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SOUTHERN CALIFORNIA
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(U 338-E)

***Phase 2 Of 2025 General Rate Case
Amended Marginal Costs And Sales Forecast
Proposals***

Before the
Public Utilities Commission of the State of California

Rosemead, California
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SCE-02A: Amended Marginal Costs And Sales Forecast Proposals

GRC Phase 2

Table Of Contents

Section		Page	Witness
I.	MARGINAL COSTS.....	1	A. Baltaji
A.	Introduction And Summary of Recommendations	1	
B.	Overview	4	
1.	Marginal Cost Principles.....	5	
2.	Marginal Cost Scope and Application	5	
3.	Cost Drivers	6	
a)	Electricity Usage	6	
b)	Design Demand.....	6	
c)	Number And Type of Customers.....	7	
4.	Annual Cost of Capital Investments – RECC Methodology	8	
C.	Marginal Cost Methodology	10	J. Yan
1.	Electricity Usage Marginal Costs	10	
a)	Marginal Energy Costs (MECs).....	10	
(1)	Methodology And Data Sources.....	10	
(2)	Key Assumptions	12	
b)	Generation Capacity Marginal Cost.....	12	
(1)	Proxy Resource and Valuation.....	13	
(2)	Hourly Allocation Methodology.....	15	
2.	Design Demand Marginal Costs	21	A. Baltaji
a)	Capital Component of Design Demand Marginal Cost.....	21	
b)	O&M Component of Design Demand Marginal Cost.....	23	

SCE-02A: Amended Marginal Costs and Sales Forecast Proposals

GRC Phase 2

Table Of Contents (Continued)

	Section	Page	Witness
	c) Functionalizing Costs Between Peak and Grid24		
	(1) Distribution Circuit Costs24		
	(2) Subtransmission Circuit Costs25		
	(3) Distribution And Subtransmission Substation Costs.....25		
	d) Relating Marginal Costs To Measurable Customer Attributes26		L. Pan and C. Sorooshian
	(1) PLRF Methodology For Peak Capacity-Driven Costs26		
3.	Customer Marginal Costs39		A. Baltaji
4.	Street Lighting and Outdoor Lighting Marginal Cost.....41		E. Salazar
II.	SALES AND CUSTOMER FORECAST47		S. Verdon
Appendix A Glossary			
Appendix B Circuit Analysis For Determination Of Effective Demand Factors			
Appendix C SCE TOU Period Study			
Appendix D NCO Marginal Cost Methodology			
Appendix E Design Demand Marginal Cost Working Group			
Appendix F Distribution Cost At The Regional And Substation Level			
Appendix G PLRF Results Based on Recorded Load Data			

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15

I.

MARGINAL COSTS

A. Introduction And Summary of Recommendations

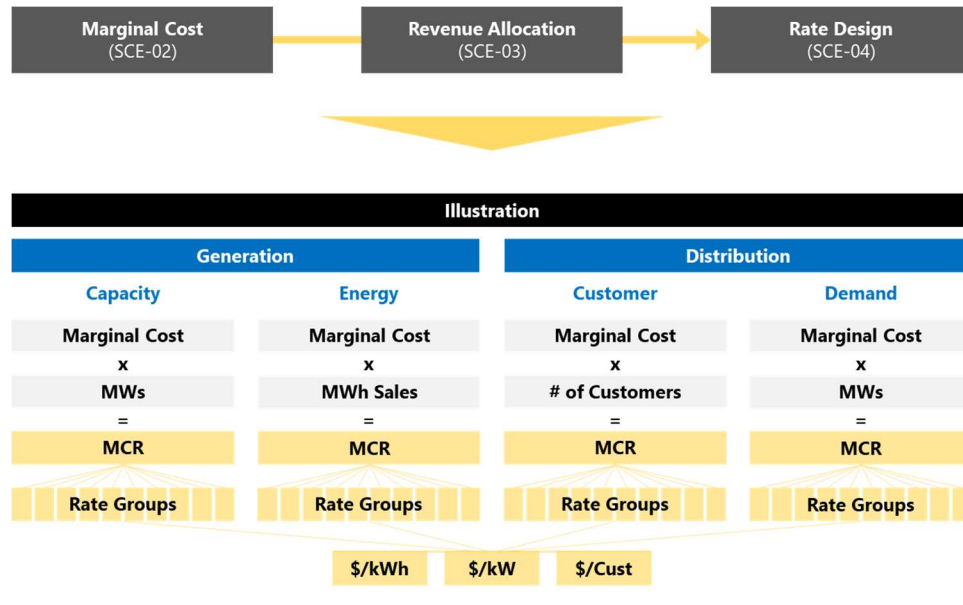
For over thirty years, the California Public Utilities Commission (Commission or CPUC) has relied on marginal cost principles to assign authorized revenue requirements to customers (by rate group), and as guidance for setting the level of individual rate components.¹ This section presents SCE's marginal costs for providing regulated utility services to its customers.

Marginal costs represent the change in costs incurred to serve a marginal increment of demand for utility services. The starting point for calculating marginal costs is identifying the cost drivers required to meet customers' electricity needs. Next, marginal costs are calculated for each cost driver.² These marginal costs are then applied to measurable customer attributes to estimate marginal cost revenues – the revenues SCE would collect if all its customers were charged rates that equaled marginal costs. Finally, these marginal costs and marginal cost revenues are used to allocate SCE's authorized revenue requirements to rate groups (SCE-03) and to inform SCE's rate design (SCE-04), as shown in Figure I-1 below.

¹ Authorized revenue requirements are the costs of providing utility services that the Commission has determined are appropriate to recover through customer rates. Rate groups are categories into which similar types of customers are grouped, such as residential service or small general service. Rates are the regulated (tariffed) prices charged to customers in each rate group for utility services. These rates typically consist of multiple components, such as energy charges, demand charges, and monthly fixed charges.

² Typically, both short run and long run marginal costs are used when designing rates. Long-run marginal costs are used for utility services that require capital investments in long-life utility assets (*e.g.*, distribution design demand marginal costs). Short-run marginal costs are used for services that are provided based on a predetermined level of available capacity (*e.g.*, marginal energy costs).

Figure I-1
Illustration of Marginal Costs, Revenue Allocation, & Rate Design



In this section, SCE presents marginal costs based on the following three cost drivers:

- **Electricity Usage:** The cost of procuring electricity to meet customers' electricity demands (energy and capacity), as summarized in Table I-1 below.³

Table I-1
Generation Marginal Costs
(2025\$)

Cost Component	Annual	Summer			Winter		
Component		On	Mid	Off	Mid	Off	Super Off
Energy (¢/kWh)	4.778	6.056	5.111	4.741	5.502	5.334	3.293
Capacity (\$/kW-Year)	104.69	40.32	1.06	16.27	42.44	4.60	-

Energy marginal costs are based on average Total Fuel Cost of \$6.93/MMbtu \$1.54/MMbtu GHG-related costs based on Cap-and-Trade Program and \$5.38/MMbtu based on SoCal Citygate gas price).

Capacity marginal costs include a 17% Planning Reserve Margin.

- **Design Demand:** The cost of delivering electricity to, and from, customers on SCE's distribution system. It represents the *amount* and *configuration* of capacity that system planners determine is necessary to serve additional demand expected on SCE's distribution system. In this Application, SCE proposes to continue functionalizing design

³ SCE and other load serving entities are required to procure generation resources with sufficient capacity to meet 117 percent of forecast demand. See D.23-06-029 at Conclusion of Law 5.

demand marginal costs between peak and grid, as shown in Table I-2.

Table I-2
Design Demand Marginal Costs
(2025\$, By Asset Type)

Design Demand Marginal Costs (\$/kW-Yr)								
Item	Asset Type	Summer			Winter			Annual
		ON	MID	OFF	MID	OFF	SOF	
Sub-Transmission								
1	Substations (Peak)	14	4	17	4	2	5	46
2	Circuits (Grid)	-	-	-	-	-	-	17
Distribution								
3	Substations (Peak)	8	2	9	2	1	3	25
4	Circuits (Peak)	9	2	11	1	1	4	28
5	Circuits (Grid)	-	-	-	-	-	-	94

- **Number of Customers:** The cost of providing customers' access to the distribution system and the on-going costs to manage customer relationships. Since these costs vary by type of customer, marginal costs are derived for each rate group, as summarized in Table I-3.⁴

⁴ SCE's customer marginal costs are calculated using the real economic carrying charge (RECC) methodology. However, to recognize the New Customer Only (NCO) methodology as an alternative method adopted by the Commission in SCE's 1995 General Rate Case (GRC), SCE presents NCO-based calculations in Appendix D of this volume.

Table I-3
Customer Marginal Costs
(2025\$)

Customer Marginal Costs (\$/Customer-Yr)		
Item	Rate Group	\$/Customer-Yr
1	Domestic	154
2	GS-1	160
3	TC-1	129
4	GS-2	1,650
5	GS-3	5,957
6	TOU-8 Secondary	12,149
7	TOU-8 Primary	1,425
8	TOU-8 Subtransmission	20,266
9	PA-2	439
10	PA-3	4,258
11	Metered Street Lights	136
12	Unmetered Street Lights* Per Customer	24.68
13	LS-1 + Per Lamp	1.17
14	LS-2 + Per Lamp	1.60
15	OL + Per Lamp	2.93
16	DWL + Per Lamp	1.14

*Unmetered includes both a customer and per lamp customer marginal cost

Section I.B. describes the principles and methodological approaches that guide the development of SCE's marginal costs. Section I.C. presents SCE's marginal cost studies and the derivation of individual marginal cost components. Section II presents SCE's sales and customer forecast. A glossary of terms is provided in Appendix A. Additional information supporting SCE's marginal cost study is presented in Appendices B through C. Appendix D includes a description and results of the NCO marginal cost methodology. Appendix E presents findings and proposals from SCE's DDMC Working Group.⁵

B. Overview

SCE contends that rate design principles based on marginal costs ensure that customers make economically efficient usage and investment decisions. In this section, SCE discusses principles, scope, and application of marginal costs in the design of its retail rates that allow SCE to recover authorized revenue requirements. Additionally, SCE discusses cost drivers and their role in applying marginal cost principles to rate design.

⁵ Refer to D.22-08-001 (SCE's 2021 GRC Phase 2), p. 16.

1 **1. Marginal Cost Principles**

2 The Commission's reliance on marginal cost principles for revenue allocation and rate
3 design is well-founded on economic principles. Marginal costs reflect the change in costs incurred to
4 serve a marginal increment of demand for utility services. Allocating a utility's authorized revenue
5 requirement based on marginal costs provides economically correct price signals that incentivize
6 customers to make efficient decisions about their usage of electricity and adoption of emerging
7 technologies (*i.e.*, electric vehicles, energy storage, distributed solar, etc.). However, setting rates
8 exclusively based on marginal costs generally results in the under-recovery of a utility's authorized
9 annual revenue requirement. As a result, the marginal costs must be adjusted to recover a utility's
10 authorized annual revenue requirement. To do this, SCE uses the equal percent of marginal cost
11 (EPMC) methodology to assign the utility's authorized revenue requirements in proportion to its
12 marginal cost revenues.⁶

13 **2. Marginal Cost Scope and Application**

14 SCE's marginal costs reflect the suite of service provisions to customers, although SCE's
15 role in the provision of such services may depend on a host of variables. State law allows some
16 customers to access markets for electricity supply directly, instead of procuring this service from SCE.
17 This includes community choice aggregation (CCA) customers and direct access (DA) customers.
18 This testimony assumes that SCE will continue to provide metering and billing services to all customers,
19 not just *bundled service* customers.⁷ For bundled service customers, SCE obtains supply of electric
20 power from wholesale market purchases, through contractual commitments or its own generating
21 facilities.

22 SCE's higher-voltage transmission facilities are subject to Federal Energy Regulatory
23 Commission (FERC) jurisdiction and are under the operational control of the California Independent
24 System Operator (ISO or CAISO). FERC-jurisdictional (ISO-controlled) assets and activities have not
25 been included in the marginal cost study presented in this testimony. Marginal costs associated with the

⁶ EPMC has been the basis of SCE's revenue allocation methodology in its last six GRC Phase 2 proceedings.

⁷ Bundled service customers receive delivery *and* generation services from SCE directly.

1 FERC-jurisdictional facilities and activities are excluded from marginal cost revenues and the revenue
2 allocation process because FERC—not the CPUC—has jurisdiction and is responsible for determining
3 revenue requirements and rates associated with these facilities and activities.

4 In this Application, SCE’s marginal costs are intended to represent conditions expected to
5 occur during the period from 2025 through 2028. Notably, electricity supply marginal costs are based
6 on a projected fundamental price forecast for the year 2025 (expressed in constant 2025 dollars).
7 Thus, upon implementation of the rates requested in this Application, there is no need to true-up SCE’s
8 marginal costs in annual rate design proceedings.

9 **3. Cost Drivers**

10 **a) Electricity Usage**

11 As described further in Section I.C.1., this cost driver is associated with the cost
12 of procuring electricity to meet customers’ electricity demands. *Energy* generation marginal costs are
13 forecast through production simulation models that derive a forecast of market clearing prices. *Capacity*
14 generation marginal costs are based on the Net Cost of New Entry (NetCONE) of a 6-hour lithium-ion
15 battery paired with solar as a proxy resource and assigned to TOU periods using a simulation model.
16 *Energy* generation marginal costs are aggregated and averaged for each TOU period.

17 **b) Design Demand**

18 As described in Section I.C.2, this cost driver is associated with the cost of
19 delivering electricity to, and from, customers on SCE’s distribution system. Design demand is a
20 function of both the *amount* and *configuration* of planned capacity that system planners determine is
21 necessary to serve additional demand expected on the distribution system.⁸ Power is typically delivered
22 to the transmission system from regional generators or interties at ≥ 220 kV. To deliver power safely
23 and reliably to SCE’s customers, electricity goes through three stages of power transformation: 1) 220
24 kV to 66 kV (subtransmission voltages), 2) 66 kV to 12 kV (primary distribution voltages), and 3)

⁸ For large customers, planners consider the customer’s electrical equipment and their expected utilization in order to size the facilities upstream of the final line transformer. For small customers, planning standards are used to identify expected peak demand, and consider the diversity of end-use within the customers’ premises and diversity between customers served from shared facilities.

primary voltages to between 120 and 480 volts at the customer premises (secondary voltages). The need for additional capacity is often studied at each of these stages. Additional substation facilities are required due to increases in transformer capacity. An increase in design demand may also result from an increase in the size and/or number of distribution circuits serving a local area.⁹

In this application, SCE continues to functionalize design demand marginal costs into *peak* and *grid*, as originally proposed and adopted in its 2018 GRC. Design demand is related to a customer's maximum expected demand at the time-of-service installation, but maximum demand may vary over time. In older neighborhoods, for example, transformer capacity and distribution circuit routings may have been reconfigured over time to keep up with increasing demand. Keeping track of the contribution of an individual customer to the capacity and configuration built to serve an area is subjective and unwieldy. Additionally, the time when maximum usage occurs varies by climate zone and by the mix of customers in an area. To account for the time-varying nature of peak usage on the distribution system, SCE continues to assign the *peak* portion of design demand marginal costs across time of use periods based on the peak load risk factor (PLRF) methodology.¹⁰ For the grid portion of design demand marginal costs, SCE continues to use the effective demand factor (EDF) method.

c) Number And Type of Customers

As described in Section I.C.3, this cost driver is associated with the cost of providing customers access to the distribution system and the on-going costs to manage customer relationships. The number and type of customers is a cost driver because each customer requires *access* to the delivery system and a meter to measure consumption. Since access to the delivery system entails investment in long-life capital equipment, SCE uses a long-run estimate of marginal costs for this component of customer marginal costs. In addition, SCE incurs short-run marginal costs in managing its relationship with customers including handling customer communications, metering, and maintaining records and billing, which are also included in SCE's customer marginal costs proposal.

⁹ Distribution circuits are lines connecting customers in an area to a nearby substation.

¹⁰ The PLRF methodology identifies hours of the year when expected load may result in capacity constraints on the system. Since the distribution system is geographically disparate, the PLRF methodology is applied to each individual substation and circuit to consider load diversity on the system.

1 The cost of providing *access* to the delivery system varies by type of customer,
2 reflecting differences in size, service voltage, metering requirements, and other factors. The change in
3 facilities cost for providing *access* to a small increment in the number of customers is identified through
4 customer cost studies for each rate group. The customer cost studies identify facilities directly
5 associated with the customer connection to the grid, such as the meter, service drop, protection
6 equipment, and final line transformer.¹¹

7 The short-run customer service component of marginal customer costs also
8 includes activities such as handling customer communications, measuring usage, maintaining records,
9 and billing. SCE identifies the specific activities directly attributable to providing these services and
10 then calculates the associated marginal costs.

11 **4. Annual Cost of Capital Investments – RECC Methodology**

12 When developing marginal costs, SCE estimates the opportunity cost of capital
13 investments using the Real Economic Carrying Charge (RECC) methodology. As illustrated in Figure I-
14 2, this methodology derives and compares the present worth of the annual revenue requirements for an
15 asset and its subsequent replacements installed today with the present worth of an equivalent asset and
16 its subsequent replacements installed one year later.¹² The only difference between these two scenarios
17 is that, in the second scenario, SCE would defer the opportunity to use the asset in the first year. Thus,
18 the difference in present worth between the two scenarios measures the implied economic (opportunity)
19 cost of using the asset during the first year. As shown in Figure I-3, the net present value (NPV) of the
20 two payment streams are the same and the RECC results in the same real payment over time. This
21 conclusion is important because, in real terms, the charge and value received from an asset is the same
22 over time regardless of the age of the equipment. Therefore, the proper charge can be calculated for

¹¹ Final line transformers are associated with the customer cost driver because the cost-per-customer varies for customers in different rate groups depending on the type of access needed by those customers. With respect to final line transformers, the study accounts for the specific service configuration, e.g., if a transformer is shared or whether multiple transformers are required to serve accounts. Facilities employed when providing grid access for a subtransmission customer (e.g., a steel mill) are very different from those employed for a small commercial customer (e.g., a dry cleaning retail store).

¹² The revenue requirement includes return of capital (depreciation), return on capital, taxes (Federal, State, and Property), A&G, and insurance.

1 both existing and new customers by applying the RECC to the *real* cost of the equipment.¹³

Figure I-2
Illustration of the RECC Methodology

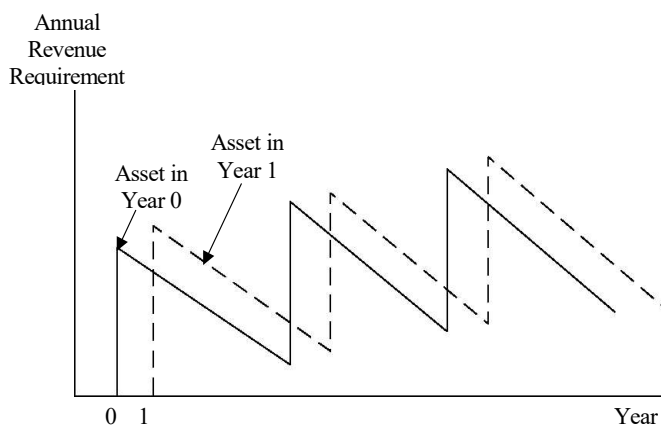
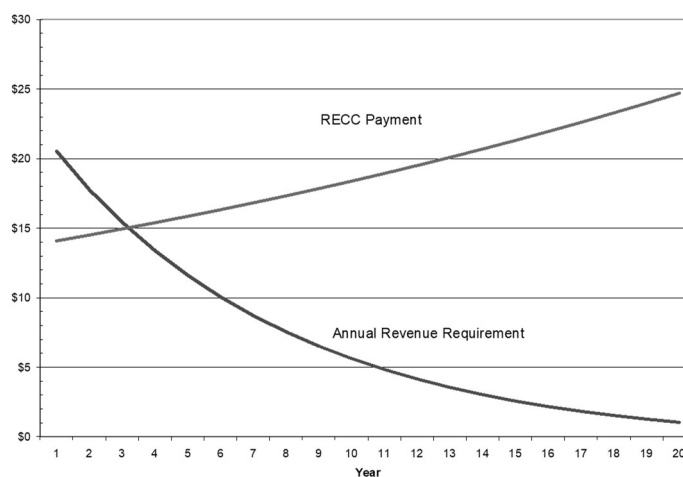


Figure I-3
**Annual Payment For \$100 Capital Investment,
10 Percent Discount Rate and 3 Percent Annual Inflation**



¹³ This RECC approach is documented in work prepared by the National Economic Research Associates (NERA) for an Electric Utility Rate Design Study, which was funded by various parties including the National Association of Regulatory Utility Commissioners. NERA #15 Topic 1.3, "A Framework for Marginal Cost-Based Time Differentiated Pricing in the United States," February 1977, pp. 90-94. *See also* "How to Quantify Marginal Costs, Topic 4, NERA Inc.," prepared for the Electric Power Research Institute, the Edison Electric Institute, *et. al.*, March 1977.

C. Marginal Cost Methodology

This section describes the calculation of electricity usage marginal costs, design demand marginal costs, and customer marginal costs. The marginal cost of streetlight facilities (streetlight poles, luminaries, and lamps) is also included.

1. Electricity Usage Marginal Costs

SCE estimates electricity usage marginal costs while planning for its future with the Commission as well as conducting its commercial operations. The Commission has a long-standing policy of estimating these costs in terms of a system marginal energy cost for estimating the short-run marginal cost of energy and a long run marginal capacity cost. This framework is appropriate for California's hybrid electricity market – where hourly energy prices are established in the day-ahead market operated by the ISO, and capacity requirements are met through utility long-term procurement and annual resource adequacy (RA) requirements. The marginal cost analysis presented here is intended to represent conditions expected to occur in 2025-2028 and uses inputs and assumptions developed by the Commission in the Integrated Resource Plan (IRP) proceeding, R.20-05-003.¹⁴

a) Marginal Energy Costs (MECs)

(1) Methodology And Data Sources

SCE proposes MECs be the hourly marginal market-clearing price of the day-ahead market operated by CAISO. SCE's marginal energy price forecast will mimic the CAISO day-ahead market using SCE's internal PLEXOS production simulation model. In this Application, SCE uses PLEXOS, a commercial software program with a mixed integer programming (MIP) optimization engine, to perform the fundamental market simulations modeling the CAISO day-ahead market for year 2025. PLEXOS commits and dispatches available generation resources to meet demand and reserve requirements at least-cost subject to other individual generation resource constraints.

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

1 The forecasted hourly energy prices (or MECs) from the simulations reflect the level of hourly net load
2 served by dispatchable generation resources and their production cost, as shown in Table I-4 below.

3 SCE's PLEXOS model used to forecast MECs is a CAISO-only zonal
4 model based on the resources that are expected to be online and operating in 2025. The PLEXOS model
5 requires the following inputs:

- 6 • Managed load projections, which include the effects of on-site load
7 impacts due to distributed energy resources (DERs), including
8 Demand Response (DR), energy efficiency (EE) and distributed
9 generation (DG) such as rooftop solar, based on the load forecast from
10 the 2022 Integrated Energy Policy Report (IEPR)¹⁵;
- 11 • Forecast of available resource capacity in 2025 includes existing
12 resources, scheduled retirements, and a forecast of new resources
13 based on the 2022 Renewables Portfolio Standard (RPS) plan, D. 21-
14 06-035, and D.23-02-040. Specifically, SCE's analysis assumes 50%
15 of the new resources identified as "under development" by load
16 serving entities (LSEs) in their 2022 RPS plans and ordered in D.21-
17 06-035/D.23-02-040 come online as scheduled, while 50% are delayed
18 by a year;
- 19 • Natural gas price forecasts for each "hub" from the Commission's IRP
20 assumption;
- 21 • Greenhouse gas (GHG) compliance cost forecasts from the
22 Commission's IRP assumption;
- 23 • Transmission line and interface limitations based on the transmission
24 capability of the interties and the CAISO Full Network Model (FNM);
25 and,

¹⁵ Report found at: <https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update>.

- Renewable generation forecast for the CAISO system based on its internal capacity expansion outlook.

The forecast energy prices consist of the costs of incremental fuel, variable O&M, GHG compliance, startup, and no-load fuel costs.

