

**Docket No. A.24-03-019**

**Exhibit No. \_\_\_\_\_**

**Date: January 8, 2025**

**Witnesses: Catherine E. Yap  
Sam Harper**

**TESTIMONY OF  
CATHERINE E. YAP AND SAM HARPER  
ON BEHALF OF  
THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION**

**January 8, 2025**

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**Attachment A: Qualifications of Catherine E. Yap**

**Attachment B: Qualifications of Sam Harper**

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**Attachment D: SCE Responses to Selected CLECA Data Requests**

**Attachment E: CPUC and E3, IRP Inputs & Assumptions 2023-2024 Integrated Resource  
Planning, excerpts**

**Attachment F: CPUC, 2023 Proposed PSP & 2024-2025 TPP Resolve Modeling Results  
with updated slides, November 2023, excerpt**

**Attachment G: SCE Response to PAO-03**

**Attachment H: SCE Schedule TOU-8, excerpts**

**Attachment I: SCE Preliminary Schedule W, excerpt**

**Attachment J: SCE Schedule DL-NBC, excerpt**

**Attachment K: National Energy Regulatory Associates (NERA), *A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States* (February 1977) (excerpt)**

**Attachment L: CPUC, California Industry Assistance : What is the purpose of the California Industry Assistance Credit?**

**Attachment M: A.23-05-010, SCE-04, Vol. 5, Part 1, excerpt**

**Attachment N: SEIA Fact Sheet Second Quarter 2024**

**Attachment O: California Energy Commission, California Energy Storage System Survey, excerpt**

**Attachment P: Joint Agency Reliability Planning Assessment, excerpt**

1                   **TESTIMONY OF CATHERINE E. YAP AND SAM HARPER**  
2   **ON BEHALF OF**  
3                   **THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION**

4  
5  
6   **I.     Introduction**

7                   This testimony is presented by Catherine E. Yap and Sam Harper on behalf of the  
8   California Large Energy Consumers Association (CLECA).<sup>1</sup> Ms. Yap has four decades of  
9   experience preparing and delivering testimony regarding utility ratemaking before this  
10   Commission as well as in other jurisdictions. Sam Harper has extensive experience managing  
11   energy across North American markets on behalf of large energy consumers, Independent  
12   System Operators (ISO) and Regional Transmission Organizations (RTO) governance, and  
13   delivering testimony before this Commission as well as other jurisdictions. Ms. Yap’s statement  
14   of qualifications is included as Attachment A to this testimony. Mr. Harper’s statement of  
15   qualifications is included as Attachment B to this testimony.

16                  Southern California Edison Company (SCE) filed its application on March 29, 2024, to  
17   update electric marginal costs and the associated cost of service, revise interclass revenue  
18   allocation, and modify rate designs for each customer class. SCE filed an amended application

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<sup>1</sup> CLECA member companies produce goods essential for daily life, including critical infrastructure, oxygen for hospitals, and food distribution. CLECA members represent the steel, cement, industrial and medical gas, beverage, minerals processing, cold storage, and pipeline transportation industries. Their aggregate electric demand is about 500 Megawatts, which is equivalent to the electricity consumption of approximately 470,000 average California households. CLECA members are large, high load factor and high voltage industrial electric customers in California for whom the price of electricity is essential to their competitiveness and for whom the reliability of electricity service is critically important. For both reasons, CLECA member companies have participated for decades in the Base Interruptible Program (BIP), providing reliability demand response to the grid in times of need. Some members are bundled customers, others are Direct Access (DA) customers, and some are served by Community Choice Aggregators (CCAs); several members have onsite renewable generation.

1 on August 26, 2024 that made corrections to the original application. This testimony responds to  
2 Issues 1 to 3 in the November 1, 2024, Assigned Commissioner’s Scoping Memo and Ruling  
3 that address whether SCE’s proposed marginal costs, cost of service, revenue allocation, and rate  
4 designs are reasonable.<sup>2</sup>

5 On November 22, 2024, the Public Advocates Office (Cal Advocates) served its opening  
6 testimony in the proceeding. This testimony also responds to statements and proposals made by  
7 the Cal Advocates in its opening testimony.

## 8 **II. Conclusions and Recommendations**

9 Industrial electric rates are 250% of average rates in neighboring states, which makes it  
10 difficult for companies to stay in California and remain competitive. These companies provide  
11 essential jobs and contributions to the California economy supplying critical goods and services  
12 essential to the well-being of all Californians, including materials for critical infrastructure,  
13 medical grade hospitals, and food storage and distribution. California is rightly concerned about  
14 the climate change impact of emissions leakage when energy intensive industries can no longer  
15 compete locally causing the state to import critical materials from outside California that are  
16 made with less stringent regulation, dirtier electricity and shipped over longer distances with  
17 higher transportation emissions.

18 Adhering to sound marginal cost rate making principles is critical to send proper price  
19 signals and avoid cross-subsidies, as well as to encourage efficient customer investment and  
20 consumption of energy. CLECA proposes in this testimony adoption of cost allocation and rate  
21 design with the latest resource cost data available and based on sound marginal cost causation

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<sup>2</sup> Assigned Commissioner’s Scoping Memo and Ruling, November 1, 2024 at 2.

principles. In contrast, we strongly oppose the use of outdated assumptions and faulty adjustments to resource costs, and allocation of peak related distribution costs when capacity is not constrained; we also deeply oppose allocation of costs using an arbitrary equal cents per kWh allocator which are utterly unrelated to their actual cost of service, and significantly flatter rates across time-of-use (TOU) periods, sending inefficient price signals to consumers.

## A. Marginal Cost

### 1. Marginal Generation Capacity Cost (MGCC)

CLECA recommends the following marginal generation capacity costs shown below in

Table 1:

**Table 1: CLECA’s Recommended MGCC**

<u>Net CONE Table</u>		
	Units	2025
1 CONE Battery	\$/kW-Yr	234.11
2 CONE Solar	\$/kW-Yr	91.24
3 Energy Revenues	\$/kW-Yr	157.29
4 Net CONE (Line 1 + Line 2 - Line 3)	\$/kW-Yr	168.07

As discussed in Section IV.A, the MGCCs should be based on the 2023 IRP model rather than the 2022 IRP model as SCE proposes.

### 2. Marginal Energy Costs (MECs)

CLECA recommends the following marginal generation capacity costs shown below in

Table 2:

**Table 2: CLECA’s Recommended MECs**

Cost Component	Annual	Summer			Winter		
Component		On	Mid	Off	Mid	Off	Super Off
Energy (¢/kWh)	4.962	6.705	7.720	4.868	5.681	5.939	2.637

As discussed in Section V.A, the MECs should be based on the 2023 IRP model rather than the 2022 IRP model as SCE proposes.

1                   **3.     Marginal Distribution Capacity Cost (MDCC)**

2                   As discussed in Section VI. D, CLECA recommends the adoption of A-bank substation  
3 peak load risk factors (PLRFs) based on a 73 percent of Planning Load Limit (PLL) threshold  
4 instead of a 73 percent of substation peak load threshold. Additionally, CLECA recommends  
5 that the PLRFs be developed on a regional basis and applied to customer classes on a regional  
6 basis before the regional results are rolled up into a systemwide customer class share. CLECA’s  
7 recommended PLRFs for the A-bank substation are shown below in Table 3:

8                   **Table 3: CLECA’s Recommended A-Bank PLRFs**

9

Resi- dential	GS-1	GS-2	TOU-GS	TOU- PA-2	TOU- PA-3	TOU-8 -SUB	TOU-8 -PRI	TOU-8 -SEC	Tr Contr & Strlgt	Total Regional
5,284	610	1,513	784	68	77	312	478	711	14	9,851
53.6%	6.2%	15.4%	8.0%	0.7%	0.8%	3.2%	4.9%	7.2%	0.1%	100.0%

10

11                   **4.     Marginal Customer Cost (MCC)**

12                   As discussed in Section VII, CLECA endorses SCE’s marginal customer costs based on  
13 the real economic carrying cost (RECC) methodology.

14                   **B.     Cost Allocation**

15                   Table 4 below shows CLECA’s recommended cost allocation for both bundled and  
16 DA/CCA customers:

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**Table 4**

<b>CLECA Proposed Cost Allocation</b>						
<b>Showing Bundled Service and DA/CCA Average Rates</b>						
<b>By Rate Group (c/kWh)</b>						
	<b>Bundled Service</b>			<b>DA/CCA</b>		
	<b>Current (¢/kWh)</b>	<b>Proposed (¢/kWh)</b>	<b>% Change</b>	<b>Current (¢/kWh)</b>	<b>Proposed (¢/kWh)</b>	<b>% Change</b>
<b>Total Domestic</b>	32.6	38.0	16.7%	17.3	18.8	8.3%
TOU-GS-1	29.0	23.5	-19.2%	13.1	12.5	-4.6%
TC-1	33.7	28.2	-16.5%	19.3	14.8	-23.3%
TOU-GS-2	31.6	26.6	-15.8%	13.7	12.3	-9.9%
TOU-GS-3	25.6	23.4	-8.7%	11.2	11.1	-1.0%
<b>Total LSMP</b>	29.3	24.9	-14.9%	12.8	12.0	-6.5%
TOU-8-Sec	23.5	21.7	-7.7%	10.4	10.2	-2.6%
TOU-8-Pri	22.0	20.8	-5.4%	9.2	9.0	-1.7%
TOU-8-Sub	14.8	14.4	-2.3%	4.4	4.5	1.1%
<b>Total Large Power</b>	20.6	19.3	-5.9%	8.0	7.9	-1.6%
TOU-PA-2	25.6	22.1	-13.7%	12.2	10.1	-16.6%
TOU-PA-3	21.3	21.7	1.9%	9.5	9.7	1.4%
<b>Total Ag.&amp;Pumping</b>	23.6	21.9	-7.1%	10.8	9.9	-8.7%
<b>Total Street Lighting</b>	30.5	44.6	46.1%	25.3	37.1	46.9%
STANDBY/SEC	24.8	21.8	-11.9%	11.4	10.7	-5.8%
STANDBY/PRI	24.0	22.2	-7.7%	10.7	10.1	-5.4%
STANDBY/SUB	16.3	15.9	-2.8%	5.5	5.4	-1.2%
<b>Total Standby</b>	17.9	17.1	-4.4%	7.0	6.8	-3.1%
<b>Total System</b>	27.7	27.7	0.1%	12.5	12.6	0.9%

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**C. Rate Design**

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As discussed in Section XI, CLECA has prepared a TOU-8 Option D rate design for each voltage. This rate design is based on our proposed cost allocation and basic principles of promoting cost based rates while avoiding rate shock. The results are presented below in Table 5:

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2

**Table 5**

<b>CLECA Proposed Option D Rate Design</b>							
	<b>TOU-8-SUB-D</b>		<b>TOU-8-PR1-D</b>		<b>TOU-8-SEC-D</b>		
	Distribution	Generation	Distribution	Generation	Distribution	Generation	
<b>Summer</b>							
Customer Charge \$/month	5,121.00	-	214.25	-	1,733.50		
On-Peak \$/kWh	0.00000	0.12820	0.00720	0.13482	0.00795	0.13288	
Mid-Peak \$/kWh	0.00000	0.12287	0.00655	0.12783	0.00723	0.12694	
Off-Peak \$/kWh	0.00000	0.05922	0.00642	0.06111	0.00708	0.06275	
SuperOff-Peak \$/kWh	-	-	-	-			
On-Peak \$/kW	2.64	28.16	12.18	26.98	12.41	24.49	
Mid-Peak \$/kW	-	-	-	-	-	-	
Off-Peak \$/kW	-	-	-	-	-	-	
SuperOff-Peak \$/kW	-	-	-	-	-	-	
Max-Demand \$/kW	4.62	-	15.62	-	15.17	-	
<b>Winter</b>							
Customer Charge \$/month	5,121.00	-	214.25	-	1,733.50	-	
On-Peak \$/kWh	-	-	-	-			
Mid-Peak \$/kWh	0.00000	0.09296	0.00720	0.09649	0.00795	0.09665	
Off-Peak \$/kWh	0.00000	0.07215	0.00655	0.07397	0.00723	0.07552	
SuperOff-Peak \$/kWh	0.00000	0.03207	0.00614	0.03285	0.00681	0.03354	
On-Peak \$/kW	-	-	-	-			
Mid-Peak \$/kW	0.04	14.08	1.92	12.11	1.70	10.58	
Off-Peak \$/kW	-	-	-	-	-	-	
SuperOff-Peak \$/kW	-	-	-	-	-	-	
Max-Demand \$/kW	4.62	-	15.62	-	15.17		

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### **III. Background**

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#### **A. The Importance of Competitive Electricity Rates to Large Consumers**

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CLECA member companies are interested in safe, reliable, clean and affordable electricity to supply their operations that produce critical goods and services essential for daily life. The price of electricity is essential to CLECA member companies. Most of the CLECA member company operations are highly trade exposed and compete with operations in western states, across the US, and internationally. Energy costs are a significant driver of these energy intensive operations' ability to compete and impact their ability to maintain or expand operations within the state.

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1           The ability for CLECA members to compete is important to achieve the economic and  
2 environmental policy goals of the state of California. These companies comprise a meaningful  
3 portion of the California economy across numerous sectors and provide family sustaining jobs  
4 throughout the state. Importantly, the critical materials supplied by CLECA members are energy  
5 intensive to produce and heavy to transport. Producing these materials in-state reduces emissions  
6 overall compared to production out of state with less stringent environment regulations, longer  
7 transportation distances and less clean electricity. When these critical operations are no longer  
8 able to compete, in part due to electricity prices, the production is shifted out of state and overall  
9 emissions increase.<sup>3</sup>

10           Further, many CLECA members have set individual environmental targets that involve  
11 electrifying portions of their operations, adopting carbon capture technology, or other  
12 technologies that involve consuming significantly more electricity to run their highly energy  
13 intensive processes. The ability to invest and execute in these environmental strategies depends  
14 directly on the price of electricity.

## 15           **B. Large Energy Consumers are Facing an Affordability Crisis**

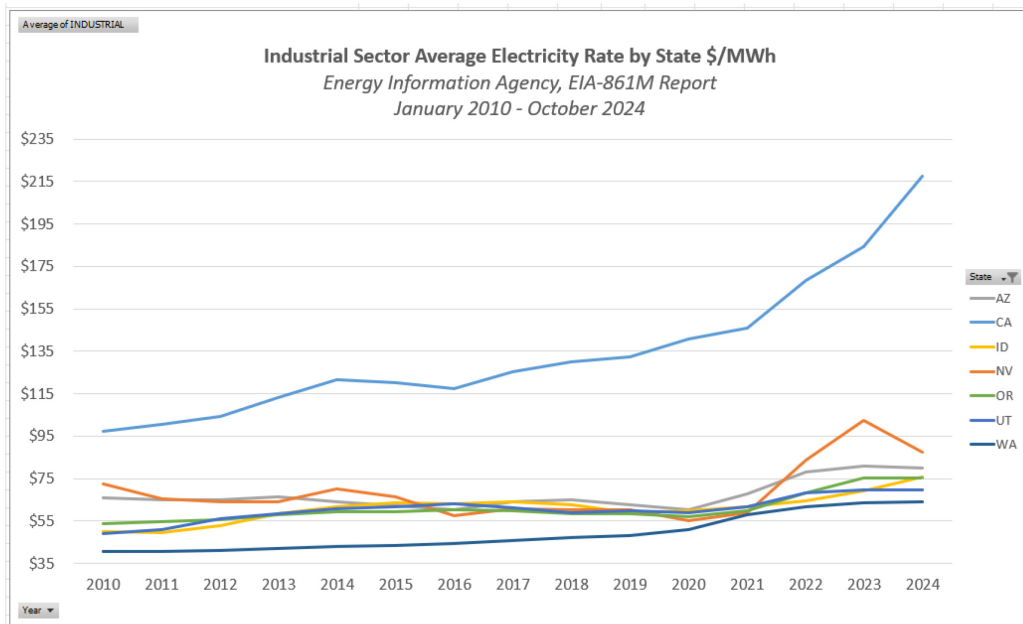
16           CLECA member companies are facing an affordability crisis. As shown in Figure 1  
17 below, California electric rates for industrial sector customers are approximately 250% of the  
18 average industrial sector rates of neighboring western states. This gap has grown dramatically in  
19 recent years, which is an extremely concerning trend for any investment, production, or closure  
20 decisions that are made based on assumptions about the future.

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<sup>3</sup> See, Attachment L: CPUC, California Industry Assistance : What is the purpose of the California Industry Assistance Credit?

1

**Figure 1**



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Furthermore, as shown below in Figure 2, SCE industrial sector rates are also much

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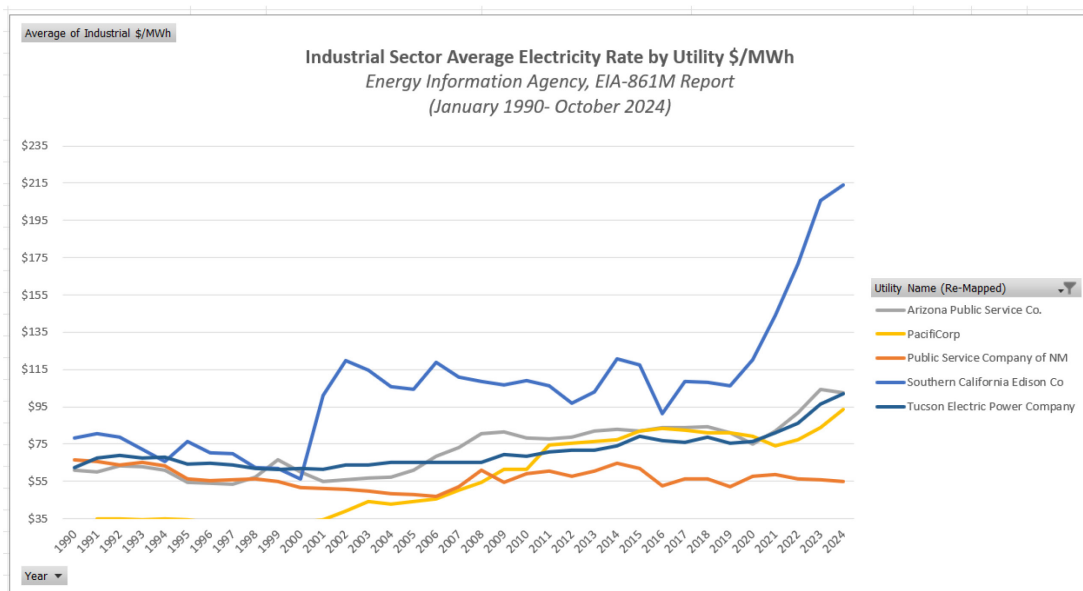
higher than neighboring states' industrial rates and very concerningly, the gap has exploded in

5

recent years.

