings to administer the state's Renewable Portfolio Standard ("RPS") program. The rulemaking initiated in 2015 (R. 15-02-020) included as an issue the continuing development of integration cost adders (see R. 15-02-020, at p. 6), but this issue was dropped in the next RPS rulemaking initiated in 2018 (R. 18-07-003).

with the increasing amounts of variable wind and solar generation. This increase in regulation accounts for part of the increase in ancillary service costs in 2016 over 2015 shown in Figure 1 (the rest of that increase appears due to wetter hydro conditions). However, after a few months in 2016 the CAISO refined its algorithm for the amount of regulation that it procures, and has been able to return to the use of just 300-400 MW of regulation, even with the steady increase in wind and solar resources over the last five years. This data on the CAISO's procurement of regulation from 2014-2018 is shown in **Figure 2** below.[10] This is another example of the "learning by doing" that is enabling system operators to minimize the integration costs associated with growing penetrations of variable renewables.

[10] The regulation up and down quantities are day-ahead procurement data from the CAISO's monthly market performance reports, at http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx. For example, Table 6 at page 16 or 45 of the CAISO's December 2018 monthly report is at http://www.caiso.com/Documents/MarketPerformanceReportforDecember2018.pdf. The wind and solar output data are monthly maximums of hourly CAISO wind and solar outputs (to show a measure of the amount of wind and solar capacity), from the CAISO's renewables watch output data files, which are available at http://www.caiso.com/market/Pages/ReportsBulletins/RenewablesReporting.aspx.

Figure 2



Q. ARE YOU AWARE OF TRADITIONAL, VERTICALY-INTEGRATED UTILITIES THAT HAVE PERFORMED A SERIES OF WIND OR SOLAR INTEGRATION STUDIES OVER TIME, AS THE PENETRATION OF WIND OR SOLAR RESOURCES ON THEIR SYSTEMS HAS INCREASED?

A. Yes. Both PacifiCorp and Idaho Power have performed several solar or wind integration studies over time, as these utilities have added significant amounts of these renewable resources to their systems.

The following **Tables 1 and 2** summarize these studies, which generally show that integration cost estimates have declined over time, even as more renewables have been added by these traditional utilities.

Table 1: *PacifiCorp Integration Costs ($ per MWh)*[11]

Resource	Date of Study		
	2012	**2014**	**2017**
Wind	$2.55	$3.06	$0.44
Solar	n/a	n/a	$0.60
	Resources (MW)		
Wind	2,126	2,543	2,793
Solar	n/a	n/a	1,000

Table 2: *Idaho Power Integration Costs ($ per MWh)*[12]

Resource	Date of Study	
	2014	**2016**
Solar	0-100 MW: $0.40 0-300 MW: $1.20 0-500 MW: $1.80 0-700 MW: $2.50	0-400 MW: $0.27 0-800 MW: $0.57 0-1,200 MW: $0.69 0-1,600 MW: $0.85
	Resources (MW)	
Solar	0	325

There are a variety of factors that account for the much lower integration costs in the most recent PacifiCorp and Idaho Power studies, including (a) methodological improvements, (b) reduced market prices, and (c) the increased availability of regulation-capable gas-fired resources displaced by new renewables. Significantly, the most recent studies from both PacifiCorp and Idaho Power included review by a technical review committee of outside experts from institutions such as the National Renewable Energy Laboratory ("NREL"), the Western Renewable Energy Generation Information System ("WREGIS"), and the Utility Wind Interest

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[11] The 2012 and 2014 wind integration costs are from PacifiCorp's 2015 Integrated Resource Plan (IRP), at Appendix H, Table H.3. The 2017 wind integration costs are from PacifiCorp's 2017 IRP, Volume II, at Appendix F, pp. 120-123, esp. Tables F.14 and F.16.

[12] For the 2014 results, see Idaho Power, Direct Testimony of Philip B. Devol, Idaho PUC Case No. IPC-E-14-18 (July 1, 2014), at p. 5. For the 2016 solar integration costs, see Idaho Power, *Solar Integration Study Report*, (April 2016), at pp. vi and 21, esp. Tables 2 and 9.