(2) Key Assumptions

The PLEXOS Model includes the following assumptions:

- 100 percent of renewable generation is scheduled in the CAISO day-ahead market;
- Renewable generation resources including small-hydro, geothermal and biomass are self-scheduled. Price sensitive bids are created for wind and solar generation to allow for economic curtailment; and,
- California exports during periods of over-generation are allowed by modeling price-sensitive loads at major intertie locations.

***Table I-4
Generation Energy Marginal Costs
(2025\$)***

Cost Component		Annual			Summer			Winter		
Component					On	Mid	Off	Mid	Off	Super Off
Energy (¢/kWh)		4.778			6.056	5.111	4.741	5.502	5.334	3.293

b) Generation Capacity Marginal Cost

SCE's generation capacity marginal cost (GCMC) proposal considers the state's path to decarbonization, which requires 60% renewable energy in 2030 and 100% clean energy by 2045. Renewable energy integration is changing California's electricity market and energy planning proceedings. GCMC has historically reflected the capacity cost of meeting system peak conditions in a single hour, but the evolution in California's electric system has highlighted additional reliability concerns, such as charging energy sufficiency for energy storage resources, winter peak capacity needs, and a multi-hour peak period. For this reason, SCE is proposing to update its GCMC methodology to

1 use a 6-hour lithium-ion battery paired with solar (hybrid PV+storage) as the proxy resource. SCE has
2 also developed a new methodology to allocate capacity costs to each hour, using the system's hourly
3 implied market heat rate (IMHR), for discussion and refinement with stakeholders in this proceeding.
4 However, in the interim SCE has applied the probabilistic results of the Capacity Allocation Tool used
5 in the 2021 GRC Phase 2 proceeding to allocate the annual GCMC to time of use periods.

6 (1) **Proxy Resource and Valuation**

7 Prior methodologies for estimating GCMC have assumed that new natural
8 gas plants would be installed to meet future capacity needs. However, continuing to install new natural
9 gas generation resources for peak needs would be antithetical to both SCE's clean energy goals and
10 California's climate policy goals. Therefore, SCE proposes to estimate the GCMC using the Net Cost of
11 New Entry (NetCONE) for a 6-hour hybrid PV+storage resource.

12 SCE has proposed to use a 6-hour hybrid PV+storage as the proxy resource instead of a
13 standalone 4-hour battery, which was the proxy resource used in previous GRC phase 2 applications.
14 A 6-hour hybrid PV+storage is effective in meeting the reliability needs of the system given the
15 lengthening peak period and concerns about having sufficient energy to charge the storage resources on
16 the system. SCE's proposed hybrid PV+storage resource assumes 1 MW of solar capacity is installed
17 per 1 MW of battery storage capacity,¹⁶ which implies the solar PV resource provides all the energy
18 needed to fully charge the battery storage resource (*i.e.*, battery storage is not assumed to charge from
19 the system and solar generation is only providing the charging energy to the battery, not exporting to the
20 system).

21 NetCONE measures the full cost of constructing a resource, less revenues it earns
22 through ISO markets. In other words, NetCONE is a residual cost that must be paid through capacity
23 transactions. Without a capacity payment to fill the gap between the full cost and ISO marketing
24 revenues, the proxy resource could not be constructed to support reliability. This simple economic
25 consideration makes NetCONE a common approach for estimating capacity value, which SCE has used

¹⁶ 1 MW of solar is expected to produce, on average, over 7,000 kWh energy daily. This output is sufficient to fully charge a 6-hour 1 MW battery, assuming an 85% roundtrip efficiency.

1 in previous GRC phase 2 proposals. Similarly, the Commission and parties adopted a lithium-ion
2 NetCONE measure for capacity value in the 2020 and 2022 Avoided Cost Calculators developed in the
3 Integrated Distributed Energy Resource proceeding.¹⁷

4 The resource cost is the annualized total fixed costs (\$/kW-yr) for a new 6-hour lithium-
5 ion battery paired with solar generation in the Southern California region, including all permitting,
6 financing and development costs, as well as inflation during the construction period. The cost
7 assumption is sourced from the 2021 National Renewable Energy Laboratory Annual Technology
8 Baseline (solar PV) and Lazard Levelized Cost of Storage v7.0 (storage), which is the data source used
9 by LSEs to develop their resource plans in the ongoing IRP proceeding. Because these resource cost
10 inputs were developed prior to the passage of the Inflation Reduction Act, SCE adjusted the 2026, 2027,
11 and 2028 resource cost downward to reflect the estimated impact of the tax credit extension.

12 Next, a forecast of energy revenues (“energy rents”) is developed to avoid overstating the
13 isolated capacity value of the proxy resource. Energy rents are the operating profits that the hybrid
14 PV+storage resource is able to earn from ISO day-ahead market. Because these market revenues reduce
15 the resource’s net fixed costs that need to be recovered in capacity markets, energy rents are also known
16 as energy-related capital costs (ERCC). The MECs described in Chapter I.C.1.a) were used as inputs in
17 PLEXOS to identify the optimal hours to dispatch the resource and the corresponding revenue.
18 Following this approach, the annualized value of 20 years of energy rents is divided by the resource’s
19 nameplate capacity, which translates the value into a \$/kW-year value that can be subtracted from the
20 resource cost, resulting in the NetCONE-based capacity value estimate, as shown in Table I-5.

¹⁷ See generally, D.20-04-010, *2020 Policy Updates to Avoided Cost Calculator* and D.22-05-002, *Decision Adopting Changes to the Avoided Cost Calculator*.

Table I-5
Generation Capacity 6-Hour Battery Proxy Costs
(2025 Forecast, 2025\$)

	Units	2025
1 CONE Battery	\$/kW-Yr	165.37
2 CONE Solar	\$/kW-Yr	85.48
3 Energy Revenues	\$/kW-Yr	161.38
4 Net CONE (Line 1 + Line 2 - Line 3)	\$/kW-Yr	89.48

(2) Hourly Allocation Methodology

The generation capacity marginal cost described above is an annual number. SCE allocates the annual value to each hour by identifying which month-hours of the year are the most vulnerable to capacity shortfalls. In the 2021 GRC, SCE performed a probabilistic analysis comparing forecasted SCE load to forecasted renewable generation under contract with SCE and available conventional capacity in SCE’s service territory to identify the hours with greatest capacity shortfall risk.¹⁸ SCE has since identified two areas for improvement and refinement: (1) the analysis should be performed at the CAISO system level rather than the SCE transmission access charge (TAC) level because hours in which the CAISO system is “tight” (*i.e.*, demand is nearing the available supply) are the hours that contribute most to generation capacity costs; and (2) the analysis should move away from “scaling” the load forecast to artificially surface more occurrences of capacity shortfall because the scaling methodology may inadvertently influence the results.

Accordingly, SCE has developed a new approach to identifying the hours that are most vulnerable to capacity shortfalls based on the CAISO system’s IMHR, or the amount of fuel needed to generate the marginal unit of electricity, in each hour. This IMHR approach is based on analysis at the CAISO system, rather than the SCE transmission access charge (TAC), level and does not require any artificial adjustment/scaling of the load forecast. Additional details on the methodology is provided below.

¹⁸ See SCE-02 at pp. 19-23.

(a) **Interim Capacity Allocation Tool Methodology**

The Capacity Allocation Tool used in the 2021 GRC Phase 2 Application produced probabilities of capacity shortfalls in each hour of the 2024 test year resulting from both forecast peak capacity needs and flexible capacity needed for forecasted load ramps. In application of the 2025 GRC Phase 2 proxy net loads, rather than using the hourly distribution, SCE aggregated the probabilities for the 2024 test year by time-of-use period and assumes that the distribution of capacity constraints across TOU periods for test year 2024 should largely be the same for test year 2025. Since GCMC is allocated to each rate group based on their share of the load during the Top 100 peak hours and Top 10 ramps of the 2025 proxy net load, only the top 100 peak probabilities and top 10 ramp probabilities from Capacity Allocation Tool were aggregated by TOU period resulting in the values shown in Table I-6 below. Each rate group's generation capacity MCRR for peak is allocated to TOU periods by weighting the TOU period distribution of their load in the Top 100 hours by the Relative Peak Allocation shown in Table I-6. Similarly, the Relative Ramp Allocation probabilities are used to allocate the generation capacity MCRR for ramp to TOU periods.

***Table I-6
2024 Capacity Allocation by Time-of-Use Period***

	Summer			Winter			Total
	On-peak	Mid-peak	Off-peak	Mid-peak	Off-peak	Super Off-peak	
Total Top 100 Relative Peak Allocation	87.20%	2.20%	5.70%	0.00%	0.00%	0.00%	95.10%
Total Top 10 Relative Ramp Allocation	0.00%	0.00%	0.00%	68.90%	0.00%	0.00%	68.90%

(b) **Implied Market Heat Rate Methodology**

The IMHR methodology identifies when generation capacity conditions are expected to be “tight” by determining the hours in which the marginal generation resource (*i.e.*, the resource supplying the last unit needed to serve customer load in a given hour) is forecast to be a simple-cycle gas turbine plant, or a “peaker” plant. Peaker plants are typically only dispatched during system peak conditions given their relative inefficiency and high heat rates, which lead to higher operating costs and less frequent use, while the hybrid PV+storage proxy resource can be

1 discharged in their place. SCE can identify the hours that peaker plants are forecast to be dispatched by
2 calculating the system's hourly IMHR.

3 The heat rate for a given generation resource is the amount of fuel
4 it needs to generate the marginal unit of electricity. The resource's heat rate is multiplied by the fuel and
5 GHG allowance cost to identify the minimum electricity market price needed to make it economic for
6 the resource to run. The IMHR of the CAISO system, or the market clearing electricity price divided by
7 the fuel and GHG allowance cost, thus represents the heat rate of the generating unit that sets the market
8 price in a given hour. An IMHR over 10,216 Btu/kWh indicates a peaker resource is the marginal
9 resource¹⁹ and implies demand is nearing the generation capacity available in that hour.

10 The following 12x24 heat map identifies the distribution of
11 months-hours where the IMHR is forecast to exceed 10,216 Btu/kWh in 2025, which corresponds to 296
12 occurrences, or 3% of hours. Specifically, SCE used the MEC price forecast described in section C.1.a
13 and its corresponding GHG allowance and gas price forecasts to calculate the hourly IMHR and count
14 the number of occurrences where the IMHR is forecast to exceed 10,216 Btu/kWh for each month-hour
15 combination.

¹⁹ 10,216 Btu/kWh is an appropriate threshold for this analysis because it represents the heat rate for one of the most efficient peaker resources. See the California Energy Commission's Quarterly Fuel and Energy Report, available at <https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/quarterly-fuel-and-energy-report-qfer-2>.

Figure I-4
Distribution of >10.216 IMHR Occurrences

Weekday (as percentage)																								
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.68%	0.68%	0.68%	0.00%	0.00%	0.00%	0.00%
2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.69%	1.69%	1.69%	0.00%	0.00%
7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.72%	3.72%	3.38%	0.34%	0.00%
8	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.34%	0.68%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.69%	4.39%	4.39%	4.05%	0.34%	0.00%
9	0.00%	0.00%	0.00%	0.00%	0.00%	0.34%	0.68%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.01%	5.41%	5.41%	5.41%	3.38%	0.68%	0.34%
10	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.68%	2.70%	2.70%	2.70%	0.34%	0.00%	0.00%
11	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.70%	3.04%	3.04%	2.70%	1.01%	0.00%	0.00%
12	0.00%	0.00%	0.00%	0.00%	0.00%	1.69%	1.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.03%	5.07%	4.73%	3.72%	1.69%	1.35%	0.00%	0.00%
Weekend/Holiday (as percentage)																								
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
8	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.34%	0.34%	0.34%	0.00%	0.00%	0.00%
10	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
11	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
12	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

SCE acknowledges this IMHR-based approach identifies significantly more occurrences of tight capacity conditions than the methodology used in SCE’s 2021 GRC Phase 2 application. However, SCE submits it is reasonable to increase the allocation of capacity costs to more hours throughout the year given the impact battery energy storage system (BESS) resources are expected to have on the system.²⁰ Specifically, SCE expects the CAISO system to have lower but longer peaks because of BESS systems’ ability to flatten the net load curve. Additionally, focusing on a more limited number of hours would make the analysis more sensitive to the modeled battery dispatch,²¹ whereas identifying a larger and broader range of hours will appropriately capture the more general condition that the system is reliant on a relatively inefficient resource.

(c) Net Load Methodology

The net load methodology is based on the proxy 2025 net load (forecasted net load less forecasted renewable generation), derived using estimated 2022 gross load and

²⁰ The Commission has, in its Integrated Resource Plan (IRP) proceeding (R.20-05-003), ordered load serving entities to procure a combined amount of 18,800 megawatts (MWs) of net qualifying capacity (NQC) of new electricity resources to come online by 2028. This amount is equivalent to over 30,000 MW of nameplate capacity, a significant portion of which are expected to be BESS resources.

²¹ For example, HE22 may have a higher IMHR than HE18 because more BESS systems are forecast to dispatch in HE18. However, HE18 could have had a higher IMHR if those BESS resources had, instead, been dispatched in HE22. It is thus appropriate to capture both HE18 and HE22 in the analysis by considering a broader range of hours.

1 forecast distributed generation, energy efficiency, transportation electrification, building electrification,
2 energy storage, and utility scale renewable wind and solar supply for the year 2025.

3 Gross load is the recorded delivered load from interval meters for
4 each rate group with the on-site consumption for the rate group's NEM customers added back to provide
5 aggregate behind-the-meter consumption. Distributed generation consumed on-site is computed
6 separately for each rate group. It is calculated as the hourly difference between the estimated rate group
7 PV production and the energy exported back to the grid by the rate group. PV production profiles are
8 estimated using hourly production data obtained from the California Solar Initiative (CSI). An hourly
9 ratio of normalized PV production and normalized solar irradiance is created to specify the level of PV
10 production through the year given the amount of solar irradiance. This hourly scalar is then applied to
11 the normalized measured solar irradiation over the time frame of interest to create an estimate of
12 normalized production which reflects the current conditions. The normalized production for each rate
13 group is then scaled to the installed capacity within the rate group at the time to produce an estimate of
14 the total hourly PV production in the rate group. Distributed generation exports are measured directly
15 from interval meters for all NEM customers within the rate group.

16 The SCE internal 2022 Q4 forecast of annual electric vehicle (EV)
17 usage in 2025 is disaggregated to each rate group based on the vehicle segment and the location of
18 charging. The forecasted usage for residential, light-duty EVs is divided into two parts. The charging at
19 home portion is assigned to the Domestic rate group, while the away-from-home portion is allocated to
20 the TOUGS-3 and TOU-8-SEC Nonstandby rate groups. This allocation ensures that the electricity
21 consumption of EVs is appropriately categorized based on where the charging occurs—whether at home
22 or away from home. Commercial light duty EVs are assigned to the TOU-GS-1, TOU-GS-2, and TOU-
23 GS-3 rate groups. Government Light Duty EVs fall under the TOU-GS-1 and TOU-GS-2 rate groups.
24 For non-light duty usage, forklifts and medium-duty vehicles are categorized under the TOU-GS-3 rate
25 group. Buses, rail vehicles, ocean-going vehicles, and heavy-duty applications are part of the TOU-8-
26 SEC Nonstandby rate group. Other non-light duty usages are grouped under the TOU-8-PRI

Nonstandby rate. No EV usage is allocated to the agricultural & pumping, traffic control, streetlight, or standby rate groups. Table I-7 represents the allocation of EV forecast usage by the rate groups.

***Table I-7
EV Forecast Usage by Rate Group***

Rate Group	Forecast Usage (GWh)
Domestic	1,437
TOU-GS-1	38
TOU-GS-2	161
TOU-GS-3	534
TOU-8-PRI Nonstandby	36
TOU-8-SEC Nonstandby	502
Total	2,708

SCE allocates its RPS forecast for solar and wind in 2025 to each customer class based on the customer class's contribution to total system annual electric sales. SCE is required to deliver a percentage of its electricity sales in the form of renewable resources in compliance with California's mandated RPS. To meet these requirements, SCE procures renewable resources at the system level, not specifically for each customer class. As a result, each customer class receives a pro-rated allocation of the hourly RPS generation equal to the customer class's contribution to total system annual electric sales. Similarly, energy storage and energy efficiency forecast are distributed among different customer classes according to their respective contributions to the total annual electric sales within the system.

Additionally, the forecast for building electrification is provided, along with a detailed breakdown for both residential and commercial revenue classes. The residential building electrification (BE) forecast is assigned to the Domestic rate group. Meanwhile, the commercial BE forecast is allocated among nonresidential customer classes, proportionally based on their share of annual nonresidential electric sales.

This process generates an 8,760-hourly net load curve with a breakdown by rate groups. In SCE-03: Revenue Allocation, there is additional discussion regarding the allocation of peak and ramp capacity costs based on this net load curve.

2. Design Demand Marginal Costs

Design demand marginal costs are attributable to the *amount* and *configuration* of distribution capacity necessary to deliver electricity to, and from, customers. Prior to the advent of DERs, the entire portion of the distribution system was viewed as a peak capacity resource because the utility was the single source of distribution capacity investments. With the increased proliferation of DERs, SCE expects to see a paradigm shift in the functionality of the distribution system. In its 2018 GRC Phase 2, SCE proposed functionalizing distribution costs into a *peak* function to meet time-sensitive peak customer demand and *grid* function that enables the two-way flow of electricity to and from customers. SCE proposes the continuation of this functionalization approach in this application.

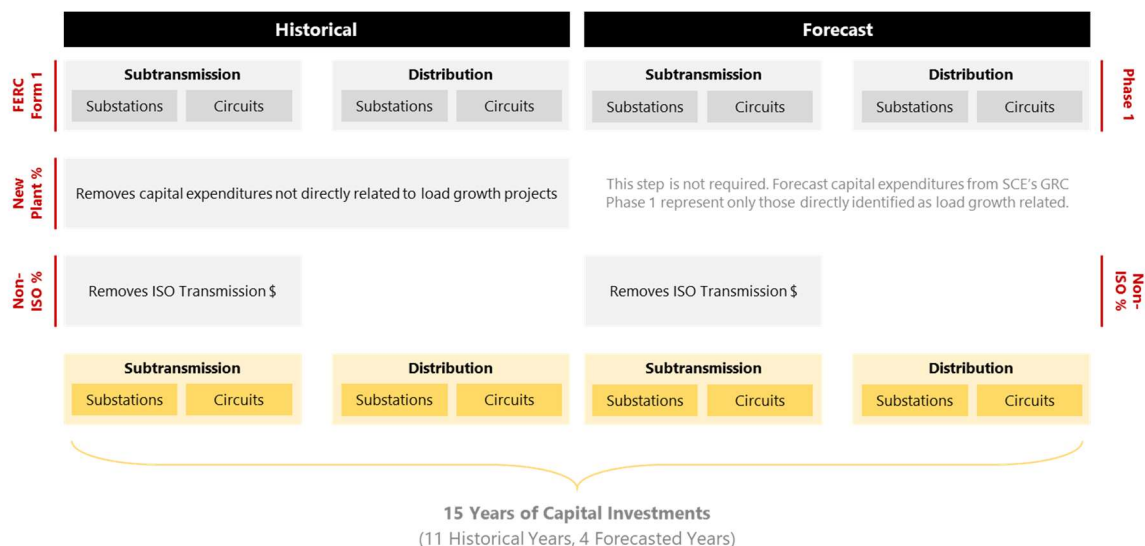
Table I-8
Illustration of Design Demand Marginal Costs
(2025\$)

	Component	Subtransmission		Distribution	
		Substations	Circuits	Substations	Circuits
1	Capital	\$41/kW-Yr	\$15/kW-Yr	\$20/kW-Yr	\$98/kW-Yr
A	NERA Regression	\$441/kW	\$174/kW	\$228/kW	\$1,068/kW
B	General Plant Loader	← 1 + 6.39 % →			
C	RECC	8.68%	8.26%	8.37%	8.65%
2	O&M	\$4.8/kW-Yr	\$1.8/kW-Yr	\$5.0/kW-Yr	\$24/kW-Yr
	Total	\$46/kW-Yr	\$17/kW-Yr	\$25/kW-Yr	\$122/kW-Yr
3	Peak • Grid	100% • NA	NA • 100%	100% • NA	23% • 77%
	Peak • Grid (\$/kW-Yr)	\$46 • NA	NA • \$17	\$25 • NA	\$28 • \$94

a) Capital Component of Design Demand Marginal Cost

To derive the capital component of its design demand marginal cost, SCE begins by applying the NERA regression methodology to 15 years of capital expenditure (Figure I-5) and planned capacity to determine the incremental cost of adding capacity to its distribution system.

Figure I-5
Derivation of Load Growth Capital Expenditures



This methodology relies on SCE's FERC Form 1 (FF1) filings, which categorize capital expenditures by asset type as outlined in Table I-8. For historical years, SCE applies an adjustment factor to the capital additions reported in its FF1 to estimate the portion of total capital expenditures related to load growth activities. For forecast years, load growth capital expenditures are based on workpapers that supplement SCE's *Load Growth, Transmission Projects, and Engineering* testimony in A.23-05-010 (SCE-02, Vol. 07).²² SCE continues to rely on planned capacity for the historical and forecast period instead of recorded load to minimize distortions caused by expansionary or recessionary business cycles.²³

²² Only projects identified as load growth projects are considered. All projects not related to load growth (*i.e.*, grid reliability, infrastructure replacement projects, grid modernization, etc.) are excluded from this analysis.

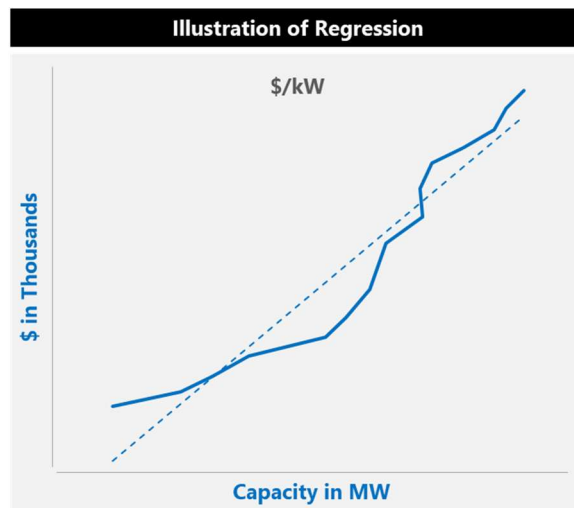
²³ Planned capacity is based on *Planning Loading Limits* and *Nameplate Capacity* for Circuit and Substation equipment, respectively.

Table I-9
FERC Account Descriptions

Distribution			Transmission		
FERC Type		Description	FERC Type		Description
360	Land/Subs	Land & Land Rights	350	Land/Subs	Land & Land Rights
361	Land/Subs	Structure & Improvements	352	Land/Subs	Structure & Improvements
362	Land/Subs	Station Equipment	353	Land/Subs	Station Equipment
364	Lines	Poles, Towers, & Fixtures	354	Lines	Poles & Fixtures
365	Lines	Overhead Conductors & Devices	355	Lines	Overhead Conductors & Devices
366	Lines	Underground Conduit	356	Lines	Underground Conduit
367	Lines	Underground Conductors & Devices	357	Lines	Underground Conductors & Devices
			359	Lines	Roads & Trails

Using the cumulative capacity (independent variable) and cumulative capital expenditures (dependent variable), SCE runs a regression to derive the incremental cost of capacity additions expressed in $\$/kW$. This value is then multiplied by an RECC factor to estimate the annual carrying charge associated with adding capacity to the distribution system expressed in $\$/kW\text{-Year}$.

Figure I-6
Illustration of Regression



b) O&M Component of Design Demand Marginal Cost

To derive the O&M component of its design demand marginal cost, SCE evaluates its historical O&M expenditures in relation to installed design demand capacity over a 10-year period. Historical O&M expenditures are based on SCE's FF1 filings and adjusted to include employee pension and benefits that represents a fully loaded O&M marginal cost expressed in $\$/kW\text{-Year}$.

