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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 24-03-019

REPLY BRIEF OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

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Pursuant to Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission) and Administrative Law Judge Marcelo Poirier's October 3, 2025 Email Ruling Setting Briefing Schedule and Granting Motion for Party Status, Southern California Edison Company (SCE) respectfully submits this Reply Brief. SCE addresses (1) its proposed TOU-D-PRIME Plus (PRIME Plus) rate, which Solar Energy Industries Association (SEIA) and the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) opposed in Opening Briefs; (2) The Utility Reform Network's (TURN) baseline allowance proposal; and (3) SEIA's Marginal Transmission Capacity Costs (MTCC) proposal. SCE also responds to Cal Advocates' opposition to the Vehicle to Grid Resource Proposal (VGRP) Settlement Agreement.

I.

PRIME PLUS

A. SEIA and Cal Advocates Ignore That PRIME Plus is an *Optional* Rate that will Appeal to Customers Who Understand the Peak Usage Charge and are Willing to Change Their Usage Patterns to Help Facilitate the Energy Transition

1. Customers that Opt-in to PRIME Plus Are Likely to Understand the Rate

SEIA and Cal Advocates claim PRIME Plus could cause customer confusion. SEIA states that customers "do not have experience with the concept of demand, measured in kW."[1]

[1] SEIA Opening Brief, p. 7.

SEIA provides a hypothetical in which a customer "is momentarily inattentive, and a member of their household mistakenly charges the EV for a single on-peak hour," resulting in "less demand response and a frustrated customer with a high bill."[2] Cal Advocates echoes SEIA's fear, claiming the optional rate's Peak Usage Charge "could punish isolated high usage"[3] and that it "require[s] customers to micromanage aspects of their usage they likely do not understand."[4] These fears are misguided and should be rejected.

The intervenors ignore that PRIME Plus would be an *optional* rate. Customers that do not understand the rate's Peak Usage Charge or that fear the cost of isolated high usage will simply choose not to enroll. Customers make similar choices when considering SCE's other optional TOU rates (i.e., they choose to enroll if they understand the rate and find it will be cost effective). And intervenors' claimed concern that a customer's isolated on-peak high usage could be subject to a significant charge is a reality under any TOU rate. Implementing high, cost-based price differentials is a widely acknowledged benefit of TOU rate designs because high differentials incentivize customers to shift their usage to off-peak periods. The Residential Rate Design Settlement Agreement submitted in this proceeding reflects this benefit; it proposes an increase in the peak to off-peak differential of the PRIME rate (i.e., an increase in the peak energy rate relative to the off-peak rate). PRIME Plus also reflects this benefit. As explained in rebuttal testimony, PRIME Plus's alignment of rate charges with the underlying cost structures encourages customers to use energy in a way that optimizes the use of grid infrastructure, reduces long-term costs, provides customers with options to manage their bills, and encourages behaviors that improve system reliability.[5]

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[2] *Id*., p. 6.
[3] Cal Advocates Opening Brief, p. 3.
[4] *Id*., p. 4.
[5] Ex. SCE-07, p. 7.

2. PRIME Plus Satisfies the Commission's Direction that Utilities Offer a Menu of TOU Options

SEIA and Cal Advocates complain that SCE does not need to introduce a new optional TOU rate design.[6] However, since 2015, the Commission has directed investor-owned electric utilities (IOUs) to offer customers a variety of TOU rates. In Decision (D.)15-07-001, the Commission began the migration of all residential customers to default TOU rates. The Commission found that TOU rates "enable the customer to better understand electricity resources and make a positive difference in the environment by adjusting their use. TOU rates can also reduce the cost of infrastructure by reducing the need for peaker plants."[7] The Commission directed the IOUs to comply with "opt-in rate design guidelines going forward," including the requirement to "[o]ffer a menu of different residential rates designed to appeal to a variety of residential customers, with different time periods and rate differentials."[8] PRIME Plus furthers this preference for a variety of TOU rate options.[9]

SCE's residential customers, as well as residential customers of each of California's electric IOUs, are adept at understanding a menu of TOU offerings in addition to other, non-traditional rate designs. The implementation of default TOU rates was also met with intervenor skepticism but has proven to be a success. SCE's default residential rates feature three TOU periods and, as of November 2025, a Base Services Charge. PRIME Plus's Peak Usage Charge is no more complicated a concept than either of these rate elements. It is also considerably easier to understand than the dynamic rates being tested in SCE's Expanded Pilot, which require customers to react to hourly pricing that changes daily, to program their energy use into devices capable of responding to dynamic

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6 SEIA Opening Brief, pp. 6-7; Cal Advocates Opening Brief, p. 6.