6

**Figure 2**



7

1 Many large energy consumers compete with these neighboring states for existing  
2 production capacity or future plant investments. These neighboring states' dramatically lower  
3 electric rates create a strong incentive to move energy intensive operations out of state and put  
4 untenable competitive pressure on operations looking to remain, expand, or electrify in  
5 California. The ongoing and potentially increasing risk economic and emissions leakage should  
6 be of great concern. The Commission should move to address this risk by adhering to cost  
7 causation principles without cross subsidies and effective price signals.

### 8 **C. High Electric Rates Have Already Driven Large Consumers out of State**

9 SCE makes several proposals that significantly increase the cost allocation to large  
10 energy consumers based on flawed assumptions or faulty adjustments to resource costs and  
11 allocation of peak related distribution costs when capacity is not constrained.

12 In its testimony, Cal Advocates makes numerous proposals that would make the cost  
13 allocation deviate sharply from a cost-of-service basis by applying capricious adjustments to  
14 resource costs and assigning cost responsibility for wildfire costs and transportation  
15 electrification on an equal cents per kWh basis.

16 The Commission should reject these proposals that deviate from sound cost causation  
17 principles and artificially push cost responsibility onto industrial rates. Driving up the level of  
18 industrial rates is inappropriate and counterproductive to California's economic and climate  
19 policy goals.

20 Industrial customers like CLECA members are unable to simply pass along the higher  
21 electricity costs proposed by SCE and Cal Advocates because they compete in out-of-state and  
22 international markets. The SCE and Cal Advocates proposals would drive up the level of already  
23 high electricity rates to an even greater extent and further undermine the viability of industrial

1 businesses in California. Cal Advocates' proposal would undermine the State's climate goals,  
2 because keeping the production of cement, steel, minerals, industrial gases, beverages, and  
3 provision of cold food storage in California enables their manufacturing where the energy is  
4 cleaner, regulations are more robust, and avoids additional emissions associated with  
5 transportation from out-of-state facilities. California is rightly concerned about greenhouse gas  
6 (GHG) leakage in the electric energy sector and GHG leakage from critical industries moving  
7 outside California as part of implementing its climate change policy; this concern warrants  
8 recognition in the rate making process.

9 Departing from proper marginal cost-based ratemaking to incorporate subsidies and  
10 inaccurate price signals creates economic distortions. The importance of accurate price signals  
11 becomes ever greater as more options emerge for customers to manage their energy consumption  
12 pattern or install their own distributed energy resources (DERs). The decision of an individual  
13 customer to electrify its industrial operation, charge an electric vehicle (EV) at a particular time,  
14 invest in onsite solar or batteries, run the air conditioning on a particular day, or continue to  
15 operate a business or expand operations in California are all influenced by the electricity price  
16 signal.

17 When rates exceed the actual cost of providing energy at a specific location and time,  
18 customers are economically incentivized to reduce energy consumption in ways that are  
19 inefficient. This behavior decreases their contribution to fixed costs, which in turn drives up rates  
20 for everyone else. On the other hand, when rates are set below the actual cost, customers are  
21 encouraged to use more energy than is economically efficient, increasing overall system costs.  
22 These additional costs must then be recovered from other customers through cross-subsidies.  
23 Over time, this creates a vicious cycle: the burden of cross-subsidies raises rates for those paying

1 them, further incentivizing those customers to find alternatives and bypass the utility system  
2 altogether.

### 3 **D. Marginal Cost Basis for Cost Allocation and Rate Design**

4 As noted by SCE, the Commission has long used marginal cost to establish the cost to  
5 serve different classes of customers. A marginal cost is the incremental cost of providing service  
6 in response to an increment of demand for that service. The Commission determined that  
7 marginal cost pricing is important because it signals to the customer the economic cost of using  
8 an additional unit of service.

9 The majority of marginal costs involve investment or fixed forward commitments of  
10 some form that are paid for by all relevant ratepayers. We note that in theory this is true  
11 regardless of whether a new customer or an existing customer is making the consumption  
12 decision. In practice, however, some aspects of utility service, like demand at peak, are more  
13 readily fungible than others, like customer connection (or hookup) costs.

14 The Commission adopted the marginal cost approach to revenue allocation in the 1980s,  
15 concluding that the use of marginal costs in ratemaking sends proper price signals that will result  
16 in more efficient consumption decision-making by ratepayers.<sup>4,5</sup> Revenue allocation  
17 determinations by the Commission have been based on marginal costs for over three decades.  
18 California is unusual in its use of marginal costs for revenue allocation purposes, in that many  
19 states allocate revenue requirement to classes using embedded cost techniques. On the other

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<sup>4</sup> See, CPUC D. 91729 (March 3, 2981) OII No 67, Investigation on the Commission's own motion into a methodology for the calculation of marginal costs of electric service.

<sup>5</sup> See, Southern California Edison Company, D.96-04-050, 65 CPUC 2d 362 (1996). "In today's decision, we reaffirm our commitment to the policy of marginal cost-based ratemaking." See pp. 383-406 for a full explanation of the Commission's marginal cost principles and their use in development of marginal costs and for revenue allocation in that proceeding. See also, Pacific Gas & Electric Co., D.95-12-051, 63 CPUC 2d 298, at 322-323 (1995).

1 hand, many jurisdictions, including California, have used marginal costs for many years for rate  
2 design purposes. Our testimony in this proceeding is based on what we believe is the closest  
3 adherence to the marginal cost policies that the Commission has pursued during this extended  
4 period of time.

5 We note that the Commission’s use of marginal costs for allocation purposes can create  
6 some problems. The use of marginal costs for this purpose, as discussed in greater detail later in  
7 this testimony, requires that the marginal cost revenues, *i.e.*, indicated marginal costs multiplied  
8 by class billing determinants, have to be scaled up or down to reconcile and collect the actual  
9 revenue requirement. This is due to the fact that marginal costs do not equal average or  
10 embedded costs; instead, the sum of the marginal costs is generally either significantly greater or  
11 significantly smaller than the related embedded costs (*i.e.*, revenue requirement) to be recovered  
12 from the several customer classes. Not only are marginal cost revenues scaled, but individual  
13 rate elements are also scaled by the same factor. This raises some concern about the accuracy of  
14 the cost responsibility price signal that is being sent by using marginal costs with such scaling.

15 Since the provision of electricity is unbundled from the provision of transmission<sup>6</sup> and  
16 distribution services, this testimony will separately address those marginal costs associated with  
17 electricity generation and those marginal costs associated with electricity delivery.

#### 18 **IV. Marginal Generation Capacity Costs**

19 CLECA’s recommended generation marginal capacity cost (MGCC) for the 2025-2028  
20 rate case cycle is shown below in Table 6:

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<sup>6</sup> The transmission of electricity is regulated by the Federal Energy Regulatory Commission and as such will not be addressed here except to include authorized costs in revenue requirement and customer rates.

1 **Table 6**

2

**Net CONE Table**

	Units	2025
1 CONE Battery	\$/kW-Yr	234.11
2 CONE Solar	\$/kW-Yr	91.24
3 Energy Revenues	\$/kW-Yr	157.29
4 Net CONE (Line 1 + Line 2 - Line 3)	\$/kW-Yr	168.07

3

4 **A. SCE’s Marginal Cost Is Artificially Low Because It is Based on Outdated**

5 **Resource Costs.**

6 SCE proposes to use a six-hour lithium-ion (Li-ion) battery paired with solar (hybrid PV

7 + storage) as its MGCC proxy resource.<sup>7</sup> SCE identifies what it terms the “net cost of a new

8 entry (CONE)” of a hybrid PV + storage project. SCE estimates the Net CONE as the cost of the

9 hybrid PV + storage project less the estimated energy rents obtained in the energy market, which

10 yields a net hybrid PV + storage cost.

11 The Integrated Resource Plan (IRP) model, as contained in the RESOLVE model

12 prepared by the consultant Energy + Environmental Economics (E3), presents solar and battery

13 costs annualized in \$/kW-year, which SCE uses directly in its Net CONE model.<sup>8</sup> In performing

14 its calculations, SCE is relying directly on these solar and battery cost assumptions from the June

15 2022 version of the model, which have become very stale. SCE then reduces the 2022 IRP cost

16 estimates to reflect what SCE believes is the impact of the Inflation Reduction Act (IRA)<sup>9</sup>.

17 Thus, SCE produces a MGCC that is artificially low.

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<sup>7</sup> SCE-02A at 12-13.

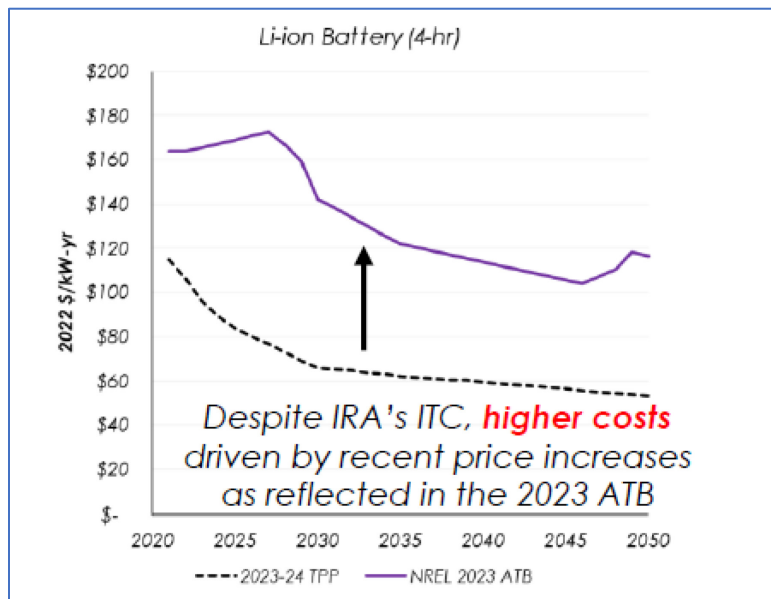
<sup>8</sup> Attachment D: SCE Response to CLECA-04, Q.4.1.1.

<sup>9</sup> Public Law No. 117-169, August 16, 2022.

1                   **1.     The 2023 IRP Model Significantly Updates Battery and Solar Costs**  
2                   **Relative to the 2022 IRP Model.**

3                   The Commission’s Energy Division staff significantly updated its resource cost analysis  
4 in 2023, recognizing the large price increases experienced by suppliers during 2021-2023. The  
5 staff’s 2023 analysis also incorporates a detailed assessment of the effects of the IRA on resource  
6 cost profiles, which offsets some of the price increases. The results, as presented in November  
7 2023, demonstrate a very large increase in battery costs, as shown below in Figure 3 for a four-  
8 hour battery, and a decrease in solar costs in the post 2030 timeframe, as shown below in Figure  
9 4 for a solar tracking project. The dotted line in each of the figures shows the cost projections  
10 associated with the 2022 version of the IRP model while the solid, colored line shows the cost  
11 projections associated with the 2023 version of the IRP model.

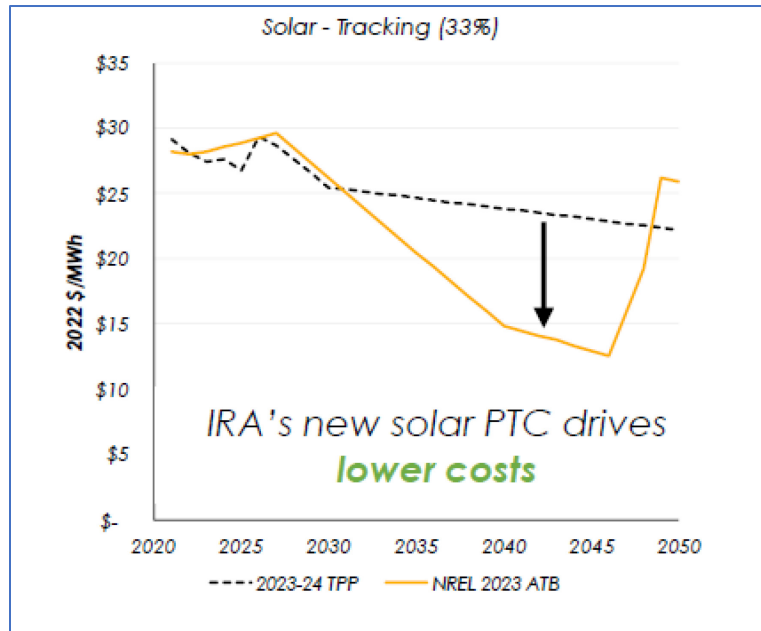
12                   **Figure 3<sup>10</sup>**



13  
14  
<sup>10</sup> Attachment F: 2023 Proposed PSP & 2024-2025 TPP Resolve Modeling Results with updated slides, November 2, 2023, at slide 12.

1

Figure 4<sup>11</sup>



2

3 Clearly, the effect of the IRA, combined with the notable price increases experienced  
 4 over the last several years, produces very significant changes in cost predictions. While there are  
 5 significant cost decreases in the solar cost profile due to the effect of the IRA in the post-2030  
 6 timeframe, there are cost increases projected through 2027. In contrast, battery costs have nearly  
 7 doubled despite the effect of the IRA, again showing cost escalation through 2027 followed by  
 8 slower declines in prices through the 2030s. Thus, given SCE's selection of a solar-battery  
 9 hybrid proxy resource for its MGCC assessment, it is imperative that these updated costs be  
 10 reflected in its analysis.

11 We asked SCE to update its MGCC calculations based on the 2023 PSP. In complying  
 12 with our request, SCE used the energy revenues calculated with their PLEXOS model and  
 13 previously based on the 2022 PSP.<sup>12</sup> CLECA's calculation below, however, uses energy

<sup>11</sup> *Id.*

<sup>12</sup> Attachment D: SCE response to CLECA-11, Q.11.2 Revised Answer.

1 revenues based on the 2023 PSP.<sup>13</sup> The hourly prices based on the 2023 PSP are placed into  
2 SCE’s model to align the time periods for generation capacity and energy revenue.

3 **2. Net CONE Energy Revenues are Overstated by Assuming Real Dollar**  
4 **Term Energy Prices are Fixed at 2028 Levels**

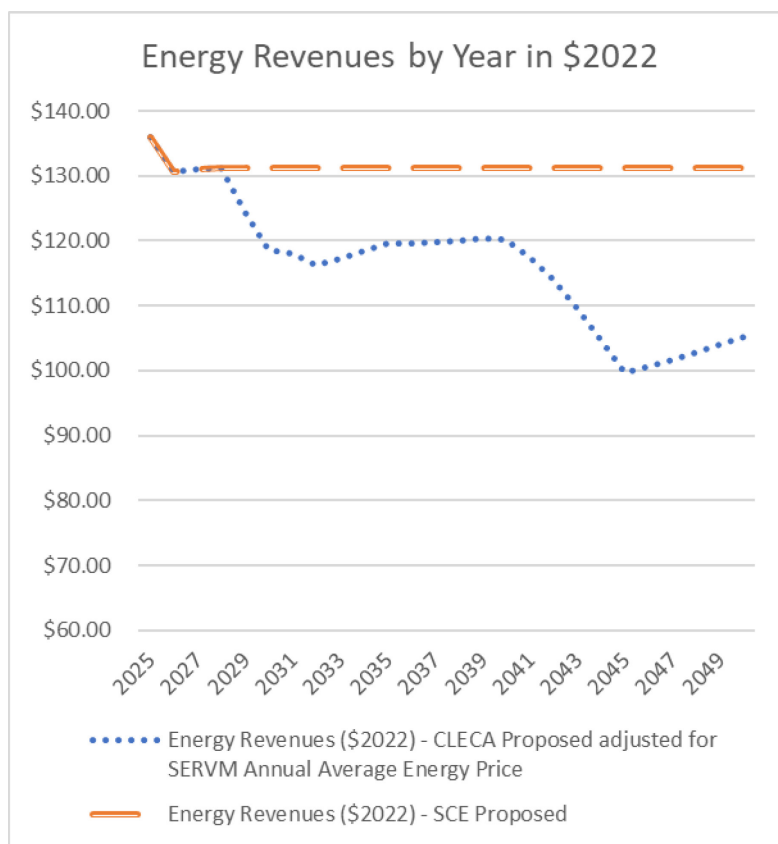
5 SCE assumes Energy Revenues in real 2022-dollar terms for the years 2029 through 2050  
6 to be fixed at the result of their dispatch optimization for 2028, and then adjusts for inflation each  
7 year. The assumption of flat energy revenues for this multi-decade period is unreasonable given  
8 the presumption of dramatically falling solar and battery resource costs throughout the same  
9 period. CLECA does not oppose the use of an inflation adjustment to the Energy Revenues each  
10 year. However, we strongly recommend adjusting the Energy Revenues assumption based on the  
11 2024 ACC SERVM average price factor by year through 2050 instead of using SCE’s proposal  
12 to use 2028 real prices to represent prices from 2028 through 2050. The use of 2028 real prices  
13 to represent 2029-2050 real prices overstates those prices as shown in Figure 5 below.

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<sup>13</sup> 2024-ACC-SERVM-Energy Prices v.1a at tab “2022 Real Prices wo Carbon”.

1

**Figure 5**



2

3 In either case, the annual average prices in real 2022-dollar terms are adjusted for  
 4 inflation. SCE’s proposal overstates the energy revenues significantly, which in turn understates  
 5 the NetCONE significantly. The CLECA proposed approach is aligned with the SERVM results  
 6 and better matches declining resource cost assumptions.

7 **3. SCE MGCC Is Understated by Not Adjusting for Effective Load**  
 8 **Carrying Capacity (ELCC)**

9 SCE calculated the marginal cost of its proxy resource without adjusting for ELCC. The  
 10 combination of solar and 6-hour battery, although reasonably matching the typical peak hours,  
 11 falls well short of a perfect resource to meet load requirements. The IRP uses ELCC to represent,  
 12 “a firm generator that has no outages, fuel constraints, or other availability limitations” and

1 “since no resource provides perfect capacity.”<sup>14</sup> To ensure resource adequacy counting is aligned  
 2 with other resource modeling assumptions, “all resources must be counted at their ELCC” as  
 3 “the contribution of each resource to the total reliability need requirement depends on its  
 4 performance characteristics, the availability to produce power during the most constrained  
 5 periods of the year, and interactive effects with other resources.”<sup>15</sup> The comparison of the  
 6 capacity value of batteries in comparison with other potential capacity resources in terms of the  
 7 ELCC of each resource type is shown below in Figure 6:

8 **Figure 6**<sup>16</sup>



10 The lower the ELCC, the lower the ability for the resource to meet the total reliability need  
 11 requirement. Therefore, the resource installed capacity must be effectively scaled up by 1/ELCC.

