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Witness: R. Thomas Beach

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PREPARED DIRECT TESTIMONY OF R. THOMAS BEACH

ON BEHALF OF

THE SOLAR ENERGY INDUSTRIES ASSOCIATION

January 8, 2025

BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for Authority to Establish Marginal Costs, Allocate Revenues, and Design Rates	)))))	Application 24-03-019

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

January 8, 2024

EXECUTIVE SUMMARY OF RECOMMENDATIONS

This testimony presents the recommendations of the Solar Energy Industries Association (SEIA) concerning Southern California Edison's (SCE) marginal costs and the design of SCE's electric rates over the next four years.

Marginal Costs

Energy. SEIA joins the California Public Advocates (CalPA) in recommending the use of the CPUC staff's SERVM modeling of the 2023 Preferred System Portfolio (PSP) as the basis for SCE's marginal energy costs (MECs). The SERVM modeling of the PSP uses the most recently approved PSP and a current natural gas forecast. SEIA's MECs differ from CalPA's, however, because SEIA includes greenhouse gas (GHG) allowance costs in the state's cap & trade market, which are included in CAISO market prices but which CalPA mistakenly omits. SEIA also does not include an adder for Renewable Portfolio Standard (RPS) costs, because at this time the state is well ahead of its RPS goals, such that there is no marginal compliance need of cost for new RPS generation.

Generation Capacity. SEIA recommends a marginal generation capacity cost (MGCC) for SCE based on the MGCC calculated in the 2024 Avoided Cost Calculator (ACC) for the year 2025 -- $160 per kW-year, which includes a reserve margin of $17%. This value is up-to-date and recognizes that there are multiple sources of capacity on the CAISO system.

Transmission Capacity. SCE did not calculate an MTCC value. However, there are a number of ratemaking applications – such as the ACC, contribution to margin calculations, dynamic rates, and the future design of more accurate and cost-based transmission rates – where the utility's long-run marginal transmission capacity cost (MTCC) is needed or informative. SEIA has calculated SCE's MTCC using two different approaches. The results are similar, and SEIA recommends the use of the lower value from the Commission-approved ACC method -- $73 per kW-year – as SCE's MTCC. Finally, the Commission should direct SCE to present MTCC calculations in future Phase 2 cases.

Distribution Capacity. SEIA recommends an adjustment to SCE's calculation of its marginal distribution capacity cost (MDDC) to include wildfire costs in the MDDC. This adjustment is needed in order to incorporate the changing standards for the safety and reliability with which a marginal kW of distribution capacity must be supplied. SEIA's recommended MDCC is $272 per kW-year, allocated $117 per kW-year to peak and $154 per kW-year to grid.

Customer Access. SEIA supports CalPA's New Customer Only (NCO) approach to calculating the marginal costs of customer access. The NCO method correctly recognizes that the utility does not incur marginal capital costs for customer access except when a customer premises is interconnected to the grid for the first time. The testimony discusses why the NCO approach is most consistent with the Commission's rate design principles that rates should be based on marginal costs and cost causation.

Rate Design

SEIA has reviewed SCE's rate design proposals, in terms of compliance with the Commission's rate design principles and policies designed to evolve electric rate design to place greater emphasis on time-of-use (TOU) and dynamic rates that encourage demand flexibility from customers. In this case, in light of these principles and policies, SEIA has the following recommendations for SCE's electric rate design:

Residential TOU Rates. The summer on-peak-to-off-peak rate differences in SCE's residential rates are well below marginal costs. This is particularly true of SCE's default residential rate (TOU-D 4p-9p). SEIA recommends an increase to these TOU rate differences. In 2025, SCE should move 20% of the way to fully-scaled marginal cost-based summer on-peak-to-off-peak rate differences in TOU-D 4p-9p and TOU-D 5p-8p. SCE then should take further steps of equal size in each year from 2026-2028, such that 80% of the difference has been bridged by the time the rates from the next SCE GRC Phase 2 are implemented in 2029. This would be similar to the gradual change that Pacific Gas & Electric has undertaken to move the TOU differentials in its default residential rates closer to marginal costs.

New TOU-D-PRIME-Plus Rate. SEIA joins CalPA in opposing SCE's proposal for a new, optional TOU-D-PRIME-Plus residential electrification rate. This new rate would have a very high fixed charge ($49 per month), plus a peak demand charge. The high fixed charge includes costs that the Commission has not determined are fixed costs, and is inconsistent with the recent decision implementing income-graduated residential fixed charges. The peak demand charge is also problematic, as there are significant problems with residential customers understanding and accepting demand charges. The Commission has not approved demand-based residential rates in the past, and should not do so here.

Commercial & Industrial Rates – Option S. This testimony discusses SCE's proposal to implement Option S rates for C&I customers that install on-site storage. Option S rates replace non-coincident demand charges (NCDCs) with an on- and mid-peak daily demand charge. The Commission ordered PG&E to implement Option S rates in D. 18-08-013. This testimony discusses how the design of Option S is intended to ensure that on-site storage is operated to charge during off-peak periods and to discharge to reduce on-peak loads. This will maximize the benefits of the storage for the system and ratepayers generally. The daily demand charge in Option S also will reduce the risks to the customer of operating this new and growing technology.

The Role of Demand Charges in C&I Rates. To encourage demand flexibility, the Commission should continue to take steps to reduce the role of demand charges in SCE's C&I rate design. In particular, the role of NCDCs in recovering distribution costs should be reduced in SCE's Option E rates, compared to what SCE has proposed.

Vehicle-to-Grid Resource Proposal. SCE has advanced a Vehicle-to-Grid Resource Proposal (VGRP) to compensate customers who use new electric vehicle-to-grid integration (VGI) technology to export available power from their EVs to the grid. But SCE's proposed compensation for such exports is much less than what customers would receive from simultaneous exports from their home solar and stationary storage systems. This makes no sense, because a kWh exported from the battery in a customer's EV allows SCE to avoid the same costs as a kWh exported at the same time and place from the customer's solar panels. The VGRP compensation rate should be based on the same ACC values used to compensate Net Billing Tariff solar and storage customers. This change in the compensation policy will allow SCE to avoid having to install a separate net generation output meter on most VGRP customers.

Observations on SCE's FERC-jurisdictional Transmission Rates. SEIA's testimony includes observations and recommendations concerning the design of SCE's FERC-regulated transmission rates, in order to provide a record foundation for such discussions in this case. The CPUC advised SCE, in D. 18-05-040, to revise its FERC-regulated transmission rate design to move away from the use of demand charges for at least 30% of SCE's transmission costs. However, SCE has not followed up on that advice. This testimony provides SEIA's views on how SCE's transmission rate design should continue to evolve. The use of NCDCs to recover the non-demand or non-time-related portion of transmission costs does not make sense, as NCDCs themselves are a measure of demand. Instead, flat energy rates should be used to recover these costs for all rate classes.

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Attachment RTB-1 – CV of R. Thomas Beach
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BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design	)	Application 24-03-019

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

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*, which is **Attachment RTB-1** to this testimony. As reflected in my CV, I have more than 40 years of experience on 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. Since leaving the Commission in 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted testimony, 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 rate design and the rates applicable to distributed generation (DG) resources.

A: Over the last 18 years, 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), including Southern California Edison (SCE), the applicant in this case. I also represented several solar industry groups in the CPUC's major investigation from 2012-2015 into residential rate design in California (R. 12-06-013) and served testimony for the Solar Energy Industries Association (SEIA) in the Commission's ongoing rulemaking (R 22-07-005) to advance demand flexibility through changes to electric rate design.

Q: On whose behalf are you testifying today?

A: I am appearing on behalf of SEIA. SEIA is the national trade association for the solar and storage industries, building a comprehensive vision for the advancement of these technologies. SEIA works with its 1,200 member companies and other strategic partners to create jobs and diversity, champion the use of cost-competitive solar in America, remove market barriers, and educate 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 continue the sustainable deployment of solar photovoltaic (PV) generation and associated storage. 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 SEIA's recommendations on the marginal costs and rate design that SCE has proposed in this Phase 2 of its general rate case. The issues discussed in this testimony are not necessarily all of the issues of concern to the solar industry in California, and SEIA reserves the right to serve rebuttal testimony, to brief, or to provide comments on other issues that may arise within the course and scope of this case.

II. POLICY BACKGROUND

A. California's "Loading Order" for New Electric Resources

Q: Please review the priorities that California policymakers have established for the utilities' procurement of new electric resources.

A: The Commission and the California Energy Commission (CEC) have established the state's procurement priorities through the "loading order" for electric resources set forth in the state's Energy Action Plans.[1] The state's first priority is to encourage energy efficiency; the second priority is to stimulate the development of renewable generation, including on-site DG such as solar PV located behind the retail meter. California continues to lead the nation in installed distributed, rooftop solar PV capacity.

The widespread solar development in California has shifted the period of peak electric demand that must be served with dispatchable resources into the late afternoon and early evening (4 p.m. to 9 p.m.), when solar output is declining as the sun sets. These evening hours are when the state's "net load" reaches its peak; the net load is the demand at the customer meter less wholesale wind and solar resources. This shift in focus to the evening hours of peak net loads has placed greater emphasis on the development of storage resources that can store excess solar output from earlier in the day, then dispatch that power into these evening hours when dispatchable generation is most valuable.

Q: The growth of customers with behind-the-meter solar generation has resulted in customers whose demand on the grid varies with their solar output. Has the Commission considered the design of time-of-use (TOU) tariffs for solar customers in the rate design phases of the GRCs for the California electric utilities, including SCE?

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[1] The state's adopted "loading order" for new resources is presented in the Energy Action Plan II adopted by this Commission and the California Energy Commission in October 2005, at page 2. The Energy Action Plan II can be found at http://docs.cpuc.ca.gov/word_pdf/REPORT/51604.pdf.

A: Yes, it has, in the GRC Phase 2 and associated rate design window (RDW) cases for all three IOUs over the last 18 years. For example, in a 2006 Phase 2 case for San Diego Gas & Electric (SDG&E), D. 07-01-047 created an Option R rate (Schedule DG-R) for large commercial customers who install distributed generation capable of serving at least 10% of their peak demand. Option R rates feature higher TOU energy charges and reduced demand charges. All generation costs are collected on a volumetric TOU basis, with no generation demand charges. For distribution costs, the demand charges are reduced significantly compared to the equivalent distribution demand charges for other commercial schedules. The distribution costs removed from demand charges are recovered through time-varying energy charges. SCE also implemented Option R rates, which it has subsequently transitioned to Option E rates that are widely available to SCE's non-residential customers.[2]

B. The Importance of Time-Dependent Rates

1. Default TOU rates for all customer classes

Q: Has the Commission generally moved toward the greater use of TOU rates for all customer classes, including residential and small commercial customers?

A: Yes. In 2015, the Commission in D. 15-07-001 announced a goal to implement default TOU rates for residential customers. As part of this process, in 2015 the Commission instituted a rulemaking (R. 15-12-012) to develop "a framework for designing, implementing, and modifying time periods for use in future time-of-use (TOU) rates."[3] D. 18-07-006 in an SCE Rate Design Window (RDW) case adopted new TOU periods for SCE that generally followed the guidelines developed in R. 15-12-012, including a new peak period of 4 p.m. to 9 p.m. In 2022, SCE completed the transition to default

[2] PG&E is the one IOU that opposed Option R rates. After a fully-litigated RDW proceeding, in D. 14-12-080 the Commission ordered PG&E to implement Option R rates for its large commercial and industrial (C&I) customers who install solar, without limits on the number of customers who can elect this cost-based option.

[3] *See* R. 15-12-012, at p. 2.

TOU rates for all of its residential customers. SCE's commercial and industrial (C&I) customers also have moved to the new TOU periods with the 4 p.m. to 9 p.m. peak period.

2. Time-dependent delivery rates

Q: Are the utilities' costs for the electric grid that delivers power also time dependent?

A: Yes. An important part of the move to TOU rates has been the Commission's recognition that a significant share of the electric utilities' transmission and distribution (T&D or "delivery") costs are time-dependent. As with generation, it is customer usage during peak demand periods that is the primary driver of a significant share of T&D costs. This has resulted in a significant move away from the use of delivery rate components that do not vary with time. For example, recent Commission rate cases have moved away from the use in commercial and industrial (C&I) rates of non-coincident demand charges (NCDCs) that are not time-dependent. As one example, in D. 17-08-030 in an SDG&E GRC Phase 2 case, the Commission rejected SDG&E's proposal to recover 100% of its distribution costs through NCDCs in its medium and large C&I rates. Instead, the Commission adopted SEIA's proposal that 100% of substation costs and 50% of distribution costs should be collected through time-dependent rates; this reduced the overall recovery of distribution costs through NCDCs to 39%.[4]

3. State policies support storage resources

Q: Why has state policy supported the growth of storage resources?

A: The time-dependence of utility costs and the state's increasing reliance on renewable resources whose output varies over time have resulted in the increasing emphasis of state policy on the development and deployment of storage resources. Assembly Bill 2514

[4] See D. 17-08-030, at pp. 39-48. Since D. 17-08-030, other GRC Phase 2 decisions also have reduced the use of NCDCs and encouraged the greater use of time-dependent charges in C&I rates. For example, D. 18-08-013 in a PG&E GRC Phase 2 case rejected a settlement on Medium & Large Light & Power (MLLP) rates, in favor of MLLP rates with lower non-coincident demand charges. The order cited

(PU Code Section 28836 *et seq.*), enacted in 2010, directed the Commission "to consider a variety of possible policies to encourage the cost-effective deployment of energy storage systems."[5] In D.13-10-040, the Commission adopted the Energy Storage Procurement Framework and Design Program (Energy Storage Framework), which authorized an initial energy storage procurement target of 1,325 MW. The definition of energy storage system embraces a mix of ownership models, including customer-side storage.[6] In crafting the Energy Storage Framework, the Commission adopted a number of principles to guide energy storage installation and procurement:

1. The optimization of the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments;
2. The integration of renewable energy; and
3. The reduction of greenhouse gas emissions to 80 percent below 1990 levels by 2050, per California goals.[7]

In GRC Phase 2 cases for PG&E and SCE, the Commission has adopted new rates designed to encourage deployment of customer-sited storage. For residential customers, these new storage-friendly rates include EV2 for PG&E and TOU-D-PRIME for SCE. For small commercial customers, the new rates are B1-ST for PG&E and TOU-GS-1 (Option ES) for SCE. These rates feature volumetric TOU rates with large differentials between on- and off-peak rates that encourage the daily cycling of the storage capacity, with the storage discharged during the peak period when marginal costs and greenhouse gas emissions are the highest.

In D. 18-08-013, the Commission approved a modified version of SEIA's proposed Option S storage rates for PG&E's medium and large C&I customers.[8] These rates are now in place. Key features of the Option S rates include:

D. 17-08-030, among other factors, and indicated, at pages 47-51, that the Commission expected to see further progress in the direction of lower non-coincident demand charges in future PG&E GRCs.

5 P.U. Code Section 2836 (a).

6 D.13-10-040, at Finding of Fact 21.

7 *Ibid*., pp. 9-10.

8 See D. 18-08-013, at pp. 105-112.

- Start with the Option R rate design.
- Replacement of 80% of the monthly non-coincident demand charge in the Option R versions of Schedules E-19 and E-20 with a daily demand charge that applies only during the 4p to 9p peak period. The remaining 20% of the original non-coincident demand charge will not be assessed on usage from 9 a.m. and 2 p.m. each day.
- Other peak- or partial-peak distribution demand charges in these schedules will be combined into the daily demand charge.
- Capped Option S at 150 MW of installed energy storage rated capacity, with 50 MW each for E-19V [< 500 kW], E-19 [500-999 kW], and E-20 [> 999 kW]).
- The energy storage system must have a rated capacity in kilowatts which is at least 10% of the customer's peak demand over the previous 12 months.

In SCE's last Phase 2 case, A.20-10-012, SEIA proposed a similar Option S rate for SCE. SCE opposed SEIA's proposal, arguing that its Option E rates could serve the same purpose. In D.22-10-022, at page 18, the Commission did not adopt SEIA's proposal, but directed SCE "to include a fully analyzed proposal for an Option S-like tariff in its next Phase 2 of the GRC."

4. Electrification rates

Q: Why has the Commission prioritized the development of residential rates that support electrification of buildings and transportation?

A: Customer adoption of electrification measures is an essential element of the state's effort to reduce greenhouse gas (GHG) emissions and to fight climate change across all sectors of the California economy. The California Air Resources Board's most recent update to its AB 32 Scoping Plan seeks to achieve carbon neutrality by 2045. The Commission has recognized that this goal is only achievable in a "High DER" future in which all Californians make personal, long-term investments in the DERs – rooftop solar, on-site storage, electric vehicles (EVs), and residential electric heat pumps – that will be needed to reduce carbon pollution in the energy, building, and transportation sectors.[9]

[9] On June 14, 2021, the Commission issued a new rulemaking (OIR) "to modernize the electric grid for a high distributed energy resources future."

Electrifying vehicles (to replace the use of gasoline and diesel) and buildings (to displace natural gas for water heating and space conditioning) is widely viewed as the least-cost means to reduce carbon emissions in the transportation and building sectors, emissions that accounted for 40% and 11% of the state's GHG emissions in 2019, respectively.[10]

For residential customers to have an economic incentive to adopt these DERs, the rate that they pay for the electricity to power the DER must be competitive with the fossil fuel that is displaced, such that the savings in operating costs contribute to offsetting what can be the higher capital cost of the DER, compared to the fossil-fueled alternative.[11] To accomplish this, economic electrification in California will require a dramatic expansion of off-peak electric use, given that average residential rates are high. Low-cost off-peak power is also needed to charge the storage that will serve on-peak loads, and to provide adequate savings to incent the beneficial daily cycling of storage. To encourage residential electrification, the Commission has approved optional electrification rates for residential customers that adopt specific DERs (EVs, heat pumps, and storage).[12] These rates have much larger on-to-off-peak rate differences than current default residential TOU rates, lower off-peak rates, and no baseline credits or usage tiers.

C. Rulemaking on Demand Flexibility

Q: What is the purpose of the Commission's ongoing rulemaking on encouraging demand flexibility through electric rate design?

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[10] California Air Resources Board, *California Greenhouse Gas Emissions for 2000 to 2019: Trends of Emissions and Other Indicators* (released July 28, 2021), at p. 8 (Figure 4). Available at https://ww2.arb.ca.gov/sites/default/files/classic/cc/ca_ghg_inventory_trends_2000-2019.pdf.

[11] For example, if gasoline costs in the range of $3 to $5 per gallon, EV charging costs for a typical EV must be below the range of $0.20 to $0.40 per kWh to provide the fuel cost savings that are an important driver of EV adoption. This assumes that a typical EV traveling 3 miles per kWh replaces a gasoline vehicle with mileage of 35 to 45 miles per gallon.

[12] The approved electrification rates are E-ELEC and EV2 for PG&E, TOU-D-PRIME for SCE, and EV-TOU-5 and TOU-ELEC for SDG&E. See D. 21-11-016 and D. 18-08-013 for PG&E; D. 18-11-027 for SCE, and D. 22-11-022 for SDG&E.

A: R. 22-07-005 focuses on a broad review of innovative electric rate designs that can improve the ability of customers to shift or change their electric demand in ways that will help California achieve its climate, clean energy, and environmental justice goals. In the coming years, California's electricity use is expected to rise significantly, as the state pursues the widespread electrification of buildings and transportation to meet the state's climate goals. Given this growth in demand, ensuring reliable electric service during peak demand periods in the summer will continue to be a challenge. Finally, the state's electric rates are high, presenting a challenge to customers' ability to afford this essential commodity – especially given that customers also will be asked (or required) to make new long-term investments in electrification technologies such as electric vehicles (EVs) and heat pumps. In this environment, there needs to be an increasing emphasis on time-varying and dynamic rates that encourage customers to focus their increased electricity use at times when electricity supplies are cleaner, more abundant, and lower in cost. The Demand Flexibility OIR has pursued these goals through several tracks that focus on the use of income-graduated fixed charges and the expansion of dynamic electric rates that respond to system conditions.

D. Revised Rate Design Principles

Q: Has the Commission recently reviewed and revised its rate design principles?

A: Yes. The Commission reviewed its rate design principles in an initial track of R. 22-07-005. D. 23-04-040 in that rulemaking adopted revised principles, to which this testimony will frequently refer.

Q: Would you like to highlight any of the changes that the Commission made in D. 23-04-040 to its prior rate design principles?

A: Yes. The new Principle 6 – *Rates should encourage customer behaviors that optimize the use of existing grid infrastructure to reduce long-term electric system costs* – replaced this prior principle – *Rates should incentivize reduction of both coincident and non-*

coincident peak demand. Removing the reference to reducing noncoincident demand recognized the clear trend in Commission policy away from the use of rate elements, such as non-coincident demand charges, that focus only on a customer's momentary peak load in a billing cycle, regardless of the time of day when that peak load occurs.[13]

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[13] See D. 23-04-040, at p. 17: "While reducing coincident and non-coincident peak demand can be a means for reducing some types of long-term infrastructure costs, a singular emphasis on reducing customer peak demand undercuts the cost-containment potential of demand flexibility. The proposed principle is more inclusive of all customer demand flexibility and load management strategies that can reduce the long-term costs of the electric system."

III. MARGINAL COSTS

Q: Does SEIA have a position on the calculation of SCE's marginal costs?

A: Yes. I will comment and provide a recommendation on all of SCE's marginal costs, including marginal energy costs (MECs), marginal generation capacity cost (MGCC), marginal transmission capacity cost (MTCC), marginal distribution demand cost (MDDC), and marginal customer access costs (MCACs). I have reviewed the marginal cost proposals of both SCE and the California Public Advocates (CalPA).

A. Marginal Energy Costs

Q: What should be the basis for SCE's marginal energy costs?

A: SEIA agrees with SCE and CalPA that the SCE MECs should be based on expected locational marginal prices (LMPs) in the CAISO energy market in SCE's service territory.[14] SCE's proposed MECs are based on production cost modeling (PCM) to develop forecasted CAISO market prices in 2025, using SCE's own internal runs of the PLEXOS production cost model and resource assumptions that date largely from 2022.[15] CalPA develops its MECs using more recent 2024 PCM results from the CPUC staff using the SERVM PCM. CalPA also includes an "RPS Adder" in its MECs.