7 D.15-07-001, p. 129.

8 D.15-07-001, p. 176.

9 In D.15-07-001 the Commission considered a San Diego Gas & Electric Company (SDG&E) proposal to adopt a residential TOU default rate with a demand component: a Demand Differentiated Monthly Service Fee. *Id.*, p. 182. The Commission "commend[ed] SDG&E for its willingness to explore the variety of TOU rates," but rejected the proposal, holding that "at this time the focus of residential TOU rates must be on studying rate designs with volumetric TOU rates and fixed charges as set forth in AB 327." *Id.*, p. 184. More than a decade later, TOU rates have been successfully rolled out. Customers are very familiar with TOU rates and there is no reason to delay in offering them a new TOU option with a demand component.

price signals, and to be aware that dynamic prices only apply to a portion of their load.[10] A residential customer that is capable of understanding the mechanics of the Expanded Pilot is equally capable of understanding a simpler Peak Usage Charge.[11]

SCE's residential customers have shown they are adept at understanding novel rate designs—there is no reason to believe peak usage or demand charges are an exception. As SCE explained in rebuttal testimony, "This is one of the reasons SCE is offering PRIME Plus on an opt-in basis, as we have learned with PRIME that customers who opt into a rate generally do so because of favorable bill impacts and because they can learn to adjust load behaviors based on the structural attributes of the newly adopted rate."[12] Further, PRIME Plus will ensure Net Billing Tariff (NBT) customers have optional TOU rates to choose from. NBT customers are served under PRIME as the default rate and currently have no other options. PRIME Plus will provide these customers, who may be more likely to have additional electrification technology, such as electric vehicles (EVs), another rate option and an opportunity to benefit from shifting their usage.

3. SCE will Educate Customers about the New Optional Rate

SCE has substantial experience introducing new residential TOU rate designs, which it will leverage to educate customers about the new PRIME Plus option. Despite this, SEIA and Cal Advocates criticize SCE for not providing a detailed education plan now, in this proceeding.[13] They ignore that two key components of an education plan are already in place.

First, SCE surveyed residential customers to gauge their interest in the rate and identify ways to educate them about the Peak Usage Charge. In Rebuttal Testimony, SCE provided a summary of the results of the survey, which asked customers questions regarding interest level in the offering and

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[10] *See* D.24-01-032 (authorizing expansion of system reliability pilots); SCE Expanded Pilot Fact Sheet, *available at* https://www.sce.com/factsheet/dynamic-pricing-rate-pilot.

[11] Cal Advocates seems to disagree, as it recommends rejecting PRIME Plus and expanding the dynamic rate pilot. *See* Cal Advocates Opening Brief, p. 7. Cal Advocates offers no explanation of why customers are capable of understanding dynamic rates but not peak usage demand charges.

[12] Ex. SCE-07, p. 13.

[13] SEIA Opening Brief, p. 8; Cal Advocates Opening Brief, pp. 4-5.

optimal rate names and program descriptions.[14] The summary included a sample of customer verbatims where they were asked their input on how to define the PRIME Plus rate that was presented to them – many of these customers were able to accurately describe the rate, which indicates that customers understood key aspects of the rate and how it worked.[15] In addition, the majority of customers stated that they were either somewhat or very interested in the rate.
The survey also identified that customers find the concept of a demand-related charge easier to understand when it is presented as a "Peak Usage Charge," which SCE decided to adopt.[16]

Second, SCE will use its online rate comparison tool to provide customers with a rate analysis for PRIME Plus so customers can see how enrollment in the rate could affect their bill. SCE will also leverage content via sce.com and other methods to educate customers about the new optional rate. Customers' motivation to save money will be a cornerstone of the education effort:

> When considering the likely customer experience, customers will initially select PRIME Plus due to the anticipated savings shown on SCE's online rate comparison tool. As historical focus group research from the time-of-use transition has shown, customers are most motivated by a rate option that saves them money. As these customers will likely already be served on a TOU rate, they will understand the notion of the on-peak period, which reduces the educational burden in describing a Peak Usage Charge. Thus, knowing customers are motivated to save money and are likely to expand consumption through electrification, SCE's additional education will focus on the explanation of the max usage during the peak period.[17]

In sum, customers' adoption of new rate designs in recent years has shown they are capable of understanding novel residential rate components. Customers that opt in to PRIME Plus are very likely to understand the charge.

4. PRIME Plus Incentivizes Customers to Shift Peak Usage

SEIA and Cal Advocates also criticize PRIME Plus for not sufficiently providing an incentive for shifting peak usage. SEIA claims if a customer inadvertently has high usage during the peak

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[14] Ex. SCE-07 p.13 and Appendix C.
[15] *See* Ex. SCE-07, Appendix C.
[16] Ex. SCE-07, p. 13; Appendix C.
[17] Ex. SCE-07, p. 14.

period "there will be no further incentive from the demand charge to limit on-peak demand below this level for the remaining days of the billing period."[18] Cal Advocates echoes SEIA's claim.[19]

The Peak Usage Charge's cost-based design provides clear and effective price signals that encourage beneficial electrification and load flexibility.[20] Further, SEIA and Cal Advocates ignore that PRIME Plus has a TOU volumetric component that incentivizes customers to shift usage away from 4-9 pm regardless of whether they have hit their peak usage for the month. As shown in Table I-1 in SCE's Opening Brief, the on-peak volumetric rate for PRIME Plus (63.7 cents/kWh) is nearly three times the off-peak rate (23.8 cents/kWh). In addition, as SCE demonstrated in Rebuttal Testimony, the addition of the Peak Usage Charge will *increase* the incentive to shift usage away from peak.[21] The intervenors' unfounded criticism should be rejected.

B. The Peak Usage Charge is Consistent with the Public Utilities Code and Commission Decisions

1. SEIA Fails to Demonstrate the PRIME Plus Fixed Charge is Improper

Pursuant to Section 739.9 of the Public Utilities Code, fixed costs are eligible for recovery through a fixed charge and variable costs are not.[22] Consistent with this requirement, the Prime Plus fixed charge does not contain any variable costs as discussed Section in B.2 below. SEIA nonetheless opposes SCE recovery of non-marginal distribution costs through the PRIME Plus fixed charge on the basis that those non-marginal distribution costs might include variable costs. But SEIA fails to identify a single variable cost that is included. Instead, SEIA claims "[t]he record is devoid of any information upon which the Commission could determine that the non-marginal distribution costs [in the PRIME Plus fixed charge] are fixed costs."[23] SEIA's claim should be rejected. Not only does

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[18] SEIA Opening Brief, p. 6.
[19] Cal Advocates Opening Brief, p. 3.
[20] SCE Opening Brief, p. 2 ("The revised proposal includes a Base Service Charge (BSC) of $49, which includes all fixed costs identified in D.24-05-028 as well as a portion of non-marginal distribution costs.").
[21] Ex. SCE-07, pp. 10-12; SCE Opening Brief, pp. 5-6.
[22] *E.g.*, D.24-5-028, p. 23.
[23] SEIA Opening Brief, p. 4.

SEIA have the burden to present evidence to support its position,[24] which it failed to meet by not presenting any evidence supporting its speculation that there might be variable costs in the PRIME Plus fixed charge, but the record in this proceeding is, in fact, voluminous and provides ample support for the fixed charge. SCE submitted seven volumes of testimony that describe in detail the development of marginal costs and SCE's proposed allocation of those costs. In addition, SCE served detailed workpapers that demonstrate the calculations of each rate element in SCE's application, and intervenors have had the opportunity to solicit additional information in discovery. The proceeding has been pending for 20 months. Despite this ample record and ample opportunity to examine cost items, SEIA does not challenge any specific non-marginal cost in the fixed charge.