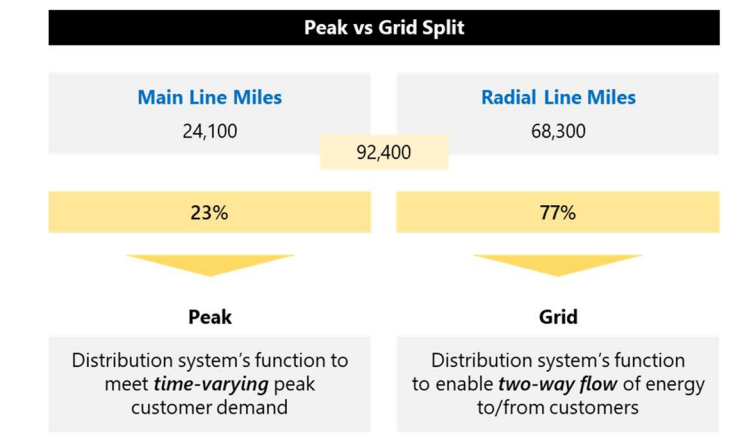
c) **Functionalizing Costs Between Peak and Grid**

Once the marginal cost of incremental capacity for each asset type has been determined, SCE functionalizes these costs into *peak* and *grid* functions based on the criteria outlined below. As noted above, *peak* refers to the distribution system's ability to meet time-sensitive peak customer demand. *Grid* refers to the distribution system's enablement of the two-way flow of electricity to and from customers. SCE proposes a time-dependent charge for the recovery of *peak* costs, and a non-time-differentiated charge for the recovery of *grid* costs.

(1) **Distribution Circuit Costs**

Consistent with the FERC method of using transmission circuit miles to allocate costs between ISO and non-ISO jurisdictional transmission assets, SCE proposes using the split between *Main Line* and *Radial Line* circuit miles as the basis of functionalizing distribution circuit marginal costs into *peak* and *grid* costs as reflected in Figure I-7.

Figure I-7
Summary Of Circuit Line Miles



- **Main Lines:** Primary voltage (4 kV to 33 kV) circuit miles form the basis of apportioning distribution circuit marginal costs to the *peak* function. The main line is the largest sized conductor used to deliver electricity from substations to geographically dispersed load clusters on the distribution grid. Since these lines primarily deliver capacity to

load centers to meet peak coincident load needs, they are functionalized as *peak* costs.²⁴

- **Radial Lines:** Primary voltage circuit miles, inclusive of secondary voltage (600 V and below) circuit miles, form the basis of apportioning functionalizing distribution circuit marginal costs to the *grid* function. Radial lines enable connectivity to SCE's main line system. Since these lines primarily deliver electricity to and from customer premises, they are functionalized as *grid* costs.

(2) Subtransmission Circuit Costs

SCE's subtransmission system is uniquely configured as a radial grid. Notably, the majority of capacity planned on the subtransmission system has the ability to 1) accommodate power flows in normal and contingency scenarios; and 2) manage congestion on the subtransmission network. While planning for such scenarios is typically done for peak load conditions, the primary function of the subtransmission system has largely evolved into one of grid connectivity and energy transfer across an integrated *sub-network*. This has resulted in nominal use of the system as a peak capacity resource under normal operating conditions. Therefore, SCE has functionalized subtransmission circuit marginal costs as *grid* costs.²⁵

(3) Distribution And Subtransmission Substation Costs

Substations transform high voltage power to low voltage power that is eventually delivered to customer loads.²⁶ Typically, multiple circuits extend from each substation to serve geographically dispersed load clusters. Since substations are generally planned and designed to

²⁴ These lines are also configured to shoulder load sharing capability in the event of a contingency scenario.

²⁵ The historical context of distribution design demand marginal costs being driven by load growth should not be indiscriminately transposed on the subtransmission system. The two systems function with different operating constraints. Subtransmission lines are planned for the non-coincident peak load of connected substations. While planning for load growth is critical, the primary driver of subtransmission system costs is contingency-driven reliability planning.

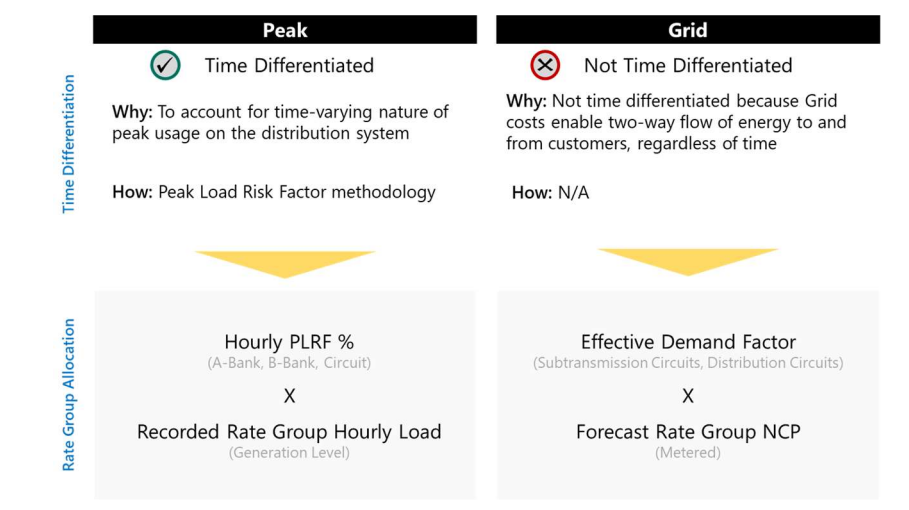
²⁶ A-banks are considered distribution assets and are typically at subtransmission voltages (greater than 50 kV and less than 220 kV). B-banks are considered distribution assets and are typically at primary distribution voltages (less than 50 kV down to 2 kV).

serve a peak level of coincident load experienced on supporting circuits, SCE assigns its distribution substation marginal costs to the *peak* function.

d) Relating Marginal Costs To Measurable Customer Attributes

Once design demand distribution marginal costs have been split between those that are peak capacity-driven and those that are grid-related, it is necessary to relate these costs to measurable customer attributes. In this Application, SCE proposes to use the PLRF method to determine the hourly allocation of peak-capacity driven costs and the traditional EDF method for assigning grid-related costs as illustrated in Figure I-8. Both methods are discussed below.

Figure I-8
Allocation of Peak and Grid Related Marginal Costs



(1) PLRF Methodology For Peak Capacity-Driven Costs

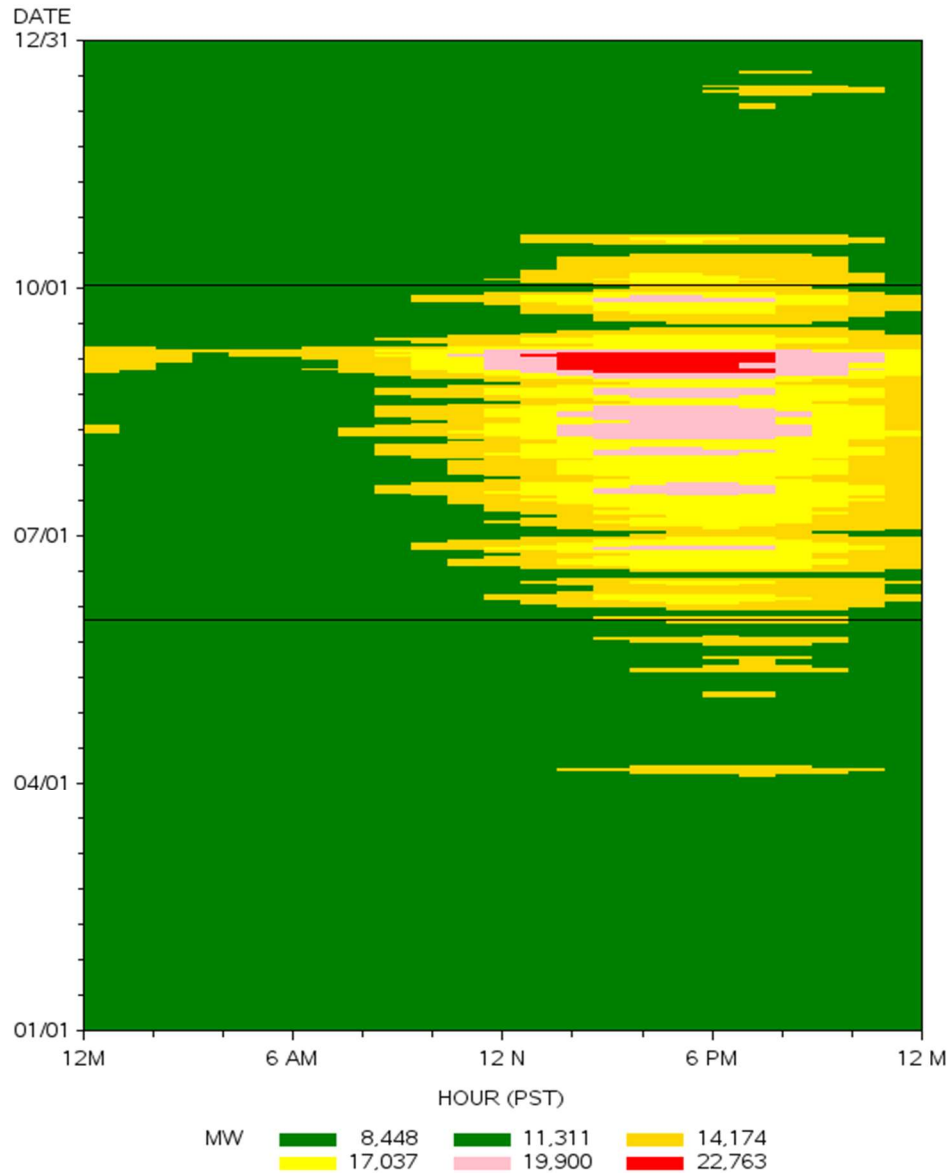
As discussed above, SCE’s distribution system is comprised of a network of substations (B-banks) that convert sub-transmission voltages (66 kV and 115 kV) carried from the A-banks to distribution voltages (33 kV and below) and includes distribution circuits used for the delivery of power from B-banks to specific customer load points. Figure I-9 shows a contour map of circuit load levels in 2022, where the load levels are color-coded to indicate intensity, with hour of the day on the x-

axis and chronological day of the year on the y-axis.²⁷ During periods of peak usage, the distribution system capacity is stressed in a similar manner as generation assets; therefore, distribution peak-capacity price signals should be time-differentiated in a similar way.²⁸

²⁷ While load levels depicted here illustrate the general use of distribution circuits, when identifying capacity constraints, the PLRF method evaluates relative use against the planned loading limits indicative of circuit capacity.

²⁸ When assessing any resource, generation or distribution, the relationship of peak demand to available capacity is an important conceptual framework that should guide the analysis for deriving the temporal nature of capacity constraints experienced by the resource. SCE's PLRF method therefore uses both load and a planned capacity threshold when determining periods of capacity constraints on the distribution system assets. The PLRF method has been conceptually illustrated in Figure I-5.

Figure I-9
Contour Map Of Hourly Coincident Circuit Load (Year 2022)



Distribution Circuits: When reviewing capacity needs for distribution circuits, system planners utilize “planning thresholds” as the primary trigger for a more comprehensive review of capacity needs. One such trigger for distribution circuits occurs when the peak circuit load is expected to reach 73 percent of the average planning load limit (PLL) of all circuits connected to a single substation. In this Application, SCE uses this same criteria when assessing the time periods

1 during which distribution circuits may have a capacity constraint. The results are then used to determine
2 the time-varying nature of peak capacity-related costs for distribution circuits.²⁹

3 Distribution Substations (B-banks): Distribution substations are designed
4 to meet the total load of connected circuits at an individual substation. The recorded load is similarly
5 compared to a threshold, defined as 73 percent of the individual substation PLL. Any load greater than
6 or equal to the threshold will be flagged as a capacity constraint. The results are then used to determine
7 the time-varying nature of peak capacity-related costs for distribution substations.

8 Sub-Transmission Substations (A-banks): Sub-transmission assets
9 typically constitute A-banks and sub-transmission circuits. A-banks are planned to account for peak
10 load needs in a similar manner as distribution B-banks. However, as discussed in the cost section above,
11 due to the sizeable impact of losing load in the event of a sub-transmission contingency, the system has
12 specifically been designed to accommodate load carrying capacity for such contingencies.

13 A contingency driven planning criteria for A-banks results in a very limited number of A-banks
14 triggering a simulated capacity constraint where peak load is greater than 73 percent of the substation's
15 planned nameplate capacity.³⁰ To accommodate this limitation, SCE therefore assesses the time varying
16 nature of capacity constraints using a proxy threshold of 73 percent of A-bank *annual peak load*.³¹

17 The results are then used to determine the time-varying nature of peak capacity-related costs for sub-
18 transmission substations.

²⁹ Distribution planning criteria states that the maximum projected load on a distribution circuit should not exceed a rated value of 550 amps, implying that on average normal projected load should not exceed 400 amps ($400/550 = 73$ percent). The physical scheduling of new circuit capacity may depend on a number of planning determinants, but the 73 percent threshold is a primary trigger used to evaluate capacity constraints on circuits.

³⁰ In this application, SCE adopts the use of forecasted A-bank load profiles for the year 2025. Because forecast load profiles are sensitized for normal weather, SCE finds it appropriate to change the PLRF threshold for A-banks to 73% of the *forecasted* peak load from the 90 percent of the *recorded* peak load used in the 2021 GRC. Lowering the load threshold allows for a sufficient inclusion of peak load events based on a weather normalized hourly load forecast.

³¹ SCE recognizes that subtransmission A-banks are a capacity resource. However, the loss of load impact at that voltage level on the grid has necessitated that planners allow for sufficient reserve margin to accommodate loss of load contingencies. Therefore, under normal operating conditions, capacity constraints derived using a planning threshold of 90 percent of installed capacity are minimal. In order to derive a proxy for the time-sensitive nature of the capacity constraints on A-banks, SCE applied the 90 percent threshold relative to the annual peak load on each A-bank.

Sub-Transmission Circuits: At this time, SCE does not have hourly load data for sub-transmission circuits and could not perform a similar analysis as was done for distribution circuits. However, as stated in the cost section above, the planning criteria and the design of the sub-transmission circuits supports the conclusion that sub-transmission circuits predominantly function for the purposes of grid connectivity and, therefore, have been functionalized as grid-related costs.

(a) **PLRF Calculations**

The PLRF methodology uses SCE's planning criteria to allocate peak-driven capacity costs to each hour of the year using a two-step approach and leverages a planning trigger when identifying the hours in which a planning threshold is reached. First, hours in which load falls below the planning threshold value are assigned a value of zero, and hours in which load exceeds the threshold are considered "peak loads" and are assigned a value of one. These ratings (0 or 1) are included in the next step of the analysis.

$$Peak Load_{i,j} = \begin{cases} 0 & \text{if } Load_{i,j} < Threshold_j \\ Load_{i,j} & \text{if } Load_{i,j} \geq Threshold_j \end{cases} \quad (1)$$

where $i = 1$ to 8760th hour, $j = 1$ to n th asset.³²

Second, the number of peak load occurrences are then summed for all assets in each hour (equation 2, below),³³ and a relative ratio is determined for these hourly peak load values (equation 3).³⁴ This relative ratio is called the PLRF.

$$Peak Load_i = \sum_{j=1}^n Peak Load_{i,j} \quad (2)$$

$$PLRF_i = \frac{Peak Load_i}{\sum_{i=1}^{8760} Peak Load_i} \quad (3)$$

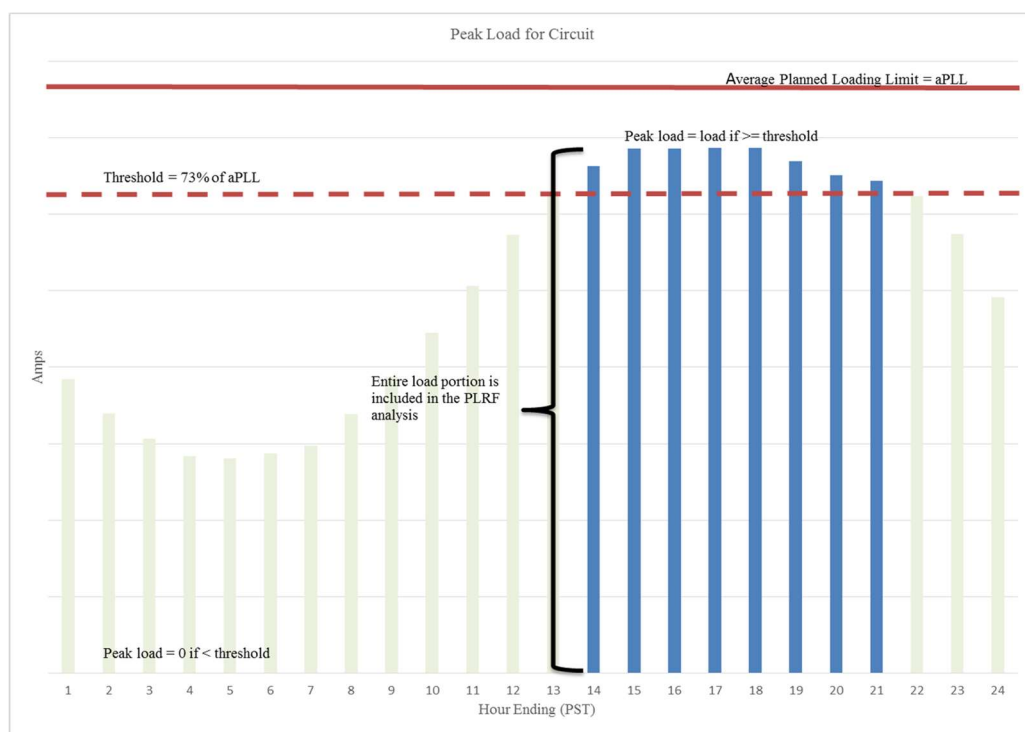
³² Assets analyzed in this section for the purposes of PLRF are distribution circuits, distribution substations (B-banks) and sub-transmission substations (A-banks).

³³ Because a small percentage of SCE's distribution circuits are customer-owned, or have a single customer contributing to more than 50 percent of the circuit load, these circuits are not representative of the entire population and do not represent SCE's typical costs. SCE has excluded these from the analysis. For the same reason, customer-owned B-banks are also excluded from the analysis.

³⁴ This relative ratio defines the percentage load in an hour to the sum of the total peak load for each hour in the year, given the specified threshold.

The steps described above for calculating the PLRFs are further illustrated in the Figure I-10 below for distribution circuits, as an example. First, an average PLL is determined for each of the circuits by taking the sum of the circuit PLLs divided by the number of circuits connected at each substation. The average PLL is used instead of the individual circuit PLL because of the ability to switch load between circuits. Next, a threshold line is drawn at 73 percent of the average PLL. Any load exceeding this threshold is considered peak load; otherwise, it is set to zero. The peak load is then summed across all circuits for each hour of the year. Finally, a PLRF for each hour is derived by taking the ratio of the peak load at that hour to the total peak load.

Figure I-10
Illustration Of PLRF Methodology Applied To Circuit Data



(i) Analysis Based On Future Test Year 2025

SCE uses an analysis of forecast system conditions in 2025 on distribution system peak loads. SCE utilizes the California Energy Commission (CEC)-developed 2020 Integrated Energy Policy Report (IEPR) forecasts which incorporate a load growth forecast and

DERs forecast, including energy efficiency, energy storage, demand response, Plug-in Electric Vehicles (PEVs), and distributed generation (DG), such as solar photovoltaic (PV) systems. The PV forecast incorporated the amount of solar PV output that is considered dependable and can be relied upon for planning purposes. The system-wide IEPR forecast is disaggregated for the distribution circuits and substations.³⁵

(ii) **Results**

Distribution Circuits: When the 2025 circuit PLRF percentages are summed by season and day type as shown in Figure I-11, the timing of circuit peak demands happen at 5 p.m. The concentration of high PLRF percentages in the late afternoon hours aligns with the proposed peak TOU period.³⁶ Each line represents the relative proportion of peak capacity constrained load when aggregated by hour and expressed as a percentage.

³⁵ See the detailed methodology in A.19-08-013, 2021 General Rate Case, SCE-02, Vol. 04, Part 2: Load Growth, Transmission Projects and Engineering, pp. 10-13.

³⁶ I.e., 4 p.m. to 9 p.m. as adopted in Ordering Paragraph No. 1 of D.18-07-006 on SCE's 2016 RDW Application. See also Appendix 2 of D.18-07-006.

Figure I-11
2025 Forecast Circuit PLRF Percentages
By Season and Day Type

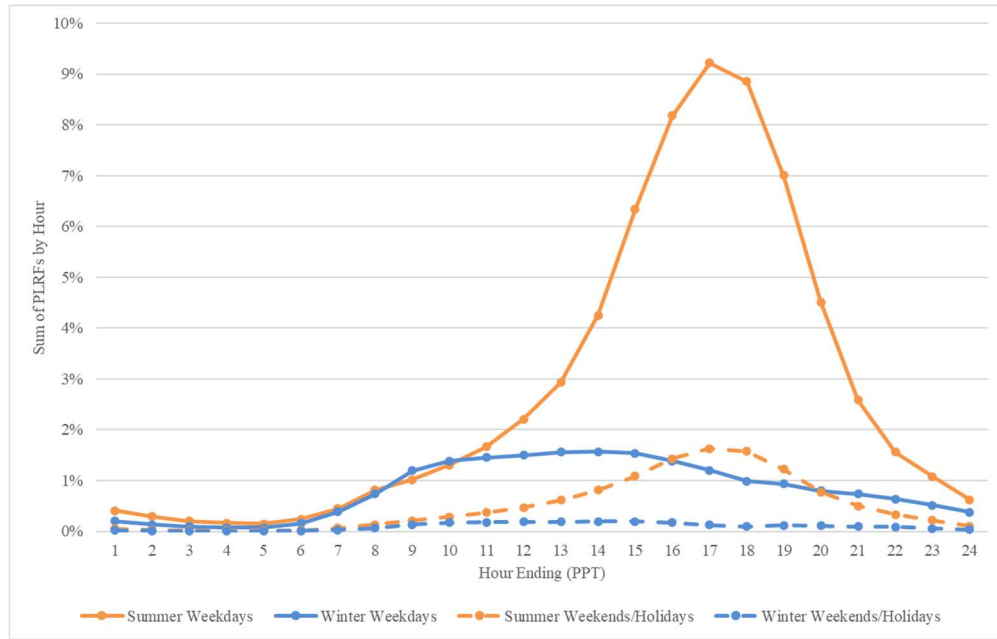


Table I-10 shows the circuit PLRFs aggregated by SCE’s proposed TOU periods as adopted in D.18-07-006.³⁷ The circuit PLRF percentages are then multiplied by the peak-capacity-driven portion of marginal distribution circuit costs (*i.e.*, \$28/kW-Yr) to compute the time-dependent allocation of such costs by TOU period.

Table I-10
2025 Forecast Circuit PLRF Percentages
By Proposed Time-Of-Use Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	32%	11%	44%	13%	100%
Summer	32%	6%	40%	n/a	78%
Winter	n/a	5%	4%	13%	22%

Distribution Substations (B-banks): Test-year 2025 incorporates the forecasted B-bank. Figure I-12 below illustrates the dispersion of 2025 B-bank PLRF for summer and

³⁷ D.18-07-006, Ordering Paragraph No. 1 and Appendix 2.

winter weekdays and weekends and hour of the day (in PPT – “Pacific Prevailing Time”). Each line represents the relative proportion of peak capacity constrained load when aggregated by hour and expressed as a percentage. The B-bank analysis shows a similar concentration of capacity constrained hours expected in the modeled year when compared to the plot of the distribution circuits.