Q: Do you agree with either SCE's or CalPA's MECs?

A: SEIA supports CalPA's use of the Commission staff's 2024 SERVM modeling as the basis for SCE's MECs. However, SEIA does not support CalPA's RPS Adder, and

[14] See Exh. SCE-04A, at p. 10: "SCE proposes MECs be the hourly marginal market-clearing price of the day-ahead market operated by CAISO."

[15] Exh. SCE-04A, at p. 10-11, especially footnote 14: "The inputs and assumptions used in this analysis are largely from the Commission's June 2022 RESOLVE package, which were used by load serving entities to develop their resource plans. This package includes resource cost assumptions, a GHG price forecast, and a fuel price forecast. However, SCE instead of using the 2021 Integrated Energy Policy Report (IEPR) demand forecast that corresponds with the June 2022 RESOLVE package, SCE used the more recently-published 2022 IEPR demand forecast for its generation marginal cost analysis."

corrects several mistakes in CalPA's use of the 2024 SERVM PCM results.

Q: Why does SEIA not support SCE's MECs?

A: SEIA agrees with CalPA that SCE's PCM results are now outdated. This is no fault of SCE – the extended schedule for this Phase 2 case has made new, more up-to-date PCM results available since SCE prepared its case. SCE's PCM uses an older Integrated Resource Plan (IRP) resource portfolio that predates the current Preferred System Portfolio (PSP) that the Commission approved in February 2024 in D. 24-02-047, as well as an older forecast of burnertip natural gas prices. The natural gas forecast is a key driver of the level of CAISO energy market prices, as gas-fired generation is the marginal market resource in many hours. The newer gas forecast used in the 2024 SERVM PCM reflects the higher level of natural gas prices in the U.S. and California since the beginning of the war in Ukraine in 2022.

Q: Why does SEIA join CalPA in supporting the use of the CPUC staff's 2024 SERVM PCM results?

A: Like CalPA, SEIA proposes to use MECs for SCE based on the marginal/avoided energy costs from the Energy Division's runs of the SERVM PCM used to develop the 2024 Avoided Cost Calculator (ACC). These runs were performed after D. 24-02-047, and thus use the current IRP resource portfolio approved in that order as well as a more recent natural gas forecast than the one that SCE used. The Energy Division has benchmarked this SERVM modeling to recent CAISO market prices, and includes an adjustment to SERVM to reflect scarcity impacts in the CAISO energy market.[16]

Q: Please discuss CalPA's use of an "RPS Adder" in its MECs.

A: SEIA does not agree with CalPA that an RPS Adder should be included in the SCE MECs. Recent modeling in the IRP with the RESOLVE capacity expansion optimization model shows that, overall, California is well ahead of schedule in reaching its RPS goals,

[16] See D. 24-08-007, at pp. 13 and 33-34.

such that there is no current "shadow price" or marginal cost associated with meeting the state's RPS goals.[17] This indicates that the use of a marginal kWh of energy does not trigger a need or a cost for additional renewable energy in the immediate future. SEIA agrees with SCE's observation that ""because the state is on- or ahead-of its RPS targets over the GRC forecast period, …there is generally no incremental RPS compliance cost to serve a marginal increment of demand over the GRC forecast period."[18]

Q: Has Commission approved the use of an RPS adder to MECs in other GRC Phase 2 cases?

A: In D. 21-11-016 in the last PG&E Phase 2 case, the Commission approved the use of an RPS Adder as part of PG&E's MECs, on the grounds that "[e]ach marginal purchase of energy by PG&E may involve the purchase of additional RPS-compliant energy," citing that PG&E sells RPS renewable energy credits (RECs) to other load-serving entities (LSEs) who may be short in meeting their RPS requirements.[19] But such REC trades among LSEs do not mean that there is necessarily an aggregate need for new, incremental RPS generation among all LSEs in an IOU service territory in the near-term, such as the forecast period for this GRC. Any such need is best determined through the most current IRP modeling that looks at the big picture of the overall status of renewable procurement in an IOU service territory. As noted, the current PSP shows no need for additional RPS procurement in SCE's service territory over the forecast period for this GRC.[20]

Q: Is the GHG Adder that CalPA proposes based on a realistic calculation of incremental RPS costs?

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17 See CPUC IRP Staff presentation to the October 5, 2023 workshop, *2023 Proposed PSP & 2024-2025 TPP Resolve Modeling Results*, at Slide 72, showing the zero RPS shadow price for the 25 MMT Core recommended portfolio for the Preferred System Portfolio: "$0/MWh shadow price indicates that there is zero incremental cost to meet RPS requirements."

18 SCE data response to CalPA, SCE-014, Q.01, cited in CalPA testimony, Chapter 1, p. 1-9.

19 See D. 21-11-016, at pp. 40-41 and Finding of Fact 9.

20 See footnote 20.

A: No, it is not. Further, the RPS Adder that CalPA proposes is not a marginal cost value, but instead represents the average cost premium for SCE's full portfolio of renewable resources, including more expensive renewable generation procured in the past under long-term contracts. The dramatic reductions in the costs for new renewable generation over the last two decades mean that CalPA's GHG Adder based on historical costs is overstated.

Q: Please discuss the other corrections you propose in CalPA's use of the 2024 SERVM PCM results.

A: I propose three corrections.

First, CalPA has misaligned the SERVM results with respect to the designation of weekdays and weekends in 2025. This appears to be why CalPA's proposed MECs are higher in the SCE summer mid-peak period (from 4 p.m. to 9 p.m. on summer weekends) than in the summer on-peak period (from 4 p.m. to 9 p.m. on summer weekdays). This result does not make sense – electric demand and market prices typically are higher on summer weekdays than on summer weekends.

Second, as noted above, the parties generally agree that the MECs should be a forecast of CAISO energy market prices in SCE's service territory, as estimated using PCM. CAISO energy market prices include the costs that gas-fired generators incur to purchase greenhouse gas (GHG) allowances in the state's cap & trade (C&T) market, because these allowances are a variable cost of gas-fired generation that generators include in their bids into the CAISO energy market.[21] However, CalPA's proposed MECs for SCE use 2024 SERVM PCM results from which the GHG C&T costs have

[21] The energy prices in the 2024 Avoided Cost Calculator (ACC) also are based on the modeling of CAISO energy market prices using the 2024 SERVM PCM runs. The 2022 ACC documentation, at page 20, states that "[CAISO] market prices reported directly from SERVM include the effects of carbon pricing from the cap-and-trade market. In post-processing the SERVM prices, the cap-and-trade value is backed out to provide an hourly energy-only value for use in the ACC. The remaining energy value includes only fuel costs and power plant operating costs." CalPA's testimony in other Phase 2 cases has recognized that MECs should include GHG C&T costs. See A. 23-01-008 (the current SDG&E Phase 2 case) Exh. CalAdv-03, p. 3-6, footnote 24.

been removed. GHG C&T costs need to be added back in to represent CAISO market prices accurately. In the 2024 SERVM modeling, these 2025 GHG C&T costs for SCE average $10.13 per MWh. SEIA has included these GHG C&T costs in its MECs.

Third, CalPA used a loss factor of 9.25%. SEIA has used the lower line loss adjustments from the 2024 ACC.

Q: What are SEIA's proposed MECs for SCE?

A: SEIA's proposed MECs are shown in the final column of **Table 1**, in comparison to the MECs recommended by SCE and CalPA. On an annual average basis, SEIA's proposed MECs are higher than SCE's but lower than CalPA's.

Table 1: *Marginal Energy Costs ($ per MWh)*

Season	TOU Period	SCE	CalPA	SEIA
Summer	On-Peak	60.56	86.30	93.26
	Mid-Peak	51.11	97.06	68.88
	Off-Peak	47.41	66.80	60.90
Winter	Mid-Peak	55.02	75.42	70.88
	Off-Peak	53.34	78.16	74.17
	Super Off-Peak	32.93	43.13	32.78
Annual average		47.78	67.79	61.82

B. Marginal Generation Capacity Costs

Q: What does SCE recommend for its marginal generation capacity cost (MGCC)?

A: SCE proposes to develop the MGCC using the net capacity-related costs of a 6-hour hybrid PV + storage unit as the proxy resource, in the year 2025.[22] This is a departure from other recent GRC Phase 2 cases that have focused on the use of the capacity-related costs of standalone 4-hour battery storage as the MGCC.[23] SCE calculates the "net cost of new entry" (net CONE) for the solar-plus-storage resource as the total resource CONE

[22] See Exh. SCE-02, at pp. 12-15.

[23] See SCE testimony, SCE-02, at pp. 16-20.

for both the solar ($85.48 per kW-yr) and storage ($165.37 per kW-yr) minus the levelized long-term energy market rents from operating this hybrid resource ($161.38 per kW-yr). SCE derives its energy rents from its MEC modeling. SCE's calculation thus is a net CONE of $89.48 per kW-year, as shown in Table I-5 of Exhibit SCE-02A. SCE then adds a 17% reserve margin to derive its proposed MGCC of $104.69 per kW-year; see Table I-1 of SCE-02A.

Q: Does CalPA recommend a different MGCC?

A: Yes. CalPA proposes to continue to use the net CONE of a 4-hour battery as a proxy for the marginal capacity resource. CalPA would use updated battery storage costs from the IRP data used for the 2023 PSP, as well as the 2024 SERVM PCM results to calculate the energy revenues earned by 4-hour storage. CalPA also would use a six-year time horizon from 2025-2030 for the MGCC, instead of SCE's single-year 2025 value. Using this approach, CalPA's recommended MGCC is $134.79 per kW-year.

Q: Please critique the SCE and CalPA proposals for the MGCC.

A: SEIA agrees with CalPA that SCE's resource costs for solar and storage, and its MECs for the energy revenues, are out-of-date and have been supplanted by more recent IRP resource costs and PCM results.[24] We also agree with CalPA that 6-hour batteries are not common on the CAISO system, with 4-hour batteries being the typical storage resource being developed today.[25] Moreover, most batteries on the CAISO system are not charged solely from on-site solar, but also can be charged and discharged with market-priced energy based on CAISO market prices for energy and ancillary services.[26]

However, CalPA's sole reliance on 4-hour batteries as the only resource for marginal capacity is also a less-than-ideal proxy. Batteries are a major, and the largest, source of new capacity, but they are not the only source of capacity for the CAISO

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[24] See CalPA testimony, at Chapter 2, pp. 2-10 to 2-11.

[25] *Id*., at pp. 2-7 to 2-8.

[26] *Id*., at pp. 2-8 to 2-9.

system. Other new resources such as solar and wind are needed to provide the incremental clean energy needed to meet state goals to reduce GHG emissions, and these resources also provide significant amounts of new capacity. Further, the marginal values for both capacity and GHG emissions must be adequate not only to support 4-hour batteries, but also to allow new solar and wind resources to recover their capital and operating costs. The Commission recently recognized this in D. 24-08-007 updating the 2024 ACC, by adopting an "Integrated Calculation" that uses data from the adopted IRP portfolio and the associated SERVM PCM to optimize and integrate the calculation of both marginal generation capacity costs and marginal GHG costs. The new Integrated Calculation recognizes the interdependence of these two marginal costs:

> We find that the Integrated Calculation allows the ACC to more accurately calculate avoided costs. The generation capacity avoided costs and GHG avoided costs are interdependent and have interactive effects because a resource can provide both generation capacity and GHG value. Unlike the methodologies used in previous ACCs that model these variables independently, the Integrated Calculation recognizes their interdependence and interactive effect by modelling these variables in an integrated manner in an optimization model. As a result, the Integrated Calculation more accurately calculates avoided costs than methodologies used in previous ACCs which modelled them as independent variables.[27]

The reference here to "methodologies used in previous ACCs" refers to the use of the net CONE of 4-hour battery storage to determine the MGCC, which was used in the 2022, 2021, and 2020 ACCs as well as in recent GRC Phase 2 cases. Notably, in the 2024 ACC update proceeding that led to D. 24-08-007, CalPA supported the use of the Integrated Calculation to determine marginal generation capacity and GHG costs.[28] Thus, CalPA's position here to revert to the prior methodology of using 4-hour battery costs appears inconsistent with CalPA's position in R. 22-11-013.

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[27] See D. 24-08-007, at p. 17.

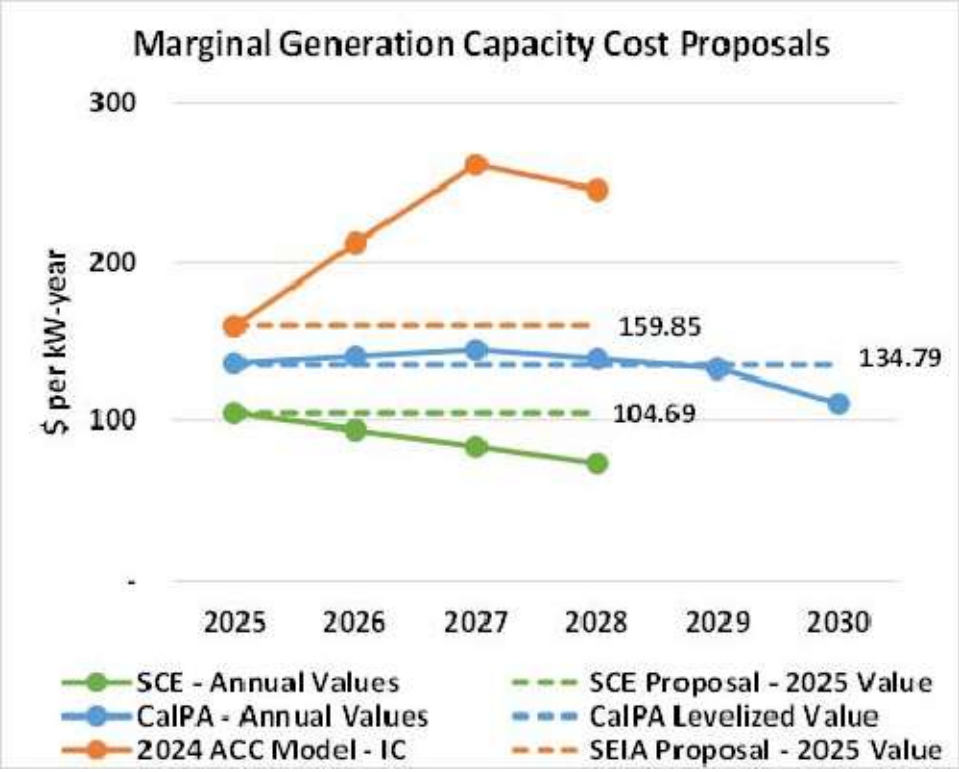
[28] *Id*., at pp. 17-18: "Cal Advocates states that the Integrated Calculation uses IRP's selected resources to calculate avoided costs in the ACC and allows the ACC to align better with climate policy goals."

Q: In R. 22-11-013, SEIA criticized certain aspects of the proposed Integrated Calculation, and did not support its use in developing the 2024 ACC. SEIA's concerns focused on (1) limiting the Integrated Calculation to just solar and storage resources, (2) the need for more testing of this new approach, and (3) whether the Integrated Calculation accurately represents the profile of fixed cost recovery over time that new solar and battery resources require. Does SEIA believe that the MGCCs determined by the Integrated Calculation for the 2024 ACC can be used for SCE's MGCC?

A: Yes. SEIA continues to believe that the Integrated Calculation needs further scrutiny and improvement. However, The Commission has now adopted an initial simplified form of the Integrated Calculation to determine the MGCC for use in the ACC, using just two resources – solar and battery storage. These are the two predominant resources that California is adding to provide, respectively, (1) clean energy and (2) capacity.[29] The initial results from the Integrated Calculation, using resource costs from the approved PSP and the same SERVM PCM results that CalPA and SEIA are proposing for MECs in this case, produce MGCCs for 2025 - 2028 that are higher than the older method of using 4-hour battery costs alone. These results are shown in the orange line in **Figure 1**, which also shows the lower CalPA and SCE MGCCs. The important point made by these results from the Integrated Calculation is that the marginal cost of generation capacity in SCE's territory must not only be high enough to meet an increment of demand for capacity (which is all that batteries provide) – it also must be high enough to ensure that additional clean energy resources are being built to meet the state's GHG emission reduction goals (which solar provides). The Integrated Calculation results show that, for the next several years, the SCE MGCC must be higher than the net CONE of 4-hour batteries alone.

[29] In the adopted PSP, significant battery storage and solar capacity are added in the period (2025-2028) covered by the rates to be adopted in this case, indicating that these two types of resources are the predominant marginal source of generation capacity and clean energy. See D. 24-02-047, at pp. 67-68, especially Figure 1 and Table 4.

Figure 1



Q: What is SEIA's recommended MGCC?

A: SEIA recommends using the Integrated Calculation results for 2025, which results in an MGCC of **$160 per kW-year**, which includes the 17% reserve margin,

C. Marginal Transmission Capacity Costs

Q: Has SCE presented a calculation of its marginal transmission capacity costs (MTCC) in this case?

A: No, it has not.

Q: SCE's transmission rates are FERC-jurisdictional, so they are not set by this Commission. Are there still reasons why the Commission should have a strong interest in SCE's demand-related marginal transmission costs?

A: Yes, there are several reasons why the Commission should review and approve a MTCC for SCE in this case.

First, the Commission is using the IOUs' marginal transmission costs directly in the export rates for new solar and storage customers under the Net Billing Tariff (NBT).[30] These Phase 2 cases, in which all of the utility's other marginal costs are reviewed and litigated, is the obvious forum in which to afford parties the opportunity to review, and to litigate if necessary, an IOU's marginal transmission costs. PG&E has filed its marginal transmission costs in its GRC Phase 2 cases for many years, and SCE's last Phase 2 case (A. 20-10-012) included a calculation of its marginal transmission costs (which SEIA supported).[31] SEIA litigated PG&E's marginal transmission costs in PG&E's last GRC Phase 2, A. 19-11-019, with the result that the Commission adopted SEIA's proposed marginal transmission costs for PG&E in D. 21-11-016.[32] These marginal transmission costs for PG&E are now used in the ACC.

Pursuant to D. 20-04-010 and subsequent orders, the marginal transmission costs for SCE and SDG&E that are used in the ACC are supposed to follow the methodology approved for PG&E in its Phase 2 decision, D. 21-11-016.[33] However, there have been limited opportunities in the process of updating the ACC to present evidence on the data that SCE and SDG&E use in applying this methodology. Although D. 24-08-007 on the 2024 ACC update stated that the current methodology for calculating avoided transmission costs would be updated with the most recent data,[34] the implementing Resolution E-5328 adopting the specific 2024 ACC values found that there was not adequate time to perform an update using cost data from the most recently approved

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30 See D. 20-04-010, at pp. 60-62, (for the 2020 ACC) adopted the use of PG&E's method used to calculate marginal transmission costs in its GRC Phase 2 cases. D. 22-05-022, at pp. 73-75 (for the 2022 ACC), and D. 24-08-007, at p. 38 (for the 2024 ACC) continued the use of this approach.

31 See Appendix F of Exhibit SCE-02 in A. 20-10-012.

32 See D. 21-11-016, at pp. 65-70.

33 See D. 20-04-010, at p. 60; D. 22-05-002, at pp. 73-75; and D. 24-08-007, at p. 38.

CAISO Transmission Plan.[35] This experience underscored for SEIA the importance of being able to litigate these marginal costs in a proceeding such as a GRC Phase 2 that is not time-constrained.

Second, marginal transmission costs are likely to be needed in other CPUC ratemaking initiatives. Marginal transmission costs will be the most accurate transmission component of the dynamic rates that are under development in R. 20-07-005 and in the application for approval of dynamic rates that SCE filed on December 20, 2024. In that application, SCE has proposed a new time- and load-dependent structure for the transmission component of its dynamic rate, which, although based on embedded costs, has characteristics of a marginal cost-based rate. In addition, commercial electric vehicle (EV) rates for PG&E and SDG&E have been structured to reduce distribution costs to marginal costs, to allow these rates to compete with liquid fuels and to provide headroom to recover the incremental costs of serving this major new load.[36] Commercial EV rates that reduce transmission rates to marginal costs would provide additional encouragement to the deployment of needed EV charging infrastructure. The same is true for economic development rates (EDR) that today only consider marginal generation and distribution costs, but also could include marginal transmission costs.[37] This could allow for larger discounts and attract more incremental loads.

Finally, as discussed in Section IV.D, this case is the logical place for parties to communicate to the Commission their views on the design of SCE's FERC-jurisdictional transmission rates, to inform the CPUC's representation of California ratepayers in that forum. A determination of SCE's marginal transmission costs, and how those costs vary

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[34] See D. 24-08-007, at p. 38: "Therefore, it is reasonable to continue to use the current methodology but updated with the most current T&D cost data to calculate avoided T&D costs in the ACC."

[35] See Resolution E-5328, at pp. 10-12: "While the Energy Division recognizes the benefit generally of using the most recent data available, given the time constraints for approval of the 2024 ACC, it is not feasible for the avoided transmission costs to be revised at this time while also providing all parties with a fair opportunity to review and comment on potential changes to inputs and underlying methodology."

[36] See D. 19-10-055, at pp. 22, 44-45. Also, D. 20-12-023.

[37] See Exh. SCE-04A, Chapter VIII.

over time, is important information relevant to re-designing SCE's FERC-regulated transmission rates so that they are more cost-based, time-sensitive, and consistent with the Commission's rate design principles. SCE acknowledged the importance of knowing its marginal transmission costs when it presented its calculation in the last GRC Phase 2, stating that its calculation "is a first step towards establishing a basis of marginal costs that can be used to better inform the design of retail transmission rates."[38] And in discovery in this case, SCE has stated that it "supports analysis that expands the conceptual understanding of Transmission Costs and its use in the design of retail rates."[39]

Q: Has SEIA calculated SCE's marginal transmission capacity cost (MTCC)?

A: Yes. SEIA has used two different methods to calculate SCE's MTCC.