Group ("UWIG").[13] Idaho Power also reached a settlement with stakeholders concerning the design of its most recent integration study.[14] DEC and DEP did not take either step in preparing their integration study for this proceeding. I recommend that the Commission require stakeholder consultation and a technical review group for any future integration studies. Finally, I note that the most recent PacifiCorp and Idaho Power studies do <u>not</u> include consideration of the intra-hour balancing savings that both PacifiCorp and Idaho Power are realizing in the western EIM, which are further reducing their intra-hour costs for the load following resources needed to integrate renewables. As discussed in greater detail below, a market of this type applied in the Carolinas could result in significant benefits for Duke and its ratepayers.

B. No Utility Is An Island

Q. ONE OF YOUR CENTRAL CRTIQUES OF THE DEC/DEP INTEGRATION STUDY IS ITS ASSUMPTION THAT DEC AND DEP ARE INDIVIDUAL BALANCING AREAS NOT CONNECTED TO THE REST OF THE EASTERN INTERCONNECTION. IN RESPONSE, THE DUKE UTILITIES RE-RAN THE STUDY FOR THE COMBINATION OF BOTH DEC AND DEP, IN OTHER WORDS, RECOGNIZING THAT THEY ARE INTERCONNECTED AND HAVE A JOINT OPERATING AGREEMENT. PLEASE COMMENT ON THE RESULTS OF THIS NEW ANALYSIS.

[13] See the 2017 PacifiCorp and 2016 Idaho Power studies referenced in footnotes 10 and 11.
[14] See the stipulation approved by the Idaho PUC in Order No. 33227 in February 2015 (Case No. IPC-E-14-18).

A. Not surprisingly, integration costs dropped by about 15% when the two utilities were analyzed together.[15] This demonstrates, on a small scale, what the EIM is demonstrating across the entire Western Interconnection – the costs of integrating renewables decline when utilities cooperate to integrate renewables across as wide a footprint as possible. I fully expect that integration costs would decline further if other adjacent utilities were added and if those utilities cooperated to reduce load following costs on a mutually-beneficial basis. It is my understanding that Duke is already in the business of making market purchases and sales with neighboring utilities, so there should be a pathway via those relationships to working with these neighboring utilities to reduce intra-hour balancing costs.

Q. DEC AND DEP DISMISS NCSEA'S COMMENTS ON THE BENEFITS OF AN EIM BECAUSE "NO SUCH MARKET CONSTRUCT EXISTS ACROSS THE ENTIRE EASTERN INTERCONNECTION."[16] PLEASE COMMENT.

A. No such market exists because utilities and system operators have not taken the initiative to create one, and because regulators have yet to encourage them to create the market construct needed to realize these ratepayer savings. The western EIM began with an agreement in 2014 between just the CAISO and PacifiCorp, but since then has spread across almost the entire Western Interconnection and now includes utilities in every state in the WECC except Colorado and Texas. There are several important reasons for the success and rapid spread of the western EIM:

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[15] DEC/DEP Reply Comments, at pp. 92-94.
[16] *Ibid*., at p. 90.

- First and foremost, since its inception, **the EIM has saved money for every participating utility.** These benefits are not "anecdotal," as DEC/DEP assert;[17] they are tracked and documented by the EIM participants in quarterly reports.[18] The cumulative benefits to EIM participants have reached $650 million as of the end of the first quarter of 2019.[19]
- The EIM is an overlay on, and does not change, traditional hourly scheduling processes. Each balancing area continues to be run by the existing operator.
- The EIM can be used by balancing areas and system operators that operate under a variety of market and regulatory structures. Western EIM participants include investor-owned utilities, publicly-owned utilities, and an independent system operator that are located across ten states and a Canadian province.
- The EIM is simply a balancing mechanism that seeks out beneficial trades of resources within the hour to reduce balancing and load following costs for participants and to decrease renewable curtailments. This is "found money" for all participants, who now have a means to seek out and resolve inefficiencies in the intra-hour dispatch of their resources.