12 Solar and batteries in particular are extremely sensitive to “interactive effects” whereby  
 13 increasing penetrations of each resource reduce their ELCC. However, at a given battery  
 14 resource penetration, additional solar improves the battery ELCC. And at a given solar resource  
 15 penetration, additional battery improves the solar ELCC. For this reason, we are supportive of  
 16 the SCE concept of a combined solar and battery resource. Critically, however, the ELCC of  
 17 batteries remains extremely sensitive to battery resource penetration even with ample solar  
 18 resources. For example, the ELCC for a 4-hour battery with 100 GWs of installed solar capacity

<sup>14</sup> Attachment E: Inputs Assumptions 2022-2023\_Final\_Document\_10052023 page 144.

<sup>15</sup> *Id.*, page 147.

<sup>16</sup> *Id.*, page 144.

1 in each case drops from 95% ELCC at 20 GWs of battery capacity to 36% ELCC at 30 GWs of  
2 battery capacity.<sup>17</sup>

3 The IRP modeling produced ELCC values for 4-hour and 8-hour batteries but not  
4 specifically for a 6-hour battery and solar resource. Given the lack of available ELCC values, we  
5 did not adjust the MGCC analysis for the SCE proposed proxy resource. However, we strongly  
6 emphasize that any MGCC value that does not adjust for ELCCs is understated. We consider the  
7 SCE proposed proxy resource with our proposed corrections the absolute minimum reasonable  
8 MGCC.

9 **4. If the Commission Declines to Update the IRP Assumptions Used to**  
10 **Develop SCE’s Hybrid Solar Battery Resource, the Commission Should**  
11 **Direct SCE to Use the 2022 IRP Results Without Modification.**

12 SCE based its MGCC analysis on inputs taken from the 2022 IRP model. However, SCE  
13 modified the 2022 IRP inputs to take into account only one factor: SCE’s estimate of the future  
14 effect of the IRA, which was signed into law in August 2022.<sup>18</sup> SCE acknowledges that it made  
15 only this one change to the 2022 IRP assumptions.<sup>19</sup> The effect of SCE’s IRA adjustment was to  
16 reduce the MGCC by \$0.46/kW-year for the battery and \$1.36/kW-year for the solar array.<sup>20</sup>  
17 However, as CLECA has demonstrated with Figure 3 and Figure 4, the 2022 IRP assumptions  
18 before adding the IRA adjustment were significantly below actual figures. Therefore, SCE’s  
19 adjustment for the IRA effect has only served to increase the error.

20 If the Commission declines to direct SCE to use the 2023 IRP to develop its MGCC, the  
21 Commission should direct SCE to utilize the unadjusted 2022 IRP inputs to develop its MGCC.

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<sup>17</sup> *Id.*, page 157.

<sup>18</sup> Attachment D: SCE Response to CLECA-07, Q.7.1.1.

<sup>19</sup> Attachment D: SCE Response to CLECA-07, Q.7.1.2.

<sup>20</sup> Attachment D: SCE Response to CLECA-07, Q.7.1.3.

1           **B.     Response to Cal Advocates**

2                   **1.     Cal Advocates’ Claim that a Standalone Four Hour Battery Is the**  
3                   **Correct Proxy Resource Is Incorrect.**

4           Cal Advocates proposes to change both SCE’s proxy resource and the source of costing  
5 data:

6                   Cal Advocates proposes a 4-hour lithium-ion battery as the  
7                   marginal proxy resource to calculate MGCCs using data from the  
8                   current Commission approved 2023 IRP workpapers, and leveled  
9                   over a six-year time horizon. As discussed herein, a 4-hour  
10                  lithium-ion battery is preferable to a 6-hour battery because it  
11                  more accurately reflects how capacity needs are met in California.  
12                  Additionally, an accurate assessment of current battery pricing  
13                  requires using 2023 data instead of SCE’s proposed use of 2022  
14                  data.<sup>21</sup>

15           As discussed previously, CLECA agrees with Cal Advocates that SCE’s data source  
16 should be the 2023 IRP rather than the 2022 IRP. However, CLECA strongly disagrees with Cal  
17 Advocates’ claim that the four-hour battery “more accurately reflects how capacity needs are met  
18 in California.”

19           Cal Advocates’ claim that the standalone Li-ion battery is the correct proxy resource is  
20 incorrect. In fact, Cal Advocates seems to have completely missed the 2023 IRP’s careful  
21 examination of the changes in the reliability outlook expected for the four-hour battery, which is  
22 highly relevant to the selection of the six-hour lithium-ion (Li-ion) battery paired with solar  
23 (hybrid PV + storage) as the appropriate MGCC proxy resource.

24           The documentation for the 2023 IRP states:

25                   At low penetration, incremental battery storage ELCCs remain  
26                   high and are not sensitive to the level of solar on the system.  
27                   However, after adding ~10-20 GW of battery storage to the  
28                   system, the net peak extends its duration such that 4-hr battery

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<sup>21</sup> Cal Advocates, Chapter 2 at 2-3.

1 resources have insufficient energy to discharge, reducing their  
2 incremental value. Incremental batteries may also struggle to  
3 charge as the net load during the charging hours has increased such  
4 that there may be insufficient charging energy. At this point, the  
5 ability for battery storage to provide significant additional ELCC  
6 depends on adding solar together with batteries.<sup>22</sup>

7 As of mid-2024, solar penetration statewide is over 49 GW<sup>23</sup> and battery penetration is  
8 over 13 GW.<sup>24</sup> The Phase 2 addresses 2025-2028 so the problem will worsen during this period.  
9 Thus, given the outlook that four hour batteries will struggle to charge fully, they will clearly be  
10 insufficient to meet peak requirements.

11 Furthermore, as SCE notes in its response to a CLECA data request, the Joint Agency  
12 (CPUC and CEC)'s January 2023 Senate Bill 846 report "shows the hours of greatest reliability  
13 need trend lines are flattening and lengthening over time"<sup>25</sup> as illustrated by Figure 7 below:

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<sup>22</sup> Attachment E: Inputs & Assumptions, 2022-2023 IRP, October 2023 at 156.

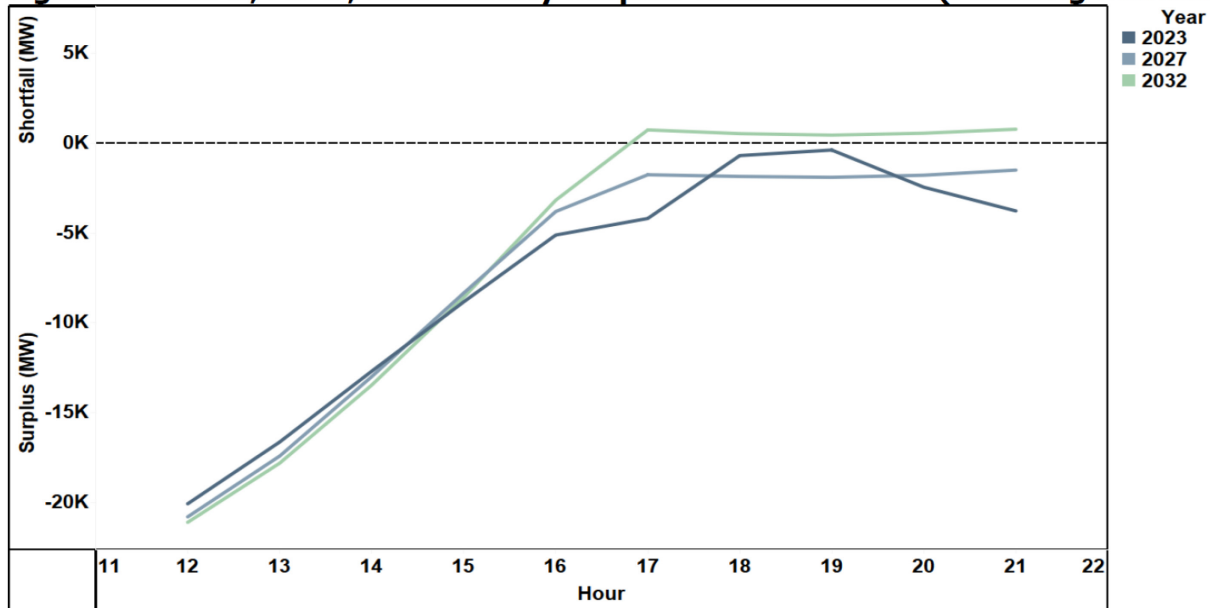
<sup>23</sup> Attachment N: Solar Energy Industries Association Fact Sheet September 2024.

<sup>24</sup> Attachment O: California Energy Commission, California Energy Storage System Survey, September 11, 2024.

<sup>25</sup> Attachment D: SCE Response to CLECA-7, Q.7.2.9, citing to CEC-CPUC, Joint Agency Reliability Planning Assessment - Quarterly Report and AB 205 Report SB 846, February 2023 at 52.

Figure 7<sup>26</sup>

Figure 10: 2023, 2027, 2032 Hourly Surplus-Shortfall Trend (Planning Standard)



It is clearly demonstrable that a four-hour battery is insufficient for the proxy resource given the width of the peak curves. The width of the peak for 2023 is already five hours and the width of the peak for 2027 is much longer. Based on Figure 7 above, one could argue that the battery size should be even longer than six hours. Therefore, the six-hour lithium-ion (Li-ion) battery paired with solar (hybrid PV + storage) is the minimum size for the MGCC proxy resource.

## 2. Cal Advocates' Battery Capacity Must Be Adjusted for Its ELCC.

If the Cal Advocates proposed 4-hour battery is considered, it must be adjusted for its ELCC. As shown above and widely accepted throughout the resource planning process, a 4-hour battery is not a perfect resource, constrained by its use limitations before requiring recharge and limited dispatch duration, and must be adjusted for its ability to meet resource adequacy needs on a level playing field with other resources.

<sup>26</sup> Attachment P: CEC-CPUC, Joint Agency Reliability Planning Assessment - Quarterly Report and AB 205 Report SB 846, February 2023 at 52.

Furthermore, as solar and storage continues to rapidly expand, the ELCC of incremental resources declines rapidly, as shown below in Figure 8:

**Figure 8<sup>27</sup>**

Figure 39. Incremental Battery Storage ELCC % across the ELCC Surface

		Calculated Incremental Storage ELCC %														
		Solar Nameplate Capacity (GW)														
		30	35	40	45	50	55	60	65	70	75	80	85	90	95	100
4-Hour Battery Nameplate Capacity (GW)	0	90%	92%	92%	92%	92%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
	5	90%	92%	92%	92%	92%	92%	92%	92%	95%	95%	95%	95%	95%	95%	95%
	10	90%	90%	92%	92%	92%	92%	92%	92%	92%	95%	95%	95%	95%	95%	95%
	15	70%	79%	79%	87%	90%	90%	91%	92%	92%	92%	92%	95%	95%	95%	95%
	20	33%	33%	33%	65%	70%	75%	81%	84%	84%	84%	90%	90%	92%	92%	95%
	25	33%	33%	33%	33%	37%	44%	45%	52%	52%	52%	52%	52%	52%	52%	52%
	30	27%	27%	27%	27%	27%	28%	30%	32%	36%	36%	36%	36%	36%	36%	36%
	35	17%	17%	17%	17%	17%	17%	17%	17%	28%	32%	36%	36%	36%	36%	36%
	40	9%	9%	9%	9%	9%	9%	9%	11%	11%	12%	12%	32%	36%	36%	36%
	45	9%	9%	9%	9%	9%	9%	9%	9%	11%	11%	11%	11%	12%	36%	36%
50	9%	9%	9%	9%	9%	9%	9%	9%	9%	11%	11%	11%	11%	11%	12%	

Applying the ELCC values from the 2024 ACC to Cal Advocates’ MGCC calculation produces the results in Table 7. If despite SCE’s proposal and our concerns raised in the previous section, the Commission were to adopt a 4-hour battery as the proxy resource, the NetCONE shown in Cal Advocates’ testimony must be adjusted for ELCC. We show the results of the calculation below in Table 7:

**Table 7**

	Units	2025	2026	2027	2028	2029	2030
1 CONE Battery	\$/kW-Yr	184.55	190.56	196.89	194.50	190.82	173.60
2 Energy Revenues	\$/kW-Yr	\$68.39	\$70.58	\$73.27	\$75.65	\$77.29	\$78.97
3 Net CONE (Line 1 - Line 2)	\$/kW-Yr	<b>116.16</b>	<b>119.98</b>	<b>123.62</b>	<b>118.85</b>	<b>113.53</b>	<b>94.64</b>
Effective Load Carrying Capacity (ELCC)		79%	66%	52%	48%	45%	42%
Net CONE = (FixedCost – Revenue)/ELCC		\$ 147.28	\$ 181.28	\$ 239.70	\$ 246.10	\$ 252.20	\$ 226.75
4 Net Present Value (NPV) of 6-Years	\$/kW-Yr	\$995.66					
5 MGCC - Levelized Cost 6 years SCE RoR	\$/kW-Yr	\$211.73					
6 PRM Scaler for Annual Capacity Cost		1.17					
7 MGCC used for revenue allocation	\$/kW-Yr	\$247.73					

<sup>27</sup> Inputs Assumptions 2022-2023\_Final\_Document\_10052023, page 157.



1 system operator dispatches generation plants, which will in turn drive fuel and purchased power  
2 costs. CLECA’s recommended MECs are shown below in Table 9:

3 **Table 9**

Cost Component	Annual	Summer			Winter		
Component		On	Mid	Off	Mid	Off	Super Off
Energy (¢/kWh)	4.962	6.705	7.720	4.868	5.681	5.939	2.637

4  
5 It is noteworthy that SERVVM’s hourly energy prices project high prices during many of the  
6 summer weekend mid-peak periods, which has resulted in the summer mid-peak MECs being  
7 noticeably higher than the summer on-peak MECs.

8 **A. SCE’s Marginal Energy Costs Should Be Based on the 2023 PSP Not on**  
9 **the 2022 PSP.**

10 SCE forecasts hourly marginal wholesale generation energy costs based on forecast  
11 market-clearing prices in the CAISO market using a production cost simulation performed with  
12 the PLEXOS model. The model determines what resource is at the margin for each hour of the  
13 year and the cost of that resource, which sets the market-clearing price. That market-clearing  
14 price becomes a proxy for the MEC. SCE separately considers the MEC for each hour of the  
15 year and then the hours are grouped into TOU periods for cost allocation purposes.

16 SCE has based its hourly MECs on a simulation of forecasted marginal generation output  
17 using assumptions from the June 2022 version of the IRP model, which is now very stale.

18 Because of this, SCE has had to make numerous adjustments as indicated in SCE’s response to a  
19 Cal Advocates data request:

20 The resource assumptions for SCE’s PLEXOS model are different  
21 from the 2023 Preferred System Portfolio. CPUC had not  
22 published the 2023 Preferred System Plan when SCE was in the  
23 process of developing the PLEXOS model for GRC Phase II. The  
24 resource assumptions that SCE used in its model are summarized  
25 on page 11 of testimony volume SCE-02 as follows:

1 “Forecast of available resource capacity in 2025 includes  
2 existing resources, scheduled retirements, and a forecast of  
3 new resources based on the 2022 Renewables Portfolio  
4 Standard (RPS) plan, D.21-06-035, and D.23-02-040.  
5 Specifically, SCE’s analysis assumes 50% of the new  
6 resources identified as “under development” by load serving  
7 entities (LSEs) in their 2022 RPS plans and ordered in D.21-  
8 16 06-035/D.23-02-040 come online as scheduled, while  
9 50% are delayed by a year...”

10 In addition, the retirement dates of gas generation units can be  
11 found in the model attached to SCE’s response to Question 10.a.  
12 The overall online capacity of gas generation units was calibrated  
13 with the CAISO generator master file. Two Diablo Canyon nuclear  
14 power plants were assumed to retire by 2024 and 2025,  
15 respectively. The renewable and battery buildout summary is  
16 shown in the figure and table below.<sup>28</sup>

17 The best solution to the problem is to use the updated 2023 PSP instead of relying upon the  
18 2021-2022 PSP. However, in response to CLECA concerns on this point, SCE states that it has  
19 insufficient time to update its MEC modeling to reflect the 2023 PSP.<sup>29</sup>

20 **B. MECs Should Be Based on the Available SERVM Output Developed**  
21 **from the 2023 PSP.**

22 Cal Advocates characterizes the output from the SERVM model as being more reflective  
23 of forward looking prices than the PLEXOS modeling that SCE has completed.<sup>30</sup> CLECA  
24 agrees that a number of substantial changes have taken place that are reflected in the 2023  
25 version of the PSP that are not properly reflected in SCE’s PLEXOS analysis. Hence, CLECA

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<sup>28</sup> Attachment G: SCE Response to PAO-03, Q.11.a.

<sup>29</sup> Attachment D: SCE Response to CLECA-11, Q.11.2. Revised

<sup>30</sup> Cal Advocates, Chapter 1 at 1-4 to 1-7. Cal Advocates claims that SERVM prices are more accurate because they are based on the 2023 PSP but also because SERVM output is more consistent with CAISO hourly prices.

1 agrees that it is entirely appropriate for the MECs to be based on the hourly energy prices  
2 produced by the 2024 version of the SERVVM model.

3 CLECA proposes to rely on the hourly energy prices from SERVVM that were produced  
4 for the 2024 Avoided Cost Calculator update.<sup>31</sup> These prices were prepared by the Energy  
5 Division’s consultant, E3, based on the 2023 PSP. Critically, if the marginal energy costs are  
6 updated, the marginal generation costs must be updated as well as previously recommended to  
7 retain consistency in resource cost assumptions.

8 **C. The Commission Should Deny Cal Advocates’ Proposal to Add RPS**  
9 **Costs to the MECs.**

10 Cal Advocates goes on to claim that “the SERVVM MECs represent the wholesale price  
11 and does not include an RPS premium because the premium is an added cost based on the  
12 Commission’s RPS program requirements.”<sup>32</sup> The Commission should reject Cal Advocates’  
13 proposal to add the RPS adder to MECs. Cal Advocates’ claim makes no sense for several  
14 important reasons.

15 First, SCE clearly explains, “there is no incremental RPS compliance cost to serve a  
16 marginal incremental of demand over the GRC forecast period,” because the State is on track or  
17 ahead of its targets.<sup>33</sup> No incremental compliance cost over the GRC forecast period is a  
18 persuasive reason to not include these costs in marginal energy costs.

19 Second, RPS resource costs are fundamentally embedded costs. RPS resources are  
20 typically procured in long term power purchase agreements with bundled energy and renewable  
21 attributes. In fact, the majority of RPS resources are procured with bundled physical delivery of

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<sup>31</sup> 2024-ACC-SERVVM-Energy Prices v.1a at tab “2022 Real Prices wo Carbon”.

<sup>32</sup> Cal Advocates, Chapter 1 at 1-8.

<sup>33</sup> Attachment G: SCE Response to CalAdvocates-SCE-014, Q.01.