The first method is to apply to SCE the Discounted Total Investment Method (DTIM) developed by PG&E to calculate its marginal transmission costs. This approach was approved by the Commission in D. 20-04-010 for use by SCE and SDG&E in calculating marginal transmission costs for use in the ACC. SEIA has started with the DTIM calculation methodology for SCE used for the 2024 ACC, and has updated the data used to include the costs of the SCE reliability-related transmission projects approved by the CAISO in May 2024 for the 2023-2024 Transmission Plan. As noted above, the Commission did not have time to include in this data in the calculations for the 2024 ACC. The result is a marginal transmission cost of **$73 per kW-year**.

The second method is to apply to SCE's historical and forecasted CAISO transmission costs the standard NERA regression method that SCE used in this case to calculate the long-run marginal costs of its lower-voltage subtransmission and distribution systems. This is the methodology that SCE used to calculate its marginal transmission costs in the last GRC Phase 2, A. 20-10-012. In discovery, SEIA asked SCE to update this analysis for this case, or to provide SEIA with the data needed to do

[38] A. 20-10-012, Exh. SCE-02, at p. 7 and Appendix F.

[39] See SCE response to SEIA Data Request No. 1, Q16(c), included in **Attachment RTB-2**.

an update. SCE refused to provide either a new analysis or an update of the underlying data, on the grounds that such an analysis is outside the scope of this case.[40] Nonetheless, SEIA has been able to apply the NERA regression method in this case, by updating SCE's FERC Form 1 CAISO transmission cost data and using data from recent CAISO transmission plans to exclude from the calculation SCE's "policy-related" RPS transmission costs whose primary purpose is to access new renewable generation. The result is a MTCC value of $75 per kW-year.

SEIA recommends adoption of an MTCC value of **$73 per kW-year** for SCE, using the Commission-approved MTCC methodology from the ACC. The similar value from the NERA regression method helps to confirm the reasonableness of this value. Given the growing importance of marginal transmission costs to the CPUC's ratemaking responsibilities, as discussed above, SEIA recommends that the Commission direct SCE to present MTCC calculations in its future Phase 2 cases

D. Marginal Distribution Capacity Costs

Q: SCE and CalPA have proposed marginal distribution capacity costs (MDCC) – see Table 2 below. Please comment on these MDCC recommendations.

A: Both SCE and CalPA use the longstanding NERA regression methodology to calculate the MDCC. This method calculates the MDCC based on the slope of a regression of the utility's distribution investments as a function of its load growth, over a long-term period (15 or more years, including both historical and forecast data). The SCE and CalPA calculations differ only in the metrics that they use for load growth, which is the independent variable in the regression calculation. SCE uses the capacity of its distribution system, while CalPA uses a rolling maximum of actual peak loads.

Q: What concerns does SEIA have with the SCE and CalPA MDCC calculations?

A: SEIA's primary concern is with the distribution investment data used by both SCE and

[40] See SCE response to SEIA Data Request No. 1, Q14(c), included in **Attachment RTB-2**.

CalPA – the dependent variable in the NERA regression. Both parties use only those distribution investments which the utility has classified as capacity-related (i.e. related to load growth). These are just a fraction of SCE's overall historical and forecasted distribution investments.[41] There are several issues with this initial process of classifying distribution investments, and excluding from the regression all distribution investments that are not deemed to be capacity-related.

- **Capacity increases as a secondary benefit.** Distribution investments whose principal purpose is not stated as capacity-related – for example, investments to improve reliability, improvements to system elements that are not now close to capacity, or end-of-life replacement projects – may have a secondary, smaller benefit of increasing capacity.[42] For example, projects that replace equipment at the end of its life, or whose principal purpose is to improve reliability, may have a capacity benefit if the new equipment is sized to provide additional capacity.[43]

- **Demand as a secondary driver.** Distribution projects whose primary purpose is not capacity-related still may be influenced by load growth as a secondary driver. For example, an upgrade may be required for reliability reasons to address contingencies that arise under high-load conditions, or to access new generation resources needed to serve growing peak demands. Even asset replacement projects can be viewed as demand-related in that they are necessary to keep the grid's capacity from declining.[44] Although peak demand may not be the primary driver of any of these types of upgrades, it may be a secondary driver, and

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[41] For the historical data used in the NERA regressions, SCE uses averages of 18.0% and 46.8%, respectively, of its historical (2012-2022) distribution and transmission investments. See SCE's "SCE-02 - I.C.2 - DDMC Study - Amended.xlsx" workpaper, at the tab "I|DMC" at lines 73 and 77. For distribution, we changed the 18.0% value to a 25.1% to correct an error in SCE's spreadsheet (evident upon review of row 24 of the "Table" tab in "Distribution Historical CAPEX - 2012-2017 (SEIA).xlsb" that SCE provided in response to SEIA-SCE-002 Question 1).

[42] SCE's description of how it categorizes capital projects indicates that it assigns just one asset type to each project and thus the utility is not able to represent projects that may have multiple attributes – for example, a replacement project that also adds capacity. See SCE response to SEIA Data Request No. 2, Q1(a-f), which is included in **Attachment RTB-2**.

[43] SCE's discovery responses make clear that replacement projects can involve an increase in system capacity. See SCE response to SEIA Data Request No. 2, Q1(g), which is included in **Attachment RTB-2**.

[44] For example, a substation may have multiple transformers, and will retain capacity to serve a portion of the loads attached to it even if one transformer fails and must be replaced.

demand has a significant overall influence on the need to invest in grid infrastructure in general. The grid is an integrated network, and thus all types of additions to the networked grid may contribute to the ability to serve peak demands. Thus, categorizing only certain investments as "capacity-related" is likely to understate how distribution costs change as a function of demand.

- **Changing standards of service.** SEIA's review of the "adjustment factors" that SCE uses to exclude costs from its NERA regression indicates that SCE has excluded virtually all wildfire costs from the MDCC calculation, by categorizing all such costs as replacements. This understates the marginal cost of distribution capacity because it does not consider the changing standards for the safety and reliability with which a kW of new distribution capacity must be supplied. For example, if the distribution line serving a community is nearing capacity and must be upgraded, the cost to do that in California today is not just the cost of upgrading the line to a higher voltage or larger conductors – the new line also must meet new requirements for fire safety and reliability. In some areas of high fire danger, the utility may choose to install the upgraded line underground. The MDCC needs to reflect that, when a utility adds distribution infrastructure in response to a change in customer demand, the new infrastructure must comply with the higher standards for safe and reliable service that are now expected of the California utilities.

Q: How can these issues be addressed in performing a NERA regression analysis?

A: The purpose of performing the regression analysis is to capture how distribution investments change as a function of load growth. This should include the impact of increasing demand on investments that are influenced by load growth even if their principal stated purpose is not to increase distribution capacity. However, SCE's method of labeling distribution capital projects does not allow for distinguishing the broader set of distribution investments that includes all projects that impact system capacity, even if their principal or initially labeled purpose may not be capacity-related. The fundamental purpose of the regression is to pick up the capacity-related impacts from the broader set of distribution projects. As a result, SEIA believes that the SCE and CalPA calculations which exclude a substantial fraction of distribution investments as being categorically not impacted by demand are likely to understate SCE's MDCCs.

Q: What is SEIA's recommendation for SCE's MDCCs in this case?

A: In this case, SEIA recommends an adjustment to SCE's calculation of its marginal distribution capacity cost (MDCC) for distribution substations and circuits, to include an estimate of the overall impact of wildfire costs on the SCE MDCC. This adjustment is needed because the SCE and CalPA MDCCs appear to exclude all wildfire costs, yet they need to be included to incorporate the changing standards for the safety and reliability with which a marginal kW of distribution capacity must be supplied. SCE's database for distribution capital projects show that, from 2020-2022, 7% of total distribution substation capital and 29% of total distribution circuit investments were wildfire-related, but none of these costs are included in SCE's or CalPA's regressions that calculate their MDCCs. SEIA recommends that SCE's MDCCs for distribution substations and distribution circuits should be increased by 7% and 29%, respectively, to incorporate the impacts of wildfire costs.[45]

I also recommend that the Commission direct SCE to work with the parties to further develop marginal distribution costs that (1) consider a broader set of investment data, including distribution investments that are impacted by load growth even if demand is not the principal driver or benefit, and (2) take into account the higher standards for safety and reliability that are now expected for electric distribution service in California. SEIA's recommended MDCCs are summarized in the final column in **Table 2**.

[45] SEIA's recommended MDCCs in Table 2 also include the correction of a minor spreadsheet error that SEIA discovered in the SCE workpaper used to calculate the adjustments to the FERC Form 1 data used to develop the MDCC regressions. That is why SEIA's marginal subtransmission costs shown in Table 2 are slightly higher than SCE's.

Table 2: *Party Positions on MDDC (2025$ per kW-year)*

Component	Party					
	SCE		CalPA		SEIA	
	Grid	Peak	Grid	Peak	Grid	Peak
Subtransmission						
Substations	0	46	0	29	0	47
Circuits	17	0	18	0	18	0
Distribution						
Substations	0	25	0	16	0	30
Circuits	94	28	85	32	137	41
Total	111	99	103	77	154	117

E. Marginal Customer Access Costs

Q: Does SEIA have a position on how to calculate SCE's marginal customer access costs (MCAC)?

A: Yes. SEIA supports the New Customer Only (NCO) method recommended by CalPA.

Q: Why does SEIA support the NCO approach?

A: Fundamentally, marginal costs are the change in utility costs per the change in a metric of the customer's use of a utility service.[46] For example, MECs are the change in energy costs per kWh of a customer's energy consumption, and demand-related marginal costs (MGCC, MDCC, MTCC) are the change in capacity-related generation, distribution, or transmission costs per a change in the kW of customer demand. MCAC are the marginal costs of access to the utility system – the change in utility costs when a new customer is added to the system. With respect to customer access to the grid, the change in customer behavior here is the one-time event of a new premises being connected to the utility grid. Thus, a utility's only ongoing marginal customer access costs are those associated with new customers joining the system. Once a property has been connected to the electric

[46] See Exh. SCE-02A, at p. 5: "Marginal costs reflect the change in costs incurred to serve a marginal increment of demand for utility services."

grid, that connection is not removed if electricity continues to be used at that site, even when the ownership of the property changes. I agree with CalPA witness Mr. Siebuhr that the NCO method best "simulates the existing ratemaking practice of socializing connection equipment costs associated with new connections to all ratepayers, in the same year when the new connection was made."[47] It is the method that most directly satisfies the third Rate Design Principle that rates should be based on cost causation, because it is new customers that cause marginal customer access costs to be incurred.

Q: How does SCE propose to determine its MCAC?

A: SCE wants to use the "rental" or real economic carrying charge (RECC) method. This approach presumes, in essence, that every customer rents new customer access equipment on a short-run basis, making, in effect, continual decisions to maintain that access. For example, the RECC factor at the heart of the rental approach values TSM (transformer, service drop, and meter) customer access facilities based on the cost of postponing for one year incurring the costs for new customer access equipment.[48]

Q: Please comment on the appropriateness of the RECC method in the context of customer access.

A: The use of a RECC calculation makes sense for those utility services where the customer is making ongoing decisions on the extent of its electric use. For example, the customer makes continual, ongoing decisions about the kilowatts (kW) of electric demand that it places on the system, and when that demand will occur. But the customer does not make such decisions on having access to the electric system. That decision was made on a one-time basis when the customer's premises was first constructed and hooked up to the grid. CalPA and the Utility Reform Network (TURN) have observed that the RECC method is flawed in its valuation of existing equipment as it is based on the concept that the cost of

[47] See CalPA testimony, at Chapter 1, p. 1-5.

new equipment to connect a new customer at one location can be deferred by an existing customer vacating their home or business at another location.[49]

Q: Does SCE's testimony defend its use of the RECC method specifically for marginal customer access costs?

A: No, it does not.

Q: Please discuss Commission decisions that have addressed the debate between the rental/RECC and NCO methods.

A: The debate between these methods has been underway for decades, and past Commissions have issued orders with different takes on this issue, in the relatively few cases where the issue has been litigated instead of settled.

In D. 96-04-050, an SCE Phase 2 case, the Commission adopted the NCO method after litigation on the issue. That order found that the addition of new customers is what causes marginal investments in customer access equipment; existing customers served from already-operating equipment do not cause such costs. The decision recognized that "[i]n the case of investment-related customer costs, the relevant unit of output is new hookups, whether for new installations or replacements."[50] The Commission rejected the idea that the rental method simulated a competitive market in customer access, finding that the rental method overstates competitive costs because "customers could get a much better deal by paying for the hookup up front, or purchasing it, particularly given the deductibility of mortgage and business interest."[51]

In D. 21-11-016 in PG&E's last GRC Phase 2, the Commission did not adopt the NCO method, but also did not adopt a RECC method based on new customer access

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[48] See SCE Exh. SCE-02A, at p. 8: "[The RECC] methodology derives and compares the present worth of the annual revenue requirements for an asset and its subsequent replacements installed today with the present worth of an equivalent asset and its subsequent replacements installed one year later."

[49] See D. 21-11-016, at p. 17.

[50] See D.96-04-050, at p. 95.

[51] *Id*., at pp. 99-1015.

costs, which is the method that SCE has proposed in this case. Instead, the Commission found that "existing access equipment should be valued as providing the ability to incrementally provide customer access to the grid" – for example, when a property is sold and a new owner takes electric service using the existing hook-up. The order adopted a version of the RECC method that, for existing customers, uses a replacement-costs-new-less-depreciation (RCNLD) approach.[52] The problematic aspect of this order is its confusion about what constitutes a "new" customer. The order assumes that, when one customer closes their account and sells their premises to someone else, the buyer of the premises is a "new" customer who is receiving new, marginal, or incremental access to the grid.[53] This leads the order to conclude, erroneously, that the capital costs of existing customer access equipment has value as a marginal cost.[54] The fallacy here is assuming that this premises is a new customer in terms of access to the grid – it is not, because the premises has been attached to the system in the past, has previously taken service, and can continue to take service through the existing equipment.[55] When a premises changes owners, the number of customers served by the utility remains the same, and the utility does not need to make a capital investment to provide grid access. The only new cost to the utility from this change in the ownership of the premises is the minor administrative cost to process the change in ownership in the utility's billing system. There is no marginal increase in the utility's capital costs because the existing access equipment remains in place and continues to provide service.

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[52] See D. 21-11-016, at pp. 17-20.

[53] *Id*., at pp. 17-18: "Marginal customer access doubtless occurs when new access equipment is installed. But it also occurs whenever a customer moves from one location to another, or when a new customer moves into a location with existing access equipment."

[54] *Id*., at p. 20: "As illustrated above, once an old customer terminates utility service the existing equipment transforms into equipment that is waiting to provide incremental access. A new customer that uses existing equipment should appropriately assume the marginal cost of that asset – both its operational costs and its depreciated value."

[55] As the Commission found in D. 96-04-050, at p. 99, footnote 29: "The marginal cost of access relates to the investment costs associated with hooking up new customers, not to the incremental costs of serving those in existing locations that already have hookups."

Q: Please comment on this issue from the perspective of the Commission's Rate Design Principles.

A: The Commission's second and third principles are that rates should be based on marginal costs and on cost causation. The only customers who cause the utility to incur new, marginal customer access costs are new customers whose premises are being hooked up to the grid for the first time. There are no capital-related marginal customer access costs caused by customers who use existing customer access equipment, including "new" customers who purchase or rent a premises in SCE's territory that already has grid access equipment installed. For this reason, the New Customer Only method employed by CalPA is most closely aligned with the rate design principles.

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IV. RATE DESIGN

A. Residential Rate Design

1. On-peak to off-peak differences in default TOU rates

Q: What changes do SCE and CalPA propose to the structure of SCE's residential TOU rates?

A: SCE proposes to raise the summer/winter seasonal differentials in its residential TOU rates. SCE would increase the summer/winter seasonal differential in its default residential TOU rates from $0.01 per kWh to $0.04 per kWh and in its residential electrification rates from $0.024 per kWh to $0.06 per kWh. SCE notes that a cost-based seasonal differential in its residential rates would be $0.15 per kWh, so these changes are needed to move SCE's residential rates closer to costs. SCE also argues that these changes will reduce rates in the eight winter months, thus supporting electrification measures to encourage adoption of heat pumps for space heating. Further, the higher summer rates will send a stronger conservation signal to reduce usage during the on-peak hours of SCE's peak season. SCE's bill impacts show that this change will reduce bills for a majority of residential customers, with higher bills experienced primarily by customers with higher-than-average summer usage.[56]

CalPA opposes SCE's proposal to increase the seasonal differential, asserting that the higher summer rates would have adverse bill impacts that will be exacerbated by the fact that summers are getting hotter. CalPA also argues that customers cannot mitigate higher summer season rates by shifting loads to winter months.[57]

Q: Does SEIA support SCE's proposed changes to the seasonal differentials in residential rates?

A: Yes, and I generally agree with SCE's reasons for this change. CalPA's argument that

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[56] See Exh. SCE-04A, at pp. 61-63.

[57] See CalPA testimony, at Chapter 6, pp. 6-12 to 6-16.

customers cannot shift electric loads from summer to winter dodges the fact that customers can shift loads from the critical summer on- and mid-peak periods (4 p.m. to 9 p.m. or 5 p.m. to 8 p.m. daily) to off-peak hours (all other hours). This highlights the importance of addressing not just the seasonal differential in rates, but also the differences or ratios between the rates for the TOU periods within the summer and winter seasons.

CalPA's argument that the seasonal or TOU rate differentiation in default residential rates should not change in order to shield residential ratepayers from higher bills as the climate become hotter is particularly troubling. The climate crisis will not be addressed if ratepayers are insulated from its effects. Ratepayers need to be nudged, through their electric rates, to shift their electric usage to off-peak periods when electricity is cleaner, less expensive, and more abundant, and to adopt electrification technologies that reduce GHG emissions. On-peak usage is particularly important as a driver of capacity-related costs for all portions of the electric system – generation, transmission, and distribution. Subsidizing on-peak usage through on-peak rates that continue to be set well below marginal costs will exacerbate California's affordability problems in the long run, by leading to over-investment in system capacity.

Q: Do either SCE or CalPA propose any changes in the existing ratios between TOU period rates within seasons?

A: No, they do not. Both SCE and CalPA argue that "customers on default TOU should not be penalized for being unable to conserve or shift load during the peak period" and it is "preferable to keep these rates "TOU-lite" as determined by D.19-07-004" (the order that first implemented default TOU rates). SCE and CalPA also argue that SCE has other rate options, such as TOU-D-PRIME or critical peak pricing (CPP), available for customers that are able to conserve or shift peak period usage.[58]

These positions are disappointing, because, by the time the rates developed in this case are implemented, all of SCE's residential customers will have had more than three

[58] See Exh. SCE-04A, at pp. 63-65. Also CalPA testimony, at Chapter 6, pp. 6-11 to 6-12.

years of experience on the existing default TOU rates (and some much longer), and, as I will show below, the marginal costs calculated by all parties demonstrate the need for much larger TOU rate differentials. SCE's proposal to increase the seasonal differentials, while helpful, does not do enough to move SCE's residential rates – especially the default rates – closer to costs.

Q: Did the Commission expect SCE to address TOU rate differentials in this case?

A: Yes. In SCE's last Phase 2 case, SEIA proposed a modest first step to move the TOU differentials in SCE's default residential TOU rates to close 15% of the difference between the existing default rate and the fully scaled marginal cost rate. SCE and CalPA opposed SEIA's proposal.[59] D. 22-10-022 did not adopt SEIA's proposal, but did direct that

> … SCE must make an affirmative showing of the most accurate and detailed calculations to support just and reasonable rates for TOU D-4-9PM and TOU-D-5-8PM in its next Phase 2 GRC. SCE must file this in addition to any other rate proposals it would otherwise prefer.[60]

Q: Does SCE's testimony include "the most accurate and detailed calculations to support just and reasonable rates for TOU D-4-9PM and TOU-D-5-8PM" that D. 22-10-022 required?

A: No, it does not. SCE presents no calculations comparing its proposed default residential TOU rates to rates based on fully scaled marginal costs. SCE does not examine possible options for gradual increases to the TOU differentials in its residential rates, such as SEIA's proposal in the last GRC Phase 2. SCE relies simply on the qualitative arguments that the TOU-lite rate structure adopted in D. 19-07-004 should continue[61] and that other

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[59] See D. 22-10-022, p. 14. CalPA suggested that "if changes are made then they should be gradual corrections to avoid 'rate shock' caused by a large single change," notwithstanding that SEIA had proposed a small change consistent with gradualism.

[60] *Id*.

[61] With respect to this argument, which SCE and CalPA also made in the last GRC Phase 2, D. 22-10-022, at pp. 11-12, observed that D. 19-07-004 adopted a settlement that has no precedential value for future cases. On this point, the Commission's order concluded that "an argument that depends on not

optional rates that are closer to marginal costs are available.[62]

Q: Please provide the data and calculations supporting the need for larger TOU rate differentials.

A: **Table 3** compares SCE's proposed default residential rates to rates at fully-scaled marginal costs (using both the SCE and SEIA marginal costs), and shows the ratios between TOU period rates (with the summer off-peak and winter super-off-peak rates in the denominators of the summer and winter ratios, respectively).[63] Even with SCE's proposed increase to the seasonal differential, its residential default TOU rates would have summer on-peak rates that are far below costs (by $0.24/kWh based on SCE's marginal costs) and off-peak rates that are too high – $0.12 to $0.17/kWh above SCE's marginal costs – in both summer and winter.[64]

Table 3: *SCE Proposed Default Rate vs. Rates at Scaled Marginal Costs ($ per kWh)*

TOU Period	SCE Proposed TOU-D 4p-9p		SCE Scaled Marginal Costs		CalPA Scaled Marginal Costs		SEIA Scaled Marginal Costs	
	Rate	Ratio	Rate	Ratio	Rate	Ratio	Rate	Ratio
Summer On	0.66400	1.61	0.91815	3.11	0.81470	2.72	0.97516	3.42
Summer Mid	0.53730	1.30	0.36838	1.25	0.40286	1.34	0.35883	1.26
Summer Off	0.41270	1.00	0.29517	1.00	0.29982	1.00	0.28496	1.00
Winter Mid	0.54743	1.45	0.43590	2.06	0.44438	2.05	0.44980	2.31
Winter Off	0.41529	1.10	0.24603	1.16	0.26545	1.22	0.24711	1.27
Winter Super-off	0.37717	1.00	0.21187	1.00	0.21683	1.00	0.19459	1.00
Baseline credit:	-0.10239							

changing a rate simply for the sake of avoiding a rate change to a more cost-based rate, is not a sufficient reason on its own."