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[17] *Ibid.*
[18] See, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.
[19] See, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

I note the recent announcement that the Southwest Power Pool (SPP) is planning to form an EIM on its footprint.[20] The western EIM in the WECC plus this new EIM in SPP would provide access to an EIM for utilities in the entire western half of the U.S. Clearly, there are system operators in the East, such as the PJM Interconnection, that have the experience and technical expertise to run an EIM. The Duke utilities would be logical partners to start an EIM with PJM given the growth of solar resources in North Carolina (and of both wind and solar elsewhere in the East) and the clear need to maximize the efficiency of intra-hour dispatch to address renewable variability. I expect that there will be interest in joining such an EIM from other utilities in the South, such as Georgia Power, that have seen significant solar development in their service territories. It is my recommendation that, in lieu of implementing an integration charge on solar QFs, this Commission should direct the utilities under its jurisdiction that run balancing areas in North Carolina to study the benefits of forming an EIM with the nearby PJM system.

[20] See, https://www.spp.org/newsroom/press-releases/spp-proposes-western-energy-imbalance-service-market-to-bring-cost-savings-and-grid-modernization-to-the-west/.

C. Stipulation on Integration Costs

Q. PLEASE ADDRESS THE STIPULATION ON INTEGRATION COST ISSUES THAT THE PUBLIC STAFF AND DEC/DEP FILED ON MAY 21, 2019.

A. The principal issues with this stipulation are (1) it fails to address the benefits of renewables that offset any integration costs and (2) it accepts the flawed DEC/DEP integration cost study that assumes the Duke utilities are islands and is based on inaccurate solar modeling (as discussed in the report "Modeling the Impact of Solar Energy on the System Load and Operations of Duke Energy Carolinas and Duke Energy Progress" attached to NCSEA's initial comments). Beyond those concerns, the stipulation is positive in exempting existing and committed QFs (i.e. those that committed to sell before November 1, 2018 or that bid into the CPRE Tranche 1 RFP) and in capping the integration charge so that prospective QFs have certainty in the integration costs that they will face during the term of their contract. However, it is inappropriate to cap the integration charge at the level of the calculated incremental cost for integrating the last 100 MW of solar additions, instead of at the level of the average integration charge for the whole tranche of solar studied. These caps of $3.22 per MWh for DEC and $6.70 per MWh for DEP are far too high and well above, to my knowledge, the solar integration charges adopted elsewhere in the U.S. As I have discussed above, the experience elsewhere has been that integration costs fall over time, as utilities gain experience operating their systems with higher penetrations of renewables and implement new forecasting, operating, and market processes to minimize those costs. Further, the growth of renewables will displace energy from flexible, gas-fired resources, which will increase the supply (and thus lower the cost) of resources available to provide the load following capacity and ancillary services needed to integrate renewables. As a result, the integration charge, if one is adopted, should be capped at no more than the average integration cost for this tranche of solar studied, that is, at $1.10 per MWh for DEC and $2.39 per MWh for DEP based on the Astrapé study (or at whatever lower average integration cost the Commission adopts after review of the critiques of that study).

Q. IS THE STIPULATION CONSISTENT WITH NCSEA'S PROPOSAL WITH RESPECT TO "DIFFERING ANCILLARY SERVICES COSTS FOR INNOVATIVE QFS"?

A. The stipulation proposes that the integration charge should apply prospectively to new solar QFs "unless those solar generators can demonstrate that the facility is capable of operating, and shall contractually agree to operate, in a manner that materially reduces or eliminates the need for additional ancillary services requirements (as reasonably determined by the Companies) through inclusion of energy storage devices, dispatchable contracts, or other mechanisms that materially reduce or eliminate the intermittency of the output from the solar generators ("controllable solar generators")."

This provision is headed in the right direction, in my opinion, but lacks needed specificity so that prospective QFs understand more precisely the requirements necessary to avoid the integration charge. For example, my Report recommended that solar projects that include significant storage (a four-hour discharge capacity equal to at least 50% of the AC solar nameplate) should not be assessed integration costs. The Commission also should recognize that the new peak periods and structure for avoided cost rates are likely to result in less variability and more control in solar output even without explicit requirements, as generators add storage and dispatchability in response to the new pricing periods.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158

In the Matter of:	)	
Biennial Determination of Avoided Cost	)	**DIRECT TESTIMONY OF**
Rates for Electric Utility Purchases from	)	**R. THOMAS BEACH**
Qualifying Facilities – 2018	)	
	)	

Exhibit 1

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

    - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

    - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

    - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

    - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

    - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

- *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

- *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

- *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

- *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

- *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems*.