1 energy and renewable attributes and with contract durations over 10 years because that is  
2 required under RPS program rules<sup>34</sup>. The cost of RPS resources are historical contract embedded  
3 costs and not appropriate to be included in marginal energy costs.

4 Third, the RPS premium calculation recommended by Cal Advocates is an element of the  
5 Power Cost Indifference Adjustment (PCIA) calculation.<sup>35</sup> The PCIA rate is “intended to  
6 equalize cost sharing between departing load and bundled load;” in other words, the PCIA rate  
7 relates to the embedded generation costs of the incumbent utilities. Thus, the PCIA calculation  
8 is not an hourly calculation nor is it a marginal calculation. Instead, the PCIA calculation is  
9 intended to determine whether there are any potential stranded costs in the utility’s generation  
10 (ERRA) costs. These embedded costs are simply inappropriate for marginal cost rate making.

11 The PCIA RPS Adder proposed by Cal Advocates for marginal cost rate making is not fit  
12 for purpose. For RPS resources, the benchmarking process looks at a cross section of RPS  
13 contracts taken from an up to three-year period prior to the calculation and compares the forecast  
14 of power costs under these contracts to a measure of “brown power” wholesale prices.<sup>36</sup> The  
15 2024 Market Price Benchmark Forecast explains that the RPS Adder is compiled from “eligible  
16 IOU, CCA, and ESP **market transactions executed** from September 2022 through August  
17 2023.”<sup>37</sup> A historical compilation of executed market transaction prices is not a sound  
18 methodology to determine marginal cost. Further to the point, the PCIA RPS Adder is “based on  
19 bundled, short-term (under ten-years), index-plus, Portfolio Content Category 1 (PCC-1)

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<sup>34</sup> CPUC, 60% RPS Procurement Rules, available at: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-compliance-rules-and-process/60-percent-rps-procurement-rules>

<sup>35</sup> D.18-10-019, slip op. at 3.

<sup>36</sup> D.19-10-001, slip op. at 13-14.

<sup>37</sup> Microsoft Word - Calculation of the Market Price Benchmarks 2023-2024. (emphasis added)

1 transactions.”<sup>38</sup> Applying RPS Adder figures to marginal energy costs that exclude transaction  
2 types that are required for or commonly used RPS compliance such as contracts that exceed 10  
3 years in duration, fixed price PPA with bundled RECs, PCC-2 and PCC-3 transactions is entirely  
4 inappropriate for rate making purposes. The PCIA calculation simply does not produce marginal  
5 costs.

6 The SERVM modeling produces hourly marginal energy prices based on a fully built out  
7 resource plan that includes a substantial portion of RPS resources. These are truly the marginal  
8 energy costs; and, in many hours, the marginal source of energy is RPS resources. Thus, the  
9 SERVM hourly prices already reflect RPS resources and there is no reason to concoct any adder.  
10 The Commission should reject Cal Advocates’ proposal to add the RPS adder to the MECs.

## 11 **VI. Marginal Distribution Capacity Cost**

12 CLECA addresses SCE’s PLRF methodology in depth in this section, most particularly  
13 the SCE recommendation to significantly reduce the threshold for PLRFs on A-bank substations.  
14 First, CLECA recommends the adoption of A-bank substation PLRFs based on a 73 percent of  
15 Planning Load Limit (PLL) threshold instead of a 73 percent of substation peak load threshold.  
16 Second, CLECA recommends that the PLRFs be developed on a regional basis and applied to  
17 customer classes on a regional basis before the regional results are rolled up into a systemwide  
18 customer class share. CLECA’s recommended A-bank substation class shares resulting from  
19 this analysis are presented in Table 10:

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<sup>38</sup> Microsoft Word - Calculation of the Market Price Benchmarks 2023-2024.

**Table 10: CLECA’s Recommended A-Bank PLRFs**

Resi- dential	GS-1	GS-2	TOU-GS	TOU- PA-2	TOU- PA-3	TOU-8 -SUB	TOU-8 -PRI	TOU-8 -SEC	Tr Contr & Strlgt	Total Regional
5,284 53.6%	610 6.2%	1,513 15.4%	784 8.0%	68 0.7%	77 0.8%	312 3.2%	478 4.9%	711 7.2%	14 0.1%	9,851 100.0%

**A. Background**

SCE’s electric delivery system includes higher voltage (transmission and subtransmission) and lower-voltage (distribution) facilities.<sup>39</sup> The term subtransmission is used to denote facilities operated at voltages (115 kV and 66 kV)<sup>40</sup> that are higher than distribution voltages (33 kV and below)<sup>41</sup> but are not operated by the California Independent System Operator (CAISO).<sup>42</sup> These subtransmission facilities are subject to this Commission’s jurisdiction and thus fall into the “distribution” category. We will refer to both the distribution and subtransmission costs categorically as distribution costs.

Marginal distribution capacity cost (MDCC) is a joint cost<sup>43</sup> that is dependent upon both demand and distance. Wires for the circuits cannot be produced without a demand element (4 kV, 12 kV, 33 kV, 66 kV, etc.) and without a distance element that connects a circuit between two points. Hence, the cost measure that is used for circuits is “circuit miles.” Furthermore, the number and placement of substations is driven by the geographic size of the distribution system as well as by the level of demand on the various circuits included therein.

<sup>39</sup> SCE-02A at 2.

<sup>40</sup> SCE-02A at 26. Also, footnote 26 defines subtransmission voltages as “greater than 50 kV and less than 220 kV.”

<sup>41</sup> SCE-02A at 24.

<sup>42</sup> SCE-02A at 5.

<sup>43</sup> A joint cost is a cost driven by two or more variables where the cost dependence cannot be separated among the variables.

1           However, for policy reasons, the Commission has decided to only address the demand  
2 aspect of the MDCC joint cost in developing marginal costs for allocation and rate design  
3 purposes. SCE’s work in separating out distribution costs between the peak and grid functions  
4 implicitly recognizes that certain elements of the distribution system, particularly substations and  
5 central lines, are driven more heavily by demand while other elements of the distribution system  
6 are driven more heavily by distance, specifically radial and secondary circuits. Furthermore, to  
7 the extent these radial and secondary lines are driven by demand, the demand element is more  
8 localized and influenced by non-coincident demand.

9           **B.     SCE Has Broken Down Distribution Costs by Functional Category and**  
10           **Determined the Degree of Time Dependency in an Acceptable Manner**

11           SCE has concluded that distribution (B-Bank) and subtransmission (A-Bank) substations  
12 are planned and designed for a peak level of coincident load and should be functionalized as  
13 peak.<sup>44</sup> SCE proposes “functionalizing distribution costs into a *peak* function to meet time-  
14 sensitive peak customer demand and *grid* function that enables the two-way flow of electricity to  
15 and from customers.”<sup>45</sup> SCE uses its peak load risk factor (PLRF) method to determine the  
16 hourly allocation of peak-capacity driven costs.<sup>46</sup> We accept SCE’s characterization of its  
17 substations as peak-related; however, we strongly disagree with the threshold that SCE has  
18 established for measuring PLRFs on A-bank substations. Furthermore, we disagree with SCE’s  
19 centralized basis for calculating PLRFs and propose an alternate regional based PLRF  
20 methodology.

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<sup>44</sup> SCE-02A at 21 (Table I-8).

<sup>45</sup> SCE-02A at 21.

<sup>46</sup> SCE-02A at 2.

1 SCE has found that the size and number of subtransmission circuits is driven primarily by  
2 grid connectivity, energy transfer, and contingency planning, concluding that these are grid  
3 functions. SCE characterizes its subtransmission system as a radial grid that “accommodate[s]  
4 power flows in normal and contingency scenarios” and “manage[s] congestion on the  
5 subtransmission network”.<sup>47</sup> On this basis, SCE considers the entire subtransmission network to  
6 be grid-related on the grounds that its “primary function...has largely evolved into one of grid  
7 connectivity and energy transfer across an integrated *sub-network*.”<sup>48</sup> We accept SCE’s  
8 characterization of the subtransmission circuits as grid but note that its grid attributes as well as  
9 its contingency design characteristics call into doubt SCE’s proposal to incorporate a 73 percent  
10 of peak load planning factor into its PLRF calculation for the A-bank substations.

11 SCE considers a portion of distribution lines, *i.e.*, the mainline circuits that deliver power  
12 from the B-bank substations to a geographical area, to be peak-related because the coincident  
13 loads for the specific geographical area drive the need to expand the capacity of the mainline  
14 circuit. The mainline circuits make up about 23% of primary circuit miles.<sup>49</sup> In contrast, the  
15 remaining circuits in the geographical area, the radial and secondary circuits, are sized to meet  
16 local loads; and, as discussed previously, much of the cost of these lines is related to the  
17 distances over which they must travel to reach customer locations.<sup>50</sup> SCE has categorized radial  
18 lines at primary voltage and secondary circuit as grid-related costs. The radial lines, including  
19 secondary voltage circuit miles, make up the remaining 77% of distribution circuit miles.<sup>51</sup> We  
20 find this categorization reasonable based on the data that SCE has amassed.

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<sup>47</sup> SCE-02A at 25.

<sup>48</sup> SCE-02A at 25, see also footnote 25.

<sup>49</sup> SCE-02A at 24 (Figure I-7).

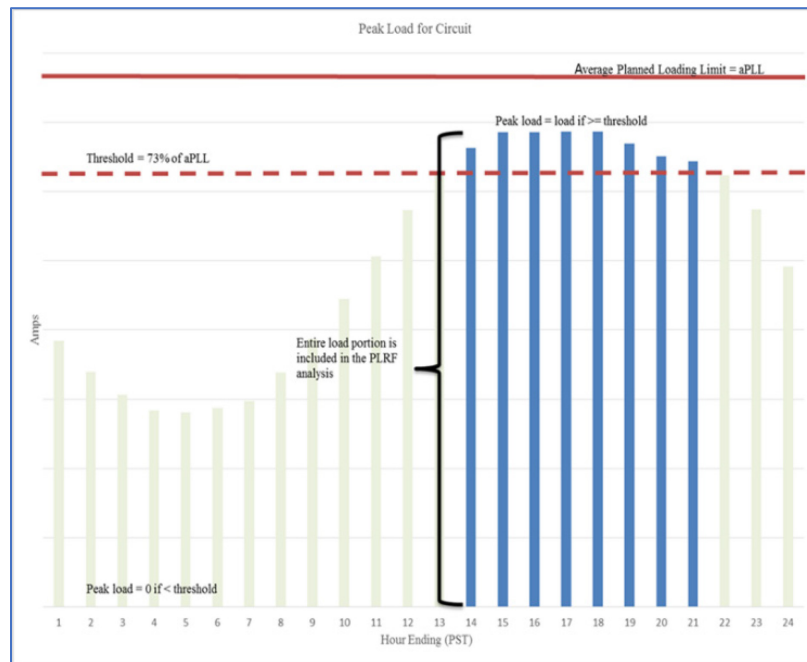
<sup>50</sup> SCE-02A at 25.

<sup>51</sup> SCE-02A at 26, see also Table I-8 on page 21.

### C. A Brief Description of SCE’s PLRF Methodology

SCE’s current PLRF methodology identifies each hour for which the “peak load” identified for the particular type of facility exceeds the defined threshold, assigning a one for those hours while the remaining hours (below the threshold) are all assigned a value of zero.<sup>52</sup> This process is illustrated for primary circuits in Figure 10 below:

Figure 9<sup>53</sup>



For each type of facility, *i.e.*, A-bank substations, B-bank substations, and primary circuits, the PLRFs are then added together for each hour.<sup>54</sup> The analysis creates a single 1 x 8760 matrix of PLRFs for each facility type, which attempts to represent the hours in which loads impose peak related costs on a particular type of equipment.

<sup>52</sup> SCE-02A at 30.

<sup>53</sup> SCE-02A at 31 (Figure I-10).

<sup>54</sup> SCE-02A at 30 and footnote 32.

1           **D.     SCE’s Proposal to Base A-Bank Substation PLRFs on 73 Percent of**  
2           **Forecasted Peak Substation Loads Should Be Rejected in Favor of a**  
3           **Threshold Based on 73 Percent of Substation Planning Load Limits.**

4           SCE proposes to base the PLRFs calculated for its A-bank substations on a threshold that  
5           is far too low to be meaningful for cost causation purposes. We recommend that the *PLRF*  
6           *threshold for A-bank substations be based on the same threshold that is applied to the B-bank*  
7           *and circuits, i.e., 73 percent of the Planning Loading Limit (PLL).*

8                   **1.     SCE’s Proposed Substation Load Based PLRF Threshold Is**  
9                   **Meaningless for Cost Causation Purposes.**

10           Referring back to **Figure 10**, the red dotted line illustrates the PLRF threshold for  
11           primary circuits. SCE proposes a PLRF threshold of 73 percent of the average PLL for its  
12           circuits and B-bank substations. *This threshold ties directly into SCE’s primary circuit and B-*  
13           *bank substation planning process and, thus, is reasonable to identify hours that exceed this*  
14           *planning threshold.*<sup>55</sup> SCE states: “Distribution substations are designed to meet the total load of  
15           connected circuits at an individual substation. The recorded load is similarly compared to a  
16           threshold, defined as 73 percent of the individual substation PLL. Any load greater than or equal  
17           to the threshold will be flagged as a capacity constraint.”<sup>56</sup> Based on the direct connection  
18           between the SCE distribution planning process and the 73 percent threshold, we agree that this  
19           PLRF threshold is an appropriate cost causation metric.

20           SCE does not make this same recommendation for the A-bank substations, claiming that  
21           A-bank substations are designed for a variety of variables including system reliability.<sup>57</sup>  
22           However, SCE is attempting to attribute cost causation to peak load factors. In doing so, it must

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<sup>55</sup> SCE-02A at 28-29.

<sup>56</sup> SCE-02A at 29.

<sup>57</sup> SCE-02A at page 29, footnote 31.

1 use a cost causation factor that actually is indicative to hours when SCE truly faces a signal of  
 2 need to expand the capacity of the A-bank substations. Otherwise, SCE should conclude that the  
 3 A-bank substations are entirely grid in nature because of the importance of the other variables in  
 4 determining the need for capacity. In completing our analysis, we are assuming that SCE  
 5 recognizes the significance of hourly loads in determining the capacity of its A-bank substations.

6 SCE’s recommended peak substation load basis for assigning cost causation to hourly  
 7 loads is meaningless. As demonstrated below in Table 11, the proposed threshold has fallen to a  
 8 point where SCE cannot demonstrate that there is any real signal for need to expand the capacity  
 9 of the A-bank substation. Thus, SCE’s proposed threshold should be rejected.

10 **Table 11: Planning Load Limit vs Peak Load**

Baseline Region	PLL	Pk Load	100% Pk Load/PLL	90% Pk Load/PLL	73% Pk Load/PLL
Region 6 total	4,629	2,757	60%	54%	43%
Region 8 total	10,569	6,368	60%	54%	44%
Region 9 total	5,316	3,669	69%	62%	50%
Region 10 total	9,608	6,839	71%	64%	52%
Region 13 total	2,020	1,272	63%	57%	46%
Region 14 total	3,298	1,701	52%	46%	38%
Region 15 total	2,254	1,145	51%	46%	37%
Region 16 total	<u>1,837</u>	<u>684</u>	<u>37%</u>	<u>34%</u>	<u>27%</u>
System Total	39,530	24,436	62%	56%	45%

11  
 12 As discussed previously, SCE more generally uses 73 percent of PLL as the basis for  
 13 determining the need to expand substation capacity to respond to load growth. However, as  
 14 shown above in Table 11, when the analysis is based on peak substation loads rather than PLLs,  
 15 the evaluation goes awry. The system total peak substation loads represent an average of only 62  
 16 percent of the PLLs, which far below the 73 percent level that is used by SCE’s planners. Five  
 17 out of nine regions have a threshold that is at or below 60 percent of the corresponding PLL.  
 18 Furthermore, applying SCE’s proposed threshold of 73 percent of peak load represents an

1 average of only 45 percent of PLL with six out of nine of the regions at levels significantly less  
 2 than 45 percent of PLL. Relying on such low thresholds renders the measure meaningless for  
 3 cost causation purposes.

4 **2. SCE Should Base Its A-Bank PLRF Threshold on 73 Percent of PLL.**

5 SCE should use the same threshold of its A-bank substation PLRFs as it uses for its B-  
 6 bank and primary circuits PLRFs. Relying on the 73 percent of PLL to set the PLRF threshold  
 7 focuses the calculation on substations that are experiencing significant load growth during  
 8 certain hours and provides a direct connection between the loads during these hours and the need  
 9 to expand capacity. Completing our A-bank PLRF analysis with this corrected threshold of 73  
 10 percent of PLL but doing so on a centralized basis similar to SCE’s analysis produces the results  
 11 shown below in Table 12:

12 **Table 12**

13

	Resi- dential	GS-1	GS-2	TOU-GS	TOU- PA-2	TOU- PA-3	TOU-8 -SUB	TOU-8 -PRI	TOU-8 -SEC	Tr Contr & Strlgt	Total Regional
Total	5,847	725	1,711	828	218	174	680	552	747	11	11,493
	50.9%	6.3%	14.9%	7.2%	1.9%	1.5%	5.9%	4.8%	6.5%	0.1%	100.0%

14

15 However, in showing this table for comparison purposes, we are not endorsing SCE’s centralized  
 16 PLRF methodology, as we discuss further below in Section E.

17 **E. SCE’s Centralized PLRF Methodology for Assigning Peak Cost**  
 18 **Responsibility to Customer Classes Is Flawed.**

19 SCE explains its PLRF methodology by stating: “During periods of peak usage, the  
 20 distribution system capacity is stressed in a similar manner as generation assets; therefore,  
 21 distribution peak-capacity price signals should be time-differentiated in a similar way.”<sup>58</sup>

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<sup>58</sup> SCE-02A at 27.

1 However, the distribution system is not the same as the generation system in a very important  
2 respect since distribution loads are actually served on a more local basis.

3 Under SCE's methodology, however, the PLRFs for each type of facility, *i.e.*, A-bank  
4 substations, B-bank substations, and primary circuits, are added together for each hour regardless  
5 of where the facility is located.<sup>59</sup> The analysis creates a single 1 x 8760 matrix of PLRFs for  
6 each facility type, which attempts to represent the hours in which loads impose peak related costs  
7 on a particular type of equipment. SCE then applies the PLRFs to a system level customer class  
8 loads to assign cost responsibility for each customer class. Effectively, SCE is creating an  
9 averaged PLRF profile for each type of facility, *i.e.*, A-bank substations, B-bank substations, and  
10 primary circuits. SCE then applies this PLRF profile to the averaged customer for each customer  
11 class.

12 We disagree with SCE's proposed centralized methodology for determining PLRFs for  
13 facilities and ultimately for assigned customer class cost responsibility for those PLRFs. The  
14 correct approach is to determine PLRFs on a regional basis and use those PLRFs to assign  
15 customer class responsibilities.