[62] See Exh. SCE-04A, at pp. 63-65.

[63] SCE calculated the scaled marginal cost rates based on its marginal cost proposal. See SCE response to SEIA Data Request No. 1, Q19, which is included in **Attachment RTB-2**. SEIA calculated the scaled marginal cost rates for its proposed marginal costs and those of CalPA.

[64] The default rate does include a baseline credit of $0.10239 per kWh that reduces off-peak rates by this amount, but only for the initial baseline quantity of usage. The Tier 2 rates shown in Table 3 are the rates that likely will apply to incremental customer usage, for example, for electrification measures adopted by a customer.

Table 4 is the same comparison for SCE's TOU-D-PRIME rate, the utility's residential rate option with the largest TOU period ratios.

Table 4: *SCE Proposed TOU-D-PRIME Rate vs. Rates at Scaled Marginal Cost ($ per kWh)*

TOU Period	SCE Proposed TOU-D-PRIME		SCE Scaled Marginal Costs		CalPA Scaled Marginal Costs		SEIA Scaled Marginal Costs	
	Rate	Ratio	Rate	Ratio	Rate	Ratio	Rate	Ratio
Summer On	0.71705	2.60	0.91815	3.11	0.81470	2.72	0.97516	3.42
Summer Mid	0.41351	1.50	0.36838	1.25	0.40286	1.34	0.35883	1.26
Summer Off	0.27586	1.00	0.29517	1.00	0.29982	1.00	0.28496	1.00
Winter Mid	0.58850	2.58	0.43590	2.06	0.44438	2.05	0.44980	2.31
Winter Off	0.22797	1.00	0.24603	1.16	0.26545	1.22	0.24711	1.27
Winter Super-off	0.22797	1.00	0.21187	1.00	0.21683	1.00	0.19459	1.00

Again, the summer on-peak rate in TOU-D-PRIME is well below costs -- $0.20 per kWh below SCE's summer on-peak marginal cost-based rate. Table 4 shows that the off-peak rates in TOU-D-PRIME are relatively close to costs.

Q: Should the difference between summer on-peak and off-peak rates in SCE's residential default rates move toward scaled marginal costs?

A: Yes. In particular, the summer on-to-off peak rate difference in SCE's current default residential rate is well below SCE's marginal costs. This gap should be closed over time. This is particularly important given the state's current tight supply/demand conditions in the summer months and its affordability issues; customers on the default TOU rate should be sent an increasingly stronger signal to conserve energy in the summer peak period.

Further, there has been a continuing issue regarding the impact that NEM 1 and NEM 2 solar customers have on other customers not participating in those rate schedules. SEIA believes that any such impact can be improved by gradually moving the TOU rates paid by NEM customers to marginal costs. Measured rate design changes to bring TOU rates into line with marginal costs are a means to improve the cost effectiveness of NEM programs in a way consistent with gradualism, with the Commission's Rate Design Principles 2, 4, 8, 9, and 10, and with the respect that the Commission has shown to

customers' investments in California's clean energy infrastructure.[65]

Q: Have other California IOUs received Commission approval to move, gradually, the TOU differentials in their default residential rates toward differences based on marginal costs?

A: Yes. PG&E completed its transition to default TOU rates in about May 2023, almost a year after SCE completed this change in June 2022.[66] Nonetheless, in D. 21-11-016 the Commission approved a residential rate design settlement in PG&E's last GRC Phase 2 case (A. 19-11-019), in which the parties proactively agreed to start to move PG&E's default residential default rates closer to marginal costs beginning one year after PG&E's transition to default residential TOU rates was complete, with small annual increases to the differentials between on- and off-peak rates in both summer and winter.[67]

Q: Is PG&E proposing to continue this transition?

A: Yes. In PG&E's current GRC Phase 2 case (A. 24-09-014), PG&E has proposed to continue this transition through 2029, which is the last year of the forecast period for its current Phase 2 case. In 2029, PG&E expects to come close to completing the transition of the TOU differentials in all of its residential rates to marginal costs. For example, in 2029 the on-to-off peak differential in PG&E's default TOU-D-C rate would be $0.243 per kWh, which is 88% of the marginal cost difference of $0.275 per kWh.[68] PG&E's showing in its current Phase 2 case, which I have included as **Attachment RTB-3**, includes a detailed comparison of the TOU differentials in all of its residential TOU rates to its marginal costs, with a game plan for gradually reaching marginal cost-based TOU rate differences. SEIA is still reviewing PG&E's proposal in A. 24-09-014, and does not

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65 See D.14-03-041, D. 16-01-044 (at pp. 100-101), and D. 22-12-056, at pp. 163-164 and 189-194.

66 See Exh. SCE-04A, at p. 54.

67 See D. 21-11-016, at pp. 106-108.

68 See A. 24-09-014, Exh. PG&E-3, at pp. 3-17 to 3-23. The comparisons of PG&E's proposed TOU-D-C TOU differentials to its marginal costs over time are shown in Tables 3-7 through 3-10.

necessarily agree with all of the details of PG&E's proposals for marginal costs or rate design. That said, SEIA strongly supports PG&E's proactive development of a strategy for moving its TOU rate differences to marginal costs. PG&E's testimony is exactly the sort of "detailed calculations to support just and reasonable rates for TOU D-4-9PM and TOU-D-5-8PM" that is lacking in SCE's showing in this case.

Q: What is SEIA's proposal for a plan to move the TOU differentials in SCE's default residential rates to marginal costs?

A: SEIA proposes that, beginning when rates from this proceeding are implemented in early 2026, SCE should increase (or decrease) the TOU differentials in its residential TOU rates (both TOU-D 4p-9p and TOU-D 5p-8p) to close 20% of the differences between current rates and fully scaled marginal costs. SCE then should take equal steps in each year from 2026-2029, such that 80% of the difference has been bridged before rates from the next SCE GRC Phase 2 are implemented in 2030. This would be comparable to the gradual change to cost-based residential TOU rates that PG&E has charted in A. 19-11-019 and A. 24-09-014 and whose first steps the Commission approved in D. 21-11-016.

Q: Have you calculated what SCE's TOU-D-4p-9p default rate would be with the initial 20% move toward TOU rate differences based on SEIA's marginal costs?

A: Yes. These rates are shown in **Table 5**, which show both the rates and the ratios of each rate to either the summer off-peak or the winter super-off-peak rates.

Table 5: *SEIA's Recommended Residential Default TOU-D-4p-9p ($ per kWh)*

Season	Rate or Ratio	On Peak	Mid Peak	Off Peak	Super Off Peak
Summer	Rate	0.75973	0.51055	0.39648	--
	Ratio	1.92	1.29	1.00	--
Winter	Rate	--	0.58733	0.40607	0.35583
	Ratio	--	1.65	1.14	1.00
Baseline credit: -0.10239					

Q: Does SEIA recommend any changes to the TOU differences in SCE's TOU-D-PRIME rate?

A: Table 4 shows that, compared to marginal costs, the summer on-peak rate is too low and the winter mid-peak rate is too high. SEIA also proposes a 20% adjustment to move these rates closer to marginal cost-based TOU rate differences. SEIA's proposed TOU-D-PRIME rates are shown in **Table 6**.

Table 6: *SEIA's Recommended Residential TOU-D-PRIME ($ per kWh)*

Season	Rate or Ratio	On Peak	Mid Peak	Off Peak	Super Off Peak
Summer	Rate	0.74686	0.39129	0.26956	--
	Ratio	2.77	1.45	1.00	--
Winter	Rate	--	0.57613	0.23243	0.23243
	Ratio	--	2.48	1.00	1.00

2. SCE's proposed optional TOU-D-PRIME-Plus rate.

Q: Please describe SCE's proposed optional TOU-D-PRIME-Plus rate.

A: TOU-D-PRIME-Plus would be a new optional residential rate which SCE says is designed, like the PRIME Rate itself, for electrification customers with flexible loads. It would be a version of the PRIME rate with the following differences:

- a higher customer charge than the $24 per month approved in D. 24-05-028 – initially $33 per month but then raised in supplemental testimony after D. 24-05-028 to $49 per month[69] – that recovers marginal customer costs and non-marginal distribution costs,
- a seasonal time-related demand (TRD) charge of $3.18 per kW in the summer and $2.62 per kW in the winter, with a customer's demand based on their highest 60-minute usage in a billing period, and
- a higher seasonal rate differential of $0.08 per kWh (vs. $0.06 per kWh for TOU-D-PRIME).[70]

[69] See Exh. SCE-06, at pp. 22-25.

[70] See Exh. SCE-04A, at pp. 68-70.

The higher fixed charge will result in lower volumetric rates in all TOU periods, while the TRD Charge will lower on- and mid-peak volumetric TOU rates.

Q: Does SEIA support the TOU-D-PRIME-Plus proposal?

A: No. SEIA often welcomes new optional rates that are designed to meet specific customer needs not addressed by other rates. However, with TOU-D-PRIME-Plus, SCE has not articulated a customer need that cannot be met with the existing TOU-D-PRIME rate. For example, SCE has not shown that there are specific electrification measures that would be significantly more economic for customers under TOU-D-PRIME-Plus compared to TOU-D-PRIME. SCE's bill impact analysis shows that the only customers to benefit significantly (i.e. bill savings greater than 5%) from TOU-D-PRIME-Plus are very large (and likely wealthier) residential customers with usage of 1,399 kWh per month or more, presumably because such large customers benefit from the high fixed charge and have higher load factors that mitigate the impact of the demand charge.[71]

Moreover, the unstated result of this variation on TOU-D-PRIME is that it would introduce two problematic elements into SCE's residential rate design – first, a higher fixed charge that fails to comply with Commission policy for the "fixed costs" eligible to be recovered through a residential fixed charge and, second, a demand charge that residential customers are ill equipped and poorly prepared to manage.

Q: Why is the proposed $49 per month fixed charge contrary to Commission policy?

A: SCE filed its TOU-D-PRIME-Plus proposal before the Commission issued its decision (D. 24-05-028) adopting new policies for residential income-graduated fixed charges (IGFCs). That order reviewed and approved the specific categories of "fixed costs" eligible to be recovered through a residential fixed charge, limiting eligible fixed costs to (1) marginal customer costs, (2) public purpose program costs, (3) new system generation and local generation charges, and (4) nuclear decommissioning non-bypassable charges.[72]

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[71] See Exh. SCE-06, at Table IV-15.

[72] See D. 24-05-028, at pp.64-72.

Contrary to this decision. SCE proposes that the new TOU-D-PRIME-Plus rate would recover marginal customer costs plus all non-marginal distribution costs, a category of costs which D. 24-05-028 specifically excluded from residential fixed charges.[73] In addition, the TOU-D-PRIME-Plus proposal also violates D. 24-05-028's direction that all optional residential rates should have the same IGFC as default residential rates (i.e. $24 per month for non-CARE customers).[74]

SCE filed supplemental testimony in this case that was supposed to conform its rate proposals to D. 24-05-028, but instead of conforming the TOU-D-PRIME-Plus fixed charge to the findings of that order, SCE doubled down on its proposal and raised the proposed TOU-D-PRIME-Plus fixed charge from $33 to $49, with the higher fixed charge now recovering all of SCE's non-marginal distribution costs proposal.[75] SCE modified its testimony after D. 24-05-028, despite the Commission's explicit finding that non-marginal distribution costs are not fixed costs eligible to be recovered in a residential fixed charge. SCE also ignores D. 24-05-028's clear direction that both optional and default residential rates should have the same IGFC.

Q: Please discuss the issues with SCE's use of a TRD Charge in the proposed TOU-D-PRIME-Plus rate.

A: Demand charges are rarely used in residential rates, largely because they are difficult for customers to understand and accept. Customer understanding and acceptance, especially of new rates, are embodied in the Commission's Rate Design Principles 7 and 10.

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[73] *Id*., at p, 69: "The record is not sufficient to determine which portion of Non-Marginal Distribution Costs are fixed costs. We will not recover these costs through income-graduated fixed charges at this time. However, we may consider whether a portion of Non-Marginal Distribution Costs are fixed costs in Phase 2 of this proceeding or a successor rulemaking." This GRC Phase 2 case is not Phase 2 of the Demand Flexibility rulemaking.

[74] *Id*., at p. 89: "It is reasonable to apply income-graduated fixed charges adopted for default rates to all optional rates, except for master-metered rates that are not sub-metered, separately-metered electric vehicle rates for customers whose primary meter has an income-graduated fixed charge, or rate schedules that are scheduled to be eliminated by the second quarter of 2026." (emphasis added)

[75] See Exh. SCE-06, at pp. 22-25.

The potential for customer confusion is high, because residential customers have no experience with demand charges. To my knowledge, demand-based charges have never been part of any residential rate design for SCE or any other IOU in California, and are rare for residential customers elsewhere in the U.S. Residential consumers have experience with their energy use, in kilowatt-hours, because that is the basis on which they have been billed in the past. They do not have experience with the concept of demand, measured in kW, which is the rate at which a customer uses energy as a function of time. In mathematical terms, it is the first derivative of energy use with respect to time. To understand their 60-minute demand, customers must not only understand their monthly energy use, but also must know and monitor the rate of their energy use over small, one-hour blocks of time.

Even if a customer understands the difference between kWh of energy and kW of demand, the customer does not have readily available data on the kW power demand of their household appliances. Energy usage data for home appliances is typically expressed in term of the annual kWhs of energy use, for example, as in Energy Star ratings for appliances.[76] Ratings are not given in terms of the maximum power use, in kW. As a result, consumers do not have accurate information today to make intelligent decisions to reduce their maximum kW demand.

Q: Do customers have ready access to information about their current one-hour demand, or what their highest one-hour demand has been in recent days?

A: No. In discovery, SEIA asked SCE for the process that a residential customer would have to take to ascertain what their maximum one-hour demand has been in the past month.[77] On the customer's account page on the SCE,com website, the customer would have to navigate to the screen that shows their hourly use for the most recent available day, determine which hours are on-peak, and write down their maximum hourly on-peak use for that day. Then the customer would have to page back to the same hourly graph

[76] See https://www.energystar.gov/products/certified-products.

[77] See SCE response to SEIA Data Request No. 2, Q4(b), which is included in **Attachment RTB-2**.

for all of the prior days in the billing period, and keep a running tally of the highest hourly on-peak use in the peak period. This would need to be repeated for the 12 prior billing periods to obtain a full year of data. Alternatively, the customer could go through a non-trivial, nine-step process of downloading 15-minute usage data on their energy usage into a spreadsheet. This would be 35,040 data points for a year of 15-minute demand data. The customer would then need to combine the 15-minute data into hourly data, pick out the on-peak data, and calculate the maximum hourly on-peak usage for each billing period in the year.[78] It does not appear that SCE reports maximum one-hour demand on a customer's monthly statement, and real-time or near-real-time data are not readily available to residential customers through other vendors unless they are solar customers with an internet-connected monitoring system.

Timely information on a customer's hourly demand would be essential if customers are to be able to determine the economics of investing in a DER technology under the proposed TOU-D-PRIME-Plus rate, or, once on the demand-based rate, to take actions to monitor and to reduce their current maximum demand. And even if the customer has access to real-time demand data through a solar or storage monitoring system, it is unlikely that customers will be willing or able to monitor that data regularly, in order to alter their behavior so as to impact the level of their maximum kW of demand, which only occurs in one 60-minute period each month.

Q: Please provide an example of the type of problem that a residential customer could encounter under the TOU-D-PRIME-Plus rate.

A: A customer with an EV might sign up for TOU-D-PRIME-Plus in order to take advantage of the low off-peak rate to charge their EV. However, Level 2 home EV chargers can cause significant increases in demand, because they can draw 7 to 10 kW of power. The TOU-D-PRIME-Plus's on-peak demand charge of $3.18 per kW-month dramatically increases the cost consequences of mistakenly charging the EV in even one on-peak hour in a billing period. For example, an inattentive or uninformed family

[78] *Id*.

member who charges the EV at 10 kW for a single on-peak hour can cause the family's electric bill for that month to increase by $32.[79] In contrast, under the all-volumetric TOU-D-PRIME rate, the cost consequences of such an error would be less than $5.[80]

Q: Should SCE know that demand-based charges will be difficult for residential customers to understand and accept?

A: Yes, because SCE has conducted customer surveys on this very topic. In 2013, the three IOUs commissioned a customer survey as part of the Commission's comprehensive rulemaking proceeding on residential rate design.[81] This study concluded that a demand charge "was confusing" to participants, who ended up making inaccurate comparisons to a fixed monthly service fee because they failed to comprehend that a demand charge "varies based on kW demand levels."[82]

As another example of customer feedback on demand charges, in 2015 SDG&E conducted a survey of customer preferences for a new net energy metering (NEM) tariff in California. This survey looked at possible new structures for the NEM successor tariff, including a demand-based rate similar to those used in commercial and industrial (C&I) rates. The survey concluded that for customers the key drawbacks of the demand charge are that it is "confusing," "unpredictable (may pay more)," and "can be difficult to change behavior" to reduce their maximum one-hour demand each month.[83]

One of the respondents to the SDG&E NEM Survey summarized the problematic behavioral economics associated with extending demand charges to residential customers:

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[79] 10 kW times the on-peak demand charge of $3.18 per kW-month.

[80] The cost of such an error under the TOU-D-PRIME rate would be 10 kWh times the on-to-off-peak volumetric rate difference in TOU-D-PRIME.

[81] CPUC Docket R. 12-06-013.

[82] Hiner and Partners, Inc. *"RROIR" Customer Survey*, April 16, 2013, p. 22.

[83] Hiner & Partners, *Final Report: Solar (NEM) Rate Preferences Survey Results* (June 2015), at Slides 7 and 8, hereafter "SDG&E NEM Survey." This survey is labeled as confidential, but was made public in CPUC Docket No. 14-07-002 as Exhibit 29 on the record of that case.

"I don't like anything about it. I will constantly have to monitor how many electric appliances are being used at each time, and will have to become the "electricity police" in my household and make sure that each family member is complying."[84]

Q: Has SCE obtained customer feedback to see if there is customer interest in a rate structured like TOU-D-PRIME?

A: No, it has not. CalPA posed this question to SCE in discovery.[85] SCE responded with a study which it asserts "provides evidence that residential customers may be interested in adopting rates with greater alignment to cost." However, the study asked customers if they would be interested in dynamic rates that change on an hourly or daily basis (but are all-volumetric). SCE did not ask about a rate with TOU-D-PRIME-Plus's structure, whose two main characteristics are a very large fixed charge and a demand charge.

Q: Have other California IOUs proposed a demand-based charges for residential customers in the past, and did the same concerns arise concerning the ability of customers to understand demand-based rates?

A: Yes. SDG&E has twice proposed "demand differentiated fixed charges" for its residential customers. These proposals have involved a schedule of increasing levels of monthly fixed charges, with the applicable fixed charge based on the customer's maximum kW demand in the prior month or year. SDG&E first advanced this idea in 2014 in R. 12-06-013, the CPUC's rulemaking proceeding on residential rate design. SDG&E also proposed a similar structure in 2021 in A. 21-09-001, as part of its proposed TOU-ELEC residential electrification rate. The issues of customer understanding and acceptance arose with both proposals, and the Commission rejected them both.[86] Specifically, with respect to the 2021 TOU-ELEC proposal, in D. 22-11-022 the

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[84] SDG&E NEM Survey, at Slide 24.

[85] See SCE response to CalPA Data Request PubAdv-SCE-012, Q2, which is included in **Attachment RTB-2**.

[86] See D. 15-07-001, at pp. 183-184; also D. 22-11-022..

Commission rejected SDG&E's demand-based fixed charges, making the following findings of fact:

6. SDG&E's proposal is inconsistent with the Commission's rate design principles, because SDG&E's proposed rate does not reflect cost-causation and its adoption may pose risks of undue revenue shift onto non-participating ratepayers.
7. SDG&E's proposed tiered flat rate is complex and might not be easily understandable to customers.
8. SDG&E's multi-tiered fixed charge proposal is a form of demand charge which may not incentivize customers to shift loads from the peak hours to off-peak hours and consequently reduce GHG emissions.
9. SDG&E's proposed four-tiered fixed charge, which is a form of demand charge, is not in alignment with the Commission's current policy direction.

Q: The Commission's third Rate Design Principle is that rates should be based on cost causation. Please discuss, from a cost causation perspective, whether demand charges make sense for residential customers.

A: SCE proposes to use the demand charges in the TOU-D-PRIME-Plus rate to recover peak-related distribution costs.[87] There is a level of diversity on residential circuits with many small customers, even during the limited number of peak period hours, such that the utility does not have to plan to size residential circuits to serve the sum of the non-coincident demands of all residential customers on the circuit. Such diversity does not exist to the same extent on circuits serving larger C&I customers, and thus demand charges are more reasonably a part of commercial and industrial distribution rates (although, as discussed in Section IV.B.2 below, they are also over-used in C&I rates). For residential customers it is more reasonable to collect peak-related distribution costs based on their average demand over a summer on-peak TOU period that covers the hours when the circuit is most likely to peak. This can be accomplished through a volumetric

[87] See SCE's "Residential Optional Rates Amended.xlsx" workpaper, the "TOU-D-PRIME_Dmd" tab, at column BQ. The demand charges are based on 46.03% of the Distribution TRD costs shown in column X.

TOU charge to recover such costs during these peak hours. A customer's kWh usage over the peak period measures the customer's contribution to the average demand during those hours and is a reasonable, cost-based charge. An even more accurate rate would be a Critical Peak Pricing (CPP) rate, which are volumetric TOU rates that charge very high on-peak rates to customers in a limited number of high-demand hours each year that the utility or system operator declare on a day-ahead basis. These critical peak hours are the ones which drive the need for future distribution capacity costs.

Q: What is CalPA's position on SCE's TOU-D-PRIME-Plus proposal?

