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Witnesses: R. Behlihomji
D. Hopper
K. Kan
C. Sorooshian
S. Verdon
J. Yan

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(U 338-E)

Phase 2 of 2018 General Rate Case Marginal Cost and Sales Forecast Proposals

Before the

Public Utilities Commission of the State of California

Rosemead, California
June 30, 2017

SCE-02 – Marginal Costs and Sales Forecast Proposals

GRC Phase 2

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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 chapter presents SCE's marginal costs for providing regulated utility services to our customers.[2]

The starting point for calculating marginal costs is identifying the cost drivers for meeting customer electricity requirements. Next, marginal costs are calculated for changes in each cost driver, specific to the functionalized provision of utility service, namely *generation, delivery* and *access*.[3] Finally, these marginal costs are attributed to measurable aspects of customer requirements such as energy consumption, peak demand, and customer type. This allows the rate components most associated with these measurable customer requirements, specifically energy charges, demand charges and monthly customer charges, to be designed based on the corresponding marginal cost components.

Marginal costs are used to calculate marginal cost revenues—that is, the revenues that SCE would collect if all of its customers were charged rates that equaled marginal costs. Marginal cost

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[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] Regulated utility services refer to electricity supply (production or procurement of power for customers), electricity delivery (transmission, subtransmission and distribution) and customer services (access to the delivery system and managing SCE's relationship with customers, including handling customer communications, metering, maintaining records, and billing).

[3] 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).

revenues are then used to allocate the authorized revenue requirements to rate groups, a process called revenue allocation.[4] Finally, marginal costs are considered when designing rates (for each rate group) to recover the allocated revenue requirements.[5]

In this chapter, SCE presents marginal costs based upon three cost "drivers" or "factors" impacting SCE's cost to serve customers: (1) electricity usage, (2) delivery-related design demand,[6] and (3) number of customers. The cost of procuring electricity to meet changes in customer electricity usage varies hourly. SCE and other load serving entities are required to procure dependable generation resources with sufficient capacity to meet 115 to 117 percent of forecast demand.[7] Marginal generation costs (energy and capacity) are associated with the electricity usage cost driver and are aggregated in time-of-use (TOU) periods that group together hours with similar load characteristics and costs.

SCE's electric delivery system consists of a network of higher-voltage (transmission and subtransmission) and lower-voltage (distribution) facilities that connect generation resources to customer facilities. The delivery system is designed and constructed to meet expected peak demand, so design demand is the associated cost driver. Historically, the entire portion of design demand delivery-related marginal costs were considered peak-capacity related, and effective demand factor (EDF) studies were used to analyze some time dependency of this cost driver coincident with circuit peaks. In this Application, SCE has refined the historical assessment of design demand marginal costs and proposes the following: (1) functionalizing design demand marginal costs as <u>peak</u> capacity-related costs that are time differentiated and <u>grid</u>-related costs that are generally recovered on a non-time-variant basis, (2) allocating peak costs to TOU periods using the peak load risk factor (PLRF) methodology, and (3) allocating grid costs using the EDF method.

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[4] Revenue allocation is addressed in Exhibit SCE-03.

[5] Rate design is addressed in Exhibit SCE-04.

[6] Design demand is the amount of delivery capacity that transmission and distribution planners determine to be necessary when planning to serve the additional demand of a customer or group of customers.

[7] *See* R.14-10-010. Annual reports are *available at* http://www.cpuc.ca.gov/RA.

Finally, the number of customers is a cost driver, reflecting the marginal cost of providing customer access to the delivery system and various customer services. Because the marginal costs for customer access to the distribution grid and customer services vary by customer type, there is an individual marginal cost for each customer class. Like generation capacity and delivery marginal costs, SCE's customer marginal costs are calculated using the real economic carrying charge (RECC) methodology.[8] However, to recognize the new customer only (NCO) alternative method adopted by the Commission in SCE's 1995 General Rate Case (GRC), SCE presents NCO-based calculations in Appendix E of this volume as well.

SCE's proposed marginal costs are summarized in the three tables below.

Table I-1
Electricity Usage-Related Marginal Costs
(2018$)

Cost Components	Annual	Summer			Winter		
		On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak	Super-Off-Peak
Energy (¢/kWh)	3.654	4.884	4.397	3.559	4.622	3.906	2.475
Peak Capacity ($/kW-yr.)	94.4	88.3	5.7	0.3	0.1	0.0	0.0
Ramp Capacity ($/kW-yr.)	52.5	0.0	0.0	0.0	52.5	0.0	0.0

The figures above are based on the time periods in Schedule TOU-8 and at the generator level.
They include GHG-related costs and are based on an average gas price of $3.37/mmBTU.
Resource adequacy not included in the marginal cost capacity values.
Energy includes an RPS adder.
Generation Capacity Marginal Costs are functionalized between Peak and Ramp based on the 2018 split illustrated in Table I-6
The Peak Capacity portion of cost indicated above includes the 15% PRM adder

8 This methodology is also called the rental value method, or in practice, is typically referred to as the economic deferral method.