2. <u>The Record in this GRC Phase 2 Provides Ample Support for SCE's Cost Recovery; it is Substantially Different from the Record in R.22-07-005</u>

SEIA compares this proceeding to Phase 1 Track A of R.22-07-005,[25] in which the Commission authorized "all investor-owned utilities to change the structure of residential customer bills by shifting the recovery of a portion of fixed costs from volumetric rates to a separate, fixed amount on bills," known as the Income Graduated Fixed Charge.[26] In the Phase 1 Track A decision, the Commission decided not to include non-marginal distribution costs in the Income Graduated Fixed Charge because the utilities that advocated for their inclusion did not "include a list of all components of Non-Marginal Distribution Costs and justification for considering each component as a fixed cost in testimony."[27] The Commission said it "may consider whether a portion of Non-Marginal Distribution Costs are fixed costs in Phase 2 of [the] proceeding or a successor rulemaking."[28] SEIA's comparison is inapposite and should be rejected. Unlike R.22-07-005, this

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[24] "Commission decisions consistently hold the utilities to their ultimate burden to prove the reasonableness of the relief they seek and the costs they seek to recover. Yet when other parties propose a different result, they too have a 'burden of going forward' to produce evidence to support their position and raise a reasonable doubt as to the utility's request." D.20-07-038, pp. 3-4 (rejecting repeated intervenor claims that the Commission failed to hold the applicant utilities to their burden of proof).

[25] SEIA Opening Brief, pp. 3-4.

[26] D.24-05-028, p. 2.

[27] D.24-05-028, p. 69.

[28] *Id.*

proceeding is a Phase 2 GRC with a substantial record of SCE's proposed recovery of fixed and variable costs for all rate classes, including residential.

SCE's GRC Phase 2 rate designs are based on the Commission's long-standing principle of marginal cost of service rate making. This methodology was reaffirmed by the Commission in D.25-08-049: "The marginal cost of service ratemaking methodology has historically been the principal basis for revenue allocation and rate design among California's Large IOUs."[29] As marginal cost of service rate making is the primary purpose of GRC Phase 2, throughout its testimony SCE discusses this methodology and its various attributes, including the identification of marginal and non-marginal costs and whether they vary with changes in usage.[30]

Starting with Exhibit SCE-02, the determination of unit marginal costs, SCE provides an introduction to marginal cost of service ratemaking in Section I.A., where SCE describes its overall marginal cost methodology and illustrates how marginal cost allocations determine revenue allocations and then determine rate design.[31] SCE then discusses its marginal cost principles and describes how "marginal costs must be adjusted to recover a utility's authorized annual revenue requirement by using the Equal Percent of Marginal Cost (EPMC) methodology to assign the utility's authorized revenue requirements in proportion to its marginal cost revenues. SCE further discusses its design demand marginal costs (DDMCs), which are attributable to the amount and configuration of distribution capacity necessary to deliver electricity to, and from, customers, and explains how it functionalizes costs between peak and grid functions.[32] SCE also describes how it determines customer marginal costs, which include capital costs to connect a customer to the grid, ongoing costs of operating and maintaining (O&M) such equipment, and customer service costs.[33]

Exhibit SCE-03 addresses the methodology for developing Marginal Cost Revenue Requirements (MCRR) and outlines their application in revenue allocation. The exhibit also

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29 D.25-08-049, p. 67.

30 "[A] fixed cost has a revenue requirement that does not vary based on the electricity usage of the customer from whom the revenue is being collected." D.24-05-028, pp. 22-23.