A: CalPA also opposes the introduction of this rate, for many of the same reasons discussed above. SEIA agrees with CalPA that TOU-D-PRIME-Plus's on-peak demand charge will not incent residential customers to reduce their peak demand as effectively as dynamic or critical peak pricing rates that focus on peak periods when reliability is most at issue.[88]

B. Medium & Large C&I Rates

1. Option S Rates to Support On-Site Storage

Q: The decision in the last SCE Phase 2 case ordered SCE "to include a fully analyzed proposal for an Option S-like tariff" in this Phase 2.[89] SCE has provided this proposal in Section II.C.2 of Exhibit SCE-04A. Before you comment on SCE's Option S proposal, please review the policy reasons for such a tariff.

A: C&I rates typically include two types of demand charges: (1) noncoincident demand charges (SCE's facilities-related demand [FRD] charges) and (2) peak-related or coincident demand charges (SCE's time-related demand [TRD] charges). FRD charges are assessed based on a customer's maximum 15-minute demand, whenever it occurs. TRD charges generally apply to the customer's maximum 15-minute demand only during the on- and mid-peak periods.

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88 See CalPA testimony, at Chapter 7, pp. 7-4 to 7-10.

89 See D.22-10-022, at p. 18.

C&I customers who install on-site storage often do so to manage their demand charges. If they are on a rate with high FRD charges, they will operate the storage to reduce their own noncoincident peaks, which may not occur at the same time as the system peak. Thus, operating storage on C&I rates with high FRD charges may not help the system or reduce GHG emissions, because storage discharges may not reduce on-peak demand and may not lower the high marginal GHG emissions that occur in the peak period. The initial evaluation of storage units installed by commercial customers under the Self Generation Incentive Program (SGIP) revealed this problem.[90]

The purpose of the Option S rate structure is to address this issue, by moving distribution costs that otherwise would be recovered in an FRD charge into a daily demand charge that applies only during the on- and mid-peak periods. This change provides an unambiguous signal for the C&I customer to discharge their storage during the on- and mid-peak periods, so that the storage is operated with a profile of charging and discharging that also benefits the system and reduces GHG emissions.

Q: Please discuss in more detail how Option S incentivizes the optimal operation of on-site storage.

A: The storage operation that is optimal is for customers to charge the storage in off-peak hours, then discharge the storage to minimize demand in the 4p to 9p on-peak or mid-peak hours. Option S shifts the costs collected through the noncoincident demand charge (which applies to the maximum 15-minute load at any time in the monthly billing period) to a daily demand charge that applies to the maximum 15-minute load during the 4p to 9p on-peak or mid-peak period. This provides a stronger incentive for the customer to operate the storage to reduce on- or mid-peak demand, rather than using the storage to reduce non-coincident demand that can occur in off-peak hours. Option S also encourages the storage customer to discharge the storage to level their on- and mid-peak demand. The Option S rate adopted for PG&E also includes a provision that no

[90] See *2016 SGIP Advanced Energy Storage Impact Evaluation*, available at 6442454964-2016-sgip-advanced-energy-storage-evaluation.pdf.

distribution demand charges shall be assessed between 9a and 2p, in the hours when GHG emissions are the lowest, and when the storage can be filled with the cleanest energy.

The daily demand charge also reduces the risks for the customer who invests in and operates distributed storage. The daily demand charge provides a consistent incentive for the customer to cycle the storage every day. Under a traditional monthly demand charge, if the customer does incur a significant 15-minute demand on one day, it loses any incentive to reduce its demand below this level for the rest of the billing period, and the customer could simply not run the storage unit for the rest of the month. A daily demand charge, in contrast, maintains the incentive to cycle storage every day, but does not penalize the customer with a large demand charge for the entire month if the storage does not operate as expected on one day.

Q: Should there be concerns that Option S will cause a cost shift?

A: No. In the last SCE Phase 2 case, SCE presented a study showing that bills for storage customers under Option S will be similar to bills under Option E. As a result, the impacts of the new Option S on SCE's revenue recovery should not be a concern to the other ratepayers in the class, and there is no need for a cap on the adoption of Option S rates, such as was adopted for PG&E. Moreover, other ratepayers will benefit because Option S will encourage the operation of this C&I on-site storage in ways that will benefit the system through lower GHG emissions and a reduction in SCE's overall cost of service, compared to operating the storage under Option E rates.

In sum, the central intent of the Option S rate is not to produce additional savings for the Option S customer compared to Option E, but to provide a stronger incentive to cycle the storage in the most beneficial way for the system as a whole and to reduce the risks to the customer of investing in and operating this new technology.

Q: Did the Commission agree with this rationale for Option S rates when it adopted them for PG&E?

A: Yes. The Commission adopted Option S rates for PG&E in Decision 18-08-013 in PG&E's last GRC Phase 2 case, based on a proposal from SEIA.[91]

Q: Does SEIA have any issues with the details of the Option S proposal that SCE included in its testimony in this case?

A: Yes. SCE's proposed Option S rate has two significant problems. First, and most important, SCE proposes to move only about 40% of the distribution costs in its Option E FRD into the peak daily demand charge.[92] The result would be that, in the eight winter months, the total FRD charges in Option S would be similar in magnitude to the peak daily demand charge.[93] Thus, under SCE's Option S the commercial customer would not have a clear incentive on a daily basis to operate their storage to discharge during the peak period, versus operating to reduce the maximum monthly demand in any hour. This would not accomplish the essential purpose of the Option S rate. Consistent with the Option S rate design adopted in D. 18-08-013 for PG&E, the Commission should direct SCE to design its Option S rate with at least 80% of the costs in SCE's distribution FRD moved into the peak daily demand charge.

Second, SCE's Option S proposal is not clear that it would include the provision of the PG&E Option S rate whereby no distribution FRD charge is assessed between 9 a.m. and 2 p.m., the hours when greenhouse gas emissions are the lowest, when renewable energy is most abundant, and when it benefits the system to fill storage with the cleanest energy. The Commission also should adopt for SCE this provision in the PG&E Option S rate.

Q: PG&E's Option S rates have required that the nameplate continuous discharge capacity of the installed storage unit, in kW, should be at least 10% of the

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[91] See D. 18-08-013, at pp. 105-108.

[92] See Exh. SCE-04A, at Table II-10, shows SCE's proposed Option S distribution FRD of $4.15 per kW-month, versus the Option E distribution FRD of $7.00 per kW-month.

[93] The FRD charges in SCE's Option S would total $9.76 per kW-month; the daily demand charge (over 30 days) would total $9.72 per kW-month. See Exh. SCE-04A, at p. 36 and Table II-10.

customer's 15-minute peak demand, in kW, over the last 12 months. Do you recommend a similar requirement for SCE's Option S?

A: Yes. This would provide a safeguard against customers installing a very small storage unit simply to qualify for the Option S rate. Once a site is deemed eligible for Option S rates, it should remain so until the storage resource is removed from the site.

Q: Does SEIA continue to recommend that the Commission should adopt Option S rates for SCE's C&I customers in the TOU-GS-2, TOU-GS-3, and TOU-8 customer classes?

A: Yes. Option S rates would start with the design of Option E rates, then at least 80% of the noncoincident demand charge for distribution costs should be converted to a daily coincident peak demand charge, applicable during SCE's on- and mid-peak periods and designed to recover the same class revenues as the portion of the noncoincident distribution demand charge that it replaces. For simplicity, the small time-related generation demand charge that applies in on- and mid-peak periods under Option E for the TOU-GS-3 and TOU-8 classes should be combined into the daily demand charge; there is a comparable provision in the design of PG&E's Option S rates.[94]

Q: Please summarize the policy reasons that continue to support the adoption of Option S rates.

A: The Commission has made clear that it expects utilities to offer "a menu of TOU options for all of its non-residential TOU customers."[95] This should include a variety of rate designs, including innovations like a daily demand charge that moves beyond traditional rate elements such as the monthly demand charge. The Commission needs to test such rate design innovations to see what will encourage the most beneficial use of new DER

[94] See D. 18-08-013, at p. 109: "all existing Option R monthly peak demand charges shall be converted to daily peak distribution demand charges for Option S customers. And all existing Option R monthly part-peak demand charges shall be converted to daily part-peak distribution demand charges for Option S customers."

[95] *Ibid*., at p. 51.

technologies such as on-site storage. As the Commission stated in D. 18-08-013, at page 112: "[b]ecause daily demand charges have yet to be tested at this scale in California, it is important that we study the experience with Option S rates to determine if they optimize the behavior of customer-sited energy storage systems."

2. The Role of Demand Charges in C&I Rates, Generally

Q: Are there reasons to look more closely at the incentives that each type of rate design charge presents to C&I customers, and to move away from traditional rate elements such as the monthly demand charge?

A: Yes. It is important to understand the costs that are recovered through each type of charge and whether the structure of the charge sends the right price signal to the customer to align its consumption with the needs and marginal costs of the system.

For example, C&I rates with large demand charges traditionally have provided C&I customers with strong incentives to use electricity at high load factors. This made sense when large baseload coal and nuclear plants were the least-cost sources of electricity. Today, the California grid relies on variable wind and solar resources, with increasing amounts of short-duration battery storage expected to store excess renewable energy to meet the evening "net load" peak after the sun sets. In this world, the most valuable customers (i.e. the least expensive to serve) are the ones with the flexibility to place their load on the grid at times when renewable energy is most abundant, and to minimize their use from the grid during the 4 p.m. to 9 p.m. peak hours. Demand charges send the wrong signal to customers to use power at high load factors, without any flexibility to avoid peak hours. This of course is true of NCDCs (SCE's FRD charges), which lack any time sensitivity and which reward customers who have a constant load in every hour. But it is also true of TRD charges that may only apply during the 5-hour on-peak period. TRD charges are an improvement over NCDCs because at least they focus on high-demand hours. However, TRD charges still encourage customers to use up to their maximum 15-minute on-peak demand in every peak hour of the month. The TRD charge provides no incentive to use less peak power in any 15-minute interval except in

the interval that sets the maximum demand for the month. In contrast, an on-peak volumetric rate sends the customer a consistent signal to minimize their on-peak usage in every on-peak hour, and rewards customers who use as little power during peak hours as possible. Similarly, the on-peak daily demand charge sends a consistent signal for the customer to reduce their on-peak load every day. The accuracy of this signal can be further honed with volumetric Critical Peak Pricing (CPP) rates that target very high rates, called in advance, to the limited number of on-peak hours when system conditions are particularly challenging.

For example, with a TRD charge, a customer who has usage of 500 kW in 100 on-peak hours of the month will have the same bill for capacity as a customer who uses 500 kW in just one hour of the month. Not all on-peak hours have critically high loads, but the first customer is much more likely than the second to use power during the critical on-peak hours. In contrast to the TRD charge, with a volumetric on-peak rate (perhaps with a CPP overlay) or a daily demand charge, the first customer will pay appropriately more for his much greater and riskier use of capacity than the second customer.

Q: Are there specific adjustments to SCE's C&I rate design that SEIA recommends in this case as a means to phase out the role of demand charges, especially non-time-sensitive FRD charges?

A: Yes. SCE presently designs Option E rates for Medium and Large Power customers to recover distribution design demand revenues 60% via TOU cents-per-kWh energy charges, 30% by FRD charges, and 10% with flat, equal cents-per-kWh energy charges.[96] SEIA recommends adjusting this division in this case to 60% via TOU cents-per-kWh energy charges, 20% by FRD charges, and 20% with flat, equal cents-per-kWh energy charges.

[96] See Exh. SCE-04A, Chapter II, at pp. 8-9.

C. SCE's Vehicle-to-Grid Resource Proposal

Q: SCE's rate design testimony includes a Vehicle-to-Grid Resource Proposal (VGRP).[97] What is the purpose of the VGRP?

A: SCE's VGRP is designed to be a permanent program to integrate electric vehicles (EVs) into the grid. VGRP moves beyond initial vehicle-to-grid (VGI) pilot programs and includes provisions for compensating EV owners if they feed available energy from their EVs back into the SCE grid. Such programs have significant potential, given the large mobile storage capacity inherent in EVs[98] and the fact that most vehicles spend 95% of the time stationary. Significant progress has been made in resolving technical issues associated with exporting power from EVs to customers' homes and to the grid.[99] SEIA agrees with SCE that exports to the grid from EVs have significant potential to reduce GHG emissions during peak periods by discharging to the grid stored energy in the EV that is not needed by the driver/owner.

Q: What is SEIA's interest in the VGRP?

A: First, there is a significant overlap between solar customers and EV customers. 2021 data from discovery in R. 20-08-020 shows that 34% of customers who own an EV also have solar on their home. This was about three times the penetration of solar among all customers in California at that time.[100] Second, the addition of storage to a solar system inherently makes the solar output more valuable. Since the EV is purchased to provide

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97 See Exh. SCE-04A, at Chapter IX.

98 EVs have large batteries – for example, Tesla EVs have battery packs ranging from 60 to 100 kWh; the Ford F-150 Lightning and Rivian pickups have batteries with more than 130 kWh. See https://electricvehicles.energysage.com/?.

99 See https://www.youtube.com/watch?v=P7gCIT5FoAw. And https://www.greencarreports.com/news/1135793_california-utility-expands-bidirectional-ev-charging-pilots.

100 This percentage has grown from 27% in 2018. See R. 20-08-020, *Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association and Vote Solar* (July 16, 2021), at p. 57.

transportation, using the EV battery to provide storage for the home through a VGI system may be very low-cost source of storage, so long as its use for the home is coordinated with the customer's transportation needs. EVs also may have access to nearby public fast-charging stations where they can be re-filled while the owner is shopping or recreating, and/or to workplace charging while the owner is at work. This provides additional potential sources of energy to charge storage that a customer can use to reduce their peak usage from the grid at home and potentially to export peak power to the grid, where those exports can serve neighboring loads and thus unload the upstream portions of the grid. Third, at least one SEIA member (Sunrun) already is working with a major automotive company (Ford) to make VGI systems available to EV owners.[101]

Q: Please provide an overview of SCE's VGRP proposal.

A: Only bundled customers would be eligible for enrollment in the program, with certain exceptions. SCE would require residential customers enrolled in VGRP to subscribe to the PRIME electrification rate with aggressive TOU pricing. Customers currently enrolled in Net Energy Metering (NEM) or the Net Billing Tariff could participate in VGRP. Significantly, SCE would require all VGRP customers to have, and to pay for,[102] a separate V2G Net Generation Output Meter (V2G-NGOM) installed on their V2G equipment. The V2G-NGOM would measure the power discharged from the EV, and when compared to SCE's main retail meter, could distinguish the exports from the EV separately from exports from a customer's NEM or NBT eligible solar system and/or stationary storage installed on the customer's premises. The additional V2G-NGOM meter would be required even if the customer is not now an NBT customer, just in case the customer ever installs on-site generation in the future.[103]

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[101] See https://media.ford.com/content/fordmedia/fna/us/en/news/2022/02/02/f-150-lightning-power-play.html.

[102] See SCE response to SEIA Data Request No. 3, Q6(c), included in **Attachment RTB-2**.

[103] *Id*. See SCE response to SEIA Data Request No. 3, Q6(b).

Q: How would exports from the customer's EV be priced?

A: SCE proposes that the export compensation for EV exports would be based on a limited number of the cost components of the current ACC – essentially, the generation components of the ACC, but not including the GHG Adder component that covers the long-run resource costs of mitigating GHG emissions.[104] SCE would also aggregate these components into just eight prices for the entire year, differentiated by summer/winter, weekday/weekend, and on/off-peak, arguing that this would be a "a simple, manageable, and stable structure of export prices that is easily understandable by customers."[105]

Q: Is this export compensation reasonable?

A: No, it is not. VGRP customers who are also NBT customers would receive far less for the exports from their EVs than for exports at exactly the same time and place from their solar or solar-plus-storage systems, which are valued using all components of the ACC and a completely different set of pricing periods. It makes no sense that a kWh exported from one source (the EV) on a customer's premises somehow avoids fewer costs than a kWh exported in the same hour from another source (the solar system) on the same premises and through the same utility meter and interconnection. All of the exports – regardless of the behind-the-meter source – from a customer's premises in a particular hour avoid all of the components of the ACC for that hour. It is not just the on-site solar-generated kWh that avoid all components of the ACC.

In this regard, it is important to remember that the purpose of the ACC is to determine the utility costs avoided by any DER technology, in any hour of the year. The ACC is technology neutral; it is not designed solely for solar and stationary storage.

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[104] SCE's proposed export price would include these ACC components: (1) GHG Cap and Trade (Marginal Emissions); (2) Generation Energy; (3) Generation Capacity; (4) Ancillary Services Procurement; and (5) Losses.

[105] Exh. SCE-04A, at p.132 and Table IX-31.

Q: Does SCE offer any justification for such disparate compensation for VGRP exports versus NBT exports?

A: SCE offers no reason that makes any sense. In discovery, SEIA posed the example of a solar customer who is looking to add storage. The customer could either (1) add a stationary battery attached to its solar system, or (2) buy an EV that could interact with the grid through a VGI program such as VGRP. We asked SCE to assume that the change in the customer's exports after adding each type of storage are the same, in terms of volume and timing. Why should the pricing for those exports differ between these two options for a customer to add grid-interactive storage? In response, SCE noted that the EV could be charged from a variety of sources and responded that "the VGRP structure was designed with the lean on system level generation avoided costs and therefore a different compensation structure than a stationary battery tied to a NEM/NBT system because there is more uncertainty with the charging behavior of the EV battery" (emphasis added).[106] SCE fails to provide a reason why the time or location of EV charging makes any difference in the costs avoided by exports from the EV battery at the entirely different time when it is discharging. In fact, where or when the EV battery is charged makes no difference in the costs that SCE avoids when energy from the EV battery is exported to the grid. A kWh exported to the grid on a particular day and in a particular hour avoids all components of the ACC in that hour, regardless of the source of the kWh.

Q: Avoided T&D costs are among the avoided cost components in the ACC that would be excluded from the VRGP's export compensation. Does SCE have a convincing explanation for that exclusion?

A: No. When asked about this in discovery, SCE responded:

> NBT resources have the potential of avoiding some cost associated with the distribution and transmission grids by virtue of a paired storage system that charges the battery with solar energy. The mobility associated with EVs means

[106] See SCE response to SEIA Data Request No. 1, Q29(d); also the SCE responses to Q30(b-d). These responses are included in **Attachment RTB-2**.

> they can be charged from sources connected to the distribution and transmission systems, such level 2 or 3 charging stations or even at home overnight. It is for this reason that SCE has not associated avoided transmission and distribution costs with VGRP.[107]

SCE appears to be asserting that exports from batteries charged by on-site solar avoid T&D costs because the T&D system is not used when the batteries are charged, whereas EV batteries can be charged from numerous sources at multiple locations, and may use the grid in the hours when they are charged. The problem with this is that SCE does not avoid costs when customers import power to charge a battery. If the customer charges their EV at a fast-charging station, at work, or at home at night, they pay for their use of the T&D system at the prevailing retail rate at that time, and SCE fully recovers the T&D costs that they incur to provide that service. SCE only avoids costs in the hours when customers export power, which serves neighboring loads, allows the utility to avoid producing or buying that power, and avoids the costs of the upstream T&D system to deliver that power.

In other discovery responses, SCE tries out another dubious rationale for the disparate pricing of exports from NBT and VGRP that occur at the same time and in the same location: "[d]ue to the unpredictability of exports from an EV as compared to the predictable nature of site-specific solar generation and exports, it is a matter of such unique considerations that supports a difference in compensation for exports from EVs."[108] There is always inherent uncertainty in the early stages of a new DER technology whose performance is controlled by many customers instead of the utility directly. But such uncertainty declines quickly as customers adopt the technology and experience and data are gained on how the DER operates and on its impact on the grid. That is what happened when customers first added on-site solar under NEM. Compared to VGRP, there are similar uncertainties today in how residential customers operate their on-site stationary storage – customers do not have to cycle their storage, and can choose

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107 See SCE response to SEIA Data Request No. 1, Q30(c), included in **Attachment RTB-2**.

108 See SCE response to SEIA Data Request No. 3, Q9(b,c), included in **Attachment RTB-2**.

simply to keep the battery full to provide the maximum amount of backup power in the event of a grid outage. Yet, despite this uncertainty, exports from paired storage are compensated at the full NBT export rate. With respect to VGRP, SCE is not completely in the dark – the utility will know where the exports will take place – at the customer's premises. SCE also can expect that the EV usually will be charged at the customer's premises or nearby (although how that impacts the value of exports is unclear), because it will be rare that an EV driver will bring home excess kWh from a trip where the EV was charged a significant distance away. SCE can also expect that exports will occur when the power is most valuable, as signaled by NBT pricing. SCE should gain experience quickly in the extent to which VGRP customers are willing and able to export excess kWh from their EVs. Finally, data on expected program performance may already be available from the results of V2G pilots.

Q: Will SCE's proposal for lower compensation for exports under VGRP discourage customers from signing up for the program?

A: Yes. Assume an NBT customer with a solar-plus-storage system also has an EV that it could sign up to participate in SCE's VGRP. Solar customers should be a key market for the VGRP, as they are more likely already to have an EV or to be interested in buying one, and NBT solar customers already are on the TOU-D-PRIME electrification rate. The NBT customer can use their solar output to charge both the stationary battery and the battery in the EV. But such a customer is unlikely to participate in VGRP due to the lower export rate, and will focus on programs to export just from the stationary battery at the full NBT export rate. SCE's attempt to explain to the customer why their solar and EV exports at the same time through the same interconnection should be priced differently will be no more convincing and no less confusing to a customer than they are on the record of this case.

Q: Does SEIA recommend that the export pricing under the VGRP should be the same as export pricing under the NBT, and thus should use the same components of the

ACC and the same month/weekday-weekend/hour-of-the-day pricing structure as the NBT?

A: Yes, that is SEIA's recommendation.

Q: In addition to how VGRP exports are compensated, do you recommend any other changes to the VGRP?

A: Yes. Here are the other areas of the VGRP of concern to SEIA.

V2G-NGOM Requirement. The requirement that all VGRP customers install a separate V2G-NGOM may have the result of prohibiting innovative V2G configurations and will increase costs, by ruling out system designs where both the solar and the bi-directional EV are DC-connected and can share the same inverter. Further, NGOM installation can create serious delays due to the need for the utility to schedule the time to perform the work. For this program to be successful at scale, there needs to be a clearly-defined, expedited, low-cost process for V2G interconnection.