Figure I-12
2025 Forecast B-bank PLRF Percentages
By Season and Day Type

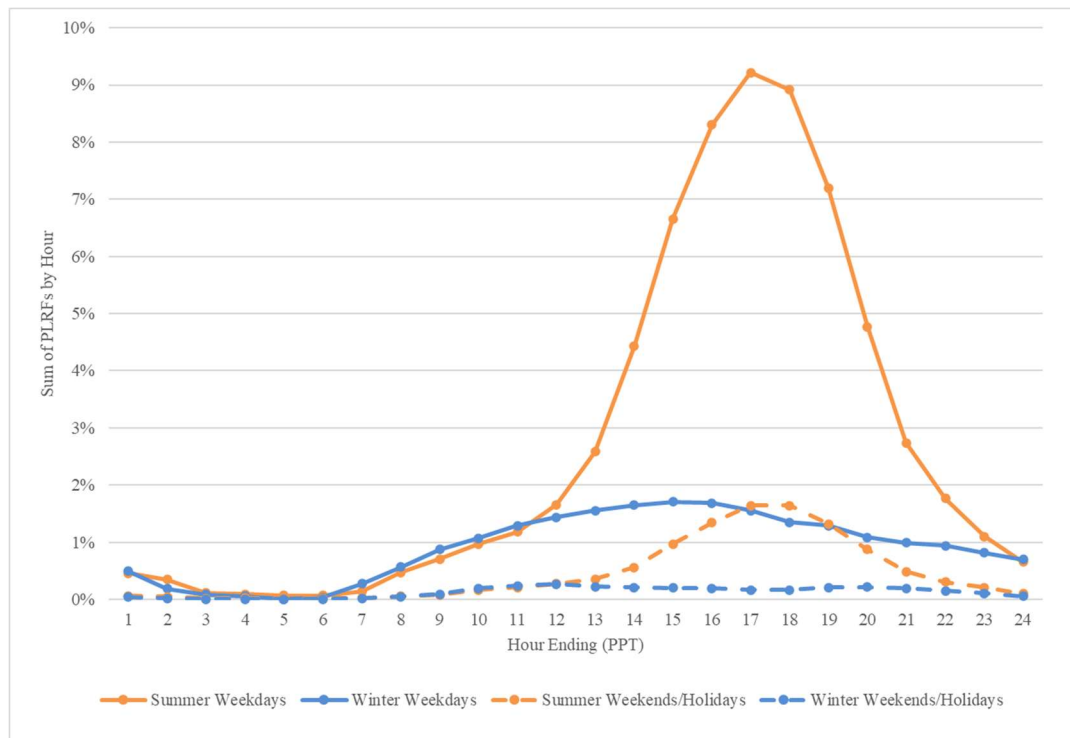


Table I-11 below depicts the same PLRF percentages when aggregated by SCE’s proposed TOU periods and shows that the results at the B-bank level are directionally aligned with the circuit PLRFs. The B-bank PLRF percentages are then multiplied by the specific peak-capacity-driven portion of the respective marginal distribution costs (*i.e.*, \$25/kW-Yr) to determine the time-dependent allocation of such costs by TOU period.

Table I-11
2025 Forecast B-Bank PLRF Percentages By Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	33%	13%	41%	13%	100%
Summer	33%	6%	37%	n/a	75%
Winter	n/a	7%	5%	13%	25%

Subtransmission Substations (A-banks): Test-year 2025 incorporates the forecasted A-bank. Figure I-13 illustrates the dispersion of 2025 A-bank PLRF for summer and winter weekdays and weekends and hour of the day. Each line represents the relative proportion of peak capacity constrained load when aggregated by hour and expressed as a percentage. The A-bank results show a higher concentration of capacity constrained hours in the summer months of the modeled year.

Figure I-13
2025 Forecast A-Bank PLRF Percentages By Season And Day Type

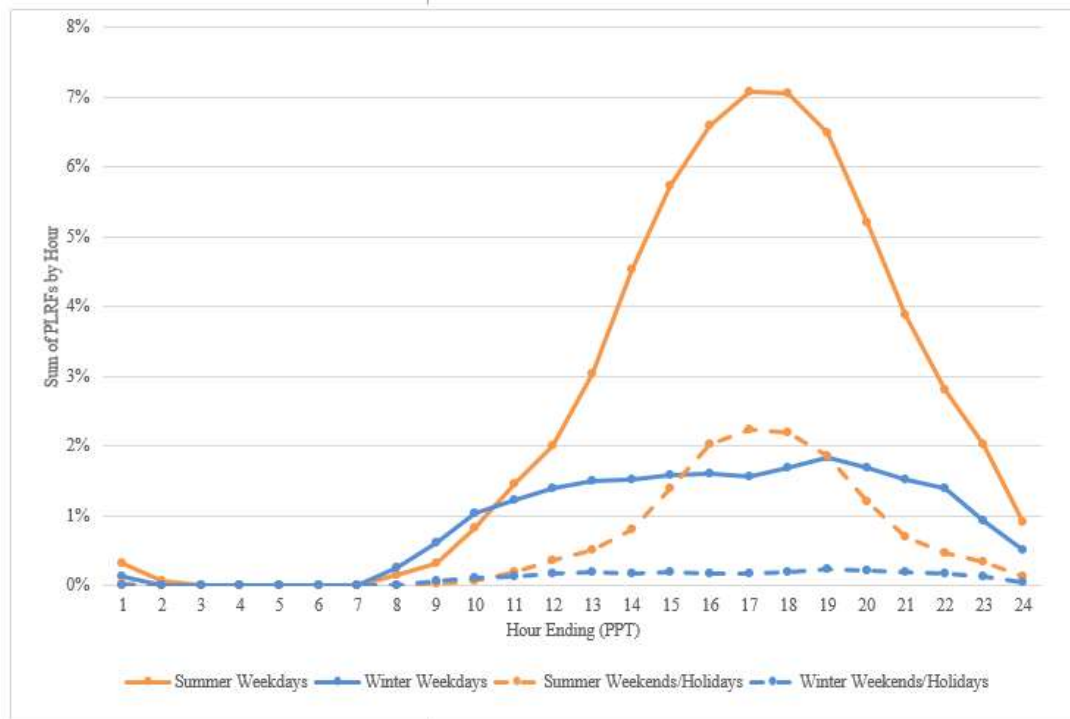


Table I-12 below depicts the same PLRF percentages when aggregated by SCE's proposed TOU periods and shows that the results at the A-bank level are similar to the profile of

PLRFs determined at the B-bank level. The A-bank PLRF percentages are then multiplied by the specific peak-capacity-driven portion of the respective marginal distribution costs (*i.e.*, \$46/kW-Yr) to determine the time-dependent allocation of such costs by TOU period.

Table I-12
2024 Forecast A-Bank PLRF Percentages By Proposed TOU Periods

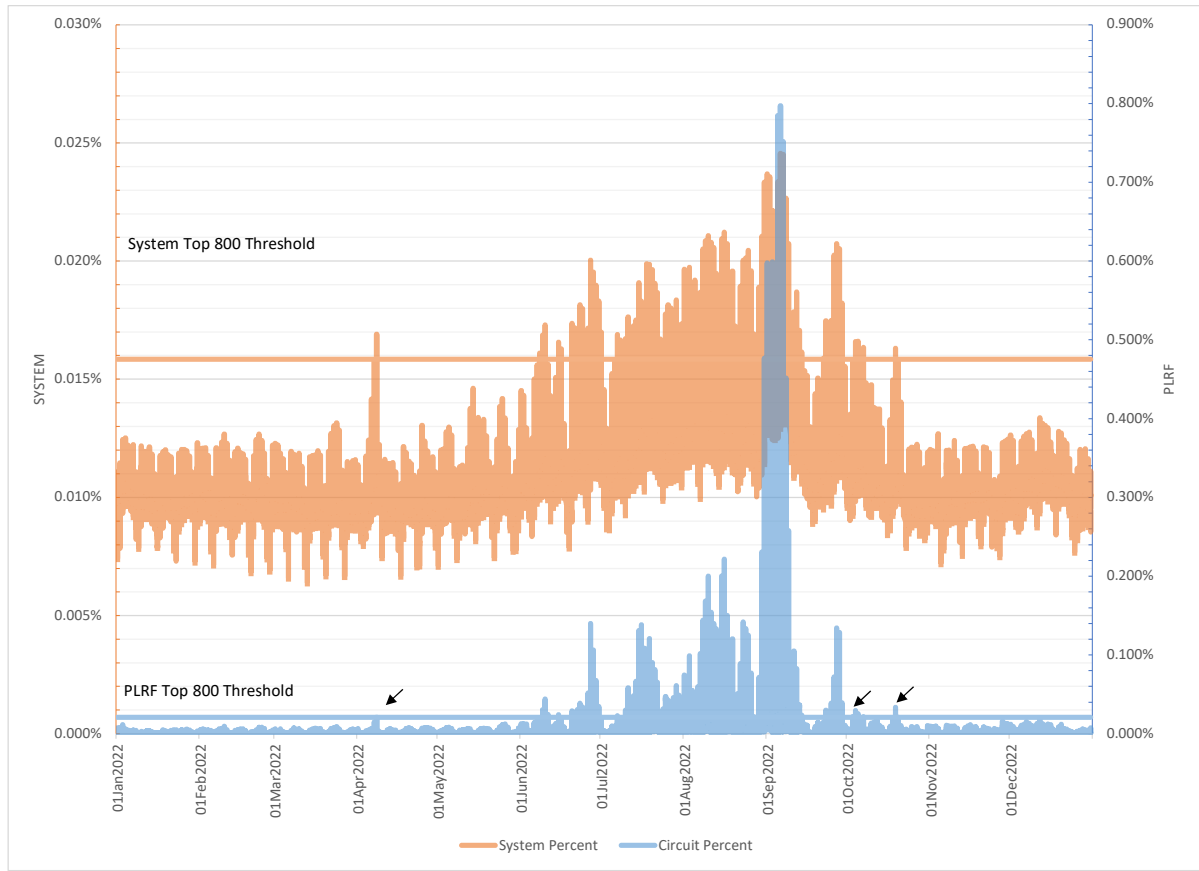
Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	30%	18%	41%	12%	100%
Summer	30%	8%	37%	n/a	75%
Winter	n/a	9%	4%	12%	25%

(iii) PLRF Methodology Accounts For Load Diversity

SCE’s distribution system has evolved over time as load has grown across SCE’s service territory. This growth has resulted in a variety of circuit load profiles and configurations across SCE’s distribution system. The PLRF methodology captures the effect of this load diversity, as shown in Figure I-14. Based on 2022 hourly load data, the graph compares SCE’s hourly system load (expressed as a percentage of the sum of all the hourly system loads in the year) to the circuit PLRF percentages described above.³⁸ While the graph demonstrates that peak load patterns on individual distribution circuits are largely consistent with peak load patterns on the system as a whole, the arrows highlight the hours where the circuits peak, but the system does not. This helps validate that the sequential step of first identifying the PLRF load by hour on each circuit and then aggregating such load across all circuits captures the effect of load diversity across the circuits.

³⁸ The graph has dual y-axes, with the PLRF percentages represented on the right axis and the system load percentages represented on the left axis. The x-axis represents a chronological layout of 8,760 hours of the year. A peak threshold line for the top 800 hours for the system and the top 800 hours for the PLRF values was drawn.

Figure I-14
Circuit PLRF and System Load Percentages In 2022



To illustrate the regional diversity of peak load risk hours, SCE is presenting monthly PLRF percentages by planning region³⁹ and climate zone in Appendix G.

(b) EDF Methodology For Grid-Related Costs

To link grid-related design demand to measurable customer attributes, SCE developed a method for measuring peak load diversity, referred to as “effective demand.” Effective demand is expressed as a factor (effective demand factor, or EDF), which is the ratio of a customer’s contribution to the peak load on a transmission or distribution circuit to the customer’s annual non-coincident peak demand. EDFs vary by type of customer and by the voltage level of the circuit. Unlike rate group coincident demand, which is measured for customers within a

³⁹ SCE’s distribution circuits are classified into eight planning regions, namely Desert, Metro East, Metro West, North Coast, Orange, Rural, San Jacinto Valley, and San Joaquin Valley.

1 particular rate group, effective demand takes intergroup diversity into account. This is important
2 because the impact of a particular customer on delivery capacity in an area may vary depending on the
3 characteristics of nearby customers. For example, a medium-sized business connecting to a distribution
4 circuit primarily serving other business customers would cause planners to consider the customer's
5 entire maximum load when undertaking circuit design. However, the same business connecting to a
6 distribution circuit in a residential area would not have as large an impact on circuit peak demand
7 because residential customers' demands tend to peak later in the day than business customers.

8 SCE has over 4,600 distribution circuits, each of which typically provide
9 service to customers in a variety of rate groups. Distribution circuit EDFs are calculated as follows.
10 First, the number of customers by rate group is determined for each circuit and is used to develop a
11 profile of the number of customers by rate group on a typical distribution circuit. These profiles are
12 calculated for each type of customer, using an average of the circuits weighted by the number of
13 customers of the particular type. For example, the typical TOU-8 (large customer) distribution circuit
14 serves fewer residential and small business customers because the design demand of the large customer
15 leaves less capacity available for others.⁴⁰ Next, a Monte Carlo simulation method is used to randomly
16 populate each typical circuit type with customers from SCE's load research samples. This step is
17 performed for each circuit type. Next, individual customers on each simulated circuit are selected, and
18 the contribution of the customer to the circuit peak is determined. For example, if the Monte Carlo
19 simulation is for a typical TOU-8 customer distribution circuit, the effect of one of the TOU-8
20 customer's load on the circuit is calculated. Finally, the second and third steps are repeated a sufficient
21 number of times to produce statistically valid results. A similar approach is used to determine EDFs for
22 subtransmission (e.g., 66 kV) circuits. Due to the greater geographic area typically served by these
23 higher voltage circuits, a single typical customer profile is used for all customer types.

24 Distribution circuit EDFs vary from around 28 percent to 43
25 percent for residential and small agricultural customers to 62 to 74 percent for medium and large

⁴⁰ Distribution circuits are typically sized to handle about 400 amperes of current flow. At 12 kV, this is adequate to serve a maximum of 4,800 kW.

commercial and industrial customers. In general, higher load factor customers have higher EDFs because their peak demands are more coincident with circuit peaks. Also, larger customers tend to have greater EDFs because their load has proportionately greater influence on circuit peaks than smaller customers. The load research study performed to compute EDFs (by customer group and voltage level) is described in greater detail in Appendix B of this exhibit. Because EDFs associate an individual customer's peak demand to that customer's contribution to delivery system demand, the marginal cost revenues associated with a rate group's design demand are defined as the product of that rate group's annual non-coincident peak demand, the EDF for that rate group, and the marginal cost per unit of design demand.

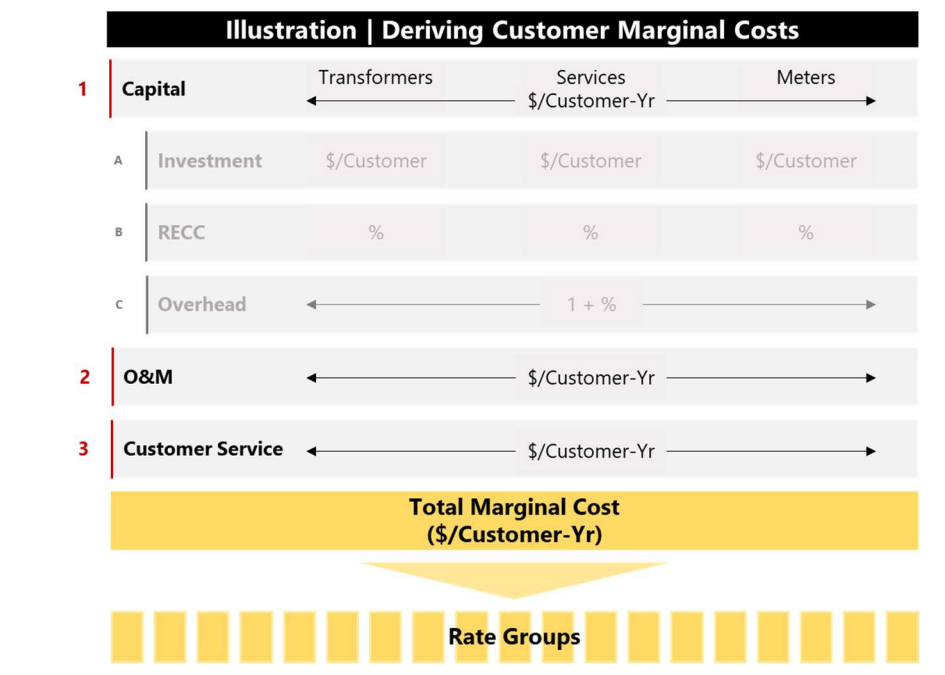
Currently, SCE has approximately 230 standby customers who self-generate to meet a portion of their electric service requirements, and who rely on SCE for generation service to supplement their generation, or who rely on SCE when their generation facility is unavailable due to maintenance or a forced outage. The EDFs that SCE calculates for these customers are applied to both regular and standby customers because SCE needs to reserve sufficient delivery system capacity to serve standby loads without adversely affecting other customers.

The results of SCE's EDF analysis are included in Appendix B of this exhibit.

3. Customer Marginal Costs

Customer marginal costs include the 1) capital investment costs associated with equipment connecting a customer to the grid; 2) ongoing costs of operating and maintaining (O&M) that equipment; and 3) customer service costs (*i.e.*, billing, customer inquiries, meter reading, etc.). Figure I-15 illustrates how customer marginal costs are derived.

Figure I-15
Derivation of Customer Marginal Costs



SCE's approach to calculating the capital investment costs begins by evaluating the cost of equipment directly related to providing different types of customers access to the grid. For smaller customers, this reflects costs of the service drop, the meter, and a prorated portion of transformer equipment – generally shared by multiple customers. For larger customers, this reflects the costs of the service drop, meter, and final line transformer – generally dedicated to an individual customer. The capital investment costs are differentiated by rate group and subgroups based on the specific method of service (*i.e.*, single-phase vs. three phase service voltage) and their average load characteristics. Once the cost of equipment has been determined for each rate group and subgroup, SCE uses the RECC methodology to convert these capital investments into an annualized customer marginal cost. Next, O&M expenses related to the final line transformer are added to the annual capital cost. Finally, customer service costs based on studies developed by subject matter experts are added.⁴¹ Table I-13 summarizes the resulting customer marginal costs for all rate groups.

⁴¹ Customers were grouped into residential; small and medium agricultural and pumping (≤ 200 kW) and large agriculture and pumping (> 200 kW); and small commercial (≤ 20 kW), medium commercial (20 – 200 kW),
(Continued)

Table I-13
Customer Marginal Costs
(2025\$)

Customer Marginal Costs (\$/Customer-Yr)				
Item	Rate Group	Capital	O&M + CS	Total
1	Domestic	137	17	154
2	Single Family	136	17	153
3	Multiple	135	17	152
4	Master Meter	898	127	1,025
5	GS-1	134	26	160
6	Single Phase	110	26	136
7	Three Phase	169	26	195
8	Primary	409	25	434
9	TC-1	104	25	129
10	GS-2	1,516	134	1,650
11	Single Phase	898	127	1,025
12	Three Phase	1,604	135	1,739
13	Primary	409	115	524
14	GS-3	4,943	1,014	5,957
15	Secondary	5,111	1,035	6,146
16	Primary	409	969	1,377
17	TOU-8	9,208	1,074	10,283
18	Secondary	11,027	1,122	12,149
19	Primary	456	969	1,425
20	Subtransmission	19,297	969	20,266
21	AG <= 200	274	165	439
22	Single Phase	273	162	435
23	Three Phase	274	165	439
24	AG > 200	3,624	808	4,432
25	Three Phase	3,710	808	4,517
26	Primary	831	808	1,638
27	Metered Street Lights	110	26	136
28	Unmetered Streetlights (\$/Customer)*		25	25
29	LS-1 (+\$/Lamp)	1.16	0.02	1.17
30	LS-2 (+\$/Lamp)	1.58	0.02	1.60
31	OL (+\$/Lamp)	2.37	0.56	2.93
32	DWL (+\$/Lamp)	1.12	0.02	1.14

*Unmetered includes both a customer and per lamp customer marginal cost

4. Street Lighting and Outdoor Lighting Marginal Cost

Street lighting customers can take service with various lamp sizes and types and may choose to own and/or maintain portions of their streetlight facilities.

The three major categories of street lighting services are:

1. SCE-owned and unmetered (LS-1/OL-1/DWL-A): SCE owns and maintains the street lighting or walkway equipment and associated facilities and provides unmetered

and large commercial and industrial (> 200 kW). Each include costs associated with *Metering Services*, *Customer Services* (customer inquiries and major account management), and *Billing* (billing exceptions, collections, credit checks, payments, and payment processing).

1 service at secondary distribution voltage. DWL-A customers will be migrated to Rate
2 Schedule OL-1 on the next scheduled read date after October 1, 2024.⁴²

- 3 2. Customer-owned and unmetered (LS-2/DWL-B): The customer owns the street
4 lighting or walkway equipment and is responsible for maintaining the facilities.
5 SCE provides unmetered service at the secondary distribution voltage under two
6 service plans.
- 7 a. LS-2 Rate A: The customer owns all the street lighting facilities after the delivery
8 point including, but not limited to, the pole, mast arm, luminary and lamp, and all
9 connecting cable and conduit in the streetlight system. The customer takes
10 unmetered service from a dedicated distribution system circuit with a single
11 photocell controller located at the SCE side of the point of delivery which
12 services multiple customer-owned lights.
- 13 b. LS-2 Rate B: The customer owns the pole, mast arm, luminary, photocell, and
14 lamp. SCE owns and maintains the conductor to the point of delivery, which is
15 located at the base of a customer-owned fixture. The customer takes service from
16 individual SCE feed points instead of a customer-owned streetlight circuit serving
17 multiple lights.
- 18 3. Customer-owned and metered (LS-3): The customer owns the street lighting facilities
19 and takes metered service from the distribution system either at secondary or primary
20 voltage.

21 SCE has developed marginal street lighting costs separately because of the unique
22 characteristics of streetlight service and the dedicated nature of these costs. Marginal street lighting
23 facilities costs are incurred in addition to marginal transmission and distribution (T&D) and customer
24 costs. Street lighting marginal cost is the sum of O&M costs and streetlight facilities costs.

⁴² See 2021 GRC Phase 2 Streetlight and Traffic Control Rate Group Settlement Agreement at Attachment A-14.

1 O&M costs are expenses associated with lamp replacement, repair, routine inventory and
2 mapping, field inspection, and night patrolling. Facilities costs are specific to the type of street lighting
3 facilities provided, which may include bracket, bolt, pole, luminaire, lamp, photo controller, handholds,
4 conduit, and overhead or underground cable. Series service includes the cost of regulated output
5 transformer, which is a special transformer necessary for providing service at primary voltage level
6 (known as series service) to customer-owned street lighting systems.

7 Street lighting investment costs have been annualized by taking the current replacement
8 costs for each component of street lighting facilities, and multiplying them by a RECC. The total
9 replacement cost for each component includes supply expense, administration expense, and general
10 plant. The sum of annual investment costs plus O&M expense is the total facility cost for streetlights, or
11 the marginal street lighting cost.

12 SCE utilizes the existing methodology, established in D.13-03-031, in this Application to
13 set the current streetlight facilities rate. This method more closely resembles rate design principles used
14 to set rates in other classes by allocating authorized revenue requirements on an MCRR basis.

15 SCE calculates the cost of streetlight services based on a typical standard installation to
16 calculate the length of circuits, lamps per circuit, span length, lamp size, and transformer connections.
17 Tables I-14 through I-16 show the marginal streetlight costs. SCE continues to offer a distribution pole-
18 mounted street lighting rate option for lamps that are mounted on SCE's distribution poles as opposed to
19 being mounted on poles that solely support streetlights. Details of this rate option are included in
20 Exhibit SCE-04. Table I-14 below illustrates the marginal costs of replacements for streetlights.
21 Columns A - C reflect marginal costs for standard configuration lamps mounted on wood poles, adjusted
22 by the ratio of revenues recovered through facilities charges for lamps on distribution poles and those on
23 wood poles. Columns D - F reflect marginal costs for lamps mounted on distribution poles.

24 Additionally, as part of 2021 GRC Phase 2 Streetlight and Traffic Control Rate Group
25 Settlement Agreement, settling parties agreed to conduct a dimmable streetlight feasibility pilot study.
26 SCE's results and recommendations are detailed in SCE-04.