31 Ex. SCE-02, p. 1.

32 Ex. SCE-02, pp. 21-24.

33 Ex. SCE-02, pp. 39-41.

discusses the allocation of other non-marginal and public policy revenue requirements.[34] SCE describes how the total functional Distribution MCRR is comprised of customer, grid-related design demand, and peak-capacity related design demand revenues by rate class. Specifically, Table A-1 (Appendix A) reflects SCE's Proposed System Retail Revenue Allocation, which presents the percentage of MCRR associated with each rate class. SCE's MCRR workpapers identify the rate class revenue responsibility and identify distribution related revenue requirements allocated to rate groups using the marginal cost of service methodology. Specifically, the MCRR workpapers identify residential class revenue requirements of $72 per customer-month, which includes all fixed and all variable costs. SCE also identifies total distribution MCRR for the residential class of $45 per customer-month, including the breakdown of the total distribution MCRR into the respective cost components: customer, grid-related design demand, and distribution peak-capacity related marginal costs.[35] The difference between the class revenue requirement and the total distribution MCRR of $27 is the non-marginal cost per customer allocated to residential customers. The grid portion of residential revenues is $20 per customer-month on a marginal cost basis, and $33 per customer per month on the basis of retail revenue requirement. Of the total non-marginal cost revenues for the residential customer class, SCE identified the proposed recovery of non-marginal fixed costs through PRIME Plus fixed charges in its workpapers, which is set at $20 per customer per month.

This detailed evidence and supporting workpapers contrasts with the more general information the Commission considered in R.22-07-005. In the rulemaking, the Commission was presented only with some of the components that make up non-marginal distribution costs.[36] Here, SEIA had the opportunity to review not only each component, but also the calculations supporting each cost SCE proposes to recover in rates. Unlike the rulemaking, the evidence provided in SCE's 2025 GRC Phase 2 showing is sufficient to determine the proportion of non-marginal costs recovered through rates and to identify specific costs items that are fixed based on the Commission

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34 Ex. SCE-03, pp. 1-3.
35 Exhibit SCE-03, pp. 12-14.
36 D.24-05-028, p. 69.

adopted definition in D.24-05-028: "costs that do not directly vary based on the electricity usage of the customer from whom the revenue is being collected…"[37]

3. SCE Provided Further Support for the PRIME Plus Fixed Charge

The record contains additional evidence of SCE's fixed costs. For example, Table I-3 in the marginal cost settlement agreement provides line-item references and descriptions of wildfire-related costs allocated to rate classes based on SCE's proposed Wildfire Special Allocator.[38] The balancing accounts that contain wildfire-related costs are also identified in Table I-3. With the balancing accounts identified, information regarding the cost recovery authority and the type of costs recovered in each balancing account is readily available in SCE's Preliminary Statements establishing the balancing accounts. The Preliminary Statements identify the nature of these costs as either variable or fixed, and in some cases the Final Decision or Resolution where those costs were identified.[39]

In addition, in Exhibit SCE-04, SCE discusses the use of EPMC scalars to set rates where applicable. SCE explains that PRIME Plus includes customer costs and the allocated non-marginal portion of functionalized grid-related cost recovery.[40] Therefore, in reviewing SCE-02 through SCE-04, SCE has provided an overwhelming amount of evidence for the Commission to determine how much revenue is marginal, how much revenue is non-marginal, and how much of that is distribution grid related, as well as how much of those distribution grid costs are fixed. The justifications for all proposed rates in this case rely on these connected exhibits and the associated workpapers, and it is in these exhibits and associated workpapers that fixed versus variable costs are described. In addition, the proportion of revenue associated with marginal versus non-marginal costs is defined in a manner consistent with the Commission's characterization that "[t]he difference between an IOU's total

[37] At pp. 22, 23

[38] Joint Motion to Adopt Marginal Cost Revenue Allocation Settlement Agreement, p. 24.

[39] Most Wildfire related costs can be deemed as fixed as they are not correlated with changes in consumption and are incurred in response to, or to improve SCE's resiliency to wildfire risk events.

[40] A.24-03-019 Exhibit SCE-03, p. 68.

authorized revenues and its marginal cost revenues are referred to as 'non-marginal' or 'residual' costs."[41]

Exhibit SCE-03 addresses two categories of non-marginal costs: one containing items that are not directly tied to marginal costs or changes in customers' usage patterns (clearest examples being vegetation management and safety and risk related costs) and a second category containing costs that may vary as a function of incremental usage-based drivers (such as costs associated with "contracts for generation, distribution, and transmission resources that are incremental to the IOU's most recently determined marginal costs").[42] The non-marginal costs recovered through PRIME Plus fall into the first category of non-marginal costs, which in Exhibit SCE-04, SCE describes as the functionalized distribution grid-related portion and the customer access portion of the non-marginal costs.[43]