SEIA believes that there are few circumstances in which the additional V2G-NGOM should be required as a condition on participation in the VGRP. If SEIA's recommendation on export pricing is adopted, such that VGRP and NBT exports have the same pricing, there is no need for the separate V2G-NGOM for NBT customers. SEIA also recommends that NEM 1 and 2 customers who wish to participate in VGRP have the option to avoid the cost and hassle of V2G-NGOM installation if they agree to move to NBT pricing for all exports, from both their solar system and their EV. SEIA also does not understand why a V2G-NGOM is needed for a customer who has standalone stationary storage, but no on-site generation. So long as the export compensation does not exceed avoided costs, there would be no harm to other ratepayers even if the stationary storage contributes to exports along with the bi-directional EV. Finally, a V2G-NGOM is not needed for customers who have no on-site generation or storage at all. The only reason that SCE advances for such customers needing a V2G-NGOM is to be prepared in case, one day in the future, they install solar and become NBT

customers.[109] Obviously, such a need goes away if NBT customers do not need a V2G-NGOM, as would be the case under SEIA's recommended export pricing.

There are just a few circumstances in which the V2G-NGOM is necessary and can be required. One is if a NEM 1 or 2 customer wishes to participate in VGRP but also wants to retain their legacy export pricing under NEM 1 and 2. The V2G-NGOM is needed in this case to distinguish NEM and EV exports that are priced differently. A second circumstance is if a customer is a NEM or NBT Multiple Tariff Generating Facility[110] that includes both NEM or NBT-eligible generation and non-eligible generation, where the customer is required to have a NGOM on the NBT or NEM system.

Annual credit forfeiture. SCE proposes that customers must forfeit VGRP credits that remain unused at the end of a calendar year, without being able to offset non-energy and non-bypassable charges.[111] There is no stated rationale or logical purpose for this provision – it simply means that a VGRP customer might receive no compensation at all for a portion of the valuable peaking power that it supplied to the grid. This also will create confusion for NBT / VGRP customers that would be on different true-up schedules for each program. Further, because VGRP exports are an additional service that the customer is providing to the utility and because VGRP exports do not offset any retail rate, the compensation for this service should be able to offset any charges that the customer would pay to the utility for any service that the utility provides. If VGRP credits remain at the end of the year after all utility charges have been offset, the utility should send the VGRP customer a check for the remaining credits.

Available to unbundled customers. SEIA also supports extending the VGRP to both bundled and unbundled customers, just as the NBT's full ACC-based export pricing

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109 Exh. SCE-04A, at pp.130-131.

110 As defined in Special Condition 1 of SCE's NEM and NBT tariffs.

111 See Exh. SCE-04A, at p. 133: "VGRP credits may carry over month-to-month, however, will not be applied to non-energy and non-bypassable charges. The VGRP credits will also not carry over into a new calendar year. Any credits left over after December 31st will be forfeited.

is available to both bundled and unbundled customers.[112] The generation-related portion of the VGRP export rate should be credited against the generation portion of the customer's bill, while the delivery elements of the VGRP export rate should be credited against the customer's delivery charges.

D. The Design of SCE's FERC Transmission Rates

Q: Please describe the design of SCE's present FERC-regulated transmission rates.

A: SCE's transmission rates generally are flat volumetric rates for small customers and NCDCs for medium and large C&I customers.

Q: As a threshold matter, SCE's transmission rates are FERC-jurisdictional and are not subject to this case. Please be clear about the purpose of these comments on SCE's transmission rate design and what you are proposing that the Commission should do in this proceeding on this topic.

A: This Commission represents the interests of the citizens and ratepayers of California in transmission rate cases before the FERC, and thus participates actively in SCE's transmission rate cases. SEIA expects that the Commission is interested in a broad range of input from the parties to this case, all of whom have a strong interest and expertise in electric rate design, to inform its representation of the state of California before the FERC in SCE's transmission rate cases. California rate design proceedings such as this one are logical public forums in which knowledgeable and interested parties should be encouraged to provide input to the CPUC on FERC transmission rate design, and in particular on the impacts which FERC rate design may have on the design of CPUC-jurisdictional rates, and vice versa. The parties to this case all have a strong interest and expertise in electric rate design, but many parties lack the resources to intervene in Washington before the FERC in transmission rate cases. SEIA believes that both the Commission's deliberations in this case and its advocacy before the FERC on behalf of

[112] See D. 22-12-056, at pp. 143-144 and 147.

the broad interests of the entire state of California benefit from input from a broad cross section of California parties on rate design issues that impact all components of SCE's electric rates, both CPUC- and FERC-jurisdictional.

SEIA reiterates that it is not proposing that the Commission should do anything about the design of SCE's FERC transmission rates in this case, unless, in the context of a settlement in this case, the Commission is presented with a proposal from the parties that includes commitments from SCE to take certain actions before the FERC on the design of its transmission rates. For example, at times in the past, CPUC dockets (including Phase 2 cases) have been the forums for reaching settlements with California IOUs in which the IOU has agreed to propose to the FERC certain changes in its transmission rates.[113] For example, in D. 18-05-040 in the Transportation Electrification (TE) dockets (A. 17-01-020 *et al*.), the Commission adopted a stipulation under which SCE would seek to implement commercial EV charging rates – Schedules TOU-EV-7, TOU-EV-8, and TOU-EV-9 – with all-volumetric rates, including the FERC-regulated transmission rates, for an initial five-year period. After the initial five-year period, the commercial EV rates would transition to a design that includes transmission costs allocated 30% to volumetric rates and 70% to demand charges.[114] SCE subsequently made the necessary FERC filings to implement the initial all-volumetric transmission rates for commercial EV customers, which remain in effect today.

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[113] See, for example, A. 15-04-012, "Joint Supplemental Testimony of Cynthia Fang on behalf of San Diego Gas & Electric Company, R. Thomas Beach on behalf of the Solar Energy Industries Association, Maurice Brubaker on behalf of the Federal Executive Agencies, and William A. Monsen on behalf of the City of San Diego" (dated November 14, 2016), at p. 2. Also see A. 11-10-002, "Motion of San Diego Gas & Electric Company and Settling Parties to Adopt Partial Settlement Agreement on Distribution Demand Charges for Medium and Large Commercial and Industrial Customers and for a Shortened Response Time and Modified Comment Procedures" (filed October 19, 2012), at Attachment A, pp. 3-5.

The CPUC requires that settlements and decisions are supported by the record in the case, and in past Phase 2 cases SEIA has offered its views on IOU transmission rates to develop a record if such a settlement were to materialize.

[114] See D. 18-05-040, at pp. 112-115, approving a stipulation under which SCE would file with the FERC to implement transportation electrification rates that allocate 30 percent of transmission costs to volumetric rates and 70 percent to demand charges.

Moreover, D. 18-05-040 extended the Commission's policy direction as follows: "Further, any introduction of time-dependent transmission rates should not be limited to EV rates but should encompass non-residential transmission rates generally."[115] In its testimony in A. 20-10-012 and in response to discovery from SEIA in that case, SCE stated that its calculation of marginal transmission costs "is a first step towards establishing a basis of marginal costs that can be used to better inform the design of retail transmission rates." Further, in discovery in A. 20-10-012, SCE stated its intention at that time to make the necessary FERC filing to accomplish these transmission rate design changes in the near future, with the filing submitted by March 1, 2022.[116]

Q: Has SCE carried through on this indication of an intention to reform the design of its transmission rates?

A: No, it has not. Discovery in this case indicates that SCE has backed away from the intentions to reform its transmission rate design that it indicated in the TE dockets and in its last Phase 2 case. SCE now states that "SCE has not formed a general position on how transmission rates should be time differentiated for use in default rate structures."[117] SCE does indicate that it expects to seek FERC approval for the time-and load-differentiated transmission rate that is included in the application that it filed on December 20, 2024 for approval of a set of dynamic rates.[118]

Q: Should the design of SCE's transmission rates be changed?

A: Yes. The transmission component in SCE's residential and small commercial rates should be re-designed to be a combination of on-peak and mid-peak volumetric TOU rates to recover capacity-related transmission costs, plus a flat volumetric rate to recover

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115 See D. 18-05-040, at p. 114.

116 See A. 20-10-012, Exh. SCE-02, at p. 7; also, SCE response to SEIA Data Request No. 1, Q20(c), in A. 20-10-012, which is included in **Attachment RTB-2**.

117 See SCE response to SEIA Data Request No. 1, Q16(a), also SCE responses to Q13(a,f) and Q15(a,b,c), all of which are included in **Attachment RTB-2**.

118 See SCE response to SEIA Data Request No. 1, Q15(c), included in **Attachment RTB-2**.

the non-time-dependent portion of transmission costs. For C&I rates, the transmission component should be re-designed to eliminate NCDCs in favor of a combination of on-peak volumetric TOU rates or TRD charges to recover capacity-related costs, plus flat volumetric rates to recover the remaining non-time-dependent portion. For the reasons discussed above, I recommend the use of volumetric TOU rates in preference to TRD charges. For Option S rates, capacity-related transmission costs should be included in the daily demand charge.

Q: Please comment on the 30% / 70% split in the transmission revenues recovered in (1) volumetric rates versus (2) demand charges, which the Commission favored in D. 18-05-040.

A: D. 18-05-040 is unclear on the basis for this 30% / 70% split, which was the product of a settlement focused on the needs of commercial EV customers. Moreover, a split between volumetric rates and demand charges is not a cost causation study; it does not indicate what portion of SCE's transmission costs are time dependent. SCE's marginal transmission capacity costs of about $73 per kW-year indicate that SCE's capacity-related transmission costs may be a large portion of its transmission costs, as SCE's marginal capacity-related transmission revenues exceed its transmission revenue requirement.[119] Capacity-related transmission costs clearly are driven by peak system demands. For these reasons, SEIA supports the recovery of SCE's transmission costs primarily through on- and mid-peak volumetric TOU rates or time-related demand charges.

Q: Why should NCDCs not be used in C&I rates to recover the non-time-dependent portion of transmission costs?

A: The portion of transmission costs that is not related to demand is not driven in any way

[119] At $73 per kW-year and assuming a coincident peak demand of 24,000 MW, SCE's marginal capacity-related transmission revenues are $1.75 billion per year, compared to SCE's transmission revenue requirement of $1.4 billion per year.

by the individual, non-coincident peak demands of customers. A better metric for these costs is a customer's kWh usage, because every kWh delivered uses the transmission system. Thus, a flat per kWh charge for these costs that are not demand- or time-related is a more equitable way to measure each customer's relative use of the transmission system.

Q: Does this conclude your testimony in this case?

A: Yes, it does.

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.*

88. Prepared Direct and Rebuttal Testimony on behalf of **Calpine Corporation** (A. 17-11-009 – July 20 and August 20, 2018)

    - *Gas transportation rates for electric generators, gas storage and balancing issues*

89. Prepared Direct Testimony on behalf of **Gas Transmission Northwest LLC** and the **City of Palo Alto** (A. 17-11-009 – July 20, 2018)

    - *Rate design for intrastate backbone gas transportation rates*

90. Prepared Direct Testimony on behalf of **EVgo** (A. 18-11-003 – April 5, 2019)

    - *Electric rate design for commercial electric vehicle charging*

91. Prepared Direct and Rebuttal Testimony on behalf of **Vote Solar** and the **Solar Energy Industries Association** (R. 14-10-003 — October 7 and 21, 2019)

    - *Avoided cost issues for distributed energy resources*

92. Prepared Direct and Rebuttal Testimony on behalf of **EVgo** (A. 19-07-006 – January 13 and February 20, 2020)

    - *Electric rate design for commercial electric vehicle charging*

93. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 19-03-002 — March 17, 2020)

    - *Electric rate design issues for solar and storage 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

2. Direct 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 – 2018; Docket E-100 Sub 158; June 21, 2019)

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

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).

    - *Resource value of solar resources in Oregon*

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

Selected Data Responses from SCE

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Jacob P Narvaez
Job Title: Associate Specialist
Received Date: 12/4/2024

Response Date: 12/17/2024

Question 13.a,f:
In SCE's last GRC Phase 2 (A. 20-10-012), SCE provided an exemplary calculation of SCE's CAISO-level transmission marginal costs of $54.93 per kW-year, presented in A.20-10-012, Exh. SCE-02, Appendix F.

a. Please explain why SCE has presented no similar calculation of its marginal transmission costs in this case.

f. Please provide SCE's own estimate of its demand-related marginal transmission cost, and the workpapers supporting SCE's recommended value.

Response to Question 13.a,f:

In response to question 13.a, the transmission capacity cost study reflected in SCE-02, Appendix F, of SCE's 2021 GRC Phase 2 was developed solely for illustration purposes to meet the requirements outlined in Decision (D.)18-05-040[1] on the Transportation Electrification Standard Review Projects. Costs presented in that Study were not adopted for cost allocation or rate design in the 2021 GRC. Since the study was not continuing in nature and is not used for rate-setting purposes in this proceeding, a similar study was not developed for SCE's 2025 GRC Phase 2 application.

In this Application SCE does not have an estimated value for transmission marginal cost, supporting workpaper, or recommended value for reasons explained in question 13.a.

[1]Application for Approval of SB 350 Transportation Electrification Proposals (A.17-01-020, A.17-01-021, A.17-01-022)

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Jacob P Narvaez
Job Title: Associate Specialist
Received Date: 12/4/2024

Response Date: 12/17/2024

Question 14.a-f:
This request seeks to obtain the data needed to update SCE's marginal transmission cost calculation presented in A. 20-10-012, SCE-02, Appendix F. See the white colored tabs in SCE's "GRC 2021 SCE-02 Distribution Streetlight Workpapers.xlsm" workpaper in A.20-10-012. That workpaper is attached.

a. Please provide SCE's current cost of capital structure from a recent FERC TO filing. The 2021 GRC values used were as follows:

Cost of Captial (FERC Filing TO2020)			
	Capital Ratio	Cost Factor	Weighted Cost
Debt	44.4%	4.68%	2.08%
Preferred Stock	8.1%	5.71%	0.46%
Common Equity	47.5%	12.47%	5.92%
Transmission Discount Rate	**100%**		**8.46%**

b. Please provide 2020-2023 annual Transmission Plant data from FERC Form 1 in order to update the "Plant Study" tab. We understand that this includes annual cost data for FERC accounts 350-359.1.

c. From the FERC Form 1 data provided in Q13(b), please provide the ISO portion of the transmission plant costs, similar to SCE's prior analysis, to "expand upon FERC Form 1 balances to show plant balances by asset type and voltage across FERC Transmission accounts." (See page F-1). See rows 24-47 of the "Plant Study" tab, which provides ISO costs that are a portion of the Total Transmission Plant data from FERC Form 1 shown in rows 5-22.

d. Please provide the 2024-2027 annual forecasted transmission plant costs, similar to the 2020-2023 annual forecasts that were included in SCE's 2021 GRC workpaper (i.e. the tabs "2020 Forecast" through "2023 Forecast", etc.).

e. Please provide updates, for 2020-2023, of SCE's FERC/ISO related O&M and general plant loaders. We understand SCE used values of $3.57 per MWh for O&M and 6.7% for the general plant loader in its last GRC. See cells H15:I16 on the "Regression" tab of SCE's 2021 GRC workpaper referenced above.

f. Please provide updates to SCE's historical (2020-2023) and forecast (2024-2026) transmission capacity by year, as shown in column k (500 kV AA Bank Capacity in 2010-2023) of the "Regression tab" in SCE's 2021 GRC workpaper

Response to Question 14.a-f:

In response to question 14.a-f, these question are outside of the scope of SCE's 2025 GRC. The transmission capacity cost study reflected in SCE-02, Appendix F, of SCE's 2021 GRC Phase 2 was developed solely for illustration purposes to meet the requirements outlined in Decision (D.)18-05-040[1] on the Transportation Electrification Standard Review Projects. Since the study was not continuing in nature and is not used for rate-setting purposes in this proceeding, a similar study was not developed for SCE's 2025 GRC Phase 2 application.

[1]Application for Approval of SB 350 Transportation Electrification Proposals (A.17-01-020, A.17-01-021, A.17-01-022)

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Berton Hansen
Job Title: Senior Advisor
Received Date: 12/4/2024

Response Date: 12/17/2024

Question 15.a-b:
At page 7 of Exh. SCE-02 in A. 20-10-012, SCE states that its transmission marginal cost study in that case "… is a first step towards establishing a basis of marginal costs that can be used to better inform the design of retail transmission rates."

a. Please provide any FERC transmission rate design changes that SCE has proposed and had approved by the FERC since submitting that testimony in A.20-10-012. If SCE has proposed and implemented any transmission rate design changes over that period, please provide those FERC transmission rate filings.

b. Please discuss whether any other parties to SCE's recent transmission rate filing(s) before the FERC (including the CPUC) have proposed rate design changes that were rejected by the FERC or that are pending before the FERC.

Response to Question 15.a-b:

a. SCE has not proposed any changes to the retail transmission rate design, as reflected in SCE's Formula Rate, Schedule 33, since the A. 20-10-012 proceeding.

b. No other entity, including parties to SCE's recent transmission rate filings, have proposed rate design changes to SCE's Formula Rate in a FERC proceeding.

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Dan Tang
Job Title: Senior Advisor
Received Date: 12/4/2024

Response Date: 12/17/2024

Question 15.c:
At page 7 of Exh. SCE-02 in A. 20-10-012, SCE states that its transmission marginal cost study in that case "… is a first step towards establishing a basis of marginal costs that can be used to better inform the design of retail transmission rates."

c. Please specify whether SCE has plans for changes to its FERC transmission rate design that it is planning to propose to the FERC. If so, when will SCE propose those changes?

Response to Question 15.c:
c) Currently, SCE has no pending submission of a filing to FERC proposing changes to its retail transmission rate design.

Pursuant to the requirements of CEC's Load Management Standards, on October 2, 2023, SCE filed its 2023 Load Management Standards Compliance Plan (Compliance Plan) that, among other things, demonstrates compliance with the requirements of Title 20, California Code of Regulations (CCR) Sections 1621 and 1623. SCE anticipates that modifications to the submitted Compliance Plan will be filed as the proceeding timelines at the CPUC and the FERC unfold. This preliminary plan includes a general description of the interaction with FERC's regulatory procedures necessary to effectuate changes to Transmission Retail Rate Design. Figure 1 presents a preliminary timeline for a rate design application at the FERC.

SCE Filing to Docket 23-LMS-01; Load Management Standards Implementation: **23-LMS-01 SCE 2023 Load Management Standards Compliance Plan**

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Reuben Behlihomji
Job Title: Rates Manger
Received Date: 12/4/2024

Response Date: 12/17/2024

Question 16.a-c:
In D.18-05-040 in the consolidated Transportation Electrification dockets (A.17-01-020 et al.), at pp. 113-114, the Commission directed SCE to take steps to move its transmission rate design toward less reliance on non-coincident demand charges and a greater reliance on volumetric rates differentiated by TOU period, because TOU volumetric rates "will enable customers to appropriately see a portion of transmission costs in the TOU rates which will provide customers further incentive to charge during the off-peak or super off-peak instead of the on-peak period." This order also stated that "any introduction of time-dependent transmission rates should not be limited to EV rates but should encompass non-residential transmission rates generally."

a. Please explain why, notwithstanding D. 18-05-040 and California's state policy goals to support electrification, SCE's residential and non-residential transmission rates remain today either (1) 100% non-coincident demand charges or (2) 100% volumetric rates with no time differentiation. This includes SCE's commercial EV rates.

b. Please discuss what steps SCE has taken since 2018 to implement the policy direction in D. 18-05-040. Has SCE proposed time-differentiated transmission rates that the FERC has rejected?

c. What is SCE's current position on whether a calculation of its marginal transmission costs, and understanding the time dependence of those marginal costs, would "better inform the design of retail transmission rates."

Response to Question 16.a-c:

a. SCE's Transmission Retail rates are designed and set based on allocation and design principles approved and adopted by the FERC. Transmission retail rates are set based on Schedule 33 that uses a 12 monthly coincident peak (12-CP) methodology for allocating costs to rate groups and a non-coincident demand and energy rate structure for recovering those costs; demand charges for demand metered rate groups; and energy charges for non-demand metered rate groups.

   Costs expended on the Transmission network are primarily expended in support of the State's goals for decarbonizing the grid; optimizing the use of that network to enable the economic transmission of power from generation supply resources to load pockets; relieving congestion when transmitting such power (such costs are currently included in Marginal Energy Costs); ensuring that the system has the reliability to support normal operating conditions and conditions when contingencies arise, namely N-1 contingencies and N-2 contingencies; and supporting the resiliency of the transmission grid during resilience events. Of these five functions, arguably only one of the five functions is time-dependent.

   Pursuant to CPUC Decision D.18-05-040, SCE presented a transmission cost causation

study in the its 2021 GRC Phase 2; however, the results of the study were not adopted or utilized in the design of Transmission retail rates by any party in the proceeding. Because of the complexity, breadth of use, as described above, and the network nature of the Transmission network, SCE has found that there are many unique considerations that can affect how Transmission costs can be differentiated as time-varying or not and can change every day depending on how power-flows are planned for and effectuated on the network. Therefore, SCE has not formed a general position on how transmission rates should be time differentiated for use in default rate structures. With respect to optional rates, in SCE's 2016 Rate Design Window (RDW) Application (A.16-09-003) and more recently in SCE's Large Power Dynamic Pricing Rate Application, SCE has presented simpler approaches that utilize the FERC's 12-CP load approach in determining simpler proxies for differentiating Transmission cost recovery between Time-Varying and Non-Time varying, but such approaches have not been vetted or adopted yet by the CPUC, and therefore have not as yet been presented to the FERC for ultimate approval.