### 16 **3. SCE's Distribution System Is Much More Diverse than Is** 17 **Represented by Its Proposed Centralized PLRF Methodology.**

18 SCE's distribution system is much more diverse than can be represented by a single set of  
19 hourly figures. Applying a single 1 x 8760 matrix to represent the entire distribution system at  
20 each major voltage level, *i.e.*, A-bank substations, B-bank substations, and primary circuits, is  
21 inadequate for properly measuring cost responsibility. For example, under SCE's methodology,  
22 loads throughout its territory are assigned 3.9 percent PLRF cost responsibility for hours within

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<sup>59</sup> SCE-02A at 30 and footnote 32.

1 the month of January regardless of whether they are actually located in regions 5, 9, 10, 13, 14,  
 2 and 15, which individually have no PLRF loads during January, as shown in Figure 11 below:

3 **Figure 10: A-Bank Substation PLRFs<sup>60</sup>**

Month	Baseline Regions									Grand Total
	6	8	16	5	9	10	13	14	15	
1	2.3%	1.5%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.9%
2	1.6%	1.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.9%
3	0.8%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%
4	0.7%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%
5	0.8%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%
6	2.1%	1.7%	0.0%	0.0%	0.1%	0.0%	1.1%	0.5%	0.4%	5.9%
7	4.4%	6.2%	0.2%	0.0%	2.5%	5.1%	3.1%	2.5%	1.7%	25.7%
8	4.9%	7.2%	0.2%	0.0%	2.7%	5.5%	2.4%	2.4%	1.6%	26.9%
9	4.2%	6.0%	0.1%	0.0%	1.8%	2.9%	0.5%	0.6%	0.7%	16.7%
10	3.8%	3.4%	0.0%	0.0%	0.2%	0.1%	0.0%	0.0%	0.0%	7.5%
11	1.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%
12	2.3%	1.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.8%
<b>Grand</b>	<b>28.9%</b>	<b>31.8%</b>	<b>0.8%</b>	<b>0.0%</b>	<b>7.3%</b>	<b>13.7%</b>	<b>7.1%</b>	<b>6.0%</b>	<b>4.5%</b>	<b>100.0%</b>

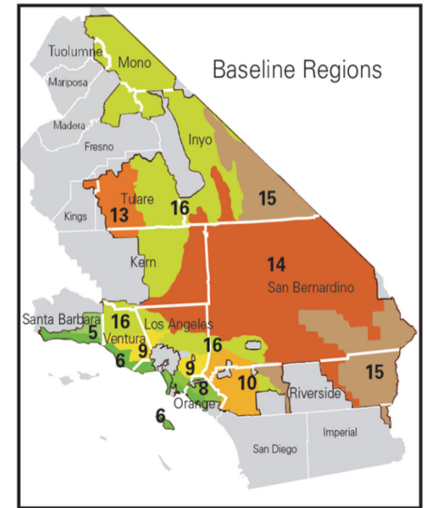


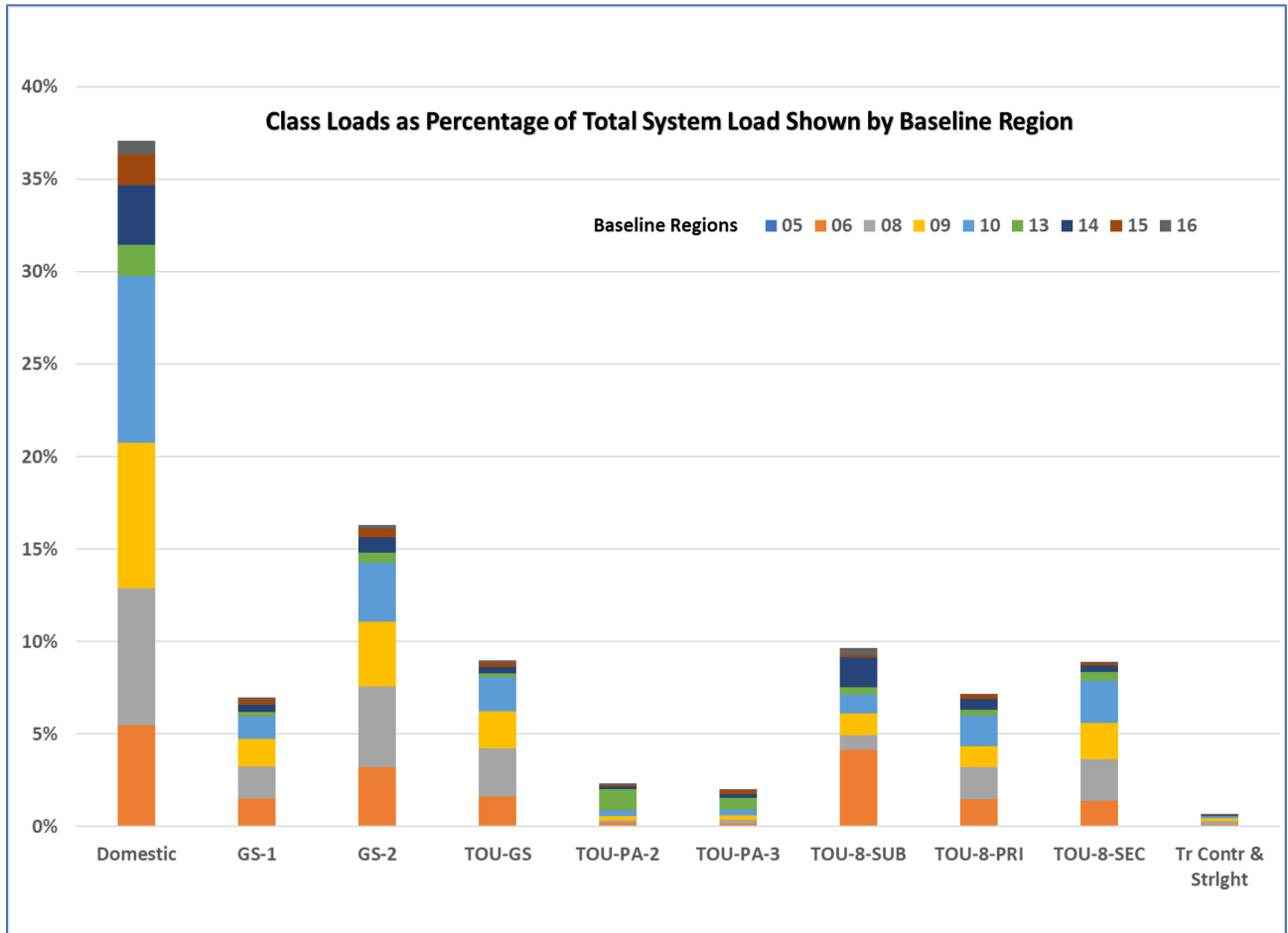
Figure 3: Southern California Edison Baseline Territories Map, 2010

6 This oversimplification of the assignment of cost responsibility might be acceptable as an  
 7 approximation if every customer class had the same basic geographical distribution, but the  
 8 following figures demonstrate clearly that this is not the case. Instead, there is a great deal of  
 9 diversity in how the various customer classes are distributed throughout SCE's service territory:

<sup>60</sup> SCE 02\_Appendix F\_Dist Cost at Regional and Substation Level.xlsx at tab "Table F-7".

1  
2

Figure 11<sup>61</sup>



3

4

In Figure 12 the multicolored bars show the size of the customer class as a percentage of overall system load, while the various colors show how each class is distributed across the various baseline regions.

5

6

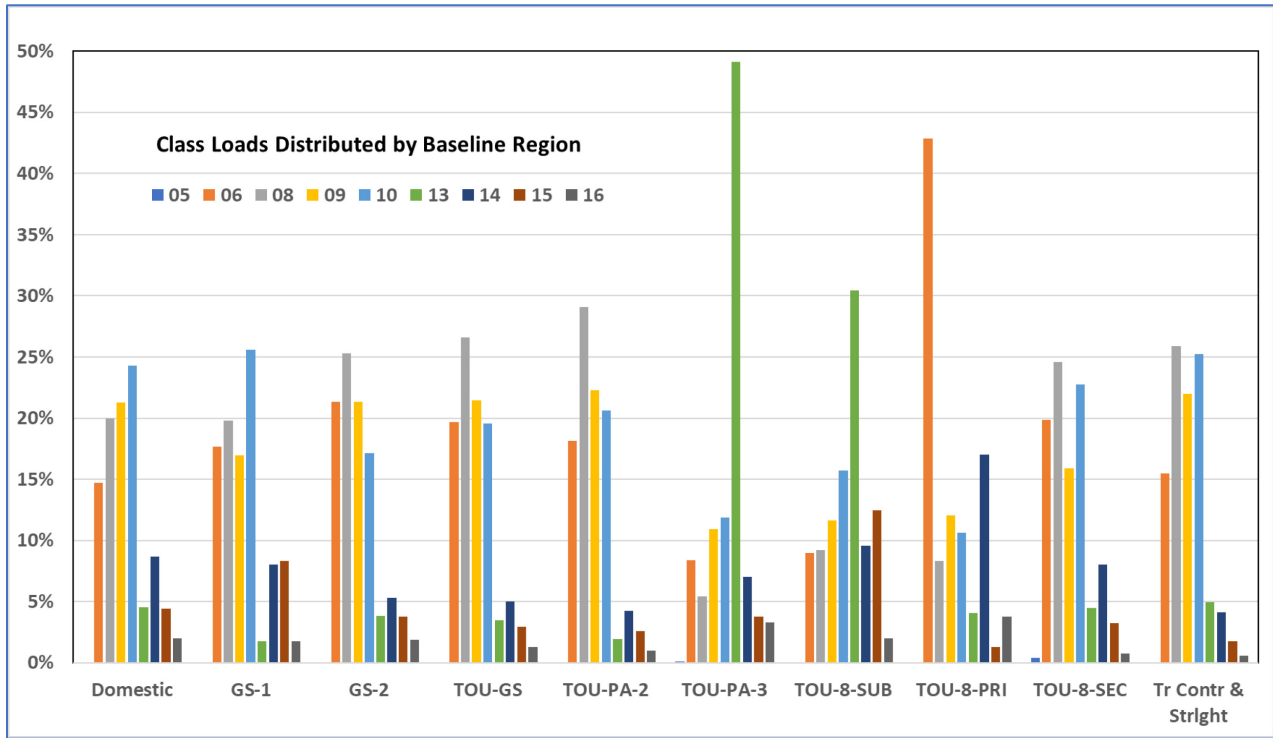
Figure 13 below provides the distribution on a percentage of overall class load (where each group of bars adds to 100%) to provide additional detail for the customer class with smaller overall loads:

7  
8  
9

<sup>61</sup> Attachment C.7 based on SCE workpaper DDMC Study\_PLRF MW by Zone 2022 Load Data.

1  
2

Figure 12<sup>62</sup>



3

Figure 13 shows, for example, that the residential class distribution, which is largely to baseline regions 6, 8, 9, and 10, does not represent well the class distribution for non-residential classes, particularly, the agricultural and large power customers. Thus, when the PLRF loads are rolled up across the system for each facility type and then applied to customer class loads, these averaged PLRFs significantly misrepresent the amount of load that the agricultural and large power customers actually impose on local facilities.

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**4. SCE Should Assign PLRF Cost Responsibility Based on a Regional Rather than Centralized Analysis.**

10

11

12

SCE determines its hourly PLRFs for each individual facility throughout its distribution system. Thus, it is feasible to compile the hourly facility-specific PLRFs on a regional rather than centralized basis for each facility type, *i.e.*, A-bank substations, B-bank substations, and

13

14

<sup>62</sup> Attachment C.7 based on SCE workpaper DDMC Study\_PLRF MW by Zone 2022 Load Data.

primary circuits. By maintaining the PLRFs by region, the hourly customer class loads can also be identified by region, which assigns local cost responsibility more appropriately to customer classes. The hourly PLRF factors are then multiplied by the hourly customer class loads in each region and then the values for each region are summed together.

Referring back to Figure 11, the localized analysis eliminates the erroneous PLRF cost assignment for customer using facilities that are located within the baseline regions that have no PLRFs during the winter months. Thus, customer classes with a larger proportion of class loads located within these regions will appropriately see a reduction of cost responsibility for these distribution facilities, as shown below in Table 13:

**Table 13: Regional Compilation of A-Bank PLRFs<sup>63</sup> at 73 Percent of PLL Threshold**

Baseline Region	Residential	GS-1	GS-2	TOU-GS	TOU-PA-2	TOU-PA-3	TOU-8-SUB	TOU-8-PRI	TOU-8-SEC	Tr Contr & Strlgt	Total Regional
05	0	0	0	0	0	0	0	0	0	0	0
06	0	0	0	0	0	0	0	0	0	0	0
08	1,351	236	574	311	13	19	78	186	241	6	3,015
09	1,748	206	481	243	25	24	132	116	210	3	3,189
10	2,185	168	458	230	30	34	102	176	261	5	3,648
13	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0
Total System	5,284	610	1,513	784	68	77	312	478	711	14	9,851
	53.6%	6.2%	15.4%	8.0%	0.7%	0.8%	3.2%	4.9%	7.2%	0.1%	100.0%

It is noteworthy to observe that for many years the Commission has approved PG&E’s distribution marginal cost methodology that assigns customer class cost responsibility on regional distribution basis and then rolls up the cost responsibility for each customer class across

<sup>63</sup> For comparison purposes, this table incorporates SCE’s proposed 73 percent PLRF threshold although we do not agree that this is the correct PLRF threshold for A-bank substations.

1 its system. We are proposing a distribution analysis that is consistent with the PG&E  
2 methodology.

3 **F. SCE’s Reliance on the NERA Regression Method to Produce a Separate**  
4 **MDCC for Each Functional Category Is Appropriate.**

5 SCE uses accounting costs from the Federal Energy Regulatory Commission (FERC)  
6 Uniform System of Accounts for both distribution plant and subtransmission plant.<sup>64</sup> The asset  
7 types identified are distribution substations, distribution circuits, subtransmission substations and  
8 subtransmission circuits.<sup>65</sup> Within each of these categories, SCE uses the National Economic  
9 Research Associates (NERA) regression method to regress ten years of historical and five years  
10 of forecast load growth capital expenditure data against planned capacity (rather than cumulative  
11 load growth) for each asset type.<sup>66</sup> We support SCE’s use of the NERA regression method for  
12 establishing its MDCCs.<sup>67</sup>

13 We also agree with SCE’s approach of breaking down the distribution system into these  
14 functional categories for analysis. SCE measures planned capacity at different points across the  
15 distribution system for different categories of cost, *i.e.*, B-Bank nameplate capacity is used for  
16 distribution substations but circuit planning load limits are used for circuits.<sup>68</sup> There is a separate  
17 regression of cumulative capital expenditures to cumulative planned capacity that yields a

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<sup>64</sup> SCE-02A at 22-23.

<sup>65</sup> SCE-02A at 36, Table I-13.

<sup>66</sup> SCE-02A at 22.

<sup>67</sup> While CLECA generally supports SCE’s regression analysis to develop MDCCs, and CLECA is using SCE’s numbers in its calculations, CLECA cannot and does not express specific support for SCE’s MDCCs. In particular, the MDCC for A-bank has increased significantly in this case relative to its value in the last GRC Phase 2 and CLECA is not satisfied with SCE’s justification for the increase. CLECA further notes that Cal Advocates’ MDCC for A-banks is much lower than SCE’s, but Cal Advocates’ workpapers in this proceeding are much more limited than they were in the last GRC Phase 2. Without further substantiation of SCE’s and Cal Advocates’ MDCCs, CLECA cannot be certain whether CLECA would support Cal Advocates’ numbers over SCE’s numbers.

<sup>68</sup> SCE-02A- I.C.2 – DDMC Study – Amended.xlsx at tab “Capacity”.

1 separate marginal cost for each functional category, *i.e.*, distribution substations, distribution  
2 circuits, subtransmission substations, and subtransmission circuits.<sup>69</sup> The slope of each  
3 regression line is multiplied by the RECC factor to estimate the capital part of the marginal cost  
4 to which O&M is added.<sup>70</sup>

## 5 **VII. Marginal Customer Costs**

6 Marginal customer costs (MCCs) are the incremental costs of providing a new customer  
7 with access to the utility system for service (often called “hook-up” costs), maintenance and  
8 replacement of customer access equipment, and customer services, including billing and meter  
9 reading. Hookup costs have included the cost of the final line transformer (FLT) serving the  
10 customer, the service drop, and the meter, often referred to as TSM.

### 11 **A. The RECC Method Is the Correct Method for Estimating Marginal** 12 **Customer Costs**

13 SCE proposes to use the RECC method to develop MCCs in this proceeding.<sup>71</sup> We agree  
14 with SCE’s proposal and have accordingly used SCE’s MCCs in preparing our recommended  
15 cost allocation.

16 The RECC method starts with the development of a separate marginal capital cost, stated  
17 in dollars per customer, for each customer class or rate group, reflecting the differences in  
18 customer size and metering requirements that exist among the various rate groups. For each rate  
19 group, a forecast is made of both the test year capital cost of hooking up a new customer, and the  
20 test year expenses associated with adding the new customer to the system. The MCC is based on  
21 the annualized capital cost as determined by applying the RECC to the total test year cost of the

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<sup>69</sup> SCE-02A- I.C.2 – DDMC Study – Amended.xlsx at tab “DMC”.

<sup>70</sup> SCE-02A- I.C.2 – DDMC Study – Amended.xlsx at tab “Summary”.

<sup>71</sup> SCE-02A at 40. This method is also called the “Rental” method.

1 new hook-up. The annual expenses, including billing, metering, and other O&M as well as  
 2 administrative and general (A&G) costs, are then added to the annualized hook-up cost to  
 3 determine the total marginal customer cost. The class-specific MCC revenues are equal to the  
 4 class-specific MCC in dollars per customer times the total number of customers in that rate  
 5 group.

6 The RECC formula recognizes that utility investments are subject to inflation and have a  
 7 lifespan. The marginal cost of the capital asset can be calculated as the difference between  
 8 starting the investment this year and deferring the investment by one year. As noted by NERA:

9 When a choice is made to purchase a new machine, we can think of it as the choice  
 10 between purchasing it this year or next year. If the machine is installed this year, a stream  
 11 of charges is incurred with replacement 30 years from now, 60 years from now, and so  
 12 on. If it is installed next year, a stream of charges begins next year with replacement 31  
 13 years from now, 61 years from now, and so on. The difference in cost between those two  
 14 options is the marginal cost of the machine for the year. This has been variously called  
 15 the "fair rental cost" or the "amortization."<sup>72</sup>  
 16

17 The RECC formula <sup>73,74</sup> is stated as follows:

$$\text{value in year 1} = \text{cost of plant} \times \text{one-year deferral} \times \text{investment life}$$

18  
 19 Where the one-year deferral and investment life are themselves expressed as formulas:

$$\text{one-year deferral} = \frac{(\text{discount rate} - \text{inflation})}{(1 + \text{discount rate})}$$

---

<sup>72</sup> Attachment K: National Economic Research Associates, (1977) *A Framework for Marginal Cost-Based Time-Differentiated Pricing in The United States: Topic 1.3*, at Attachment C-3.