63. a. Phase II Direct Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

    - *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems*.

67. Prepared Rebuttal Testimony on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

    - *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
b. Supplemental Prepared Rebuttal Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
c. Supplemental Prepared Reply Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

- *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony on behalf of The Vote Solar Initiative (A. 10-11-015—June 1, 2011)

- *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony on behalf of the Solar Alliance (A. 10-03-014—August 5, 2011)

- *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A. 11-06-007—February 6, 2012)

- *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony on behalf of the Northern California Indicated Producers (R.11-02-019—January 31, 2012)
b. Prepared Rebuttal Testimony on behalf of the Northern California Indicated Producers (R. 11-02-019—February 28, 2012)

- *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A. 11-10-002—June 12, 2012)

- *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony on behalf of the Southern California Indicated Producers and Watson Cogeneration Company (A. 11-11-002—June 19, 2012)

- *Natural gas pipeline safety policies and costs*

75. a. Testimony on behalf of the California Cogeneration Council (R. 12-03-014—June 25, 2012)
    b. Repl y Testimony on behalf of the California Cogeneration Council (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony on behalf of the Southern California Indicated Producers and Watson Cogeneration Company (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony on behalf of the Southern California Indicated Producers and Watson Cogeneration Company (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony on behalf of the **Joint Solar** Parties (R. 14-07-002 — September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

85. Prepared Direct Testimony on behalf of the **Solar** Energy Industries Association (A. 15-04-012—July 5, 2016)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

86. Prepared Direct Testimony on behalf of the **Solar** Energy Industries Association (A. 16-09-003 — April 28, 2017)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

87. Prepared Direct Testimony on behalf of the **Solar** Energy Industries Association (A. 17-06-030 — March 23, 2018)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

Expert Witness Testimony Before the Arizona Corporation Commission

1. Prepared Direct, Rebuttal, and Supplemental Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).

   - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*

2. Prepared Surrebuttal and Responsive Testimony on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).

   - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

3. Direct Testimony on behalf of the **Solar Energy Industries Association** (Docket No. E-01345A-16-0036, February 3, 2017).

4. Direct and Surrebuttal Testimony on behalf of **The Alliance for Solar Choice and the Energy Freedom Coalition of America** (Docket Nos. E-01933A-15-0239 (TEP), E-01933A-15-0322 (TEP), and E-04204A-15-0142 (UNSE) – May 17 and September 29, 2017).

Expert Witness Testimony Before the Colorado Public Utilities Commission

1. Direct Testimony and Exhibits on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009). https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).

   - *Development of a community solar program for Xcel Energy.*

3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).

   - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).

    - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony on behalf of the Idaho Conservation League (Case No. IPC-E-12-27—May 10, 2013)

    - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

    - *Issues concerning the term of PURPA contracts in Idaho.*

2. a. Direct Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — December 22, 2017)
   b. Rebuttal Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — January 26, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)

    - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

1. Prepared Direct Testimony on behalf of Vote Solar (Case No. U-18419—January 12, 2018)

2. Prepared Rebuttal Testimony on behalf of the **Environmental Law and Policy Center, the Ecology Center, the Solar energy Industries Association, Vote Solar, and the Union of Concerned Scientists** (Case No. U-18419 — February 2, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

    - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39,October 14 and November 9, 2016).

    - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

    - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

4. a. Prepared Direct Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
   b. Prepared Direct Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).

c. Prepared Rebuttal Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).

- *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).

   - *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011) http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443
June 20, 2104:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

3. Direct Testimony on Behalf of the **Oregon Solar Energy Industries Association** (UM 1910, 1911, and 1912 — March 16, 2018).

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)
   https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony on behalf of the **Solar Energy Industries Association** (SEIA) (Docket No. 44941 – December 11, 2015)

   - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

    - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)
http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.