Counter to SEIA's assertion, and unlike the record in R.22-07-005, the fixed non-marginal costs recovered through rates are detailed in SCE-03 and include those associated with specific balancing accounts that are also further described in the Preliminary Statements. Specifically, SCE identifies wildfire related costs[44] and their associated balancing accounts,[45] and Transportation Electrification (TE) costs associated with various TE infrastructure programs such as: Charge Ready 1&2 and Charge Ready Schools and Parks.[46] Thus, the evidence provided in SCE's 2025 GRC Phase 2 showing is sufficient to determine the proportion of non-marginal costs recovered through rates and to identify specific cost items that are fixed based on the Commission-adopted definition in D.24-05-028. This record evidence of marginal and non-marginal costs, combined with the policy benefits of the new rate make clear that offering Prime Plus as an optional rate at this critical time when electrification should be incentivized is in the public interest.

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[41] D.25-08-049, p. 67.
[42] *Id.*
[43] Exhibit SCE-04, p. 68.
[44] The wildfire related costs applicable to the Special Allocator are all non-marginal costs.
[45] Ex. SCE-03, beginning at p. 14.
[46] Ex. SCE-03, beginning at p. 19.

C. SEIA's Claim that Residential Demand Charges are not Cost Based Should Be Rejected

SEIA claims that a demand charge is "not suitable" and "inappropriate" for residential customers as the residential class has greater load diversity than the commercial class.[47] However, the greater load diversity by residential customers proves SCE's Peak Usage Charge is the most appropriate method to accurately bill customers for the usage of the grid instead of spreading those costs across every minute of the peak period. Further, in the absence of the Peak Usage Charge, such costs would still be recovered during the same peak period, albeit volumetrically, which SEIA supports. Indeed, SEIA has a long-standing preference for recovering costs during peak periods volumetrically.[48] SEIA's preference for including distribution grid-related costs in the on-peak period acknowledges the peak charges exist, and are indeed cost based, whether they are recovered through an on-peak volumetric charge or a Peak Usage Charge.

II.

TURN'S BASELINE ALLOWANCE PROPOSAL SHOULD ONLY BE CONSIDERED IN A BROADER PROCEEDING, IN WHICH ALL IOUS PARTICIPATE AND ALL IMPACTS OF THE PROPOSAL CAN BE EXAMINED

As SCE explained in its Opening Brief, TURN's baseline proposal should be rejected because it is inconsistent with the Public Utilities Code. If the Commission considers the proposal, it should do so in a proceeding in which all IOUs are put on notice that the proposal may be addressed so they can participate.[49] The opening briefs submitted by TURN and Cal Advocates further demonstrate why TURN's proposal should not be considered in this proceeding.

TURN notes the decline in annual residential usage in recent years but does not quantify the drivers of changes in residential usage over that period, which include distributed generation, energy efficiency, the COVID-19 pandemic, electrification and a host of other factors. If these drivers are

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47 SEIA Opening Brief, p. 5.

48 D.15-07-001 captured SEIA's position to maintain higher tiered rates to continue to provide incentive for conservation at p. 33 & p. 110. D.24-05-028 captured SEIA's justification for a low fixed charge, "SEIA argued that high fixed charges paired with volumetric rate reductions across all time-of-use periods will unreasonably impair incentives for conservation and energy efficiency." P. 163.

49 SCE Opening Brief, pp. 7-10.

not understood and accounted for, adjusting the baseline allowance would not be evidence-based or reasonable. Perhaps in recognition of this, TURN does not ask for an immediate change to the baseline allowance calculation but instead asks the Commission "to direct SCE to develop adjustment factors to account for behind-the-meter usage in its calculation of baseline allowances."[50] Developing the adjustment factors would be a complex and far reaching effort that should be undertaken only in an appropriate proceeding, such as a rulemaking, in which all impacted parties can participate and the Commission has sufficient time to develop an adequate record and to consider the implications of adjusting the baseline allocation.