Table I-14
Monthly Street Light Facility Marginal Costs
(2025\$)

LS-1: SCE Owned Streetlights			[A]	[B]	[C]	[D]	[E]	[F]
			Wood Pole Streetlights Only			Distribution Pole-Mounted Streetlights		
Lamp Type	Watts	Lumens	Facilities	O&M	Total	Facilities	O&M	Total
			\$/lamp/mo.	\$/lamp/mo.	\$/lamp/mo.	\$/lamp/month	\$/lamp/month	\$/lamp/month
INCANDESCENT LAMPS								
INCAND	103	1,000	16.71	3.38	20.09	11.49	3.38	14.87
INCAND	202	2,500	16.71	3.30	20.01	11.49	3.30	14.79
INCAND	327	4,000	16.71	3.30	20.01	11.49	3.30	14.79
INCAND	448	6,000	16.71	3.62	20.33	11.49	3.62	15.11
MERCURY VAPOR LAMPS								
MV	100	4,000	16.71	2.02	18.73	11.49	2.02	13.51
MV	175	7,900	16.71	1.46	18.17	11.49	1.46	12.95
MV	250	12,000	17.17	1.64	18.81	11.44	1.64	13.08
MV	400	21,000	17.82	1.51	19.33	12.10	1.51	13.61
MV	700	41,000	16.64	1.38	18.02	10.92	1.38	12.30
MV	1,000	55,000	16.78	2.26	19.04	11.06	2.26	13.32
HIGH PRESSURE SODIUM								
HPSV	50	4,000	16.71	1.62	18.33	11.49	1.62	13.11
HPSV	70	5,800	16.71	1.62	18.33	11.49	1.62	13.11
HPSV	100	9,500	16.66	1.54	18.20	11.44	1.54	12.98
HPSV	150	16,000	17.12	1.53	18.65	11.40	1.53	12.93
HPSV	200	22,000	17.82	1.58	19.40	12.10	1.58	13.68
HPSV	250	27,500	17.83	1.54	19.37	12.11	1.54	13.65
HPSV	310	37,000	16.64	1.54	18.18	10.92	1.54	12.46
HPSV	400	50,000	16.78	1.54	18.32	11.06	1.54	12.60
LOW PRESSURE SODIUM								
LPSV	35	4,800	19.37	2.36	21.73	14.15	2.36	16.51
LPSV	55	8,000	19.38	2.36	21.74	14.17	2.36	16.53
LPSV	90	13,500	19.71	2.41	22.12	13.99	2.41	16.40
LPSV	135	22,500	19.38	2.61	21.99	13.66	2.61	16.27
LPSV	180	33,000	16.98	2.89	19.87	11.25	2.89	14.14
METAL HALIDE								
MH	70	5,500	16.17	3.74	19.91	10.95	3.74	14.69
MH	100	8,500	16.12	2.99	19.11	10.91	2.99	13.90
MH	150	12,000	16.45	2.54	18.99	10.73	2.54	13.27
MH	175	12,000	16.51	2.28	18.79	10.78	2.28	13.06
MH	250	19,500	16.39	2.09	18.48	10.67	2.09	12.76
MH	400	32,000	17.14	1.61	18.75	11.42	1.61	13.03
MH	1,000	100,000	18.14	1.93	20.07	12.42	1.93	14.35
MH	1,500	150,000	NA	NA	NA	NA	NA	NA
LED WATTAGE OF HPSV EQUIV								
LED	22	50	16.29	0.28	16.57	11.08	0.28	11.36
LED	29	70	16.37	0.28	16.65	11.15	0.28	11.43
LED	37	100	16.42	0.28	16.70	11.20	0.28	11.48
LED	59	150	17.26	0.28	17.54	11.53	0.28	11.81
LED	76	200	17.97	0.28	18.25	12.24	0.28	12.52
LED	121	250	18.24	0.28	18.52	12.51	0.28	12.79
LED	130	310	19.15	0.28	19.43	13.43	0.28	13.71
LED	160	400	18.99	0.28	19.27	13.27	0.28	13.55
Tap Devices	Tap Devices		2.70		2.70			

Table I-15
Monthly Street Light Facility Marginal Costs (Continued)
(2025\$)

	[A]	[B]	[C]
	Monthly Costs		
LS-2: Customer Owned Streetlights			
Rate Option	Facilities	O&M	Total
	\$/lamp/mo.	\$/lamp/mo.	\$/lamp/mo.
LS-2 Rate A			
Series Service	36.83	0.53	37.37
Multiple Service	1.39	0.46	1.85
LS-2 Rate B			
Multiple Service	5.46	0.12	5.58
	[A]	[B]	[C]
LS-3 Metered Service	Monthly Costs		
	Facilities	O&M	Total
	per service account-mo	per service account-mo	per service account-mo
Series Service	428.17	6.67	434.84
Multiple Service	NA	NA	NA

Table I-16
Monthly Street Light Facility Marginal Costs (Continued)
(2025\$)

			[A]	[B]	[C]	[D]	[E]	[F]
OL-1: Outdoor Lighting								
Lamp Type	Watts	Lumens	Facilities \$/lamp/mo.	O&M \$/lamp/mo.	Total \$/lamp/mo.	Facilities \$/lamp/mo.	O&M \$/lamp/mo.	Total \$/lamp/mo.
MERCURY VAPOR LAMPS								
MV	75	est 4000						
MV	175	7,900	16.71	1.46	18.17	11.49	1.46	12.95
MV	400	21,000	17.82	1.51	19.33	12.10	1.51	13.61
HIGH PRESSURE SODIUM								
HPSV	50	4,000	16.71	1.62	18.33	11.49	1.62	13.11
HPSV	70	5,800	16.71	1.62	18.33	11.49	1.62	13.11
HPSV	100	9,500	16.66	1.54	18.20	11.44	1.54	12.98
HPSV	150	16,000	17.12	1.53	18.65	11.40	1.53	12.93
HPSV	200	22,000	17.82	1.58	19.40	12.10	1.58	13.68
HPSV	250	27,500	17.83	1.54	19.37	12.11	1.54	13.65
HPSV	310	37,000	16.64	1.54	18.18	10.92	1.54	12.46
HPSV	400	50,000	16.78	1.54	18.32	11.06	1.54	12.60
HPSV	1,000	35,500	19.58	2.15	21.73	14.07	2.15	16.22
LOW PRESSURE SODIUM								
LPSV	35	4,800	19.37	2.36	21.73	14.15	2.36	16.51
LPSV	55	8,000	19.38	2.36	21.74	14.17	2.36	16.53
LPSV	90	13,500	19.71	2.41	22.12	13.99	2.41	16.40
LPSV	135	22,500	19.38	2.61	21.99	13.66	2.61	16.27
LPSV	180	33,000	16.98	2.89	19.87	11.25	2.89	14.14
METAL HALIDE								
MH	70	5,600	16.17	3.74	19.91	10.95	3.74	14.69
MH	100	8,500	16.12	2.99	19.11	10.91	2.99	13.90
MH	150	12,000	16.51	2.54	19.05	10.78	2.54	13.32
MH	175	12,000	16.51	2.28	18.79	10.78	2.28	13.06
MH	250	19,500	16.39	2.09	18.48	10.67	2.09	12.76
MH	400	32,000	17.14	1.61	18.75	11.42	1.61	13.03
MH	1000	100,000	18.14	1.93	20.07	12.42	1.93	14.35
MH	1500	150,000	NA	0.00	NA	NA	0.00	NA
LED WATTAGE OF HPSV EQUIV								
LED	22	50	16.29	0.28	16.57	11.08	0.28	11.36
LED	29	70	16.37	0.28	16.65	11.15	0.28	11.43
LED	37	100	16.42	0.28	16.70	11.20	0.28	11.48
LED	59	150	17.26	0.28	17.54	11.53	0.28	11.81
LED	76	200	17.97	0.28	18.25	12.24	0.28	12.52
LED	121	250	18.24	0.28	18.52	12.51	0.28	12.79
LED	160	400	18.99	0.28	19.27	13.27	0.28	13.55
LED	174	1,000	21.42	0.28	21.70	15.81	0.28	16.09

1 II.

2 **SALES AND CUSTOMER FORECAST**

3 The kilowatt-hour sales forecast for 2025 (“Sales Forecast”) forms the basis for the billing
4 determinant forecast discussed below and is used for rate design purposes in this phase of the GRC.⁴³
5 The Sales Forecast reflects the energy that SCE expects to deliver to bundled service customers and non-
6 bundled (DA and CCA) customers in its service territory during the 2025-2028 period. It excludes sales
7 to public power customers, contractual sales, or interchange energy with other utilities.

8 Historical sales data are statistically related to the historical values of key economic drivers,
9 electricity prices, and weather conditions. Thus, SCE uses econometric models to construct its sales
10 forecasts for the major revenue classes: residential, commercial, industrial, agriculture and other public
11 authority. Revenue class data are used in the models because they have been defined in a consistent
12 manner throughout the historical period used in the econometric models. The sales forecast for each
13 revenue class is produced monthly and summed up to an annual value.⁴⁴ The resulting regression
14 equations, in conjunction with forecasts of the economic drivers including electricity prices and normal
15 weather conditions, are used to predict sales by revenue class. Model-generated forecasts may be
16 modified based on current trends, judgment, and events that are not specifically modeled in the equation.

17 Table II-17 shows SCE’s forecast of channel 1 kilowatt-hour sales and customers for years 2025
18 through 2028.

⁴³ The Sales Forecast is discussed in detail in A.19-08-013. See SCE-07, Vol. 1CA: Amended Results of Operations (R/O), Vol. 1, Chapter VI, pp. 66-77.

⁴⁴ Model inputs include monthly data for electricity sales, electricity prices and employment. Quarterly or annual economic or demographic data have been distributed to monthly values.

Table II-17
Forecast Grid Sales And Customers
For Years 2025 Through 2028

Line No.	2025	2026	2027	2028
1 Grid Sales*(GWH)				
2 Residential	29,186	30,168	31,515	32,670
4 Commercial	45,706	46,725	47,782	48,877
5 Industrial	3,923	3,538	3,158	2,973
3 Other	5,874	5,856	5,840	5,814
7 Total Retail Sales	84,689	86,287	88,295	90,334
8 Net Customer Additions				
9 Residential	31,419	31,858	31,840	31,867
10 Commercial	3,671	3,693	3,702	3,700
11 Industrial	-110	-77	-76	-68
12 Other	-101	-287	-351	-396
14 Total Customers	34,879	35,187	35,115	35,103
15 Customers				
16 Residential	4,626,593	4,658,452	4,690,292	4,722,159
17 Commercial	621,063	624,756	628,458	632,158
18 Industrial	5,515	5,438	5,362	5,294
19 Other	88,635	88,348	87,997	87,601
21 Total Customers	5,341,806	5,376,993	5,412,109	5,447,212
*Grid sales & customers include bundled and non-Bundled (DA & CCA) sales and customers.				

A forecast of billing determinants for 2025 is required to evaluate the present rate revenues, that is, the revenues that SCE's current rates would be expected to provide in 2025, and to verify that SCE's proposed rates will collect the test year revenue requirement. In addition, billing determinants are used to determine marginal costs revenues in order to allocate revenues across rate groups. Billing determinants refer to the number of customers by rate group, sales by time period by rate group, demands by time period by rate group, and other miscellaneous measures of service by which SCE assesses charges.

SCE develops billing determinants by rate group that correspond to the revenue class sales and customer forecast described above. The principles and processes by which this is done are explained in Exhibit SCE-07 of SCE's 2025 GRC Phase 1 Application.⁴⁵ Rate group billing determinants used in the revenue allocation and rate design process are included in the work papers to that GRC Phase 1 exhibit.

⁴⁵ Exhibit SCE-07, Vol. 1CA: Amended Results of Operations (R/O), Vol. 1, Chapter VII, pp. 79-82, in A.19-08-013.

1 Present rate revenues are defined as the revenues SCE would expect to collect in a future period
2 (2025) given its current rates and forecast of billing determinants. Present rate revenues are provided for
3 each revenue component, *e.g.*, distribution, transmission, generation, etc., and for each rate group.
4 As with billing determinants, SCE's GRC Phase 1 testimony contains a description of the methodology
5 SCE uses to develop present rate revenues.⁴⁶

⁴⁶ *Id.*, pp. 80-81.

Appendix A

Glossary

Back-Up Load: Electric energy or capacity supplied by an electric utility to replace energy or capacity ordinarily self-generated by a customer during an unscheduled outage of the customer's generation facility.

California Independent System Operator (ISO or CAISO): A state chartered non-profit corporation with centralized control of the statewide transmission grid, charged with ensuring the efficient use and reliable operation of the transmission system.

Coincident Demand: The aggregated demands of a group of customers at a particular time, usually at the time of a customer group peak or the system peak.

Combustion Turbine (CT): An internal-combustion engine consisting of an air compressor, combustion chamber, and turbine wheel that is turned by the expanding products of combustion. Combustion turbines are designed to start quickly to meet the demand for electricity during peak operating periods.

Community Choice Aggregation (CCA): A system incorporated into state law that allows cities, counties, and joint power authorities to aggregate the load of individual customers within a defined jurisdiction in order to procure their energy needs from alternative energy sources.

Cost Drivers: Those fundamental aspects of customer demand for services that directly cause SCE to incur costs.

Cost of New Entry (CONE): An estimate of the annualized total fixed cost to construct a power station.

Customer Marginal Costs: The change in total costs associated with providing customer services.

Design Demand: The amount of delivery capacity (in kW) that is necessary to reliably expand service to an additional customer or group of customers.

Design Demand Marginal Cost (DDMC): The opportunity cost associated with providing additional capacity on the T&D system to deliver electricity to consumers.

Direct Access (DA) Customers: Customers who have arranged to have their electricity usage supplied by an entity other than their local utility.

Dispersion Statistics: Statistical measurements, or indices of variation, that reveal how widely the distribution varies around its mean (average).

Distributed Generation (DG): A form of electric generation smaller in size than a traditional central station power plant. A DG unit may be connected directly to a customer's facilities (on-site) or on a utility's distribution system (on-grid).

Distribution System: The portion of the electrical system (50 kV and below) that transmits electric energy from convenient points on the transmission system to consumers.

Diversity of Use: The difference between the sum of the maximum of two or more individual connected loads, at a customer's site, and the expected coincident maximum load.

Effective Demand: The contribution to peak demand that a customer places on transmission and distribution circuits.

Effective Demand Factor (EDF): The ratio of a customer's contribution to the peak load on a transmission or distribution circuit to the customer's annual non-coincident peak demand.

Electricity Usage Marginal Cost: The change in costs associated with providing an additional amount of electricity to customers at a given moment.

Equal Percent of Marginal Cost (EPMC): A revenue allocation method that assigns authorized revenue requirements to customers in each rate group in proportion to the rate group's share of marginal cost revenue.

Federal Energy Regulatory Commission (FERC): The federal agency responsible for regulating wholesale electricity and natural gas markets pursuant to the Federal Power Act of 1935, as amended.

FERC Form 1: A comprehensive financial and operating report submitted to FERC by large electric utilities for electric rate regulation and financial audit purposes.

Final Line Transformer (FLT): A transformer that converts primary voltages to service voltages.

Flex Capacity: The portion of generation capacity marginal costs allocated to ramp constraints for a given modeled year.

Generation Capacity Marginal Cost (GCMC): The capacity cost of meeting system peak conditions in a single hour.

Implied Market Heat Rate (IMHR): CAISO System based methodology that identifies when generation capacity conditions are expected to be "tight" by determining the hours in which the marginal generation resource (*i.e.*, the resource supplying the last unit needed to serve customer load in a given hour) is forecast to be a simple-cycle gas turbine plant, or a "peaker" plant.

Kilowatt-Hour: A basic unit of electrical energy. A kilowatt-hour is equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour (kWh = kW x hour).

Load: The amount of electric power delivered or required at any specified point on an electrical system. Load primarily originates at the power-consuming equipment of the customer.

Load Diversity: The difference between the sum of the maximum of two or more individual loads and the coincident or combined maximum load, usually measured in kilowatts.

Load Research: The use of statistical methods to measure and analyze the levels and patterns of electric usage to provide a thorough and reliable understanding of electric usage and load characteristics of various customer groups.

Capacity Shortfall: The portion of time that generation capacity will be inadequate to supply customer demand at any given moment, such as one event per 10 years.

Marginal Cost: The change in total cost due to a small change in the quantity produced.

Marginal Cost Revenues: The revenues that would result if all aspects of electric service were priced to reflect the marginal costs of providing such service.

Marginal Cost Revenue Responsibility (MCRR): The marginal cost revenues assigned to a particular rate group based on the cost drivers

Net Cost of New Entry (NetCONE): An estimate of the capacity payment required to incentivize construction of an original power station. The measurement is defined as the forecasted annualized total fixed cost (*i.e.* CONE) minus the forecasted annualized revenues from CAISO wholesale markets

Net Present Value (NPV): The difference between the present value of cash inflows and the present value of cash outflows.

Net Qualifying Capacity (NQC): A fraction of a power station's nameplate capacity which is deemed to contribute to meeting California's Resource Adequacy requirements.

New Customer Only (NCO): Methodology to calculate marginal customer cost that considers the incremental cost of facilities needed when providing new customers access to the distribution grid

Street Lighting Marginal Costs: The marginal cost of providing street lighting service, which is in addition to the marginal cost of delivery, interconnection, and producing electrical energy for such service.

Monte Carlo Simulation: A study in which repeated random selections from a sample are used to create (simulate) a population (or a sub-set of population) which the sample represents.

Non-Coincident Peak Demand: The individual customer's peak demand measured irrespective of the time of system peak and irrespective of the peak demand of any other customer or group of customers.

Power Charge Indifference Adjustment (PCIA): A mechanism adopted by the Commission as part of a ratemaking methodology developed to ensure that when electric customers of an investor-owned utility (IOU) depart from IOU service and receive their electricity from a non-IOU provider, those customers remain responsible for costs previously incurred on their behalf by the IOUs.

Peak Load Risk Factor (PLRF): A deterministic approach that computes the relative ratio of peak load at risk in a given hour to the sum of hourly peak load at risk in a modeled year. The PLRF assigns peak-capacity-related design demand marginal costs to TOU periods.

PLEXOS: The PLEXOS model used in the price forecast is a California-only zonal model based on the Full Network Model (FNM) published by the California Independent System Operator (CAISO) on a regular basis.

Plug-in Electric Vehicle (PEV): Vehicle with battery that can be recharged from an external source of electricity

Present Rate Revenues (PRR): A computational model that calculates revenues based on present (proposed) rates and forecasted billing determinants. The present/proposed distinction is context dependent.

Primary Voltage: Facilities at which electric power is taken or delivered at voltages between 2 and 50 kV, generally at either 12 kV or 33 kV.

Ramp: The relative change in hourly load over a predefined period of time.

Rate Group: Categories into which similar customers are grouped for revenue allocation and rate design.

Real Economic Carrying Charge (RECC): A measure of the per dollar savings of deferring an investment one year, taking account of the stream of replacement investments. See "A. Framework for Marginal Cost-Based Time Differentiated Pricing in the United States," prepared by the National Economic Research Associates, Inc., # 15 NERA 1.3, Attachment G, "An Economic Concept of Annual Costs of Long-Lived Assets," February 21, 1977.

Renewables Portfolio Standard (RPS): In California, a standard that requires investor-owned utilities, electric service providers, and community choice aggregators to increase procurement from eligible renewable energy resources to 33 percent of total procurement by 2020 and 50 percent by 2030.

Revenue Allocation: The process of assigning authorized revenue requirements to rate groups.

Revenue Requirement: The costs of providing utility services that the Commission has determined are appropriate to recover through customer rates.

Secondary Voltage: Facilities at which electric power is taken or delivered at below 2kV, generally at either 120 or 480 volts.

Street Lighting Facilities: Equipment dedicated to the exclusive use of street lighting customers. For SCE-owned street lighting systems, facilities include the pole and luminaire. For customer-owned street lighting systems, facilities may include switching equipment and specialized transformers.

Subtransmission System: A portion of the transmission system (typically 66 kV and 115 kV), which SCE identifies separately because it has operational characteristics related to distribution facilities.

System Reliability: A measure of the electrical system's ability to meet some or all customer demands, given uncertainty in the availability of generating resources. System reliability is often measured using Loss Of Load Probabilities.

Transmission System: The transmission system transport electric energy in bulk (above 50 kV) from the source of supply (generating system) to other parts of the utility system or to other utilities.

Appendix B

Circuit Analysis For Determination Of Effective Demand Factors

Circuit Analysis And Effective Demand Calculations

This section describes the methodology used in calculating the Effective Demand for each rate group. The approach used is based on Monte Carlo simulations using load research samples. Monte Carlo data simulation techniques construct a database to accurately estimate each customer's contribution to the circuit from which the customer is served. This approach has been used in the past by SCE for the same analysis in the previous GRC Phase 2 proceedings since 2003, and also in projects such as residential transformer loading or calculating the diversity of residential and small commercial customers' loads at the final line transformer in our 1995 and 2003 GRCs. The effective demand factors were calculated for SCE's 11 rate groups and the three large power standby subgroups. The effective demands were calculated at the circuit level (12 kV), at the 66 kV level (sub-transmission), and at the 220 kV (transmission) levels. The following section explains the step-by-step methodology.

Circuit Level (12kV)

Step 1: Number of Customers by Circuit

This step involves the identification of the typical population of customers on each class of facilities (primary circuit, sub-transmission and transmission). This is a conditional distribution, since it varies by rate group. That is, if a circuit serves a large TOU-8 customer, it is likely to serve a very different mix of customers than a circuit in an area without any large TOU-8 customers. Also, the large load of the TOU-8 customer will crowd out other customers. Thus, the typical population distribution is not simply an average of all customers. We approach this step by building a table of customers by circuit.

This table was created using a two-step process. First, a database was created that contained all SCE active customers along with the customer identification number, the transformer pole number, circuit, and the substations to which they were connected. This database was created by extracting and merging three tables from SCE's customer database. This resulted in identifying 4,650 circuits serving 5.2 million customers. Then each customer was mapped to its appropriate rate group.

Once this database was generated, we developed a profile of the number of customers by rate group on a typical circuit. "Typical" circuit means a "weighted average" circuit, using number of customers in all rate groups on all circuits. This is a weighted average calculated using the following formula¹ (illustrated for the domestic and TOU-GS-1 customer groups):

¹ Notation is as follows: $N(c,i)$ is the number of customers in rate group c on circuit i . $\sum_i N(c,i)$ is the summation notation – the sum of $N(c,i)$ for a particular rate group c across all circuits.

Domestic Customer Distribution:

$$\sum N(DOM,i) * N(DOM,i) / \sum N(DOM,i)$$

$$\sum N(DOM,i) * N(GS1,i) / \sum N(DOM,i)$$

$$\sum N(DOM,i) * N(GS2,i) / \sum N(DOM,i)$$

Etc.

TOU-GS-1 Customer Distribution:

$$\sum N(GS1,i) * N(DOM,i) / \sum N(GS1,i)$$

$$\sum N(GS1,i) * N(GS1,i) / \sum N(GS1,i)$$

$$\sum N(GS1,i) * N(GS2,i) / \sum N(GS1,i)$$

Etc.

As a simple example of this methodology, consider a system of three circuits, with four, three, and two customers, respectively, as follows:

<u>Circuit</u>	<u># of Domestic Customers</u>	<u># of GS-1 Customers</u>	DOM * DOM	GS-1 * GS-1	DOM * GS-1
A	3	1	9	1	3
B	2	1	4	1	2
C	<u>0</u>	<u>2</u>	<u>0</u>	<u>4</u>	<u>0</u>
Total	5	4	13	6	5

A typical domestic (residential) circuit would be derived by weighting circuit A with a factor of 3 and circuit B with a factor of 2. A typical TOU-GS-1 circuit would be derived by weighting circuits A and B with a factor of 1 and circuit C with a factor of 2. The results would be as follows:

<u>Typical Circuit</u>	<u>Number of Customers</u>	
	<u>Domestic</u>	<u>GS-1</u>
Domestic	2.6	1
GS-1	1.2	1.5

The results are contained in Table B-1.

Step 2: Monte Carlo Simulations

SCE performed a series of Monte Carlo simulations for each customer group. For example, the typical circuit serving domestic (residential) customers serves 1,841 domestic (1,113 Single, 725 Multiple, 3 Master Metered), 181 TOU-GS1, 5 TC-1, 25 TOU-GS-2, 2 TOU-GS-3, 5 TOU-PA-2, and 6 street lighting customers. Therefore, we made repeated random drawings of 1,841 Domestic, 181 TOU-GS-1, ...etc. from load research sampled customers. For this study, only the sampled customers with a full year of load data were used. The interval load data from these randomly selected accounts were used to build each particular circuit's load profile in each of the simulations. We used a different number of Monte Carlo simulations for each of the typical customer distributions.