In the past SCE has adopted the use of a Single Issue 205 filing at the FERC to request approval of Transmission Retail Rate designs that have been vetted in a CPUC proceeding and then adopted by a CPUC Decision.

b. Please see response to 16.a. SCE has not presented time-differentiated transmission rates at the FERC. On November 20, 2018, SCE filed a Single Issue 205 Filing (ER19-374) for SCE's current all-energy EV rates, seeking an effective date of January 21, 2019. Changes to Schedule 33 (retail rate calculation) were accepted by FERC in an order issued January 10, 2019.

c. Please see response to 16.a. SCE supports analysis that expands the conceptual understanding of Transmission Costs and its use in the design of retail rates and notwithstanding the complexity of the analysis discussed in 16.a, has presented simpler proxies to further that understanding.

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Andre Ramirez
Job Title: Senior Advisor
Received Date: 12/4/2024

Response Date: 12/16/2024

Question 19:
Please provide a comparison of: (a) the peak-to-off-peak (POP) rate differences in SCE's default residential rate, and (b) the POP differences in this rate if the differences reflected SCE's fully scaled marginal costs.

Response to Question 19:

Please find the requested information in the attachment provided in response to Question 18, **Column L**, highlighted in blue. Please note both the scaled and unscaled marginal cost based rates do not include a baseline credit and commensurate baseline allocations as the baseline credit structure does not align with marginal costs.

Southern California Edison
A.20-10-012 – 2021 General Rate Case Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 1 - T B

To: SEIA
Prepared by: Alexander Echele
Job Title: Rate Design, Sr. Specialist
Received Date: 5/10/2021

Response Date: 5/24/2021

Question 20.a-c:
At page 7 of SCE-02, SCE states that its transmission marginal cost study "… is a first step towards establishing a basis of marginal costs that can be used to better inform the design of retail transmission rates." Please provide any new FERC rate designs that SCE has developed to date:

a. Please discuss whether SCE has proposed any changes to the design of its transmission rates in its recent transmission rate filings before the FERC. If SCE has proposed any rate design changes, please provide those FERC transmission rate filings, and provide the status of those cases.

b. Please discuss whether any other parties to SCE's recent transmission rate filing(s) before the FERC have proposed rate design changes that are pending before the FERC.

c. Please specify whether SCE has plans that it is willing to share now about changes to its FERC transmission rate design that it is planning to propose to the FERC. If so, when will SCE propose those changes?

Response to Question 20.a-c:
SCE objects to the instruction stating that the data request is "continuing in nature" on the grounds it is unduly burdensome. Subject to and without waiving this objection, SCE responds as follows:

a. In FERC Docket No. ER19-374, SCE proposed changes to Schedule 33 of its then-effective Formula Rate to create three new voluntary, optional volumetric rates—Commercial EV Rates TOU-EV-7, TOU-EV-8, and TOU-EV-9—consistent with CPUC Decision (D.)18-05-040.[1] Please see the attached FERC Filing Letter for details. FERC approved the proposed changes by Letter Order issued January 10, 2019. In FERC Docket No. ER19-1149, SCE sought to update Retail Rate Schedules identified in Schedule 33 to SCE's Formula Spreadsheet to conform to the retail rate schedules recently adopted by the CPUC in SCE General Rate Case Phase 2 Order. Please see the attached FERC Filing Letter for details. FERC approved this filing by Letter Order issued April 15, 2019. For additional historic filings, please see: https://www.sce.com/regulatory/open-access-information?from=/openaccess.

b. No other parties in SCE's recent transmission filing(s) before the FERC have proposed rate design changes that are pending before the FERC.

c. As established in D.18-05-040, and discussed in Exhibit SCE-02 at p. 7, SCE intends to file

[1] D.18-05-040.

a single-issue Section 205[2] filing to revise its FERC-jurisdictional Formula Rate's determination of retail transmission rates to reflect changes to retail rate design consistent with D.18-05-040. Such a filing must conform to Section 8 of SCE's Formula Rate Protocols, which provides in pertinent part:

> SCE may make a single-issue Section 205 filing to change the Formula Rate as provided in Section 8, part (f). The Commission is not limited in its ability to review the entirety of any filing made by SCE in compliance with this Section 8 of the Formula Rate Protocols.
> …
> In a proceeding commenced by a single-issue filing under Section 8, part (f), the sole issue which may be contested is whether the changes proposed by SCE are just and reasonable. The proceedings commenced in response to the filings described in this Section shall not include or allow for consideration or examination of any other aspects of the Formula Rate or other issues associated with the Formula Rate, except to the extent that the proposed changes directly impact other Formula Rate components that are not the subject of the single-issue filing. All parties will have all applicable rights under the Federal Power Act and FERC's regulations with respect to such single-issue Section 205 filings, except as limited by this Section 8.
> …
> f) SCE may make a single-issue Section 205 filing to revise the Formula Rate determination of retail transmission rates to reflect changes to retail rate design pursuant to CPUC Order D.18-05-040 at any time, requesting an effective date of not less than 60 days from the date of filing. Thirty days prior to making this single-issue Section 205 filing, SCE will notify the CPUC and meet and confer with the CPUC regarding the contents of the filing.[3]

SCE currently anticipates making this filing not later than March 1, 2022. Please note that, pursuant to a settlement adopted in FERC Docket ER19-1553, SCE shall not make any unilateral filings under Section 205 to revise its Formula Rate that seek an effective date prior to January 1, 2022.

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[2] 18 CFR § 385.205.

[3] SCE's Formula Rate is available at: https://www.sce.com/regulatory/open-access-information?from=/openaccess. SCE's Formula Rate Protocols are Attachment 1 to Appendix IX of its Transmission Owner (TO) Tariff. SCE's Formula Spreadsheet is Attachment 2 to Appendix IX of its TO Tariff.

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Blake Evan Heidenreich
Job Title: Advisor
Received Date: 12/4/2024

Response Date: 12/16/2024

Question 29.a-d:
Assume that an SCE customer with a solar-only system (NEM or NBT) purchases an EV with bidirectional capability, and then operates the EV in such a way that the volume of the customer's exports decreases (due to the added EV charging load and to losses in the EV battery), but the timing of the exports changes from the mid-afternoon to the evening.

a. Would this customer be required to be on the VGRP tariff?

b. Does SCE agree that this customer would not violate any NEM or NBR export restrictions, assuming they were in compliance with such restrictions before buying the EV?

c. How would SCE distinguish between such a customer purchasing a bi-directional EV versus adding a stationary battery?

d. If the change in a solar customer's exports (volume and timing) are the same between (i) adding a bi-directional EV versus (ii) adding a stationary battery, why should the export pricing differ between these two circumstances?

Response to Question 29.a-d:

a. Yes, the customer would be required to be on VGRP.
b. If the customer was on VGRP and was not violating any NEM or NBT export restrictions, then yes. In this example, the timing of exports changes after purchasing the EV and it is assumed that the evening exports would come from the EV, therefore the customer would need to be on VGRP to not violate export restrictions.
c. A customer would need to declare the device that they are interconnecting to the grid. This declaration would happen during interconnection through Rule 21 and getting on VGRP. The NGOM requirement of VGRP would then help distinguish the energy associated with VGRP. Without such a distinction, the standalone storage and EV exports would be limited to the existing rules regarding standalone storge exports.
d. A stationary battery paired with solar is eligible under NEM and NBT. An EV is not eligible under NEM or NBT. Because of the decentralized nodes available for EV charging, it is impossible to ascertain the specific charging timing and volume of a customer with EVs – so in this case the question assumes that the customer is using their NEM/NBT system to charge the EV but that may not always be the case as the customer also has the option to charge at an away-from home site, and additionally may be charging overnight. When designing the VGRP structure SCE assumes that the decentralized network of

charge/discharge nodes in SCE's service territory does not allow for traceability in the amount and timing of each charge to the corresponding discharge. As such the VGRP structure was designed with the lean on system level generation avoided costs and therefore a different compensation structure than a stationary battery tied to a NEM/NBT system because there is more uncertainty with the charging behavior of the EV battery. Additionally, VGRP was developed to apply to all EV exports to the grid, not just those that are collocated with a NEM/NBT system.

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 1

To: SEIA
Prepared by: Blake Evan Heidenreich
Job Title: Advisor
Received Date: 12/4/2024

Response Date: 12/17/2024

Question 30.a-e:
SCE proposes that the export rate for the VGRP will be different than NEM or NBT export rates.
a. Please confirm that the TOU structure will be different than NBT export rates, and the rate itself will use fewer components of the Avoided Cost Calculator than are used in the NBT export rates. See page 133.
b. If a VGRP/NBT customer is exporting power at the same time from both the NBT system and from the EV, please explain why the pricing for these exports should be different for the NBT exports than the EV exports. Please explain why the NBT exports in a particular instant of time will avoid a different level of costs on the SCE system than the exports from the EV in the same instant.
c. Please explain why NBT exports avoid transmission and distribution costs, but VGRP exports (esp. from 6 to 9 p.m. in summer months) would not.
d. How will SCE explain to the customer the bifurcated export pricing for NBT vs. VGRP?
e. Does SCE acknowledge that this disparate export pricing may cause customer confusion?

Response to Question 30.a-e:

a. The VGRP export will be different than the NBT export rate. The VGRP export rate will have a peak period (6 p.m. to 9 p.m.) when compared to SCE's 4 p.m. to 9 p.m. TOU period. The VGRP export rate is based on the subset of system level generation-only components of the ACC.
b. NBT includes solar paired storage energy for eligible equipment. Because of the EV's mobility, the EV may have been charged from sources other than the solar system such as power from a charging station connected to the grid. Therefore, the energy in the EV will not have the same avoided cost attributes as the solar paired storage system.
c. NBT resources have the potential of avoiding some cost associated with the distribution and transmission grids by virtue of a paired storage system that charges the battery with solar energy. The mobility associated with EVs means they can be charged from sources connected to the distribution and transmission systems, such level 2 or 3 charging stations or even at home overnight. It is for this reason that SCE has not associated avoided transmission and distribution costs with VGRP.
d. The explanations will center on the fact that EVs are mobile and can be charged from a variety of sources that are directly connected to the transmission and distribution grids.
e. SCE believes the differences between NBT and VGRP compensation can be explained with

the appropriate level of ME&O engagement.

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 2

To: SEIA
Prepared by: Joe Herrera
Job Title: Senior Advisor
Received Date: 12/13/2024

Response Date: 12/26/2024

Question 01.a-f:
Page 22 of Exh. SCE-02A discusses the data used in the regression analysis that determines SCE's proposed marginal distribution demand costs (MDDC). SCE states that it

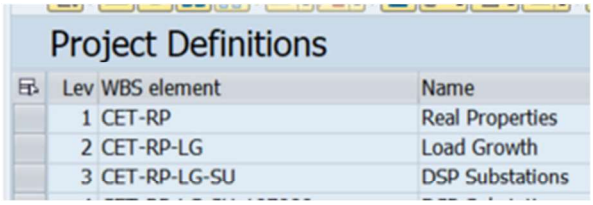
…relies on SCE's FERC 1 Form 1 (FF1) filings, which categorize capital expenditures by asset type as outlined in Table I-8. For historical years, SCE applies an adjustment factor to the capital additions reported in its FF1 to estimate the portion of total capital expenditures related to load growth activities. For forecast years, load growth capital expenditures are based on workpapers that supplement SCE's Load Growth, Transmission Projects, and Engineering testimony in A.23-05-010 (SCE-02, Vol. 07).

Footnote 22 to this passage states that "[o]nly projects identified as load growth projects are considered. All projects not related to load growth (i.e., grid reliability, infrastructure replacement projects, grid modernization, etc.) are excluded from this analysis."

a. Please provide the specific written criteria that SCE personnel use to categorize transmission or distribution projects as "load growth" versus "grid reliability," "infrastructure replacement," "grid modernization", and all other categories included in the "etc" in this quote.
b. Please provide the complete derivation of the "adjustment factor to the capital additions reported in its FF1" for all years in SCE's regression analysis. SEIA does not believe that SCE's workpapers include the derivations of these factors.
c. SCE's regression analysis only uses the factors for the percentage of SCE's T&D capital additions that are "load growth" related. Please provide the similar factors for all other categories used by SCE to categorize historical T&D capital additions, e.g. "grid reliability, infrastructure replacement projects, grid modernization, etc."
d. If a project to replace a piece of distribution or transmission infrastructure at the end of its useful life also results in an increase in SCE's transmission or distribution capacity, please explain whether SCE categorizes this project as "load growth" or "infrastructure replacement." If SCE divides the cost of such a project between these two categories, please explain how SCE does this.
e. If a "grid modernization" project also results in an increase in SCE's transmission or distribution capacity, please explain whether SCE categorizes this project as "load growth" or "grid modernization." If SCE divides the cost of such a project between these two categories, please explain how SCE does this.
f. In general, please explain how SCE considers and categorizes projects that have multiple purposes, such that they fit into more than one of these categories.

Response to Question 01.a-f:
a. SCE personnel leverage SAP master data available for each cost object/WBS (work

breakdown structure) to identify and categorize work. The distinction of Transmission vs Distribution is also based on SAP master data and identified by the attribute, "Asset Class." In this example below, work identified for DSP (Distribution Substation Plan) Substations would be considered new load growth. A similar work categorization is leveraged to inform the GRC rate case structure.



Project Definitions

Lev	WBS element	Name
1	CET-RP	Real Properties
2	CET-RP-LG	Load Growth
3	CET-RP-LG-SU	DSP Substations

If additional project specific information is available to classify work, it may be taken into consideration to determine new capacity or replacement.

b. Please see attached excel files for the complete derivation.

c. Please see attached excel files for the complete derivation. These files include the classification for all capital expenditures by cost object by year.

d. SCE has not divided the cost of cost object into load growth and infrastructure replacement, or any categorization. The classification is primarily based on SAP master data and a classification is assigned based on the type of work. While project specific information may be taken into consideration to add accuracy where available, the classification by SAP master data is an effective way to identify type of work for the volume of cost objects included in CapEx details.

e. As mentioned in the response to question "d," SCE does not divide the cost between categorizations, nor for 'load growth' vs 'replacement' classification. The SAP master data only allows for a single categorization/description of the type of work, and a classification is assigned based on that description of work in the context of the cost object hierarchy in SAP.

f. The SAP master data leveraged for this assignment are identified when the cost object is requested by subject matter experts familiar with the scope of work and primary purpose of the work. Unless project specific information is available to identify whether it is for a load growth purposes or not, the classification does not change.

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 2

To: SEIA
Prepared by: Christopher Ohlheiser
Job Title: Senior Manager
Received Date: 12/13/2024

Response Date: 12/26/2024

Question 01.g:
Page 22 of Exh. SCE-02A discusses the data used in the regression analysis that determines SCE's proposed marginal distribution demand costs (MDDC). SCE states that it

…relies on SCE's FERC 1 Form 1 (FF1) filings, which categorize capital expenditures by asset type as outlined in Table I-8. For historical years, SCE applies an adjustment factor to the capital additions reported in its FF1 to estimate the portion of total capital expenditures related to load growth activities. For forecast years, load growth capital expenditures are based on workpapers that supplement SCE's Load Growth, Transmission Projects, and Engineering testimony in A.23-05-010 (SCE-02, Vol. 07).

Footnote 22 to this passage states that "[o]nly projects identified as load growth projects are considered. All projects not related to load growth (i.e., grid reliability, infrastructure replacement projects, grid modernization, etc.) are excluded from this analysis."

g. When SCE replaces a T&D asset, please describe how SCE evaluates the equipment that will be used to replace that asset. In particular, please explain whether (a) SCE always replaces equipment with new equipment of exactly the same capacity, or (b) SCE evaluates whether the replacement should be of higher capacity to accommodate future load growth. Please use (i) a distribution circuit and (ii) a distribution substation transformer as examples to explain how SCE evaluates the capacities of new equipment to use in "infrastructure replacement" projects. Please provide any GRC Phase 1 testimony in which these practices are discussed.

Response to Question 01.g:
Assets identified for replacement are not always replaced with equipment with the same capacity. While load growth could be a factor in the identification of new equipment, it is not the only factor that could result in a capacity change. For instance, when replacing assets the new asset must meet the latest standard. The new standard may result in a larger substation transformer due to the existing size no longer being available. On a distribution circuit, when replacing a section of overhead conductor to covered conductor for wildfire mitigation the capacity of the new conductor may be higher than that of the existing bare wire. It is important to note that these projects could also result in a reduction of capacity as well. For instance, a section of underground cable identified for replacement due to age could be replaced by smaller cable to fit within the existing duct and structures and avoid costly reconstruction. Loading is considered in such a case to ensure the new, smaller cable does not conflict with any potential growth in the area.

In areas identified as high load growth, distribution and substation equipment will try to

accommodate future load growth if the existing infrastructure does not require massive upgrades. This is an efficient use of resources and aims to minimize the impact on existing customers with multiple planned interruptions. A common example is a mainline switch targeted by Infrastructure Replacement, which is also being targeted for load growth to be replaced with an extra position. The planner will review the in-flight design and recommend increasing the extra position to accommodate load growth and the IR program.

Capacity additions could result in any projects that change the distribution and subtransmission systems. Unless capacity is the primary driver, such as load growth projects, these capacity increases are not tracked on a project-by-project basis.

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 2

To: SEIA
Prepared by: Andre Ramirez
Job Title: Advisor
Received Date: 12/13/2024

Response Date: 12/30/2024

Question 04.a-b:
Page 58 of SCE-04A, concerning SCE's TOU-D-PRIME Plus proposal, states that "[b]ecause most residential customers do not have fifteen minute demand interval meters, SCE proposes to implement the time-related demand charge based on the customer's maximum hourly demand within the pertinent time-of use period."

a. Please describe the hourly demand data that is accessible to "most" SCE residential customers. Does this data currently appear on either (i) the customer's monthly billing statement from SCE or (ii) on the pages of the customer's online account?

b. Please specify the exact steps that a residential customer would be required to take to access and to determine their "maximum hourly demand within the pertinent time-of use period," starting from the online home page for the customer's account and ending with the customer knowing their "maximum hourly demand within the pertinent time-of use period" for the last 12 monthly billing periods for that customer, including the hour when each such maximum hourly peak demand occurred.

Response to Question 04.a-b:

a. Hourly demand is not shown to residential customers today, but SCE proposes to use the kWh in a specific hour to determine demand. While SCE has not developed bill or website mock-ups for its rate design proposal at this time, today, a customer could use their online account to view the number of kWhs used in a specific day and specific hour. Viewing demand information for residential customers takes several steps today because no residential customer is billed on demand. If SCE's proposal is accepted, and demand becomes a billing determinant for residential customers, SCE will consider options for making this information more available to residential customers on SCE.com and/or on customer billing statements.

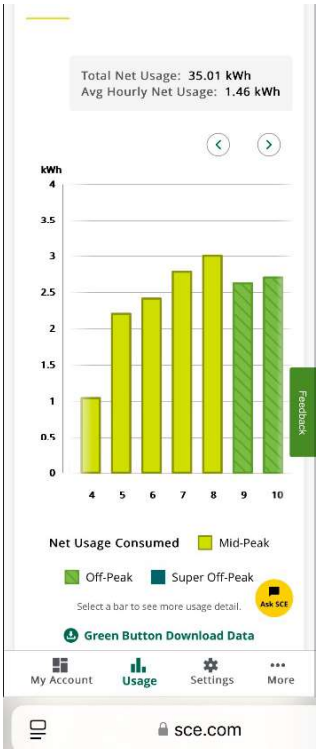
b. Today SCE makes hourly usage values available in graphical format on SCE.com. To reach this information after a customer logs into their account on the SCE.com website the customer should take the following steps:
    i. Click "usage"
    ii. Click "hourly"

    This view shows the customer's hourly usage for the selected day. The customer can then select each day in a billing period to view the values for each day. The highest value for the pertinent time of use period among all days in the billing period would equal the maximum hourly demand. In the provided example, below, one can see the usage at 8pm was approximately

3kW-h, which would translate to an assumed 3kW for that hour.

Additionally, SCE makes downloads of interval usage data available to all customers though a data sharing application on the SCE.com website. After the customer logs into their online account on SCE.com the customer would need to take the following steps:

iii. Click “more”
iv. Click "data sharing and download”
v. Click “download”
vi. Click on the applicable account
vii. Select a date range for the desired billing period
viii. Choose a file format (csv or xml)
ix. Complete "captcha"
x. Click “download”
xi. The resulting file will be a .csv file containing usage data by date for each day included in the date range selected for customers metered at hourly intervals. The customer’s maximum demand for the billing period would be the highest value found in the “usage” column that is applicable to the pertinent time of use period. For customers metered at 15-minute intervals, the customer should convert the 15-minute kWh values to hourly kWh values by summing the values within each our and then the maximum demand would equal the highest value within the hours that fall in the pertinent time of use period.



Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 3

To: SEIA
Prepared by: Blake Evan Heidenreich
Job Title: Advisor
Received Date: 12/19/2024

Response Date: 1/6/2025

Question 06.a-c:
SCE's response SEIA-SCE-001, Question 25(a) states: "the current [VGRP] program design requires all VGRP customers to install a separate V2G Net Generation Output Meter (NGOM)."

a. Why is a second meter necessary for standard, non-NEM, non-NBT customers who do not have onsite generation and who do not currently export power to SCE?

b. Why won't the export channel of a non-NEM, non-NBT customer's standard SCE TOU meter accurately record exports from their EV under the VGRP?

c. Who will pay for the separate V2G Net Generation Output Meter (NGOM)? If the VGRP participating customer will pay, what will be the level and design of the meter charge?

Response to Question 06.a-c:

a. The separate V2G NGOM will be used to identify and ensure that energy being compensated through VGRP is coming from an EV and not from another non-eligible device. VGRP includes EVs as the only eligible devices and would not apply to any other device exporting energy. Other devices installed in the future at a customer premise could include future NBT or solar customers, standalone stationary storage, or any DER that has the capability to generate or export power.
b. If it was impossible for a customer to have another DER onsite with the ability to export power, then the SCE TOU meter would be capable of accurately recording exports from their EV. However, after installing a V2G capable system it is possible that a customer could install solar, stationary storage, or another DER capable of exporting energy that could be recorded through the SCE export channel (i.e. channel 2). Therefore, SCE requires the use of a NGOM to confirm energy exported and recorded in channel 2 of the SCE meter is in fact energy from the EV.
c. The customer will be responsible for the cost associated with the V2G NGOM. The level and design of the meter charge will be addressed through the same process as NBT.