<sup>73</sup> Attachment K: National Economic Research Associates, (1977) *A Framework for Marginal Cost-Based Time-Differentiated Pricing in The United States: Topic 1.3*, at Attachment C-16.

1           The RECC method results in correct pricing for customer access to the utility system as it  
2 represents the annual value of the asset in real dollars. The MCC is the cost of providing access  
3 to an additional customer regardless of location. The RECC method results in the same value  
4 whether the assets are new or existing. The customer may be added at an “existing” site (where  
5 TSM facilities are already in place) or at a “new” site (where TSM facilities must be added.)  
6 The MCC is the incremental cost of access to the utility system, regardless of the nature of the  
7 site.

8           Customers are constantly entering and exiting utility service. Houses, buildings,  
9 factories, etc. have long lives. They are not regularly replaced. Yet, the opportunity cost of  
10 TSM facilities that are left behind by an existing customer is still a cost to the utility system. The  
11 utility is still obligated to maintain the facilities. These facilities could be also used at another  
12 location to provide access for a similar type of customer. The opportunity cost of the TSM  
13 facilities is the installed facility cost times the RECC factor. The RECC factor turns the installed  
14 cost of the TSM facilities into a stream of annual values that are equal in real dollars but increase  
15 when converted to nominal dollars.

16           Customers that obtain service at a new building will have newly-installed TSM facilities  
17 that also have an opportunity cost. As in the case of the customer added at the existing facility,  
18 the opportunity cost is the installed cost times the RECC factor. Thus, adding a customer of any  
19 type will cost the same whether it is located at a new or existing facility.

1           **B.     The Commission Should Reject Cal Advocates’ Proposal to Use the New**  
2           **Customer Only (NCO) Method to Estimate MCCs**

3           Cal Advocates proposes to use the NCO method for calculating MCCs.<sup>75</sup> The NCO  
4 method also relies on a rate-group-specific forecast of both the test year capital cost of hooking  
5 up a new customer and the test year expenses associated with adding the new customer to the  
6 system. The key difference between the NCO method and the RECC method lies in the  
7 treatment of the installed capital hookup cost. The NCO method applies the hookup cost solely  
8 to customers in each rate class that are projected to be physically added to the system during the  
9 test year. The NCO method then divides the total new customer hookup cost for each customer  
10 class by the total number of customers (both existing and new) in that rate class.<sup>76</sup> In other  
11 words, the NCO method considers the opportunity cost of TSM facilities for an existing  
12 customer to be zero.<sup>77</sup>

13           The NCO method develops incorrect values for MCCs. Reviewing the NCO calculation  
14 will show that it is incorrect because the definition of the numerator and denominator are not the  
15 same. Under the NCO method, the numerator is the cost to connect only **new** customers to the  
16 class while the denominator is **all** customers in the class. This is counter to the definition of  
17 marginal cost, which is the cost of providing an additional unit of service, in this case customer  
18 access, to a single customer. A value based on NCO grossly underestimates the cost of adding a  
19 single customer; therefore, it cannot be a marginal cost.

---

<sup>75</sup> Cal Advocates, Chapter 4 at 4-2. PAO refers to MCC as marginal customer *access* cost or “MCAC”.

<sup>76</sup> For simplicity in the revenue allocation process, the NCO capital cost for these new customers is divided by the number of customers in the class in order to develop a figure that can be multiplied by the total number of customers in each rate class.

<sup>77</sup> The NCO method also does not consider any ongoing cost obligation that existing customers have for the TSM facilities that provide them access to the utility system.

1                   **1.     The NCO Method Is Fundamentally Not a Marginal Cost**  
2                   **Methodology**

3                   Cal Advocates claims that the “NCO method is consistent with short-run marginal cost  
4 theory”<sup>78</sup> but this statement is simply incorrect. The NCO method fundamentally is not a  
5 marginal cost approach but a cost allocation approach whereby an upfront payment—the net  
6 present value of the revenue requirement stream—to connect new customers is spread to all  
7 current customers. The NCO method produces results that are in contradiction to marginal cost  
8 theory. A marginal cost is the change in cost due to a change in output, in this case, a customer.  
9 If the marginal cost is correct, then it should recover the increased cost from serving one  
10 additional customer. However, the NCO dollar per customer result multiplied times one  
11 customer will fail to recover the marginal cost of installing a customer connection. Therefore,  
12 NCO cannot be a marginal cost.

13                   **2.     Contrary to the Claims of the Proponents of NCO, Customer Access**  
14                   **Equipment Is Fungible**

15                   Cal Advocates attempts to justify the NCO method by claiming that capital costs  
16 associated with customer hookups are attributed to only a few “new” customers who are being  
17 physically added to the utility system. Cal Advocates claims that the customer hookup costs are  
18 sunk and are not fungible because they are somehow dedicated to specific customer sites. They  
19 argue that, as a consequence, the entire capital cost of the hookup is only marginal in the year  
20 that it is installed.<sup>79</sup> We do not agree.

21                   First, some customer access equipment could be relocated if there was truly no need for  
22 the equipment at a given site. For example, a customer meter has a 20-year life and would

---

<sup>78</sup> Cal Advocates, Chapter 4 at 4-8.

<sup>79</sup> *Id.* at 4-9.

1 continue to operate if it were disconnected at one location and reconnected at another. Similarly,  
2 if a final line transformer were truly not required at a location for any other customers, the  
3 equipment could be relocated and it would continue to operate. Only the service drop may not  
4 be relocated if service is no longer provided to a premise.

5 Second, a new customer can locate at an existing location or a new location. Regardless  
6 of the location, the utility still has the obligation to provide customer access in perpetuity unless  
7 somehow the site is destroyed. Thus, the existing equipment could be used at its location to  
8 provide service to a different customer if the existing customer chooses to terminate service and  
9 move. This happens all the time.

10 This is analogous to the rental market for buildings or houses where the opportunity cost  
11 to the landlord is represented by the future tenant that would replace the existing tenant, possibly  
12 at a different rent. No one suggests that to have an opportunity cost associated with a particular  
13 tenant, the landlord would have to somehow move the building to a new location. Furthermore,  
14 the landlord would not assume that his/her investment was sunk and therefore charge zero rent to  
15 a new tenant.

16 Another alternative market is an internet service provider who could add a new customer  
17 at a new or existing location. The internet service provider does not charge a new customer a  
18 zero rate (or a price below its true opportunity cost) at an existing location even though the  
19 internet service provider already has capital equipment at that location.

## 20 **VIII. Revenue Allocation**

21 Revenue allocation is the process by which revenue responsibility for the utility's entire  
22 revenue requirement is assigned among groups of the utility's customers. Bundled customers are

1 assigned responsibility for a share of all utility costs,<sup>80</sup> including above-market generation  
2 costs.<sup>81</sup> Direct Access (DA) and Community Choice Aggregation (CCA) customers are assigned  
3 responsibility for a share of all delivery costs and “non-bypassable costs”, which include above-  
4 market generation costs incurred by the utility when they took bundled service,<sup>82</sup> subject to a  
5 capping methodology.<sup>83</sup>

6 Delivery costs include transmission,<sup>84</sup> distribution, and appropriate customer costs. Thus,  
7 the process of revenue allocation is one of dividing up responsibility for the utility’s revenue  
8 requirement between bundled and DA/CCA customers and then among all the customer classes  
9 covered by the utility’s tariffs. A revenue allocation may also allocate revenues directly to rate  
10 schedules within the class. Since the Commission has endorsed marginal-cost ratemaking for  
11 decades, marginal costs are used to perform the revenue allocation.

12 The Marginal Cost Revenue Responsibility (MCRR) for each customer class (or rate  
13 schedule) is the product of the usage pattern associated with each type of marginal cost  
14 multiplied by that marginal cost, aggregated for each class across all marginal costs that are  
15 applicable to the category the customer class falls into, that is, bundled or DA/CCA. The MCRR  
16 for each class within the category represents its share of the total MCRR for that category. The  
17 total utility revenue requirement for each category is then divided by the total MCRR across all  
18 the classes in that category. This creates a multiplier (*i.e.*, a ratio), called the EPMC multiplier,

---

<sup>80</sup> Total rates include distribution, transmission, generation, nuclear decommissioning, wildfire fund charge, public purpose programs, and new system generation service. SCE-03A at 1.

<sup>81</sup> See, for example, Special Condition 22 of SCE Schedule TOU-8.

<sup>82</sup> DA and CCA customers pay PCIA and CTC; and, if new generation resources are added that provide reliability benefit to the entire system, a share of these costs are allocated to DA and CCA customers through the New System Generation Charge, along with a share of the resource adequacy value.

<sup>83</sup> SCE-03A at 8, footnote 10.

<sup>84</sup> Transmission costs for CAISO-controlled facilities are separately allocated by the Federal Energy Regulatory Commission (FERC). These costs are excluded from the CPUC jurisdictional allocation and added into rates separately.

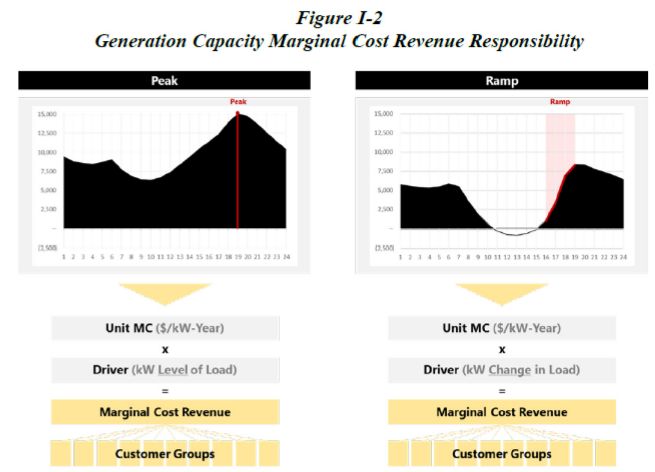
1 that is applied to the MCRR for each class to allocate revenue requirement associated with each  
2 category.

### 3 **A. Allocation of Generation Costs**

#### 4 **1. Peak and Ramp Are Separate and Distinct Requirements for** 5 **Generation Capacity**

6 SCE has identified distinct peak and ramp requirements for generation capacity. Indeed,  
7 the SCE Capacity Allocation Tool identified “probabilities of capacity shortfalls in each hour of  
8 the 2024 test year resulting from both forecast peak capacity needs and flexible capacity needed  
9 for forecasted load ramps.”<sup>85</sup> SCE applies generation capacity costs to their, “respective cost  
10 drivers represented by MWs of demand and change in demand at the time of system peak and  
11 ramp, respectively.”<sup>86</sup> The distinct and separate peak and ramp cost drivers are further illustrated  
12 in Figure 13.

13 **Figure 13**<sup>87</sup>



14 <sup>85</sup> SCE-03A at 16.

15 <sup>86</sup> SCE-03A at 9.

<sup>87</sup> SCE-03A at 9.

1 SCE states: “allocation of peak capacity costs is based on the relevant top 100 hours of  
2 *net* loads. Allocation of flexible capacity costs is based on the relevant top 10 maximum daily 3-  
3 hour change in *net load*.”<sup>88</sup> However, SCE does not propose to attribute the full MGCC to each  
4 of these separate capacity requirements, hence the term “MGCC factor” when discussing the  
5 development of the generation capacity MCRRs.

6 Under SCE’s methodology, the average net loads for each customer class during the top  
7 100 net load hours is multiplied by an MGCC factor to produce net peak generation MCRRs.  
8 Similarly, the average 10 highest daily 3-hour change in net loads is multiplied by an MGCC  
9 factor to produce ramp generation MCRRs. We believe that this approach is incorrect; the net  
10 peak MCRR should be developed based on the entire MGCC as should the ramp MCRR without  
11 the use of an “MGCC Factor”.

12 The resource requirement to meet the maximum net peak is separate and distinct from the  
13 resource requirement to meet ramp requirements. In each circumstance, a different capacity  
14 resource is required to meet each respective requirement.

15 SCE rightly uses only the highest peak and ramp requirements for cost allocation which  
16 represent the required resource design and associated cost causation drivers. However, a resource  
17 designed to meet the Top 100 highest net peak hours, will also be relied upon to meet daily net  
18 peak requirements throughout the year. A resource designed to meet the Top 10 highest 3-hour  
19 ramps, will also be relied upon to meet daily ramps throughout the year. The same resource  
20 cannot be used for both purposes even on non-peak days due to the inherent use limitations of  
21 batteries, the hourly pattern that each needs occurs, and the daily requirements to meet both peak  
22 and ramp needs.

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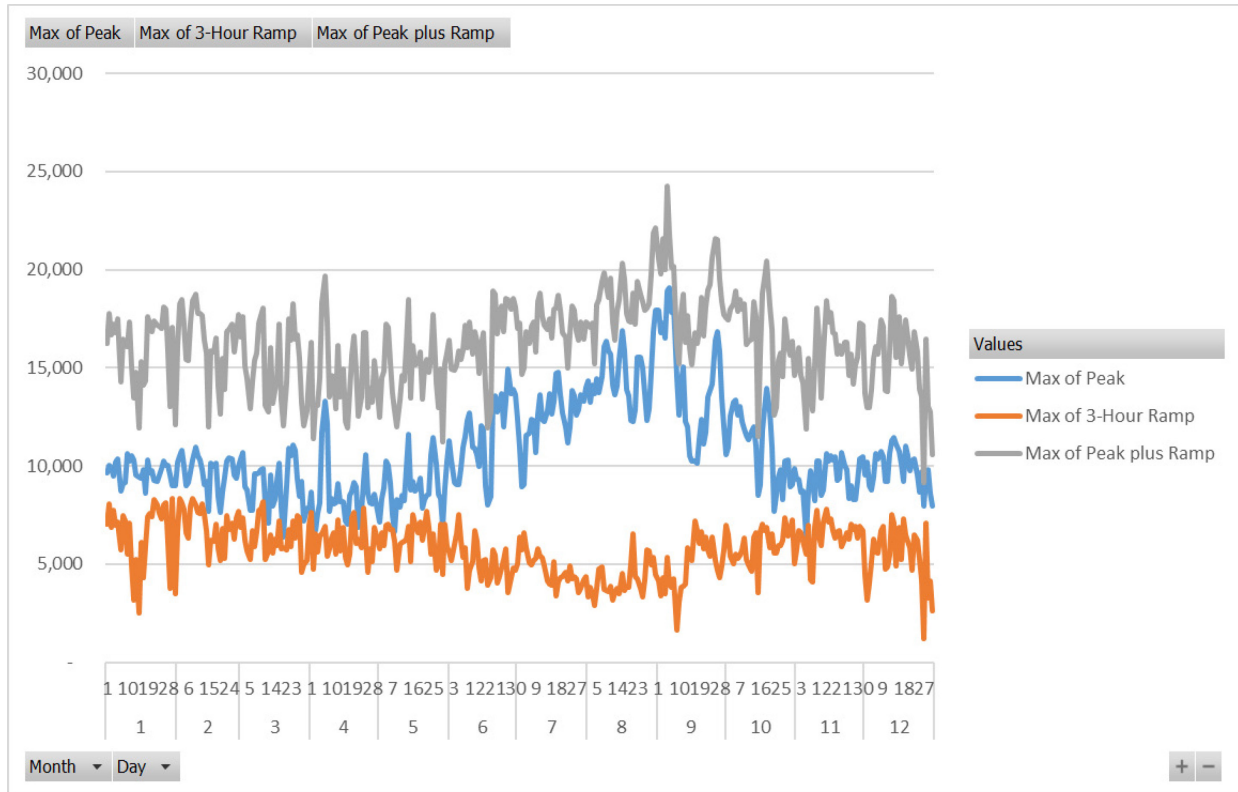
<sup>88</sup> SCE-03A at 10 (footnote omitted).

1 Batteries are inherently use limited. Once dispatched for their use limited duration to  
2 meet a system need, they must be recharged before being redeployed. Ramping and peak  
3 requirements typically occur at different times throughout the day with ramping requirements  
4 occurring first as the rate of solar output decline is steepest and peak requirements occurring later  
5 once solar output is near zero. But both needs occur to some degree each day. A battery  
6 dispatched to meet a ramping need cannot be counted on to then meet the peak requirement later  
7 that same day. Conversely, a battery that is being relied upon to meet a peak requirement is  
8 unavailable for dispatch for a ramping requirement.

9 Figure 14 below illustrates the daily requirement to meet both peak and ramp  
10 requirements showing the daily maximum hourly peak and the daily maximum 3-hour Ramp.  
11 Days that include the Top 100 peak load hours also have significant ramp requirements. Days  
12 that include the Top 10 ramp requirements also have significant peak requirements. Counting on  
13 the same resource for both requirements results in insufficient resources to meet daily reliability  
14 requirements.

1  
2

Figure 14<sup>89</sup>



3

4 We propose the marginal generation cost revenues for bundled customers to be the  
 5 product of customer demand by class for the top 100 net peak load hours times the MGCC plus  
 6 the product of customer demand by class for the top ten ramp periods times the MGCC plus the  
 7 kWh usage for each TOU period for each class times the MEC for that time period. Thus, each  
 8 class of bundled customers will have a percentage share of the marginal generation costs.

9

### B. Allocation of Distribution Costs

10

Marginal costs of distribution and customer access are allocated on a combined basis,  
 11 excluding the FERC-regulated transmission costs.<sup>90</sup> First, the time-related marginal distribution  
 12 capacity cost is multiplied times the distribution PLRFs for each customer class, which represent

<sup>89</sup> SCE-03A - I.C.3.a - Generation Capacity Retail Net Load and Revenue Allocation - Peak Ramp distinction

<sup>90</sup> Our approach is consistent with SCE's methodology which is described in SCE-03A at 13.

1 the localized peak demands imposed by that class on the local distribution system. This creates  
2 the time-related distribution capacity MCRRs. Second, the grid related (non-time related)  
3 marginal distribution capacity cost is multiplied time the effective demand factors times the non-  
4 coincident demands for each class to create the non-time related distribution capacity MCRRs.  
5 Third, for each customer class, the marginal customer cost based on the RECC method is applied  
6 to the number of customers to determine the customer-related MCRRs.

7 The MCRRs for distribution and customer costs are combined for each class. The total  
8 MCRR for each class is then multiplied by the ratio of the revenue requirement for distribution  
9 and customer access costs divided by the system wide MCRRs for distribution and customer  
10 costs, creating a distribution/customer EPMC factor. The EPMC factor is then applied to the  
11 marginal cost revenue responsibility for each class to determine its allocated share of the  
12 distribution/customer revenue requirement.