Based on the dispersion statistics observed in the results, we concluded that 50 simulations (samples) were statistically sufficient for the domestic, TOU-GS-1 and TOU-GS-2 rate groups. Based on the same results, we increased the number of simulations for all other rate groups to 100 and to 150 for the TOU-8 rate group. We did not see any significant improvement in the statistics after we reached these levels. In other words, the effective demands converged to their limits. As expected, there was a relationship between the rate group load homogeneity and the number of samples we needed.

Step 3: Effective Demand Calculation

We compared a customer's non-coincident peak demand with its contribution to the peak demand on the circuit in order to calculate effective demand. In the example above, there are 50 Monte Carlo simulations for the domestic customer distribution circuit, each containing 1,841 customers. This provided 92,050 observations (some of which were duplicates since this is larger than the total residential load research sample of approximately 14,000 accounts).² For each of these 92,050 domestic customers, we calculated the peak demand for the Monte Carlo selection that the customer was in, both with and without the customer. The difference was the customer contribution to the circuit peak load. For each customer in each sample (simulation), we computed the ratio of that customer's contribution to circuit peak load to its non-coincident peak demand. The average of these ratios, in each sample, provided the EDF for that particular simulation. Next, we averaged the EDFs over all the 50 samples (simulations) to obtain the EDF at the distribution circuit level. The statistical distribution of these EDFs, across all the simulations, also provided the dispersion statistics used in determining the final

² The selection is done with replacement. That is, each sampled customer can appear more than once in a simulation and in a series of simulations.

number of simulations. TOU-8-subtransmission customers are excluded from the EDF calculation at the distribution circuit level since they are hooked up to the system at higher voltage levels.

These simulation runs are extremely time-consuming. Therefore, we also used another approach to verify the results with a higher number of repeated samples. In this alternative approach, we used the load profiles for the average customers in various rate groups to estimate the circuit's load profile. One random account was then added to the circuit to calculate the incremental load. Effective demands were then calculated based on 500 random samples (accounts). The results were very close to what was observed in the simulations described above. Although, the results from this approach were not used at the circuit level, the same approach was used later, when estimating the effective demand at the 66 kV and 220 kV levels (described below).

Sub-Transmission And Transmission Level

Unlike distribution circuits, sub-transmission and transmission facilities span a sufficiently large geographic area such that it is reasonable to ignore conditional distributions. Instead we used “average” circuit, assuming all the circuits attached to a substation are the same. The number of customers in each rate group on the average circuit is then the number of customers in the rate group divided by the number of circuits.

66 kV:

We considered a substation configuration in which six circuits and no TOU-8 sub-transmission customers are attached to the 66 kV line. We then used the average load profiles for each rate group to build the substation load. One account at a time was added to the circuit to calculate the additional load of that customer (or that customer's contribution to the circuit peak).

Effective demand was calculated using four simulation runs, each with 500 random accounts.

220 kV:

We considered a configuration in which 65 circuits and four TOU-8-subtransmission customers are attached to the 220 kV transmission line. We then used the same methodology as the 66 kV to calculate the effective demands.

Table B-2 contains the EDFs for all the rate groups at the circuit level (12 kV), sub-transmission substation (66 kV), and transmission substation (220 kV).

Table B-1
Effective Demand Calculation
Monte Carlo Simulations
Typical Circuit For Each Rate Group

Typical Circuit	Domestic			GS-1	TC-1	GS-2	TOU-GS-3	TOU-PA-2	TOU-PA-3	TOU-8		TOU-8-S		Street Lighting	Total
	Single	Multiple	Master Metered							Secondary	Primary	Secondary	Primary		
Domestic	1,113	725	3	181	5	25	2	5	0	0	0	0	0	6	2,065
- Single	1,245	508	2	151	5	22	2	5	0	0	0	0	0	5	1,945
- Multiple	839	1,143	3	231	6	31	2	4	0	0	0	0	0	7	2,266
- Master-Metered	865	981	10	243	6	31	2	5	0	0	0	0	0	6	2,149
GS-1	813	754	3	251	6	37	2	5	0	1	0	0	0	6	1,878
TC-1	870	640	2	195	7	33	3	4	0	1	0	0	0	7	1,762
GS-2	691	592	2	219	6	44	3	4	0	1	0	0	0	6	1,568
TOU-GS-3	638	481	2	176	5	38	5	3	0	1	0	0	0	6	1,355
TOU-PA-2	633	272	1	127	3	15	1	68	2	0	0	0	0	2	1,124
TOU-PA-3	617	312	1	118	3	18	2	32	4	1	0	0	0	4	1,112
TOU-8-SEC	495	381	1	155	5	37	4	3	0	2	0	0	0	5	1,088
TOU-8-PRI	493	342	1	127	4	27	3	5	0	1	1	0	0	4	1,008
TOU-8-S-SEC	472	274	1	123	5	29	3	1	0	1	0	1	0	5	915
TOU-8-S-PRI	386	318	1	118	3	17	1	6	0	1	0	0	1	4	856
Street Lighting	855	665	2	186	6	30	2	3	0	1	0	0	0	15	1,765

Table B-2
Effective Demand Factors

Rate Group	Effective Demand		
	12 kV	66 kV	220 kV
Residential	0.43	0.41	0.41
GS-1	0.36	0.37	0.37
TC-1	0.59	0.59	0.59
GS-2	0.62	0.63	0.63
TOU-GS-3	0.72	0.70	0.70
TOU-PA-2	0.28	0.27	0.27
TOU-PA-3	0.47	0.39	0.38
Large Power Excluding Standby Accounts			
TOU-8-Secondary	0.72	0.68	0.67
TOU-8-Primary	0.74	0.67	0.64
TOU-8-Subtran		0.62	0.55
Street Lighting	0.05	0.05	0.05
Large Power Standby Customers Total Load			
TOU-8-Secondary-Standby	0.74	0.66	0.65
TOU-8-Primary-Standby	0.71	0.55	0.52
TOU-8-Subtran-Standby		0.28	0.14
Large Power Standby Customers Backup Load			
TOU-8-Secondary-Standby	0.68	0.65	0.64
TOU-8-Primary-Standby	0.62	0.47	0.45
TOU-8-Subtran-Standby		0.17	0.10

Standby Customers

For the purpose of this study, Standby customers are defined as those commercial and industrial customers in the TOU-8 rate group with demands in excess of 500 kW that have standby demand. By the end of 2022, SCE had approximately 220 standby customers whose regular service load was billed on schedules in the TOU-8 rate group. These customers have different mixes of generation technologies such as bio-mass, co-generation, geothermal, small hydro, wind, and solar.

Standby customers have generators with the ability to serve all or part of their load. SCE delivers energy to these customers in the event their generators do not produce enough energy to meet the customer's load. The energy provided by SCE to these customers is defined as "maintenance," "back-up," or "supplemental." Supplemental energy is the power regularly provided to the customer by SCE that is in addition to what the customer generates. Back-up energy is energy supplied by SCE during unscheduled outages of the customer's own generation.

Back-up Load

The purpose of this study is to determine the back-up portion of each Standby customer's load. For 29 of these customers, SCE had data on the generator output and the power sold to the customer by SCE in 15-minute intervals (for all of these we had one full year of data). For the remaining customers, we had only 15-minute data on the power sold to the customer by SCE.

Back-up, maintenance, and supplemental load for these customers are defined in Schedule TOU-8-S. For the customers with available generation load, the back-up load was calculated using the metered load from SCE, the customer's generation load, and the standby reservation contract capacity. For those customers without generation load, we first calculated the supplemental load based on the metered load from SCE, the supplemental contract capacity, and the standby reservation contract capacity. The supplemental load was then used with the metered load from SCE to calculate the back-up load. The supplemental contract capacity (supplemental contract kW) and the standby reservation contract capacity (standby demand or standby kW) are established by agreement between the customer and SCE.

Standby customers in the large power rate groups are treated a separate rate group, and uses the EDFs derived from the back-up load for the revenue allocation. SCE used the same methodology explained above to define the typical circuit and to calculate EDFs. The typical circuit for Standby customers is shown in Table B-1 (TOU-8-S-SEC and TOU-8-S-PRI). The results for both total load and back-up load are shown in Table B-2, above.

Appendix C
SCE TOU Period Study

SCE TOU Period Study

I. Introduction and Summary of Existing Time-of Use Rate Structure

Time-of-use (TOU) rates improve price signals that customers experience as a result of their consumption decisions and improve economic efficiency in comparison to flat rates, which do not vary by season or time of day.¹ Since it would be impractical to have rates that vary hourly based on a forecast, a set of well-designed TOU periods provides a balance between the objectives of practical retail pricing and economic efficiency. The key objective in determining a set of TOU periods is to group together hours with similar marginal costs and differentiate hours with marginal costs that are not similar, while limiting the overall number of costing periods. The current standard TOU periods are as provided in Table C-1 below:

Table C-1
SCE Current Base TOU Periods for Non-Residential Customers

Summer June – September			Winter October – May	
TOU Period	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays
On-Peak	4 – 9 pm	NA	NA	NA
Mid-Peak	NA	4 – 9 pm	4 – 9 pm	4 – 9 pm
Off-Peak	All Other Hours	All Other Hours	9 pm – 8 am	9 pm – 8 am
Super-Off-Peak	NA	NA	8 am – 4 pm	8 am – 4 pm

In each GRC cycle, SCE performs a study to determine whether a change in its TOU structure is warranted. Based on a review of its marginal costs proposals in this application, SCE concludes that the *current* TOU periods appropriately reflect the dispersion of generation and distribution marginal costs across seasons and time of day.

II. Framework for Analysis

In this exhibit, SCE has described, in detail, the methodology and framework used when estimating different marginal cost components. The time-differentiated cost components used to test the goodness of fit for TOU periods are generation marginal energy costs, marginal generation capacity costs, and peak related distribution marginal costs. The sum of all these costs is referred to as *total*

¹ Well-designed TOU periods increase economic efficiency by discouraging customers from using electricity for low value applications during times when the cost of producing the electricity is high, and conversely encouraging customers to use electricity for low value applications when the cost of producing the electricity is low. This is an improvement over flat rates, which may result in customers consuming electricity that costs more to produce than the value gained by the customer or alternatively results in a customer foregoing consumption that would have been more valuable than the cost to produce the electricity.

marginal costs in this Appendix. All other marginal cost components are considered non-time differentiated and excluded from this analysis.

SCE's current TOU periods define the summer season to include the months of June through September with the remaining months representing the winter season. The TOU periods also include on-peak, mid-peak, off-peak and super off-peak periods. Peak periods generally reflect times when marginal costs are higher due to the impacts of demand and supply constraints on the system. The mid-peak period represents intermediate times where the likelihood of stress conditions results in marginal costs that are at moderate levels compared to the on-peak period. The off-peak period reflects times when loads are low and supply is high, resulting in marginal costs that are generally lower than the peak (on and mid) periods. The winter super off-peak is a period where marginal costs are at their lowest levels, caused by the over-supply of renewable generation expected in that period.

III. Cost Analysis

In this section, variations in SCE's TOU periods are investigated. The specific scenarios investigated are summarized in Table C-2. A linear regression can be used to estimate the goodness of fit for a particular model to explain cost by calculating a best fit line through the data. The difference between the best fit line and the observed value is known as a residual. Two different models can be evaluated by comparing the adjusted R^2 , and the model with the higher adjusted R^2 has a better fit. The regression model uses marginal cost as the dependent variable and several binary variables to represent TOU periods, season, and other variables that can influence the marginal cost.

Regression Analysis on Costs

A linear regression can be used to estimate the goodness of fit for a particular model to explain load by calculating a best fit line through the data. The goodness of fit of the model to the data is captured by the adjusted R^2 .

The regression model is the following:

$$TMC_t = \alpha_0 + \beta_1 * Summer * OnPeak + \beta_2 * Summer * MidPeak \\ + \beta_3 * Summer * OffPeak + \beta_4 * Winter * MidPeak + \beta_5 * Winter * SuperOffPeak$$

Where: Summer, Winter, OnPeak, MidPeak, OffPeak, and SuperOffPeak is equal to one for each respective season and time periods and zero otherwise. The combination of season and TOU period creates an interaction variable. These variables capture the effect of both binary variables being true at

the same time. The omitted season/TOU period is Winter Off Peak.² The coefficients, the β_i' s, represent the effect of the interaction term on TMC. That is how much TMC increases in the Summer On Peak, for example, is given by β_1 . The intercept term α_0 is the TMC at time t when all of the other variables are zero and this represents Winter Off Peak.

In this regression model, the estimated values for the beta coefficients give the differences between the mean values of the total marginal cost falling within different season and time period categories. Thus, the regression equation defines a step function that best explains the total marginal cost by season and TOU period.

The regression analysis looks at three TOU period scenarios with the resulting adjusted R^2 value for each scenario presented in Table C-2:

- 1) SCE's current TOU periods with an on-peak period 4 – 9 pm (Case A)
- 2) SCE's optional TOU periods with an on-peak period of 5 – 8 pm (Case B)³
- 3) Alternative TOU periods with an on-peak period of 5 – 10 pm (Case C)

Table C-2
Goodness of Fit Comparison

Goodness of Fit Comparison	
Case	Adjusted R^2
Case A: Summer On-Peak 4 - 9 pm	0.734
Case B: Summer On-Peak 5 - 8 pm	0.730
Case C: Summer On-Peak 5 - 10 pm	0.732
Higher Value = Better Fit	

The following graphs provide a visual representation of the regression results.

² Including this variable along with an intercept would result in perfect multi-collinearity, which results in estimation not being possible.

³ This TOU period structure is currently offered as an option to SCE's Residential customers.

Figure C-1
Visualization of Current (4 – 9 PM) TOU Marginal Cost Regressions

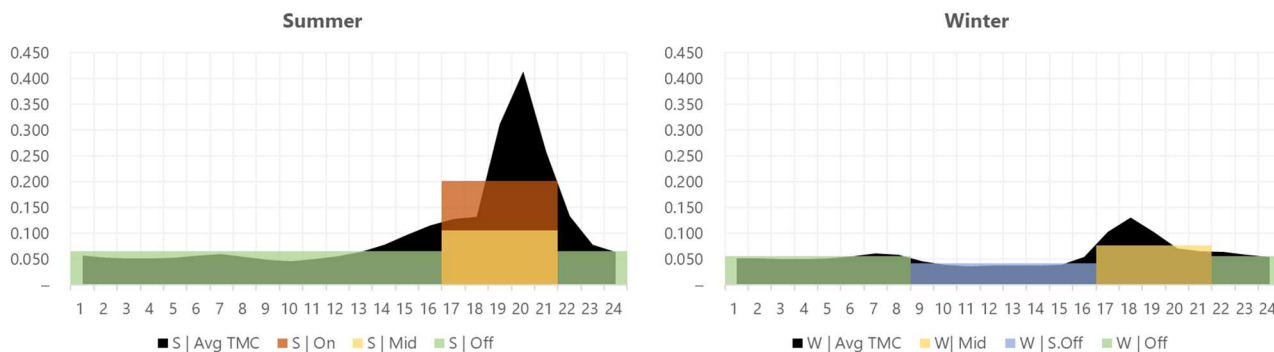


Figure C-2
Visualization of Current Optional (5 – 8 PM) TOU Marginal Cost Regressions

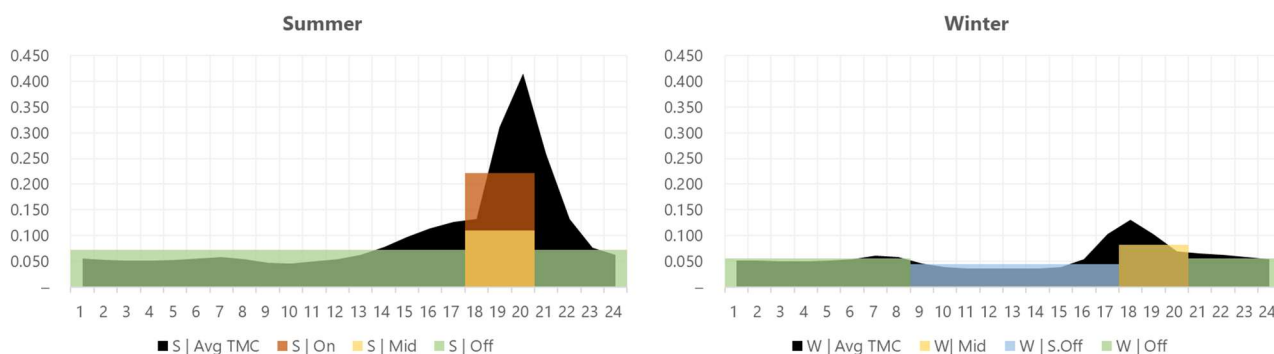


Figure C-3
Visualization of Alternative (5 – 10 PM) TOU Marginal Cost Regressions

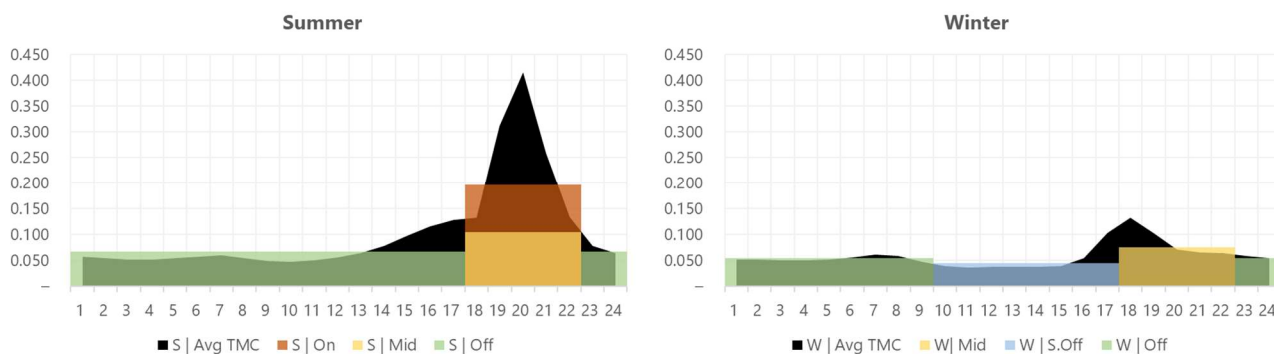


Table C-3
Regression Results for Current TOU Period

Number of Observations Read	8760
Number of Observations Used	8760

Analysis of Variance					
Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	277.01795	46.16966	4035.43	<.0001
Error	8753	100.14364	0.01144		
Corrected Total	8759	377.16159			

Root MSE	0.10696	R-Square	0.7345
Dependent Mean	0.07368	Adj R-Sq	0.7343
Coeff Var	145.1771		

Parameter Estimates						
Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > t
Intercept	Intercept	1	0.05480	0.00207	26.49	<.0001
Summer Mid		1	0.05092	0.00813	6.26	<.0001
Summer On		1	0.14713	0.00563	26.11	<.0001
Winter Super Off		1	-0.01417	0.00319	(4.45)	<.0001
Summer Off		1	0.00990	0.00304	3.26	0.0011
Winter Mid		1	0.02194	0.00370	5.93	<.0001
Top 20		1	3.56790	0.02418	147.57	<.0001

Table C-4
Regression Results for Current Optional TOU Periods

Number of Observations Read	8760
Number of Observations Used	8760

Analysis of Variance					
Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	275.24825	45.87471	3940.03	<.0001
Error	8753	101.91335	0.01164		
Corrected Total	8759	377.16159			

Root MSE	0.1079	R-Square	0.7298
Dependent Mean	0.07368	Adj R-Sq	0.7296
Coeff Var	146.45424		

Parameter Estimates						
Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > t
Intercept	Intercept	1	0.05563	0.00200	27.84	<.0001
Summer Mid		1	0.05457	0.01043	5.23	<.0001
Summer On		1	0.16635	0.00711	23.39	<.0001
Winter Super Off		1	-0.01138	0.00305	(3.73)	0.0002
Summer Off		1	0.01711	0.00292	5.85	<.0001
Winter Mid		1	0.02616	0.00447	5.85	<.0001
Top 20		1	3.57909	0.02439	146.76	<.0001

Table C-5
Regression Results for Alternative TOU Periods

Number of Observations Read	8760
Number of Observations Used	8760

Analysis of Variance					
Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	276.07463	46.01244	3984.16	<.0001
Error	8753	101.08696	0.01155		
Corrected Total	8759	377.16159			

Root MSE	0.10747	R-Square	0.732
Dependent Mean	0.07368	Adj R-Sq	0.7318
Coeff Var	145.85926		

Parameter Estimates						
Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > t
Intercept	Intercept	1	0.05331	0.00208	25.65	<.0001
Summer Mid		1	0.04990	0.00817	6.11	<.0001
Summer On		1	0.14296	0.00567	25.22	<.0001
Winter Super Off		1	-0.00931	0.00320	(2.91)	0.0037
Summer Off		1	0.01262	0.00305	4.14	<.0001
Winter Mid		1	0.02129	0.00372	5.72	<.0001
Top 20		1	3.56870	0.02432	146.73	<.0001

IV. Regression Analysis Recommendations

The results of this analysis support the use of the current TOU periods adopted in the 2016 RDW. As noted in the 2016 RDW, the limitation of this test is that increasing the number of TOU periods will likely result in better ratios than scenarios with fewer periods.⁴ Additional periods will also result in the regression model fitting the data better. Thus, there is a tradeoff between having well-designed TOU periods and simplicity.

V. Dead Band Tolerance Range Analysis

In Decision (D.)17-01-006, which resolved all issues in Rulemaking (R.)15-12-012 (TOU-OIR), the Commission directed each IOU to propose a “dead band tolerance range.” The intent of this tolerance range is to provide a trigger mechanism for more frequent reviews of existing TOU periods than every other GRC. If data used in a GRC or RDW proceeding exceeds the tolerance range, then the utility would initiate a review and determine whether its TOU periods need to be revised.

In Advice 3581-E, SCE proposed establishing a dead band tolerance range based on results of the a) 20 and 100 highest cost hours and b) 20 and 100 lowest cost hours. If the results showed that less

⁴ A.16-09-003, Exhibit SCE-1, p. 71.

than 75 percent of the 20 and 100 highest cost hours fall within the current on-peak period, the dead band tolerance range is exceeded and a more frequent update to its TOU periods may be warranted. Similarly, if less than 75 percent of the 20 and 100 lowest cost hours fall within the current super off-peak period, the band tolerance range is exceeded and a more frequent update to the TOU periods may be warranted.

Resolution E-4948 approved Advice 3581-E and directed SCE to use only the 100 highest cost hours and a trigger of 7.5 percent differential. A decline of at least 7.5 percent in the number of 100 highest cost hours that fall within the summer on-peak and mid-peak periods or a decline of at least 7.5 percent in the number of 100 lowest cost hours that fall within the winter super off-peak period will be considered as breaching the dead band. Based on these criteria, SCE determined the following:

Table C-6
Dead Band Analysis

TOU Deadband Analysis							
	S On	S Mid	S Off	W Mid	W Off	W S.Off	Peak Periods
100 Highest Cost Hours	63	6	6	22	–	3	69
100 Lowest Cost Hours	–	–	–	14	–	86	86

As shown in Table C-6 above, the results show that 69 percent of the 100 highest cost hours are concentrated in for the summer on-peak and mid-peak periods compared with 71 percent in the previous GRC filing, a decline of 2.8%. Additionally, 86 percent of the 100 lowest cost hours are concentrated in the winter super off-peak period, compared with 88 percent in the previous GRC filing, a decline of 2.3%. Both assessments fall within the +/- 7.5 percent tolerance range, indicating an update is not warranted.

Appendix D

NCO Marginal Cost Methodology

Customer Marginal Costs Based On The New Customer Only (NCO) Methodology

In SCE's 1995 GRC, the Commission adopted the New Customer Only (NCO) methodology to calculate customer marginal costs. As discussed in Section I.B. of this exhibit, SCE continues to support the RECC methodology as the correct way to calculate customer marginal costs. Despite the weaknesses of the NCO method, this section presents a calculation of customer marginal costs using a modified NCO methodology for reference purposes.