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET S E I A - S C E - 0 0 3

To: SEIA
Prepared by: Blake Evan Heidenreich
Job Title: Advisor
Received Date: 12/19/2024

Response Date: 1/6/2025

Question 08.a-b:
SCE's response to SEIA-SCE-001, Question 29(d) states: "…the VGRP structure was designed with the lean on system level generation avoided costs and therefore a different compensation structure than a stationary battery tied to a NEM/NBT system because there is more uncertainty with the charging behavior of the EV battery."

a. Does the compensation that a NEM or NBT solar-paired-storage customer earns for a kWh of exported power depend in any way on when the NEM or NBT customer charged their on-site battery? Please confirm that the compensation that a NEM or NBT solar-paired-storage customer earns for a kWh of exported power depends solely on when that kWh is exported, and not on when that kWh was produced by the solar panels or stored in the on-site battery.

b. Please explain in detail why and how "the charging behavior of the EV battery" –either in time or location – makes any difference in the value to the grid of a kWh of stored energy in that EV battery when that kWh is exported to the grid.

Response to Question 08.a-b:

a. The compensation that a NEM or NBT solar-paired-storage customer earns for a kWh of exported energy depends solely on when that kWh is exported and not when the kWh of energy was generated or when the battery was charged.
b. Site-specific behind-the-meter (BTM) resources like paired storage or standalone BTM Generation like solar that can be classified as renewable based on SCE's NEM or NBT Tariffs, act as a source of generation supply or power to the site that is independent from power supplied to the site from the Grid. Typically, a standalone EV is dependent on the Grid for charge-energy except for cases where the EV can be specifically configured to only charge from the site-specific BTM resource, and even in such cases, because of the mobile nature of the EV, the site-specific or away-from-site charging behavior of the EV is currently not traceable, not identifiable, or generally unknown. SCE's intent with designing this first step of VGRP compensation is therefore to provide the EV owner a reasonable basis of retail export compensation that is hinged to the ACC and not the retail tariffed rate, and is based on the notion that the EVs can charge away-from-site with no visibility of the pricing structure (charge-based or free) of the potential charging site where the EV was charged – While this may not be specifically relevant in simplistic terms in the billing mechanism of the VGRP compensation structure, it becomes important from a cost-shift and

revenue shift perspective especially with increasingly more EV adoption, and by extension the increasing potential of disparate charging behaviors across consumer groups and rate groups. SCE believes that the evolution of the VGRP structure from this first step will occur over time with increased learnings as we progress along the adoption curve, but the first step of designing a VGRP compensation structure based on system level avoided costs is reasonable and sufficient. The NBT mechanism was adopted as a first step in the State's transition of customer compensation for retail exports away from the retail tariffed rate, and therefore considerations included in the design of NBT were potentially guided by the importance of such a transitory compensatory mechanism – VGRP is not a transitory compensation mechanism and comes with a host of different considerations that are unique to VGRP, noting however that both the VGRP and the NBT compensation mechanisms can also evolve and change over time.

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DATA REQUEST SET S E I A - S C E - 0 0 3

To: SEIA
Prepared by: Blake Evan Heidenreich
Job Title: Advisor
Received Date: 12/19/2024

Response Date: 1/6/2025

Question 09.a-c:
SCE's response to SEIA-SCE-001, Question 30(c) states: "The mobility associated with EVs means they can be charged from sources connected to the distribution and transmission systems, such level 2 or 3 charging stations [sic] or even at home overnight. It is for this reason that SCE has not associated avoided transmission and distribution costs with VGRP."

a. Assume an NBT customer with a solar-paired-storage system buys a bidirectional EV and enrolls in VGRP at their home. Please confirm that all exports to the grid, from both the solar-paired-storage system and the bi-directional EV under VGRP will take place at the customer's home, in the same physical location on the SCE grid, and through the same SCE meter and interconnection with the grid.

b. Assume that this customer exports 6 kWh of power from his premises to the SCE system in a specific hour – 3 kWh from the NBT system and 3 kWh from the bidirectional EV. Please explain why the 3 kWh of NBT power at this location will avoid transmission and distribution costs but the 3 kWh of bi-directional EV power will not.

c. Please explain how when and where the EV battery was charged with the 3 kWh of exports referenced in part (b) of this question makes any difference to the value of those 3 kWh when they are exported to the SCE system. If SCE believes that there is any difference in the export value of these 3 kWh based solely on when and where this energy was charged into the EV battery, provide a quantitative example explaining and quantifying such difference

Response to Question 09.a-c:

a. Yes, exports to the grid, from both the solar-paired-storage system enrolled in NBT and the bi-directional EV enrolled in VGRP will take place at the customer's home, in the same physical location on the SCE grid, and through the same SCE meter and interconnection with the grid even if the sources of supply to both resources can be different, where the EV may have charged at say a local grocery store at a different time of the day while the paired storage system produces power independent of the grid and is site-specific.

b. NBT was adopted to transition customer compensation for site-specific retail exports away from the tariffed retail rate. VGRP is being proposed with a unique set of considerations that can be different from NBT including, but not limited to, the mobile nature of EV charge/discharge patterns with the potential for both at-site and away-from-site charge/discharge behavior. A specific kWh exported at a given location and time may not

have different impacts to the grid based on the device or equipment that exported the energy. Similarly, the energy delivered to a homeowner or business does not have a different impact on the grid as a result of the customer changing their rate plan. However, the cost of a specific kWh to a customer under one rate plan may differ considerably from another rate plan. Due to the unpredictability of exports from an EV as compared to the predictable nature of site-specific solar generation and exports, it is a matter of such unique considerations that supports a difference in compensation for exports from EVs.

c. The ability to incorporate EV exports into the planning of the grid and T&D system is of interest to SCE and an element of what SCE's VGI Program that is in development will aim to achieve. The track record and ability to confidently predict energy generated from site-specific BTM resources allows SCE to incorporate such BTM resources more predictably into the T&D planning process; doing so allows for the potential of infrastructure cost savings over the long-run and where applicable. Due to the evolving nature of unidirectional EV systems charging from a distributed network on the grid, and bidirectional EV systems discharging on a distributed network to the grid, the unpredictability of when EV exports may be available (i.e. the choice each customer has, daily, to export or not), the lack of a track record for EV exports, and the fact that EVs are first a means for mobility and not for grid services, SCE cannot currently reliably plan infrastructure deployment based on predictable and dispatchable EV exports. Therefore, the T&D components of the ACC were not included in the compensation value for this initial, first-step iteration of VGRP. As SCE gains experience with EV exports, it may become appropriate to include T&D elements of the ACC in future versions of VGRP.

Southern California Edison
A.24-03-019 – 2025 SCE GRC Phase 2

DATA REQUEST SET P u b A d v - S C E - 0 1 2

To: Public Advocates Office
Prepared by: Andre Ramirez
Job Title: Sr. Advisor
Received Date: 6/4/2024

Response Date: 6/18/2024

Question 02.a-b:
SCE's application proposes TOU-D-Prime Plus with higher seasonal price differentials with an additional winter SOP period of 8 cents/kwh, customer charge of $33/month, and on peak demand charge of $3.18/kW in the summer and $2.62 in the winter.

a. Provide a narrative explanation for how SCE developed this variation with on peak demand charges. Your response should identify any assumptions upon which this proposal relies and include a description of any research, including customer feedback and preference surveys indicating that customers with distributed energy resources desire such charges.

b. Provide copies of any customer reports, surveys, research, feedback, etc. identified in your narrative response.

Response to Question 02.a-b:

SCE designed TOU-D-PRIME Plus as a new optional rate with the impetus of offering a rate to residential customers that has a greater alignment to cost, and therefore enables an increased adoption of behind-the-meter technologies that positively contribute to the State's GHG reduction and electrification goals – SCE wanted to clearly distinguish this new rate option from the current TOU-PRIME rate by designing a lower volumetric rate with meaningful TOU differentials, a time related hourly-demand charge, and a higher fixed charge.

In the attached Microsoft PowerPoint reports, SCE provides evidence that residential customers may be interested in adopting rates with greater alignment to cost (TOU Overview), as well as an evaluation of the PRIME rate, which demonstrates significant load shifting from customers on PRIME. SCE hypothesizes even greater load shift can be demonstrated with the new PRIME Plus option.

4 SCE-04, at 69.

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DATA REQUEST SET P u b A d v - S C E - 0 1 4

To: Public Advocates Office
Prepared by: Desiree Wong
Job Title: Senior Advisor
Received Date: 6/6/2024

Response Date: 6/20/2024

Question 01.a-b:
Does SCE include a premium in the form of a Renewables Portfolio Standard (RPS) adderin its Marginal Energy Cost (MEC) calculations?

a. If yes, please i) identify all models containing such an adder, ii) explain what the value of the RPS adder is, and iii) identify where the value can be found in SCE's workpapers.

b. If no, please provide a narrative explanation for why SCE did not include an RPS adder in its MEC calculation.

Response to Question 01.a-b:

1a. SCE does not include a premium in the form of an RPS adder in its MEC calculations.

1b. As described on page 10 of SCE-02, SCE's proposed MECs are based on the hourly marginal market-clearing price of the day-ahead market operated by CAISO. The CAISO market prices do not include any RPS adder.

More generally, SCE does not include a marginal cost related to RPS compliance in its generation marginal cost because the state is on- or ahead-of its RPS targets over the GRC forecast period. That means there is generally no incremental RPS compliance cost to serve a "marginal increment of demand"[1] over the GRC forecast period.

[1] SCE-02 at p. 5.

Attachment RTB-3

Excerpt from

PG&E Testimony from A. 24-09-015

Application: 24-09-
(U 39 M)
Exhibit No.: (PG&E-3)
Date: September 30, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2023 GENERAL RATE CASE PHASE II

PREPARED TESTIMONY

EXHIBIT (PG&E-3)

REVENUE ALLOCATION AND RATE DESIGN

G. TOU Rates

1. Introduction

Currently, the majority of PG&E's customers take service on a TOU rate due to the transition to E-TOU-C as the default residential rate and increasing interest in optional TOU rates. The following sections describe PG&E's proposals for its various TOU rate options that are planned to remain active tariffs through the end of this proceeding; rates that currently exist but are scheduled to be eliminated are not addressed in this testimony. While PG&E proposes no changes to the TOU period definitions, it proposes to update TOU price differentials to better align these rates with the underlying marginal costs calculated in Exhibit 1. In summary, PG&E proposes to gradually move the TOU differentials of the default rate (E-TOU-C) towards marginal cost-based differentials, and to immediately move all optional rates' differentials to marginal cost.

Other than the proposed changes to differentials, any other changes to generation and distribution rates between GRCs will continue to be done on an equal cents basis.

2. Summary of TOU Period Definitions

PG&E proposes to retain the existing TOU period definitions outlined in Table 3-6 below, which avoids having to introduce structural changes to customers that have become accustomed to the existing TOU periods after significant Marketing, Education, and Outreach campaigns. Instead, customers will only need to understand that the incentive to shift usage from one period to another is increasing.

TABLE 3-6
TOU PERIOD DEFINITIONS BY PG&E RESIDENTIAL RATE

Line No.	Season	TOU Period	E-TOU-C	E-TOU-D	E-ELEC/EV2
1	Summer (June through September)	Peak	4 p.m. – 9 p.m., every day	5 p.m. to 8 p.m., Weekdays Only	4 p.m. – 9 p.m., every day
2		Part-Peak	N/A	N/A	3 p.m. to 4 p.m. and 9 p.m. to 12 a.m., every day
3		Off-Peak	All other hours	All other hours	All other hours
4	Winter (October through May)	Peak	4 p.m. – 9 p.m., every day	5 p.m. to 8 p.m., Weekdays Only	4 p.m. – 9 p.m., every day
5		Part-Peak	N/A	N/A	3 p.m. to 4 p.m. and 9 p.m. to 12 a.m., every day
6		Off-Peak	All other hours	All other hours	All other hours

3. Summary of Marginal Costs Compared to Current and Proposed TOU Differentials

PG&E's residential marginal cost differentials, and current and proposed TOU price differentials are summarized in Tables 3-7, 3-8, and 3-9 below. For E-TOU-C, the proposed differentials are the end state that is planned to be reached in 2029.[24] All other proposed differentials are intended to be implemented as soon as is practicable after a final decision is issued in this proceeding. Differentials for E-TOU-D and E-ELEC are proposed to be updated to equal the marginal cost differentials, while EV2 is proposed to move distribution differentials closer to marginal cost while setting the generation differentials equal to marginal cost.

Generation rates are differentiated according to Marginal Energy Costs and Marginal Generation Capacity Costs, while distribution costs are differentiated according to Marginal Distribution Capacity Costs – Primary.

[24] Current differentials are as of 7/1/2024. However, the E-TOU-C Summer Peak to Off-Peak differential is scheduled to increase by $0.02/kWh in 2025.

TABLE 3-7
COMPARISON OF TOTAL BUNDLED TOU RATE DIFFERENTIALS

Line No.	Schedule(s)	Scenario	Summer		Winter	
			Peak vs. Off	Part vs. Off	Peak vs. Off	Part vs. Off
1	E-TOU-C	Marginal Cost	$0.275	N/A	$0.035	N/A
2		Current	$0.103	N/A	$0.030	N/A
3		Proposed	$0.243	N/A	$0.035	N/A
4		$/kWh Change	$0.140	N/A	$0.005	N/A
5	E-TOU-D	Marginal Cost	$0.370	N/A	$0.045	N/A
6		Current	$0.135	N/A	$0.039	N/A
7		Proposed	$0.370	N/A	$0.045	N/A
8		$/kWh Change	$0.235	N/A	$0.006	N/A
9	EV2	Marginal Cost	$0.290	$0.046	$0.037	$0.007
10		Current	$0.313	$0.202	$0.185	$0.169
11		Proposed	$0.390	$0.146	$0.137	$0.107
12		$/kWh Change	$0.078	($0.056)	($0.049)	($0.062)
13	E-ELEC	Marginal Cost	$0.290	$0.046	$0.037	$0.007
14		Current	$0.219	$0.057	$0.036	$0.014
15		Proposed	$0.290	$0.046	$0.037	$0.007
16		$/kWh Change	$0.072	($0.011)	$0.001	($0.007)

TABLE 3-8
COMPARISON OF GENERATION TOU RATE DIFFERENTIALS

Line No.	Schedule(s)	Scenario	Summer		Winter	
			Peak vs. Off	Part vs. Off	Peak vs. Off	Part vs. Off
1	E-TOU-C	Marginal Cost	$0.184	N/A	$0.026	N/A
2		Current	$0.083	N/A	$0.027	N/A
3		Proposed	$0.163	N/A	$0.026	N/A
4	E-TOU-D	Marginal Cost	$0.264	N/A	$0.033	N/A
5		Current	$0.105	N/A	$0.035	N/A
6		Proposed	$0.264	N/A	$0.033	N/A
7	EV2	Marginal Cost	$0.190	$0.020	$0.028	$0.006
8		Current	$0.086	$0.041	$0.036	$0.023
9		Proposed	$0.190	$0.020	$0.028	$0.006
10	E-ELEC	Marginal Cost	$0.190	$0.020	$0.028	$0.006
11		Current	$0.144	$0.045	$0.033	$0.013
12		Proposed	$0.190	$0.020	$0.028	$0.006

TABLE 3-9
COMPARISON OF DISTRIBUTION TOU RATE DIFFERENTIALS

Line No.	Schedule(s)	Scenario	Summer		Winter	
			Peak vs. Off	Part vs. Off	Peak vs. Off	Part vs. Off
1	E-TOU-C	Marginal Cost	$0.092	N/A	$0.008	N/A
2		Current	$0.020	N/A	$0.003	N/A
3		Proposed	$0.080	N/A	$0.008	N/A
4	E-TOU-D	Marginal Cost	$0.106	N/A	$0.011	N/A
5		Current	$0.030	N/A	$0.004	N/A
6		Proposed	$0.106	N/A	$0.011	N/A
7	EV2	Marginal Cost	$0.100	$0.026	$0.008	$0.000
8		Current	$0.227	$0.161	$0.149	$0.145
9		Proposed	$0.200	$0.126	$0.108	$0.100
10	E-ELEC	Marginal Cost	$0.100	$0.026	$0.008	$0.000
11		Current	$0.074	$0.012	$0.003	$0.001
12		Proposed	$0.100	$0.026	$0.008	$0.000

4. Default Schedule E-TOU-C

Schedule E-TOU-C is now PG&E's default rate schedule; its original design as approved in D.19.07-004 was intentionally set to be "TOU Lite" so as to ease the transition of customers onto the default TOU rate and increase the likelihood of customers remaining on the rate after the bill protection period ended.[25] Specifically, the CPUC adopted PG&E's proposal for a summer Peak vs. Off-Peak Price (POPP) differential of 6.3 cents per kWh and a winter POPP of 1.7 cents per kWh.[26] In 2021, the CPUC adopted a settlement agreement to increase these differentials over time to $0.123/kWh in the summer and $0.03/kWh in the winter.[27] Currently, these differentials are $0.103/kWh for summer and $0.03/kWh for winter, and PG&E will complete this transition on June 1, 2025.

Per analysis in Exhibit (PG&E-1), the cost-based differentials for the E-TOU-C TOU period definitions are now $0.274/kWh and $0.035/kWh in the summer and winter, respectively. Given the status of E-TOU-C as the default rate, we do not propose to move all the way to these marginal cost levels immediately. We instead propose to move towards the marginal cost differential by increasing the summer peak to off peak differential by four cents per year for three years, starting in 2027. This is shown in more detail in Table 3-10 below.

TABLE 3-10
PLANNED AND PROPOSED E-TOU-C DIFFERENTIAL TRANSITION PATH

Line No.	Year	Generation Differential	Distribution Differential	Total Differential	Annual Increase
1	2024	$0.083	$0.020	$0.103	$0.020
2	2025	$0.103	$0.020	$0.123	$0.020
3	2026	$0.103	$0.020	$0.123	$0.000
4	2027	$0.123	$0.040	$0.163	$0.040
5	2028	$0.143	$0.060	$0.203	$0.040
6	2029	$0.163	$0.080	$0.243	$0.040

[25] Per D.19-07-004, p. 219, OP 29. During the transition period, customers who would have had a lower bill on the non-TOU rate were refunded the difference at the end of their first year on TOU.

[26] D.19-07-004, p. 201, COL 33.

[27] D.21-11-016, p. 107.

These changes balance the priority identified in the DFOIR to increase default rate TOU differentials against moderating bill impacts for customers. Due to the large number of customers taking service on E-TOU-C and its history as a "TOU-lite" rate, PG&E believes it prudent to gradually move towards marginal costs. Further, PG&E's plan does not fully transition to the estimated full marginal cost based differentials, instead landing at approximately 90 percent of the benchmark. This reasonably balances moving the default rate towards marginal cost against the need to maintain customer acceptance of the rate.

5. Optional TOU Schedules

PG&E's optional time-of-use rates (E-TOU-D, E-ELEC, and EV2) already feature more significant differentials than E-TOU-C. While each rate serves different niches, all are designed to provide more cost-based price signals to customers than the default rate. However, all are proposed to be designed on a revenue neutral basis to E-TOU-C.

While PG&E proposes a gradual transition towards marginal cost based differentials for E-TOU-C, adjustments to PG&E's optional time-of-use rates are proposed to be implemented in a single step. Specifically, PG&E proposes to set the TOU differentials for Schedules E-TOU-D and E-ELEC equal to the marginal cost differentials upon initial implementation of the rate design changes approved in this decision. This will maintain both as reasonable options for customers to take service on TOU rates with cost-based differentials. Since E-TOU-D has a more narrow peak period definition than PG&E's other residential rate schedules, it has higher peak rates than other rate schedules.

If the same changes were made to EV2, it would be identical to E-ELEC, as both would have the same TOU period definitions, TOU differentials, and fixed charges. Therefore, to maintain EV2's niche as a rate with artificially high TOU differentials to incent off peak EV charging more than other rates, we therefore propose to set the rate's generation differentials at marginal cost levels (reflecting an increase from the status quo), while making downward adjustments to the rate's distribution differentials to move closer to marginal cost. Specifically, the new starting point for distribution differentials remains the marginal cost basis, but these differentials are

increased by $0.10/kWh across the board, compared to approximately $0.15/kWh in today's rates. This results in this differential adder being reduced by about one third. The overall result of these changes is to more directly base the differentials on marginal cost, while (approximately) retaining existing off-peak rates for EV charging. Table 3-11 shows the proposed differentials to EV2 in more detail.

TABLE 3-11
EV2 PROPOSED DIFFERENTIALS COMPARED TO PRESENT AND MARGINAL COSTS

Line No.	Cost Category	Scenario	Summer		Winter	
			Peak vs. Off	Part vs. Off	Peak vs. Off	Part vs. Off
1	Generation	Marginal Cost	$0.190	$0.020	$0.028	$0.006
2		Current	$0.086	$0.041	$0.036	$0.023
3		Proposed	$0.190	$0.020	$0.028	$0.006
4		Change vs. Present	$0.104	($0.022)	($0.008)	($0.017)
5		Deviation vs. MC	$0.000	$0.000	$0.000	($0.000)
6	Distribution	Marginal Cost	$0.100	$0.026	$0.008	$0.000
7		Current	$0.227	$0.161	$0.149	$0.145
8		Proposed	$0.200	$0.126	$0.108	$0.100
9		Change vs. Present	($0.027)	($0.035)	($0.041)	($0.045)
10		Deviation vs. MC	$0.100	$0.100	$0.100	$0.100
11	Total	Marginal Cost	$0.290	$0.046	$0.037	$0.007
12		Current	$0.313	$0.202	$0.185	$0.169
13		Proposed	$0.390	$0.146	$0.137	$0.107
14		Change vs. Present	$0.078	($0.056)	($0.049)	($0.062)
15		Deviation vs. MC	$0.100	$0.100	$0.100	$0.100

6. Schedule EV2 Baseline Quantity Limits

In addition to the changes proposed to the EV2 TOU differentials outlined above, PG&E proposes to eliminate the requirement that EV2 customers use less than 800 percent of their baseline quantity to remain eligible for this rate.

This requirement was adopted through a settlement agreement in PG&E's 2017 GRC II proceeding as a replacement for the previous