13 We allocated marginal distribution and customer costs together on an EPMC basis. We  
14 have used an adjusted version of SCE's MDCCs estimated for the functional categories  
15 discussed previously in Section VI.C in developing marginal distribution cost revenues on a  
16 system-wide basis. We have used the RECC method for MCC and applied it to the number of  
17 customers projected for each rate class.

### 18 **C. Allocation of Public Purpose Program (PPP) and Nuclear** 19 **Decommissioning Costs (NDC)**

20 SCE breaks down the PPP costs into four categories: (1) the California Alternative Rates  
21 for Energy (CARE) program, (2) the Self Generation Incentive Program (SGIP), (3) the Tree

1 Mortality Non-Bypassable Charge, and (4) all other programs<sup>91</sup> except for CARE, SGIP and  
2 Tree Mortality. SCE proposes separate allocation methodologies for each category.

3 SCE proposes to continue the allocation of the undercollection created by the CARE rates  
4 to all customers on an equal cents per kWh basis.<sup>92</sup> This is the current practice, required by law,  
5 and we have used it for our revenue allocation.

6 SCE proposes to continue to allocate costs for SGIP using allocators adopted each year as  
7 directed by D.18-11-027.<sup>93</sup> The allocation shares are based on a rolling average share of the  
8 SGIP benefits received by each customer class over the previous three years. We have used  
9 these factors in our allocation.

10 SCE proposes to continue the current allocation method for the Tree Mortality Non-  
11 Bypassable Charge as it was established in D.18-12-003 and D.20-08-043.<sup>94</sup> We concur given  
12 that the decisions were prescriptive.

13 SCE proposes that the last category, that is, all other PPP programs, except for CARE,  
14 SGIP and Tree Mortality, be allocated on system average percent basis with generation imputed  
15 for DA/CCA customers.<sup>95</sup> We agree with SCE's proposal. Each of the programs in SCE's third  
16 category is part of the public purpose category and paying for these programs imposes a cost  
17 burden on non-participants. SCE's proposed SAP revenue allocation approach distributes the  
18 burden fairly as an equal percentage increase in rates.

---

<sup>91</sup> These programs include Electric Program Investment Charge (EPIC), Procurement Energy Efficiency, On-Bill Financing, Energy Savings Assistance, Statewide Marketing, Education and Outreach, and San Joaquin Valley Disadvantage Community Pilot Program.

<sup>92</sup> SCE-03A at 22.

<sup>93</sup> SCE-03A at 24.

<sup>94</sup> SCE-03A at 24-25.

<sup>95</sup> SCE-03A at 20-21.

1 SCE retains the equal cents per kWh basis for allocating the NDC based on the  
2 Commission directive in D.00-06-034.<sup>96</sup> We concur.

3 **D. CLECA Supports SCE’s Proposal to Continue Using the Wildfire**  
4 **Allocation Methodology Settlement Adopted for the 2021 Phase 2 to**  
5 **Allocate Fire Risk Mitigation Costs.**

6 SCE proposes to allocate the costs associated with fire risk mitigation using the formula  
7 adopted in D.22-08-001.<sup>97</sup> We concur. However, our agreement to continue the use of this  
8 formula should not be perceived as our belief that the formula is cost based. Instead, it should be  
9 recognized that this formula, which was adopted through a settlement process, involved  
10 significant concessions on the part of large power customers.

11 Most of the costs associated with fire risk mitigation are associated with vegetation  
12 management, risk inspections and remediations for distribution facilities as well as capital  
13 expenditures made to “fire harden” the distribution system.<sup>98</sup> Capital expenditures include  
14 adding covered conductor to distribution circuits and fire-retardant pole wrapping to poles  
15 holding up distribution lines. These fire mitigation costs would not exist without the distribution  
16 system; therefore, they clearly fall within the distribution function.

17 Therefore, agreeing through settlement to allocate a very significant portion of wildfire  
18 costs on an SAP basis was and continues to be a large concession. In the event that the  
19 previously carefully negotiated settlement approach is being reopened, CLECA proposes these  
20 costs to be allocated on the basis of marginal distribution costs. However, CLECA is willing to  
21 continue using the formula for the allocation of wildfire costs as SCE proposes.

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<sup>96</sup> SCE-03A at 23.

<sup>97</sup> SCE-03A at 14.

<sup>98</sup> Attachment M: A.23-05-010, SCE-04, Vol. 5, Part 1 at 1-3.

1           **E.     Cal Advocates’ Proposal for an Equal Cents per kWh Allocation of**  
2           **Distribution Costs Associated with Fire Risk Mitigation Should Be**  
3           **Rejected**

4           Cal Advocates recommends that all wildfire costs should be allocated on an equal cents  
5 per kWh basis. Cal Advocates justifies its recommendation by claiming:

6                     wildfire mitigation costs provide benefits to all customer classes  
7                     and are not being undertaken to serve new load. Wildfire  
8                     mitigation costs provide shared societal benefits to all customers  
9                     and the equal cents per kWh method reflects those benefits. The  
10                    two main benefits of wildfire mitigation are reduced risk of  
11                    material damage to life and property as well as reduced greenhouse  
12                    gas emissions (GHG). Both benefits are non-exclusive and benefit  
13                    everybody and are exceedingly critical as these risks intensify.<sup>99</sup>

14          Cal Advocates’ claim does not make sense. The fact that the utility system operates safely and in  
15 an environmentally-sound fashion does not mean that costs should be apportioned on an equal  
16 cents per kWh basis. The Commission has long found that rates should reflect the cost of  
17 providing customers with service. Wildfire mitigation is a part of the distribution revenue  
18 requirement and should be allocated as such to distribution customers.

19          Cal Advocates claims that wildfire mitigation costs are incurred irrespective the amount  
20 of demand for energy placed on the distribution system;<sup>100</sup> however, Cal Advocates fails to  
21 acknowledge that these costs are directly associated with maintaining the facilities that provide  
22 the delivery capacity needed to meet these distribution demands. Without the existence of  
23 distribution facilities, the fire mitigation requirement, and its associated cost, does not exist.

24          Hence, the distribution-based allocation factors are appropriate.

25          Cal Advocates attempts to further justify its proposal by pointing to the decision adopting  
26 the PG&E Phase 2 settlement, which similar to the SCE Phase 2 settlement discussed previously,

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<sup>99</sup> Cal Advocates, Chapter 5 at 5-9.

<sup>100</sup> *Id.* at 5-8.

1 involved significant concessions by large and medium power customers. The decision quoted by  
2 Cal Advocates that approves the settlement acknowledges the need to allow an allocation of  
3 wildfire costs that is not based on a “strict distribution cost allocation.”<sup>101</sup> The allocation  
4 incorporated in the two settlements is a far cry from the proposed equal cents per kWh allocation  
5 methodology proposed by Cal Advocates. In fact, the quoted language approving the settlement  
6 would not support an equal cents per kWh allocation.

### 7 **1. Wildfire Mitigation Costs Are Functionally Distribution Costs**

8 Wildfire costs include enhanced vegetation management and adding distribution plant  
9 such as reclosers and surge arrestors and replacing certain conductor with covered conductor to  
10 reduce the risk of wildfire.<sup>102</sup> These costs are functionally distribution costs. Yet Cal  
11 Advocates’ witness incorrectly argues that it is “appropriate” to allocate these costs on an equal  
12 cents per kWh basis.

13 This simply is not true. Allocating what are clearly demonstrated to be distribution costs  
14 on an equal cents per kWh basis creates a large cost shift from smaller customers to larger  
15 customers. There are millions of residential and small commercial customers; the service  
16 provided to these small customers drives the need to put in place thousands of miles of  
17 distribution lines. In turn, it is these thousands of miles of distribution lines that must be  
18 hardened in order to avoid creating circumstances that lead to fires. Many of the larger  
19 customers do not even take service from the distribution lines that are being hardened because  
20 they are served at a higher voltage. Yet Cal Advocates’ witnesses would have those larger  
21 customers pay for a portion of the electric system that provides no service to them, shifting costs

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<sup>101</sup> Cal Advocates, Chapter 5 at 5-9, citing to D.21-11-016, slip op. at 93-94.

<sup>102</sup> D.20-12-005 at 55-56.

1 that should be paid by the smaller customers for which the system was built to the large  
2 customers who are served at high voltage.

3 **2. The DWR Bond Charge Does Not Justifies an Equal Cents per kWh**  
4 **Allocation**

5 Cal Advocates points to the DWR bond charge as a justification to allocate costs on an  
6 equal cents per kWh basis.<sup>103</sup> This is a misleading reference because the circumstances  
7 surrounding the adoption of the bond charge allocation were exceptional. The bond charge  
8 covered a “net short” in power costs during the Energy Crisis period of 2000-2001. The  
9 Commission made a specific finding that the principle of “cost causation” did not apply in this  
10 unique situation. As Cal Advocates itself notes, in this situation “there was no relationship  
11 between the prices paid for power and the cost of producing that power.” This is clearly not the  
12 case for wildfire mitigation costs, which the Commission has already found to be reasonable  
13 improvements to the distribution system. Thus, instead of a situation where there is no  
14 relationship between prices paid and actual costs, there is a direct relationship between the cost  
15 of reinforcing the distribution system to mitigate the risk of wildfire and the proposed MDCC-  
16 based allocation of the costs.

17 **3. The Wildfire Fund Charge Does Not Justify an Equal Cents per kWh**  
18 **Allocation.**

19 Cal Advocates’ reference to the Commission’s recent decision assigning the Wildfire  
20 Fund Non-bypassable Charge as supporting an equal cents per kWh allocation for the instant  
21 securitization allocation should also be completely disregarded. The Wildfire Fund, which was  
22 adopted legislatively via AB1054, was directed to be collected on an equal cents per kWh basis  
23 solely to allow the Legislature to extend the then-existing DWR Bond Charge rate without

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<sup>103</sup> Cal Advocates, Chapter 5 at 5-9 to 5-10.

1 creating any rate impact. The adoption of the Wildfire Fund charge on the same basis as the  
2 DWR Bond charge was expedient; it was not an endorsement of a cost allocation method.

3 **F. SCE’s Proposal to Allocate Transportation Electrification Costs**  
4 **According to Authorizing Decision Is Reasonable.**

5 SCE has four transportation electrification (TE) programs already authorized for the rate  
6 period. Each program was authorized a specific cost allocation methodology in the decision  
7 authorizing its funding. SCE proposes to use the authorized allocation method for the respective  
8 TE revenue requirement associated with the program.<sup>104</sup> We agree that this is reasonable.

9 **G. Recommended Cost Allocation**

10 Our uncapped revenue allocation is shown below in Table 14, which presents the  
11 allocation results for both bundled and DA/CCA customers:

---

<sup>104</sup> SCE-03A at 19.

1  
2

**Table 14**

**CLECA Proposed Cost Allocation  
Showing Bundled Service and DA/CCA Average Rates  
By Rate Group (c/kWh)**

	<b>Bundled Service</b>			<b>DA/CCA</b>		
	<b>Current (£/kWh)</b>	<b>Proposed (£/kWh)</b>	<b>% Change</b>	<b>Current (£/kWh)</b>	<b>Proposed (£/kWh)</b>	<b>% Change</b>
<b>Total Domestic</b>	32.6	38.0	16.7%	17.3	18.8	8.3%
TOU-GS-1	29.0	23.5	-19.2%	13.1	12.5	-4.6%
TC-1	33.7	28.2	-16.5%	19.3	14.8	-23.3%
TOU-GS-2	31.6	26.6	-15.8%	13.7	12.3	-9.9%
TOU-GS-3	25.6	23.4	-8.7%	11.2	11.1	-1.0%
<b>Total LSMP</b>	29.3	24.9	-14.9%	12.8	12.0	-6.5%
TOU-8-Sec	23.5	21.7	-7.7%	10.4	10.2	-2.6%
TOU-8-Pri	22.0	20.8	-5.4%	9.2	9.0	-1.7%
TOU-8-Sub	14.8	14.4	-2.3%	4.4	4.5	1.1%
<b>Total Large Power</b>	20.6	19.3	-5.9%	8.0	7.9	-1.6%
TOU-PA-2	25.6	22.1	-13.7%	12.2	10.1	-16.6%
TOU-PA-3	21.3	21.7	1.9%	9.5	9.7	1.4%
<b>Total Ag.&amp;Pumping</b>	23.6	21.9	-7.1%	10.8	9.9	-8.7%
<b>Total Street Lighting</b>	30.5	44.6	46.1%	25.3	37.1	46.9%
STANDBY/SEC	24.8	21.8	-11.9%	11.4	10.7	-5.8%
STANDBY/PRI	24.0	22.2	-7.7%	10.7	10.1	-5.4%
STANDBY/SUB	16.3	15.9	-2.8%	5.5	5.4	-1.2%
<b>Total Standby</b>	17.9	17.1	-4.4%	7.0	6.8	-3.1%
<b>Total System</b>	<u>27.7</u>	<u>27.7</u>	<u>0.1%</u>	<u>12.5</u>	<u>12.6</u>	<u>0.9%</u>

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Capping is a process by which revenue increases to certain classes or rate schedules are reduced below the results that come from a marginal-cost-based revenue allocation. The revenue shortfall is then spread to other customer classes. It is essentially a subsidy of a certain group (or groups) of customers by the other customers that results from a belief that the rate increase that would otherwise occur would result in overly onerous bill impacts.

1           Flooring is a process by which revenue decreases to certain classes or rate schedules are  
2 kept from decreasing to the full extent that is indicated by the revenue allocation. The limitation  
3 of revenue decreases generates revenues that are then used to subsidize via capping those  
4 customers who are facing a relatively large increase under the revenue allocation.

5           We have not developed any class average rates based on a capped (and floored) revenue  
6 allocation at this time. Our allocation table shows the results of our revenue allocation proposal  
7 on a full cost-of-service basis using our marginal costs. However, we recognize that there are a  
8 few customer classes whose current rates are significantly below the level specified under a full  
9 cost-of-service allocation. Thus, it may be appropriate to cap (and floor) the revenue allocation  
10 changes in this proceeding to avoid rate shock for these customer classes.

## 11 **IX. Rate Design**

### 12 **A. Cost-Based Rate Design for Schedules TOU-8-SUB-D, TOU-8-PRI-D,** 13 **and TOU-8-SEC-D**

14           Our basic premise for rate design is that rates should be based on cost-of-service  
15 principles using updated marginal costs. The residual amount between the marginal cost  
16 revenues and the full revenue requirement for distribution and generation should be assigned on  
17 an equal percent basis to the individual rate components. The Commission has previously  
18 confirmed that “fully-scaled EPMC rates have been, and remain, the Commission’s standard for  
19 cost-based, fair, and equitable non-residential rates.”<sup>105</sup> However, in our opinion, if the full cost-  
20 of-service rates (marginal cost plus EPMC factor) would result in a very large change in one or  
21 more rate components, the change should be mitigated and phased in over more than one year or  
22 rate case cycle, depending on the potential bill impacts.

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<sup>105</sup> D.18-08-013, slip op. at 54.

1           Our priority is always to promote cost-based rates while avoiding rate shock. Since our  
2 MGCC is higher than SCE's MGCC, the resulting fully-scaled EPMC rate design will be  
3 different than the rate design proposed by SCE. We have produced our own rate design for  
4 TOU-8 customers using our recommended marginal costs that increases generation demand  
5 charges somewhat relative to current levels. We put as much as possible of the remaining  
6 MGCC related revenue (EPMC-scaled marginal costs) into on-peak and mid-peak energy rates  
7 and pick up the remaining revenue in the off-peak energy rates.

8           Our distribution demand charges follow from the EPMC-scaled marginal costs with  
9 primary marginal costs attributed to TOU periods and secondary and new customer costs  
10 associated with the maximum demand charge. We have also included EPMC-scaled primary  
11 marginal costs that are attributed to the off-peak periods in the maximum demand charges. We  
12 note that SCE is proposing a mixture of demand charges and energy charges for the time-  
13 dependent portion of the distribution cost of service. Furthermore, SCE proposes to reduce the  
14 demand charges, which are based on a strong summer allocation, and take the residual revenues  
15 and collect them through a flat charge across all TOU periods.

16           While we believe it is appropriate to mitigate increases in the distribution demand charge  
17 levels somewhat, we oppose SCE's proposal to adopt a flat energy charge across all TOU  
18 periods to pick up the remaining revenue responsibility. Instead, we recommend that the energy  
19 charges be collected only during the summer TOU periods although the charge should be the  
20 same during each of the summer TOU periods. The reason for this equality lies with the fact that  
21 a large amount of the capacity responsibility on the distribution system is created during the  
22 summer off-peak period. Since it would be confusing to customers to charge a TOU demand  
23 charge during an off-peak period, it is reasonable instead to spread those capacity costs into an

energy rate that is charged during the three summer TOU periods including the summer off-peak period.

Table 15 below presents our Option D rate design for the TOU-8 schedules based on our recommended cost allocation.

**Table 15**

<b>CLECA Proposed Option D Rate Design</b>						
	<b>TOU-8-SUB-D</b>		<b>TOU-8-PRI-D</b>		<b>TOU-8-SEC-D</b>	
	Distribution	Generation	Distribution	Generation	Distribution	Generation
<b>Summer</b>						
Customer Charge \$/month	5,121.00	-	214.25	-	1,733.50	-
On-Peak \$/kWh	0.00000	0.12820	0.00720	0.13482	0.00795	0.13288
Mid-Peak \$/kWh	0.00000	0.12287	0.00655	0.12783	0.00723	0.12694
Off-Peak \$/kWh	0.00000	0.05922	0.00642	0.06111	0.00708	0.06275
SuperOff-Peak \$/kWh	-	-	-	-	-	-
On-Peak \$/kW	2.64	28.16	12.18	26.98	12.41	24.49
Mid-Peak \$/kW	-	-	-	-	-	-
Off-Peak \$/kW	-	-	-	-	-	-
SuperOff-Peak \$/kW	-	-	-	-	-	-
Max-Demand \$/kW	4.62	-	15.62	-	15.17	-
<b>Winter</b>						
Customer Charge \$/month	5,121.00	-	214.25	-	1,733.50	-
On-Peak \$/kWh	-	-	-	-	-	-
Mid-Peak \$/kWh	0.00000	0.09296	0.00720	0.09649	0.00795	0.09665
Off-Peak \$/kWh	0.00000	0.07215	0.00655	0.07397	0.00723	0.07552
SuperOff-Peak \$/kWh	0.00000	0.03207	0.00614	0.03285	0.00681	0.03354
On-Peak \$/kW	-	-	-	-	-	-
Mid-Peak \$/kW	0.04	14.08	1.92	12.11	1.70	10.58
Off-Peak \$/kW	-	-	-	-	-	-
SuperOff-Peak \$/kW	-	-	-	-	-	-
Max-Demand \$/kW	4.62	-	15.62	-	15.17	-

**B. Current TOU-8 Option E Rate Design Creates a Revenue Shortfall**

SCE’s TOU-GS-2, TOU-GS-3, and TOU-8 tariffs include a provision for Option E rates that are available to bundled, CCA, and DA customers. We are only addressing TOU-8 rate schedules in our testimony, but the same problem, revenue shortfall due to Option E rate design, exists to a greater extent for the TOU-GS-2 and TOU-GS-3 schedules.