In the computation of customer marginal costs, the NCO method considers only the incremental cost of facilities needed when providing *new* customers *access* to the distribution grid. Thus, existing assets currently providing access to existing customers are ignored in the NCO calculation. There is also an assumption that a percentage of installations, based on the life of the meters, will need replacement. Customer service costs (*e.g.*, meter reading, billing), are calculated in the same manner as the RECC methodology and are based on all customers.

The NCO method is calculated as follows:

1. Instead of applying a RECC to capital costs to calculate an annual payment, the single life present worth of the capital investment is calculated. This is done for the transformer, service drop and meter for each customer type.
2. The result from step 1 is multiplied by the average number of forecasted new customers per year and number of replacements to calculate the total present worth capital for new investment. New customers are calculated from the average annual 2022 to 2025 customer growth. An annual replacement rate of 3.0 percent was assumed based upon the 33-year depreciation life for final line transformers, which is a large portion of the customer cost. The replacement rate is multiplied by the 2022 customer base to calculate annual customer replacements. The units added in each year is the sum of the customer growth and customer replacements for total new capital investment.
3. The total present worth capital for new investment is then divided by the total number of customers in each customer group to calculate dollars per customer. This becomes the \$/customer for NCO capital costs.¹

¹ At this point, the cost of the new customers and replacement is assigned to existing customers, not just new customers.

4. The customer services (metering, billing, etc.) marginal cost (identical to SCE’s approach) is layered onto the NCO capital cost to yield the total customer marginal cost.

Several customer groups are forecasted to decline in number over 2022 – 2025, which results in negative customer growth and negative marginal costs. SCE caps the negative growth at zero and uses the annual replacement rate based on the 2022 customer forecast to mitigate this deficiency in the NCO methodology. The table below reflects the customer marginal costs based on the NCO methodology.

Table D-1
NCO Customer Marginal Cost
(\$/Customer-Year, 2025\$)

NCO Customer Marginal Cost (\$/Customer/Year)			
Rate Group	Capital	O&M	Total
Domestic	80	17	97
GS-1	61	26	87
TC-1	53	25	78
GS-2	700	134	834
GS-3	3,461	1,014	4,475
TOU-8-SEC	5,812	1,122	6,935
TOU-8-PRI	213	969	1,182
TOU-8-SUB	7,146	969	8,115
PA-2	128	165	293
PA-3	2,059	808	2,867
Street Lights	51	26	76

Appendix E

Design Demand Marginal Cost Working Group

Introduction and Summary

In its 2021 GRC Phase 2 proceeding, the Commission directed SCE to form a working group to evaluate best practices and methodologies in the determination of design demand marginal costs for purposes of revenue allocation and rate design ahead of SCE’s 2025 GRC Phase 2 application. The settlement agreement also stated that “participants in the working group process will be encouraged to propose the kinds of data that SCE should collect”¹. Figure E-1 below outlines the framework SCE used to evaluate this topic between May 2023 – February 2024.

Figure E-1
DDMC Working Group Framework

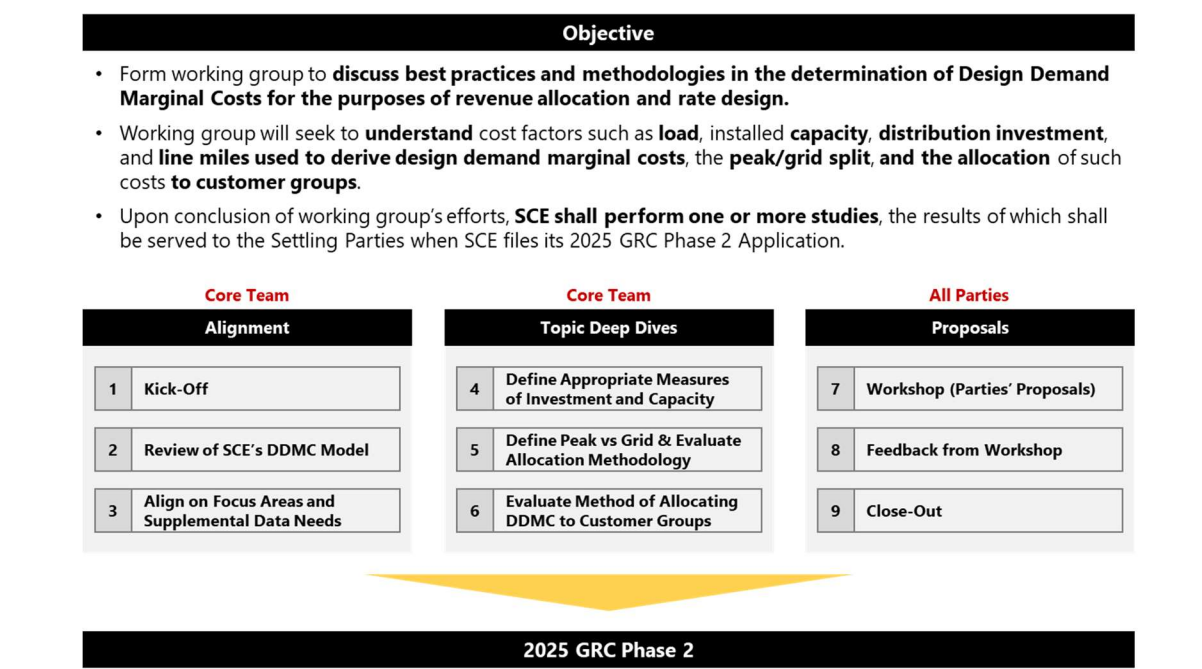


Figure E-2 below outlines the questions the working group evaluated, which were prioritized based on feedback from members of the working group.

¹ 2021 GRC Phase 2 Marginal Cost and Revenue Allocation Settlement Agreement at p. 13.

Figure E-2
Priority Topics and Questions

Component		Subtransmission		Distribution		Questions to Address	
		Substations	Circuits	Substations	Circuits		
A	Marginal Demand Cost (\$/kW)	\$238/kW	\$166/kW	\$299/kW	\$1,020/kW	A Define Appropriate Measures of Distribution Investment and Capacity 1) What measure of distribution <i>investments</i> should be included when deriving marginal costs? 2) What measure of <i>capacity</i> should be used when deriving marginal costs? 3) How should distribution <i>investments</i> and <i>capacity</i> measures be used to derive marginal costs?	
	General Plant Loader (%)	← 1 + 6.70 % →					
	RECC (%)	8.43%	8.02%	8.15%	8.53%		
	Marginal O&M Cost (\$/kW-Yr)	\$3.12/kW-Yr	\$2.18/kW-Yr	\$4.64/kW-Yr	\$16.58/kW-Yr		
	Peak • Grid Split (%)	100% • NA	NA • 100%	100% • NA	26% • 74%		
E	Peak • Grid Split (\$/kW-Yr)	\$25 • NA	NA • \$16	\$31 • NA	\$29 • \$81	E Define Peak and Grid Functions & Determine Method to Assign Marginal Cost to Each 1) What do <i>Peak</i> and <i>Grid</i> capacity represent? 2) What portions of the distribution and sub-transmission systems do these functions exist? 3) Can the costs of distribution and sub-transmission capacity be directly attributed to <i>Peak</i> and <i>Grid</i> functions? If not, what methods can be used to attribute capacity costs to each function?	
F	Customer Groups Allocation	MWs				F Allocate Marginal Cost Revenue to Customer Groups 1) What methodology should be used to allocate Peak and Grid Marginal Cost Revenues to <u>TOU Periods</u>? 2) What methodology should be used to allocate Peak and Grid Marginal Cost Revenues to <u>Rate Groups</u>?	
		MCR					
		Customer Groups					

Table E-1
Topics Parties Addressed in DDMC Workshop

Snapshot of Topics Parties' Workshop Presentations Addressed			
	SCE	Cal Advocates	CLECA
A Defining Appropriate Measures of Investment (\$) & Capacity (MW)	✓	✓	
E Define Peak & Grid Functions and Determine Method to Assign Marginal Cost to Each	✓		
F Allocate Marginal Cost Revenue to Customer Groups	✓		✓

Table E-1 highlights the specific topics that parties presentations addressed during the Design Demand Marginal Cost Workshop that SCE hosted on January 18, 2024. Overall, parties generally supported SCE's current approach to deriving its design demand marginal cost study. Instead, presenting parties proposed changes to the underlying assumptions SCE's current approach relies on and that this study be performed at a more regionalized level. A complete copy of parties' presentations is included in workpapers. At the conclusion of this working group, SCE agreed to produce a range of

datasets and analyses that parties can use to inform their proposals in this proceeding, as shown in Table E-2, which SCE intends to file as supplemental workpapers by April 29, 2024.

Table E-2
List of Requested Supplemental Data & Analyses

List of Requested Supplemental Datasets & Analyses	
#	Request
1	Annual load-related investments from 2012 - 2022 for: a. A-bank substations broken out by Planning Region and Baseline Region. b. B-bank substations broken out by Planning Region and Baseline Region c. Circuits broken out by Planning Region and Baseline Region If SCE is unable to provide this data, please describe why.
2	Hourly load data from 2012 - 2022 for all: a. A-bank substations broken out by Planning Region and Baseline Region. b. B-bank substations broken out by Planning Region and Baseline Region. c. Circuits broken out by Planning Region and Baseline Region.
3	Hourly PLRFs expressed in MWs for: a. A-bank substations broken out by Planning Region and Baseline Region. b. B-bank substations broken out by Planning Region and Baseline Region. c. Circuits broken out by Planning Region and Baseline Region.
4	Hourly rate group load used to determine revenue allocation, broken out by Planning Region and Baseline Region.
6	For a reduction in the PLRF threshold for A-banks from 90% to 73%, please provide comparison of bill impacts, for a representative group of customers.
7	Perform a regional (baseline regions) EDF study that includes the subtransmission voltages. This study should be based on regional data available for customers at the subtransmission voltages and not on a more general systemwide (and theoretical) subtransmission simulation.

Figure E-3
Working Group Members

Working Group Members (Based on Survey in May 2023)		
High Engagement	Southern California Edison	SCE
	Monica Shors, Alycia Robancho, Reuben Behlihomji, Abdallah Baltaji	
	California Public Advocates Office	CalPA
	Vanessa Martinez, Otto Nichols, Christopher Hogan	
Medium Engagement	California Large Energy Consumer Association	CLECA
	Cathy Yap, Sam Harper	
	Small Business Utility Advocates	SBUA
	Jennifer Weberski, Paul Chernick	
	Federal Executive Agencies	FEA
	Rita Liotta	
	Agricultural Energy Consumers Association	AECA
	Richard McCann	
	California Farm Bureau Federation	CFBF
	Kevin Johnston,	
	Solar Energy Industries Association	SEIA
	Tom Beach	
	Energy Producers & Users Coalition	EPUC
	Bob Stephens	

→ Explore the technical elements of DDMC

→ Evaluate derivation of DDMC

→ Develop proposals for DDMC workshop

→ Receive all working group material

→ Participate in working group meetings based on topic interest and availability

Appendix F

Distribution Cost At The Regional And Substation Level

This appendix presents distribution capacity, PLRF, and EDF measures described in Section I.C.2., broken out by planning and baseline region.

Subtransmission Substation Capacity (A-Bank MW)

Table F-1
A-Bank Nameplate MW By Baseline Regions

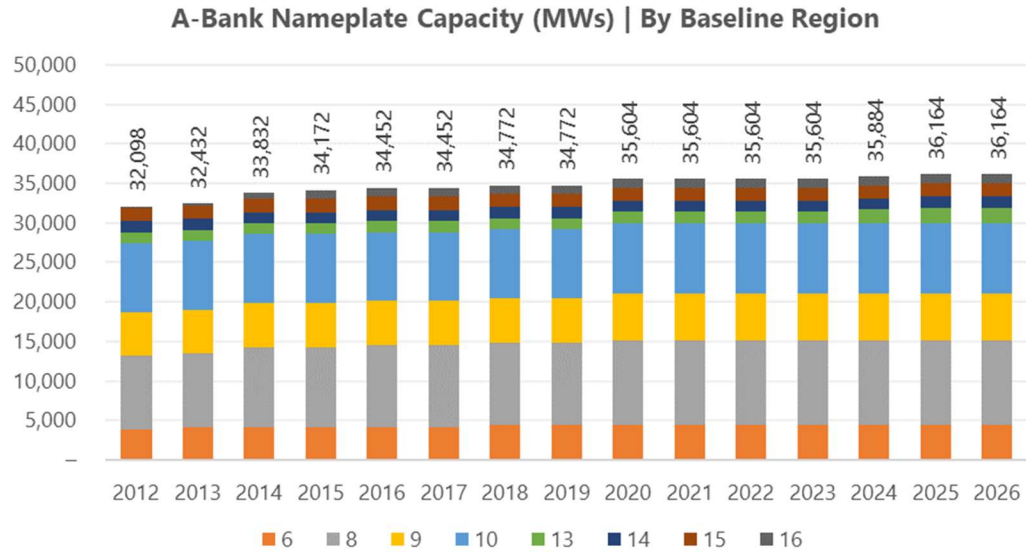
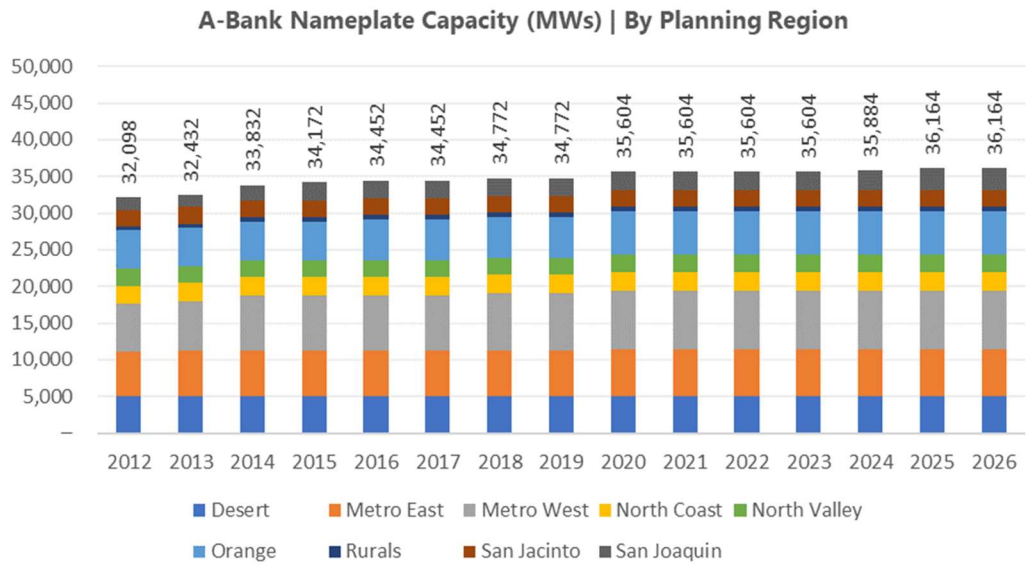


Table F-2
A-Bank Nameplate MW By Planning Regions



Distribution Substation Capacity (B-Bank MW)

Table F-3
B-Bank Nameplate MW By Baseline Region

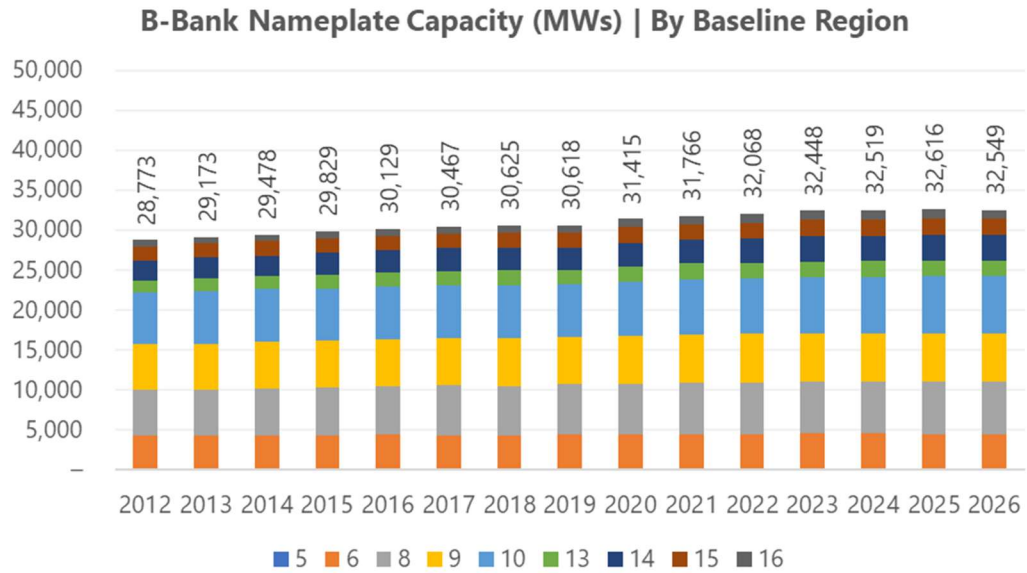
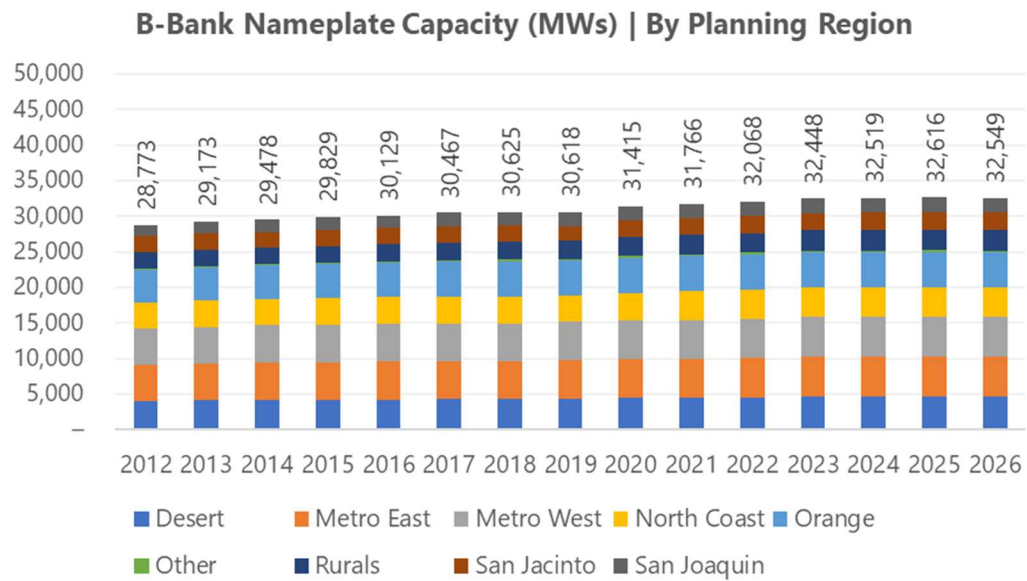


Table F-4
B-Bank Nameplate MW By Planning Regions



Distribution Circuits Capacity (MW)

Table F-5
Circuits PLL MW By Baseline Region

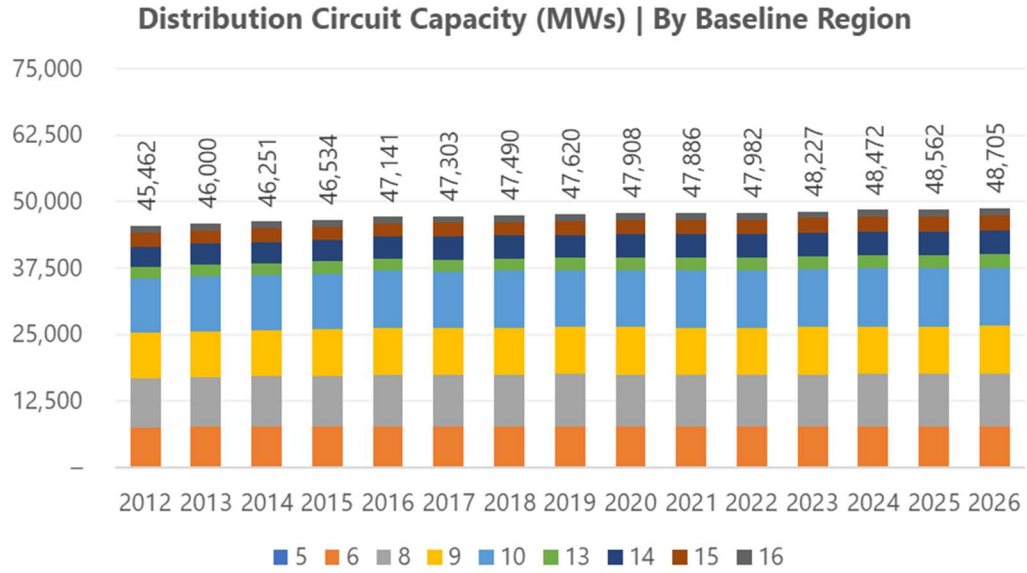
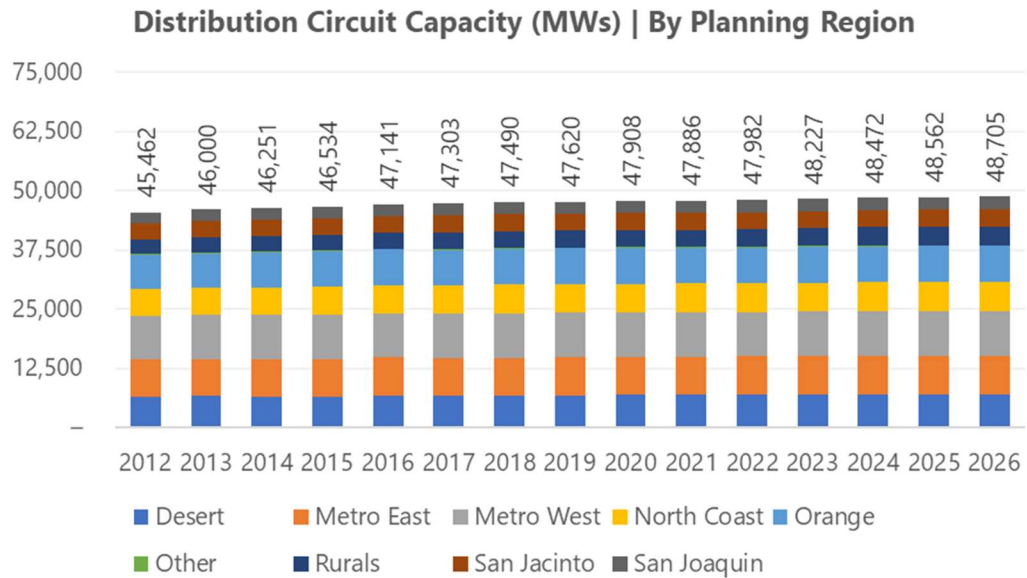


Table F-6
Circuits PLL MW By Planning Regions



Locational Peak Load Risk Factors (PLRF) Percentages

To see the effect at the regional level, the heat map in Table F-7 is derived from applying the PLRF methodology to the 2025 distribution circuit data. The percentage represented in each cell of the map is the sum of the individual circuit PLRF percentages by month and planning region. Although there is an observable diversity in the hourly load profiles for the different circuits analyzed, there is a general consistency in the seasonal load pattern across the different regions.