Another example of the need for a separate proceeding is TURN's claim that adjusting the baseline allowance could result in "ratepayer savings" ranging from $2 per month to $12 dollars.[51] This claim needs to be thoroughly evaluated, but it raises the point that any claimed savings will be offset by increased costs to customers whose usage exceeds the baseline, a group that includes low-income customers. The impact on these customers must be considered. Cal Advocates points out that the impact of TURN's proposal on customers in different baseline regions, and the potential that some regions could benefit and some could be harmed, must also be considered.[52]

SCE continues to recommend that TURN's proposal be rejected for the reasons stated in SCE's Opening Brief. Should the Commission consider TURN's proposal, it should do so in an appropriate proceeding such as a rulemaking.

III.

SEIA'S MTCC PROPOSAL SHOULD BE REJECTED

As SCE explained in its Opening Brief, SEIA's MTCC proposal should be rejected because it is out of scope for this proceeding and, if adopted, it will conflict with the guidance the Commission has already given in two other proceedings.[53] Cal Advocates raises similar concerns in its Opening

[50] TURN Opening Brief, p. 7.
[51] TURN Opening Brief, p. 4.
[52] Cal Advocates Opening Brief, pp. 13-14.
[53] GRC Phase 2's present marginal cost methodologies, revenue allocation, and rate design for CPUC jurisdictional revenue requirements.

Brief in citing the Commission's ongoing ratepayer funded Transmission and Distribution Cost Study (R.22-11-013)[54] as an example of how SEIA's MTCC proposal circumvents existing efforts and would be duplicative to the MTCC determined in R.22-11-013. The inconsistencies and inefficiencies are further exacerbated by the fact that the Commission has already provided guidance consistent with CCR Section 1623 (a) regarding MTCCs in D.25-08-049,[55] to which SCE has responded with a proposal that bridges the jurisdictional gap between the CPUC and the FERC.[56] SEIA's proposal, in contrast, only increases this jurisdictional gap by establishing transmission rates based on a MTCC value that results in a revenue requirement that is greater than the actual FERC authorized revenue requirement[57] and by changing the allocation of costs from the FERC authorized embedded cost methodology to the CPUC policy of marginal cost allocation. If SEIA's MTCC is approved for the purpose of NBT export compensation, as suggested by SEIA, the discrepancy between SEIA's value and the embedded cost of service value authorized by FERC can create a cost shift as the resulting export price will be based on a unit marginal cost value that exceeds the authorized embedded costs.

While SCE agrees with SEIA's position that some level of transmission cost of service "will be necessary to derive an accurate transmission component of the dynamic rates that are under development pursuant to R. 22-07-005," SCE disagrees with SEIA's approach, which is not aligned with the FERC's embedded cost methodology. SCE urges the Commission to continue the exploration of SCE's transmission dynamic rates through the ongoing Dynamic Rate Applications SCE filed in 2024 and the CEC Load Management Standards.

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[54] *Id*, p. 9.

[55] D.25-08-049, p. 67.

[56] A.24-06-024 et al SCE-04 Supplemental Testimony, pp. 12-16.

[57] As pointed out in Cal Advocates' Opening Brief on page 8, SEIA's MTCC value results in a revenue requirement that is 25% greater than the actual transmission revenue requirement at the time SEIA filed its testimony. When compared to current 2025 Base Transmission Revenue Requirements, SEIA's MTCC value is 31% greater than the actual revenue requirement reflected in FERC Filing ER25-550.

In its Supplemental Testimony, filed to address D.25-08-049, SCE proposes a methodology for the design of the transmission component of dynamic rates[58] that is consistent with CPUC and FERC policies regarding seasonal allocation of revenue recovery and establishment of the overall cost of service.[59] The proposal is based on the monthly Coincident Peak (CP) demand methodology to allocate costs to each rate group based on each rate group's contribution to the coincident peak demands in each month (12-CP) of the year relative to the coincident peak demands in the summer months (4-CP). Currently the 12-CP allocation methodology is used in both jurisdictions and when combined with the 4-CP is appropriate for determining seasonal allocation. The underlying data can also be reduced to hourly values as required. SCE's proposal also relies on FERC's embedded cost methodology to determine the overall unit cost of service.