1 TOU-8 schedule Option E rates are available only to customers who do not exceed 5 MW  
2 in peak demand and who install a solar system or other qualifying technology that provides at  
3 least 15 percent of the customer's annual electricity usage.<sup>106</sup> Furthermore, there is an overall  
4 participation cap of 250 MW for Option E customers on TOU-8. Nonetheless, despite these  
5 precautions, TOU-8 Option E rates have created an annual average shortfall of nearly \$8 million  
6 during 2021-2023.<sup>107</sup>

7 The Option E rates largely eliminate generation demand charges and coincident  
8 distribution charges, collecting the generation coincident capacity costs and distribution  
9 coincident capacity costs via coincident energy charges. However, SCE designs TOU-8 Option  
10 E rates based on the entire customer class. Coincident costs are driven by the coincident demand  
11 times the applicable marginal cost. The coincident costs are then spread across the total kWh of  
12 usage to create a \$/kWh rate for the various TOU periods. The Option E energy rate is thus  
13 created by:

$$\text{kW demand} \times \text{MC of (generation or distribution) capacity} \div \text{kWh usage in time period}$$

15 If the kWh usage in this equation were to increase, the \$/kWh rate would decrease, similarly if  
16 the kWh usage in this equation were to decrease the \$/kWh rate would increase. Thus, the  
17 relationship between kW and kWh is critical to setting the cost-based \$/kWh rate.

18 SCE's approach to Option E rate design creates a significant cost shift because the rates  
19 paid by Option E customers do not collect the entire capacity cost that these customers impose  
20 on the system. Therefore, cost shifting occurs. The coincident demand costs that the Option E  
21 customers are supposed to pay get allocated based on their demand, but these coincident costs  
22 are not divided by the Option E kWh but instead are divided by the typical kWh for the entire

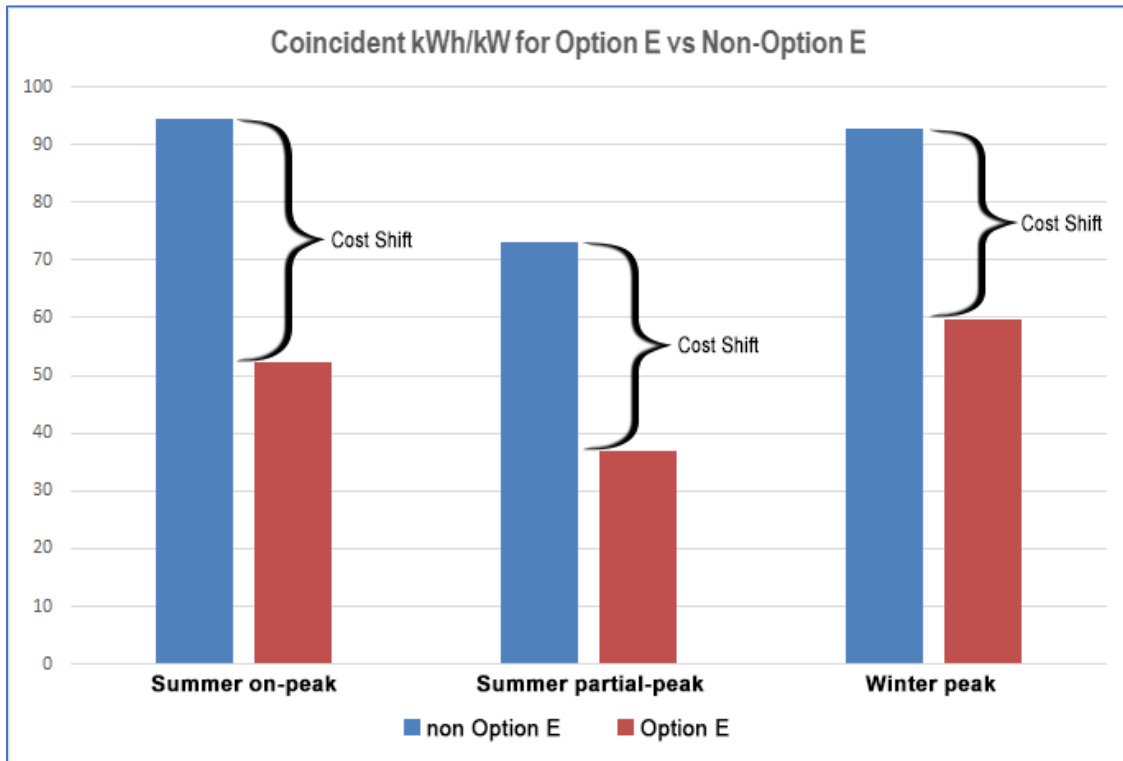
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<sup>106</sup> SCE Schedule TOU-8, Applicability: Option E at Sheets 2-3.

<sup>107</sup> Attachment D: SCE Response to CLECA-19, Q.19.2.

1 class. This does not work well. While Option E customers reduce their capacity, they reduce  
 2 their coincident energy usage even more as demonstrated by a comparison of the kWh per kW  
 3 for Option E customers and the remaining non-Option E customers. Figure 14 below illustrates  
 4 the problem:

5 **Figure 15: Option E vs Non-Option E Comparison**



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 7 CLECA recommends that Option E be discontinued for TOU-8 customers as dynamic  
 8 rates become available. SCE has a pending application applicable to TOU-8-SUB customers  
 9 also intended to integrate customer clean energy resources that would enable the Commission to  
 10 substitute a cost based dynamic rate instead of the existing rate Option E with the shortcomings  
 11 described above.

12 **C. Clarification to DL-NBC Tariff**

13 The Departing Load – Non-Bypassable Charges (DL-NBC) tariff defines departing load  
 14 and imposes various charges on customers that reduce their consumption from SCE. Tariff DL-

1 NBC generally defines reduction in utility consumption due to installation of distributed  
2 renewable resources as not departing load, consistent with State policy to encourage customer  
3 adoption of clean energy technologies. Tariff DL-NBC<sup>108</sup> should be clarified to reference PU  
4 Code Sections 2827-2827.10<sup>109</sup> to clarify that all renewable resources eligible for net energy  
5 metering as defined in statute are treated consistently under Tariff DL-NBC.

#### 6 **D. Support for Economic Development Rate**

7 CLECA strongly supports SCE's proposal for a new Economic Development Rate (EDR)  
8 cycle. As discussed previously in this testimony and, as SCE explains<sup>110</sup>, California costs of  
9 doing business are very high and competitive electricity rates are a critical driver of  
10 competitiveness with other states and other countries. Attracting, retaining and expanding at risk  
11 businesses is critical to promoting critical jobs, economic activity, tax base, and reduces emission  
12 leakage from imported goods.

13 However, the proposed increase from 12% to 20% reduction to the Otherwise Applicable  
14 Tariff (OAT) is insufficient given the continued absolute and relative increase in electricity rates  
15 compared to neighboring states. Figure 15 below illustrates the relative change in California  
16 Industrial Rates from the 2021 GRC Phase 2 to today. We recommend a new EDR reduction of  
17 at least 25% to partially narrow the increase in relative rates experienced in just the last 4 years  
18 since the last GRC cycle. Further, the 5-year EDR term is insufficient for the capital planning  
19 and reinvestment necessary to attract, retain, and expand businesses. This is especially important

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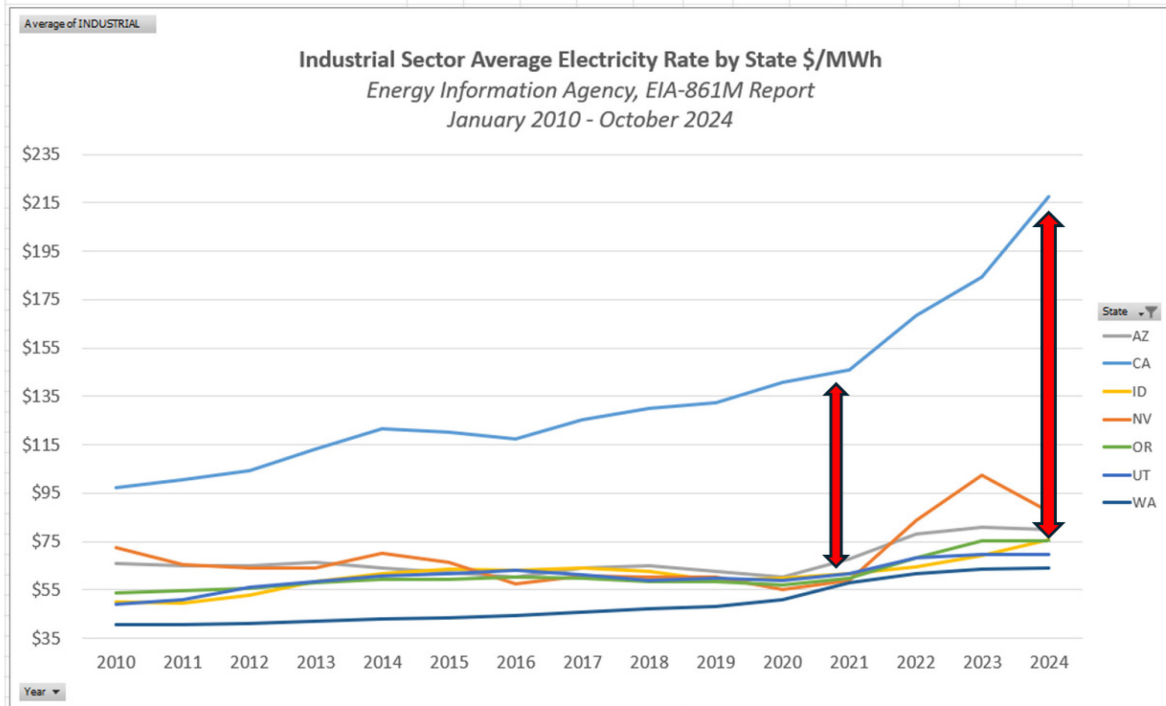
<sup>108</sup> Schedule DL-NBC Special Condition 1, states that "load that is (1) eligible for net energy metering, as defined in Public Utilities (PU) Code Sections 2827, 2827.8 and 2827.10, or (2) served by systems on the Net Billing Tariff or NEM Successor Tariffs pursuant to Decision 16-01-044 is not departing load." (See Schedule DL-NBC, Sheet 2.).

<sup>109</sup> See, SCE's Preliminary Statement W at 1.a.

<sup>110</sup> SCE-04A, page 106-110.

1 for major industrial operations deciding whether to invest in multi-decade lifespan capital  
2 equipment. We recommend an EDR term of at least 10 years.

3 **Figure 16<sup>111</sup>**  
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5  
6 The continuity of EDR programs across GRC cycles is also critical to major capital  
7 decision processes. Uncertainty about EDR program availability as a new GRC cycle approaches  
8 could significantly delay a project or lose the project entirely to another state. We appreciate  
9 SCE’s proposed language that the EDR program would continue until new rates are actually  
10 implemented<sup>112</sup> and stress the importance of clear language to avoid uncertainty in program  
11 availability for investment planning purposes.

<sup>111</sup> Attachment C.5: EIA Data - Industrial Rates.

<sup>112</sup> SCE-04A, page 113 - “The program will remain open for a customer to execute an EDR Agreement until either (1) the day before SCE’s 2029 GRC Phase 2 rates are implemented, (2) the day before the effective date of a Commission order terminating the program, or (3) the EDR cap of 200 MW is met, whichever comes first.”

1           The time allowed to energize a new project should be expanded from the current 3 year  
2 limit given the long lead times and supply chain delays now common for high voltage and other  
3 heavy industrial equipment. We recommend a maximum time of 6 years to energize a new  
4 customer project if the delay is caused by the customer and no limit if the timeline delay is due to  
5 SCE required time to interconnect the new facility.

6           Finally, we support the SCE proposals to ensure a robust program and process that  
7 ensures customers receiving the EDR are truly at risk.

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**Attachment A: Qualifications of Catherine E. Yap**

1 **Attachment A: Qualifications of Catherine E. Yap**

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3 **Q1.** Please state your name and business address.

4 **A1.** My name is Catherine E. Yap and my address is Barkovich & Yap, Inc., P.O. Box 11031,  
5 Oakland, California 94611.

6 **Q2.** Please state your qualifications to offer this testimony.

7 **A2.** I am a principal in the firm of Barkovich & Yap, Inc., and have been consulting in the  
8 utility regulatory area for over thirty-five years. During this time, I have directed and/or  
9 performed major examinations of cost-of-service requirements, allocation, rate design,  
10 and customer bill effects for electric, natural gas, and solid waste utilities. I have testified  
11 on numerous occasions before the California Public Utilities Commission (Commission)  
12 and in civil proceedings. I have consulted internationally on issues related to natural gas  
13 industry structure and marginal cost allocation and rate design.

14 Prior to this, I was employed for nine years by the Commission. Most recently, I was  
15 responsible for managing the Energy Rate Design and Economics Branch of the Public  
16 Staff Division (PSD). This branch was responsible for developing cost of service, rate  
17 design, and economic studies, such as sales forecasting and productivity assessment, for  
18 both electric and gas utilities. Members of the branch were responsible for presenting  
19 expert testimony, developing cost of service studies, and designing unbundled rates for  
20 the natural gas utilities during the Commission’s extensive hearings on gas industry  
21 structure and rate design implementation. During this time, I participated extensively in  
22 the formulation of policy regarding the appropriate structure for the natural gas industry  
23 in California.

24 Previously, I was the Supervisor of the Gas Supply and Requirements Section of the  
25 Fuels Branch of the PSD. I was responsible for directing, and in some cases performing,  
26 advanced technical studies that evaluated California gas utility operations and associated  
27 contracts, investments, and expenses. I also acted as the highest level technical  
28 representative of the Commission on natural gas matters and was involved in numerous  
29 negotiated settlements involving natural gas pipelines, distribution utilities, producers,  
30 and state and federal regulatory agencies.

1 Prior to that, I was a staff economist in the Policy Division acting as a consultant to the  
2 Executive Director and to various Commissioners. I also testified on numerous occasions  
3 as an expert witness regarding a variety of technical, economic, and financial matters  
4 related to electric and natural gas utilities.

5 I have a B.A. in chemical physics from the University of California at Santa Cruz, and a  
6 M.S. in Energy and Resources from the University of California at Berkeley. I have also  
7 taken course work in finance, accounting, and organization theory from the University of  
8 California, Extension, and Golden Gate University.

9 **Q3.** What testimony are you sponsoring in this proceeding?

10 **A3.** I am jointly sponsoring the Testimony of Catherine E. Yap and Sam Harper on Behalf of  
11 the California Large Energy Consumers Association.

12 **Q4.** Was this material prepared by you or under your supervision?

13 **A4.** Yes, it was.

14 **Q5.** Insofar as this material is factual in nature, do you believe it to be correct?

15 **A5.** Yes, I do.

16 **Q6.** Insofar as this material is in the nature of opinion or judgment, does it represent your best  
17 judgment?

18 **A6.** Yes, it does.

19 **Q7.** Do you adopt this testimony as your sworn testimony in this proceeding?

20 **A7.** Yes, I do.

21 **Q8.** Does this conclude your qualifications and prepared testimony?

22 **A8.** Yes, it does.

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**Attachment B: Qualifications of Sam Harper**

## Attachment B: Qualifications of Sam Harper

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3 **Q1.** PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

4 **A1.** Sam Harper. My business address is Harper Advisory LLC, 9002 Six Pines Drive,  
5 Shenandoah, TX 77380.

6 **Q2.** WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

7 **A2.** I am a consultant in the field of energy markets and policy. I am employed by Harper  
8 Advisory LLC.

9 **Q3.** PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

10 **A3.** I have extensive experience in energy procurement, utility regulation, ISO/RTO  
11 governance, renewable energy development, and demand response. I have direct  
12 experience with commercial energy arrangements, demand response, and the  
13 stakeholder processes in PJM, MISO, ERCOT, CAISO, IESO, CENACE, and various  
14 unorganized markets. In my current role as a consultant, I advise organizations that  
15 engage across the energy supply chain, including large energy consumers for whom  
16 energy is a significant percentage of their cost of production.

17 Prior to consulting, I was the Director of Energy of North American operations for  
18 Gerdau, a major steel producer with significant energy requirements and active demand  
19 response participation. From 2013-2022, I held a variety of positions for Gerdau, which  
20 included Regional Energy Manager and Assistant Vice President of Operations for  
21 Gerdau's subsidiary load serving entity. My responsibilities included demand response  
22 operations, RTO/ISO stakeholder process, utility regulatory intervention, commercial  
23 energy contract negotiations, commodity risk management, and renewable energy  
24 development.

25 I was elected each year from 2016 through 2021 to the Board of Directors of the Electric  
26 Reliability Council of Texas (ERCOT). I served on the Human Resources and

1 Governance Committee throughout my tenure, and in 2021 was elected Vice-Chair. I  
2 served during the Storm Uri reliability crisis in February 2021 and its aftermath.

3 I served on the Advisory Board for the Renewable Development Fund of Minnesota from  
4 2017-2020, ensuring renewable energy grants were awarded and executed prudently and  
5 consistent with state policy goals.

6 From 2008-2013, I was employed by ArcelorMittal, a global steel producer, ending as the  
7 Sourcing Manager of Electricity for US Operations. During that time, I created and  
8 managed a load serving entity and curtailment service provider in the PJM territory.

9 I earned a Bachelor of Science degree in Business Administration from the University of  
10 Illinois at Urbana-Champaign in 2008, graduating with Honors.

11 **Q4.** What testimony are you sponsoring in this proceeding?

12 **A4.** I am jointly sponsoring the Testimony of Catherine E. Yap and Sam Harper on Behalf of  
13 the California Large Energy Consumers Association.

14 **Q5.** Was this material prepared by you or under your supervision?

15 **A5.** Yes, it was.

16 **Q6.** Insofar as this material is factual in nature, do you believe it to be correct?

17 **A6.** Yes, I do.

18 **Q7.** Insofar as this material is in the nature of opinion or judgment, does it represent your best  
19 judgment?

20 **A7.** Yes, it does.

21 **Q8.** Do you adopt this testimony as your sworn testimony in this proceeding?

22 **A8.** Yes, I do.

23 **Q9.** Does this conclude your qualifications and prepared testimony?

24 **A9.** Yes, it does.

25