***Table F-7
Circuit PLRFs By Planning Regions in 2025***

Month	Desert	Metro East	Metro West	North Coast	Orange	Rurals	San Jacinto Valley	San Joaquin	Grand Total
1	0.4%	0.2%	0.7%	0.6%	0.2%	0.2%	0.0%	0.1%	2.6%
2	0.4%	0.3%	0.7%	0.5%	0.4%	0.2%	0.0%	0.2%	2.6%
3	0.2%	0.4%	0.7%	0.3%	0.1%	0.1%	0.0%	0.2%	1.9%
4	0.3%	0.4%	0.7%	0.4%	0.1%	0.1%	0.0%	0.4%	2.4%
5	0.3%	0.3%	0.7%	0.5%	0.2%	0.1%	0.0%	0.8%	3.0%
6	1.0%	0.6%	1.0%	1.1%	0.3%	0.6%	0.0%	1.9%	6.5%
7	5.6%	4.7%	2.7%	4.3%	1.3%	2.7%	0.7%	4.6%	26.7%
8	5.5%	5.8%	3.7%	3.8%	2.9%	2.6%	1.0%	3.3%	28.6%
9	2.6%	4.1%	2.8%	2.0%	2.0%	0.7%	0.5%	1.7%	16.3%
10	0.7%	0.9%	1.6%	0.8%	0.6%	0.3%	0.0%	0.5%	5.4%
11	0.3%	0.2%	0.6%	0.4%	0.1%	0.1%	0.0%	0.1%	1.7%
12	0.4%	0.0%	0.8%	0.6%	0.1%	0.2%	0.0%	0.1%	2.3%
Grand Total	17.7%	18.0%	16.6%	15.4%	8.2%	8.0%	2.2%	13.9%	100.0%

Table F-8 depicts the same PLRF percentages when aggregated the B-bank PLRF percentages by month, and by planning regions. The B-bank PLRFs across planning regions show a similar pattern as the circuit PLRFs.

Table F-8
B-Bank PLRFs By Planning Regions in 2025

Month	Desert	Metro East	Metro West	North Coast	Orange	Rurals	San Jacinto Valley	San Joaquin	Grand Total
1	0.4%	0.2%	0.9%	0.7%	0.8%	0.0%	0.0%	0.0%	3.0%
2	0.3%	0.2%	0.5%	0.6%	0.7%	0.0%	0.0%	0.0%	2.4%
3	0.2%	0.2%	0.3%	0.6%	0.9%	0.0%	0.0%	0.0%	2.3%
4	0.3%	0.2%	0.2%	0.7%	0.9%	0.0%	0.0%	0.0%	2.4%
5	0.3%	0.3%	0.3%	0.7%	0.9%	0.0%	0.0%	0.4%	2.9%
6	0.4%	0.4%	0.9%	1.5%	1.3%	0.1%	0.0%	1.1%	5.7%
7	2.1%	4.9%	3.4%	5.8%	4.7%	1.5%	0.2%	3.2%	25.7%
8	2.1%	5.5%	4.2%	5.4%	6.5%	1.4%	0.3%	2.1%	27.5%
9	1.0%	3.8%	3.1%	3.0%	4.9%	0.2%	0.1%	0.3%	16.4%
10	0.3%	0.8%	1.8%	1.0%	2.5%	0.0%	0.0%	0.0%	6.5%
11	0.2%	0.1%	0.3%	0.7%	0.9%	0.0%	0.0%	0.0%	2.3%
12	0.5%	0.0%	0.8%	0.7%	0.8%	0.0%	0.0%	0.0%	2.9%
Grand Total	8.1%	16.8%	16.7%	21.4%	26.0%	3.3%	0.6%	7.1%	100.0%

Table F-9 depicts the same PLRF percentages when aggregated the A-bank PLRF percentages by month, and by planning regions. The A-bank results show a higher concentration of capacity constrained hours in July and August of the modeled year.

Table F-9
A-Bank PLRFs By Planning Regions in 2025

Month	Desert	Metro East	Metro West	North Coast	Orange	Rurals	San Jacinto Valley	San Joaquin	Grand Total
1	0.0%	0.0%	2.2%	1.1%	0.5%	0.1%	0.0%	0.0%	3.9%
2	0.0%	0.0%	1.6%	0.9%	0.4%	0.1%	0.0%	0.0%	2.9%
3	0.0%	0.0%	0.8%	0.6%	0.2%	0.0%	0.0%	0.0%	1.6%
4	0.0%	0.0%	0.8%	0.5%	0.1%	0.0%	0.0%	0.0%	1.4%
5	0.0%	0.0%	0.9%	0.6%	0.1%	0.0%	0.0%	0.0%	1.7%
6	0.4%	0.0%	2.0%	1.5%	0.5%	0.4%	0.0%	1.1%	5.9%
7	3.9%	3.2%	5.2%	3.7%	3.6%	1.8%	1.3%	3.1%	25.7%
8	3.7%	3.5%	5.8%	3.8%	4.5%	1.8%	1.4%	2.4%	26.9%
9	1.7%	2.5%	4.9%	2.4%	3.6%	0.5%	0.7%	0.5%	16.7%
10	0.1%	0.2%	3.9%	1.7%	1.7%	0.0%	0.0%	0.0%	7.5%
11	0.0%	0.0%	1.3%	0.6%	0.2%	0.0%	0.0%	0.0%	2.1%
12	0.0%	0.0%	2.0%	1.1%	0.6%	0.1%	0.0%	0.0%	3.8%
Grand Total	9.8%	9.4%	31.2%	18.5%	16.0%	4.7%	3.5%	7.1%	100.0%

Table F-10 to F-12 below represent the A-bank, B-bank, and circuit PLRF percentages by month, and also by baseline regions. Baseline region 6, 8, 16 are the cool climate zone; Baseline region

5, 9 are the warm climate zone; Baseline region 10, 13, 14, 15 are the hot climate zone. The location of a circuit is based on the baseline regions of the substation that the circuit is connected to.

Table F-10
A-Bank PLRFs By Baseline Regions in 2025

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%
Grand Total	28.9%	31.8%	0.8%	0.0%	7.3%	13.7%	7.1%	6.0%	4.5%	100.0%

Table F-11
B-Bank PLRFs By Baseline Regions in 2025

Month	Baseline Regions									Grand Total
	6	8	16	5	9	10	13	14	15	
1	1.7%	0.8%	0.4%	0.0%	0.2%	0.0%	0.0%	0.1%	0.0%	3.0%
2	1.3%	0.6%	0.3%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	2.4%
3	1.2%	0.6%	0.2%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	2.3%
4	1.3%	0.6%	0.2%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	2.4%
5	1.3%	0.6%	0.2%	0.0%	0.4%	0.0%	0.4%	0.1%	0.0%	2.9%
6	1.4%	1.5%	0.2%	0.0%	1.0%	0.0%	1.1%	0.6%	0.0%	5.7%
7	2.3%	5.8%	0.3%	0.0%	7.1%	2.8%	3.2%	3.8%	0.5%	25.7%
8	2.9%	7.6%	0.3%	0.0%	7.6%	3.2%	2.1%	3.3%	0.4%	27.5%
9	2.6%	5.5%	0.3%	0.0%	5.2%	1.6%	0.3%	0.9%	0.1%	16.4%
10	2.1%	2.9%	0.2%	0.0%	1.0%	0.1%	0.0%	0.1%	0.0%	6.5%
11	1.3%	0.6%	0.2%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	2.3%
12	1.7%	0.6%	0.5%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	2.9%
Grand Total	21.0%	27.5%	3.4%	0.0%	23.3%	7.8%	7.1%	9.0%	1.0%	100.0%

Table F-12
Circuit PLRFs By Baseline Regions in 2025

Month	Baseline Regions									Grand Total
	6	8	16	5	9	10	13	14	15	
1	0.9%	0.4%	0.3%	0.0%	0.5%	0.2%	0.1%	0.2%	0.0%	2.6%
2	0.6%	0.6%	0.2%	0.0%	0.5%	0.3%	0.2%	0.2%	0.0%	2.6%
3	0.4%	0.4%	0.0%	0.0%	0.6%	0.3%	0.2%	0.1%	0.0%	1.9%
4	0.4%	0.5%	0.0%	0.0%	0.7%	0.3%	0.4%	0.1%	0.0%	2.4%
5	0.4%	0.5%	0.0%	0.0%	0.6%	0.5%	0.8%	0.2%	0.0%	3.0%
6	0.6%	0.6%	0.0%	0.0%	1.2%	0.9%	1.8%	0.9%	0.3%	6.5%
7	0.9%	2.6%	0.3%	0.0%	5.5%	6.0%	4.5%	4.6%	2.3%	26.7%
8	1.5%	4.4%	0.2%	0.0%	6.1%	7.1%	3.2%	4.1%	2.0%	28.6%
9	1.3%	3.0%	0.1%	0.0%	4.4%	4.1%	1.7%	1.2%	0.6%	16.3%
10	0.9%	1.2%	0.0%	0.0%	1.4%	1.0%	0.5%	0.3%	0.0%	5.4%
11	0.4%	0.3%	0.0%	0.0%	0.5%	0.3%	0.1%	0.1%	0.0%	1.7%
12	0.9%	0.3%	0.3%	0.0%	0.2%	0.2%	0.1%	0.2%	0.0%	2.3%
Grand Total	9.3%	14.8%	1.4%	0.0%	22.2%	21.3%	13.6%	12.0%	5.3%	100.0%

Locational EDF

EDF by baseline region is determined based on actual circuits not typical circuits used in EDF by simulations. Hourly load data for each circuit is used to determine the date and time of its peak. Each customer is mapped to the circuit from which it receives electric service.

EDF is the ratio of a customer's demand at the time of its circuit's peak (coincident demand) to the customer's annual non-coincident peak demand. EDF for each combination of baseline region, rate group and circuit, is the average EDF over all customers in that combination. EDF by rate group and baseline region is a weighted average of EDFs over the circuits. This is the same weight used to define rate group typical circuit. As example, to calculate EDF for GS-1 in a baseline region, the number of GS-1 customers on a circuit is weight for that circuit.

Table F-13
Rate Group EDF By Baseline Region At Circuit Level

Rate Group	Climate Zone										
	ALL	05	06	08	09	10	13	14	15	16	
DOMESTIC	0.44	0.34	0.30	0.41	0.49	0.53	0.51	0.45	0.47	0.30	
DOM SINGLE	0.47	0.34	0.34	0.45	0.52	0.54	0.53	0.46	0.51	0.30	
DOM MULTIPLE	0.38	0.34	0.27	0.37	0.44	0.48	0.47	0.42	0.43	0.29	
DOM-MM	0.52	0.20	0.41	0.56	0.56	0.68	0.60	0.57	0.58	0.47	
GS-1	0.36	0.26	0.34	0.37	0.35	0.38	0.34	0.36	0.38	0.32	
TC-1	0.63	0.52	0.60	0.66	0.66	0.58	0.64	0.61	0.57	0.59	
GS-2	0.59	0.25	0.59	0.61	0.59	0.60	0.56	0.57	0.62	0.50	
TOU-GS-3	0.66	0.66	0.69	0.68	0.67	0.61	0.60	0.59	0.65	0.65	
TOU-PA-2	0.31	0.34	0.28	0.36	0.26	0.31	0.34	0.24	0.30	0.24	
TOU-PA-3	0.48	N/A	0.44	0.42	0.37	0.46	0.57	0.45	0.45	0.38	
TOU-8-PRI	0.66	N/A	0.67	0.69	0.69	0.66	0.65	0.49	0.53	0.16	
TOU-8-PRI-STBY	0.51	N/A	0.41	0.71	0.62	0.56	0.33	N/A	0.48	0.00	
TOU-8-PRI-NSTBY	0.66	N/A	0.68	0.68	0.70	0.66	0.68	0.49	0.55	0.24	
TOU-8-SEC	0.67	N/A	0.67	0.67	0.69	0.66	0.67	0.67	0.65	0.60	
TOU-8-SEC-STBY	0.68	N/A	0.67	0.59	0.66	0.76	N/A	0.44	N/A	N/A	
TOU-8-SEC-NSTBY	0.67	N/A	0.67	0.67	0.69	0.65	0.67	0.67	0.65	0.60	
ST-LTNG	0.15	0.67	0.24	0.14	0.12	0.11	0.21	0.16	0.14	0.28	

Table F-14
Number of Circuits By Rate Group And Baseline Region

Rate Group	Climate Zone										
	ALL	05	06	08	09	10	13	14	15	16	
DOMESTIC	3,693	4	579	835	721	756	219	279	163	137	
DOM SINGLE	3,659	4	571	820	715	753	219	279	161	137	
DOM MULTIPLE	3,553	4	566	774	702	727	219	271	158	132	
DOM-MM	1,598	2	327	374	377	239	59	111	57	52	
GS-1	3,871	4	619	894	747	796	222	285	165	139	
TC-1	3,211	1	519	813	650	717	143	219	114	35	
GS-2	3,598	3	568	826	697	773	211	259	157	104	
TOU-GS-3	2,318	2	352	578	464	558	95	157	87	25	
TOU-PA-2	2,226	4	316	370	388	477	215	224	122	110	
TOU-PA-3	754	0	72	107	108	177	122	78	77	13	
TOU-8-PRI	467	0	99	110	92	92	35	22	12	5	
TOU-8-PRI-STBY	34	0	5	5	9	7	3	0	4	1	
TOU-8-PRI-NSTBY	439	0	94	106	85	87	32	22	9	4	
TOU-8-SEC	1,197	0	186	328	233	282	53	72	31	12	
TOU-8-SEC-STBY	30	0	5	6	5	13	0	1	0	0	
TOU-8-SEC-NSTBY	1,188	0	184	327	231	279	53	71	31	12	
ST-LTNG	2,889	1	456	738	523	727	116	168	120	40	

Figure F-1
SCE Planning Regions

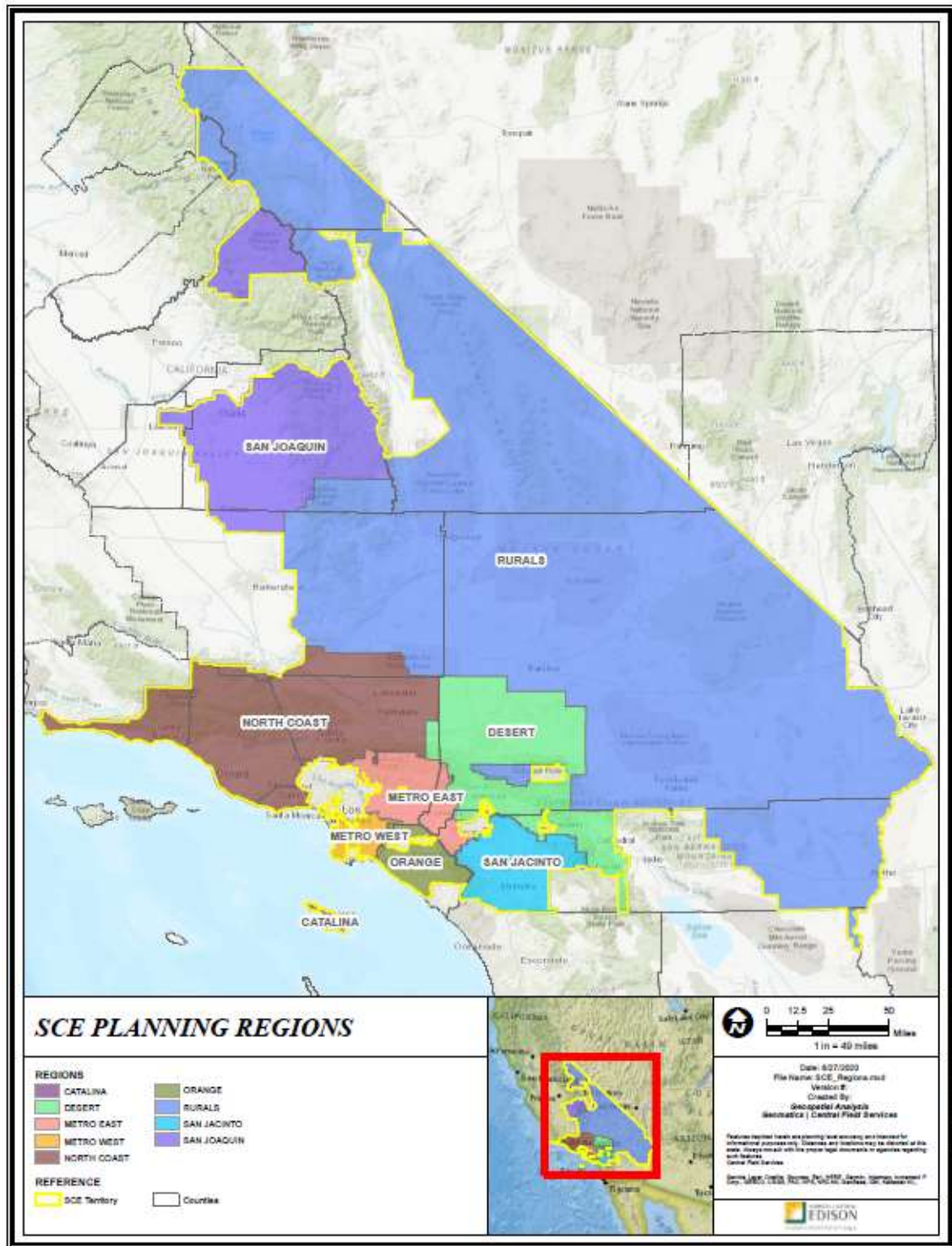


Figure F-2
SCE Baseline Regions

SCE's Baseline Regions

- SCE's service territory contains nine (9) Baseline Regions.
 - Region 5
 - Region 6
 - Region 8
 - Region 9
 - Region 10
 - Region 13
 - Region 14
 - Region 15
 - Region 16
- Regions 6, 8, 9, and 10 are the most densely populated, including 80 percent of SCE's customer population.

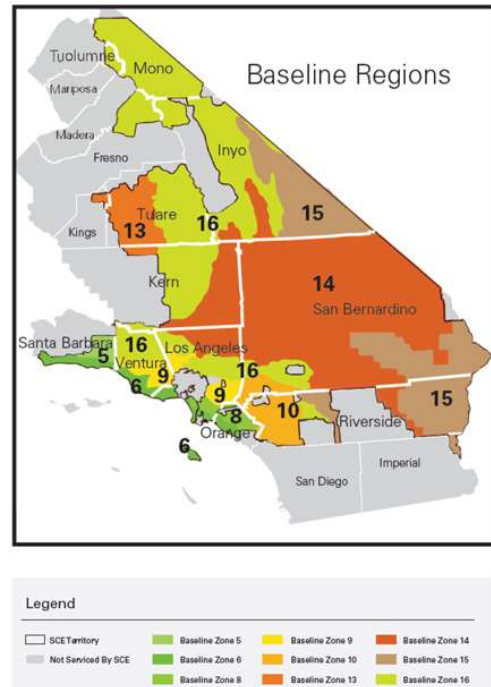


Table F-15

Baseline Regions in the SCE Service Territory

Zone #	Temperature	General Description
5	Moderate	Hills North of Santa Barbara
6	Cool	Coastal areas stretching from Santa Barbara to Orange County
8	Cool	Near Coastal area; Westwood to Mission Viejo in Orange County
9	Moderate	Inland valleys, including San Fernando and San Gabriel
10	Moderate	South Western tip of San Bernardino county, Western section of Riverside county including Moreno Valley, and Temecula; East of the Santa Rita hills
13	Hot	San Jacquin/Central Valley
14	Hot	High Desert areas including LA, Kern and San Bernardino counties
15	Hot	Death Valley, Palm Spring and the Coachella Valley area,
16	Cool	Mountainous areas; including portions of the Sierra Nevada and Transverse Ranges

Appendix G

PLRF Results Based on Recorded Load Data

Summary

SCE conducted the PLRF analysis with the forecast circuit, B Bank and A Bank load data in 2025 and presented the results in the SCE-02, C.2.(b).(a). Additionally, SCE has calculated the PLRF based on the recorded load data from 2020 and 2022 as a reference.

Table G-1 shows A Bank PLRFs using (1) 2025 forecast load with threshold at 73 percent of A Bank annual peak load, which is the proposed PLRF method for the 2025 GRC; (2) 2025 forecast load with threshold at 90 percent of A Bank annual peak load (3) 2020 to 2022 recorded load with threshold at 90 percent of A Bank annual, which was the adopted method for the 2021 GRC. A Bank forecast load was not available at the time of the 2021 GRC.

Table G-1
Forecast and Recorded A Bank PLRF

Forecast Load (73% Threshold) - Proposed Method for 25 GRC

2025 Net Load - A-Bank PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	30%	18%	41%	12%	100%
Summer	30%	8%	37%	n/a	75%
Winter	n/a	9%	4%	12%	25%

Forecast Load (90% Threshold)

2025 Net Load - A-Bank PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	57%	6%	36%	2%	100%
Summer	57%	2%	35%	n/a	94%
Winter	n/a	4%	0%	2%	6%

Recorded Load (90% Threshold) - Method for 21 GRC

2020 Net Load - A-Bank PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	38%	22%	36%	4%	100%
Summer	38%	17%	34%	n/a	89%
Winter	n/a	5%	2%	4%	11%

2021 Net Load - A-Bank PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	58%	9%	30%	3%	100%
Summer	58%	5%	29%	n/a	92%
Winter	n/a	4%	1%	3%	8%

2022 Net Load - A-Bank PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	41%	16%	34%	9%	100%
Summer	41%	10%	28%	n/a	79%
Winter	n/a	6%	5%	9%	21%

Table G-2 shows B Bank PLRFs using (1) 2025 forecast load with threshold at 73 percent of the individual substation PLL, which is the adopted PLRF method since the 2021 GRC; (2) 2020 to 2022 recorded load with threshold at 73 percent of the individual substation PLL (3) 2020 to 2022 recorded load with threshold at 90 percent of the individual substation PLL.

The B Bank PLRF analysis starts with 600+ B Banks (excluding pole tops). For B Bank PLRF, the number of B banks included depends on the threshold applied to the individual substation PLL. If a 90 percent threshold is used, only 15 to 46 B Banks are included. However, if a 73 percent threshold is applied, additional B Banks would be considered for inclusion based on their individual substation PLL. In summary, the inclusion of B Banks varies based on the chosen threshold for the individual substation PLL.

Table G-2
Forecast and Recorded B Bank PLRF

Forecast Load (73% Threshold) - Adopted Method for 21 GRC
The same method for 25 GRC

2025 Forecast B-Bank PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	33%	13%	41%	13%	100%
Summer	33%	6%	37%	n/a	75%
Winter	n/a	7%	5%	13%	25%

245 B banks above the 73% PLL

Recorded Load (73% Threshold)

2020 Net Load - B-Bank PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	38%	27%	33%	2%	100%
Summer	38%	23%	32%	n/a	92%
Winter	n/a	5%	1%	2%	8%

227 B banks above the 73% PLL

2021 Net Load - B-Bank PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	54%	16%	29%	2%	100%
Summer	54%	14%	27%	n/a	95%
Winter	n/a	2%	2%	2%	5%

105 B banks above the 73% PLL

2022 Net Load - B-Bank PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	49%	15%	35%	1%	100%
Summer	49%	14%	35%	n/a	97%
Winter	n/a	1%	1%	1%	3%

222 B banks above the 73% PLL

Recorded Load (90% Threshold)

2020 Net Load - B-Bank PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	28%	29%	41%	2%	100%
Summer	28%	25%	41%	n/a	94%
Winter	n/a	4%	0%	2%	6%

39 B banks above the 90% PLL

2021 Net Load - B-Bank PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	28%	29%	41%	2%	100%
Summer	28%	25%	41%	n/a	94%
Winter	n/a	4%	0%	2%	6%

15 B banks above the 90% PLL

2022 Net Load - B-Bank PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	37%	19%	42%	2%	100%
Summer	37%	16%	39%	n/a	92%
Winter	n/a	3%	3%	2%	8%

46 B banks above the 90% PLL

Table G-3 shows Circuit PLRFs using (1) 2025 forecast load with threshold at 73 percent of the average PLL of all circuits connected to a single substation, which is the adopted circuit PLRF method; (2) 2020 to 2022 recorded load with the 73 percent threshold.

Table G-3
Forecast and Recorded Circuit PLRF

Forecast Load (73% Threshold) - Adopted Method for 21 GRC
The same method for 25 GRC

2025 Forecast Circuit PLRF %by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	32%	11%	44%	13%	100%
Summer	32%	6%	40%	n/a	78%
Winter	n/a	5%	4%	13%	22%

Recorded Load (73% Threshold)

2020 Net Load - Circuit PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	32%	27%	33%	7%	100%
Summer	32%	20%	31%	n/a	83%
Winter	n/a	7%	2%	7%	17%

2021 Net Load - Circuit PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	41%	15%	36%	8%	100%
Summer	41%	12%	34%	n/a	87%
Winter	n/a	3%	2%	8%	13%

2022 Net Load - Circuit PLRF % by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	36%	16%	40%	7%	100%
Summer	36%	13%	38%	n/a	87%
Winter	n/a	3%	3%	7%	13%