The framework for the proposal SCE detailed in its Supplemental Testimony in D.25-08-049 was filed and approved by the California Energy Commission in its LMS Compliance Plan.[60] Therefore, SCE has considered and aligned the regulatory requirements of three regulatory authorities in developing the transmission component of its dynamic rates. By contrast, SEIA appears to have not considered any of these requirements by (1) proposing an MTCC in SCE's GRC Phase 2 proceeding when the CPUC already has an ongoing effort in R.22-11-013 and has provided guidance in D.25-08-049; (2) introducing a marginal cost of service methodology for a rate component that is based on embedded cost methodology; and (3) not taking into account the regulatory structure the CEC has already established for the determination of transmission dynamic rates. SEIA's proposed MTCC will not contribute towards more accurate transmission dynamic rates and instead will conflict

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[58] A.24-06-024 et al SCE-04 Supplemental Testimony, pp. 12-16.

[59] Here SCE refers to the overall cost of service as being MTCC with respect to CPUC ratemaking and the embedded (i.e., average) cost of service with respect to FERC ratemaking.

[60] SCE's Revised LMS Compliance Plan was filed under Docket No. 23-LMS-01 (TN# 262312) on March 24, 2025, and subsequently approved by the California Energy Commission via signed Order No. 2500508-05a (TN# 263178) on May 16, 2025. *See* https://efiling.energy.ca.gov/GetDocument.aspx?tn=262312&DocumentContentId=98828

with and detract from the ongoing efforts in this area. For these reasons, and those stated above, the Commission should reject SEIA's MTCC proposal.[61]

IV.

CAL ADVOCATES' OPPOSITION TO THE VGRP SETTLEMENT AGREEMENT SHOULD BE REJECTED

Cal Advocates claims the Avoided Cost Calculator (ACC) "was not developed for use in determining dynamic export rates, but rather to evaluate and inform planning and policies at the Commission."[62] Cal Advocates made the same argument in its Comments on the VGRP Settlement Agreement, which the Settling Parties to the VGRP Settlement Agreement refuted in Joint Reply Comments. As the Settling Parties pointed out, the Commission's decisions offer no support for Cal Advocates' position;[63] Cal Advocates has not identified newfound support here. The Commission has described the ACC as reflecting the value of exported energy and ensuring costs and benefits of net billing are approximately equal.[64] Basing export compensation on the Energy Export Credit (EEC) (the average hourly weekday and weekend ACC values applied to Net Billing Tariff exports) is appropriate for an asymmetric rate design such as VGRP.[65] Cal Advocates' opposition should be rejected and, for the reasons stated in the Motion for Adoption of the VGRP Settlement Agreement and the Joint Reply Comments, the settlement agreement should be adopted.

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[61] SEIA also claims in its Opening Brief that MTCCs should be established in this proceeding because the Commission determined MTCCs for PG&E in their 2020 GRC Phase 2 proceeding. *See* D. 21-11-016. Yet the Commission's 2021 decision in the PG&E 2020 GRC Phase 2 proceeding is inapposite. Unlike in 2021, there are now other ongoing Commission proceedings addressing the issue of MTCCs and any determination of MTCCs in this proceeding is highly likely to lead to conflicting or contradictory decisions. Regardless, the PG&E decision is distinguishable because in that proceeding, PG&E affirmatively requested that the Commission determine its MTCCs and did not argue, as SCE and Cal Advocates do here, that the issue was out of scope. *See* D. 21-11-016 at p. 65.

[62] Cal Advocates Opening Brief, p. 13.

[63] Joint Reply Comments (October 27, 2025), pp. 5-8.

[64] Joint Reply Comments, p. 6.

[65] Joint Reply Comments, pp. 5-8.

V.

CONCLUSION

For the reasons set forth in this Reply Brief as well as in SCE's Opening Brief, the Commission should approve SCE's PRIME Plus proposal, reject TURN's proposal to modify the calculation of the baseline allowances, and reject SEIA's proposed MTCC. The Commission should also adopt the EV Settlement Agreement for the reasons stated in the Motion to Adopt the settlement agreement and the Joint Reply to Cal Advocates' comments in opposition to the settlement agreement.

Respectfully submitted,

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