Table I-2
Peak Distribution Marginal Cost
($/kW-year in 2018$, at applicable voltage level and Asset Type)

Facilities-Related Cost Components	Annual	Summer			Winter		
		On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak	Super-Off-Peak
Distribution - Substations ($/kW-yr.)	25.03	11.52	0.50	5.62	6.53	0.82	0.06
Distribution - Circuit ($/kW-yr.)	26.82	6.62	2.06	7.21	4.58	3.96	2.40
Subtransmission (Non-ISO) - Substations ($/kW-yr.)	30.34	19.01	2.01	4.94	4.07	0.29	0.03
Total ($/kW-yr.)	**82.19**						

Asset Types are Distribution Circuits, Distribution Substations, Subtransmission Circuits and Subtransmission Substations
Subtransmission Circuit costs are proposed as *Grid* costs
Aggregated unit marginal costs by period, for each service voltage are not additive.
Effective distribution marginal costs in each period can be implied from SCE's proposed Marginal Cost Revenue Allocation model

Table I-3
Marginal Customer Costs
(2018$)

Rate Group Description			$/Customer/Yr.
Domestic			124.25
TOU GS-1			196.63
TC-1			195.30
TOU GS-2			1,586.05
TOU GS-3			2,954.84
TOU-8			
	Secondary		4,236.37
	Primary		2,200.81
	Sub-Trans		15,322.55
TOU PA-2			1,141.04
TOU PA-3			3,317.24
Meter Street Lights			135.58
Unmetered Street Lights*		**Per Customer**	27.21
	LS-1	**+ Per Lamp**	1.39
	LS-2	**+ Per Lamp**	0.57
	OL	**+ Per Lamp**	1.60
	DWL	**+ Per Lamp**	0.64

*Unmetered Street Light customer marginal cost is a per customer cost plus a per lamp cost.

Section I.B. describes the principles and methodological approaches that guided the development of SCE's marginal costs. Section I.C. presents SCE's marginal cost study 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 D. Appendix E includes a description and results of the NCO marginal cost methodology. Appendix F satisfies a compliance requirement regarding marginal generation capacity from Decision (D.)14-03-007, which approved a settlement agreement for rate discounts applicable to maritime entities located at the Port of Long Beach.

B. Overview

SCE contends that rate design principles based on marginal cost ensure that customers make economically efficient usage decisions. In this section, SCE discusses principles, scope, and application of marginal costs in the design of our retail rates that allow SCE to recover authorized revenue requirements. Additionally, SCE discusses cost drivers—such as electricity usage, design demand, and customer costs, used concurrently with the RECC methodology and TOU periods—and their role in applying marginal cost principles to rate design.

1. Marginal Cost Principles

The Commission's reliance on marginal cost principles for revenue allocation and rate design is well-founded on economic principles. Marginal costs reflect the change in costs incurred (or avoided) to serve a small increment (or decrement) in demand for utility services. Allocating the authorized revenue requirement on the basis of marginal costs provides an economically correct price signal, which encourages customers to use electricity efficiently and to make appropriate choices when purchasing electricity-consuming equipment and appliances. When utility rates are not set based on marginal cost allocation, users of utility services may over-consume or avoid services, depending on whether prices are set less than or greater than the marginal cost-based levels. Moreover, there is growing interest in customer-sited distributed generation (DG), other distributed energy resources (DERs) and demand response (DR), and increased awareness of distribution competition among utilities, municipalities and other public entities. In this environment, inefficient pricing can lead to uneconomic bypass of utility facilities, resulting in unnecessary investment in duplicative facilities and higher rates for utility service customers.

The Commission deviates from setting rates equal to marginal costs by necessity, in order to establish overall utility rates that recover a utility's authorized revenue requirements (which usually amount to values higher than marginal costs of service). The Commission has customarily used the equal percent of marginal cost (EPMC) methodology to assign the utility's authorized revenue requirements in proportion to its marginal cost revenues.[9]

2. Marginal Cost Scope and Application

SCE's marginal costs reflect the full gamut of services required to provide electricity to customers, although SCE's role in the provision of such services depends on several variables. State law allows some customers to access markets for electricity supply directly, instead of procuring this service from SCE. This includes community choice aggregation (CCA) service customers and direct access (DA) customers. DA, which had been suspended for new participants, was reopened in early 2010 on a limited basis. Existing DA customers are permitted to obtain some metering and billing services from their electric service provider (ESP) instead of SCE.[10] This testimony assumes that SCE will continue to provide metering and billing services to all customers, not just "bundled service" customers.[11] For bundled service customers, the testimony assumes that SCE obtains electricity supply either from wholesale market purchases or from its own generating facilities.

SCE's higher-voltage transmission facilities are subject to Federal Energy Regulatory Commission (FERC) jurisdiction and are under the operational control of the California Independent

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[9] The EPMC has been the basis of SCE's revenue allocation methodology in each of its last four GRC rate design proceedings.

[10] SCE's Tariff Rule 23, Sections N and P provide that SCE shall perform all metering and billing services for CCA service customers.

[11] Unlike CCA and DA customers, "bundled service" customers receive delivery *and* generation services from SCE directly.

System Operator (ISO). FERC-jurisdictional (ISO-controlled) assets and activities have not been included in the marginal cost study presented in this testimony. Marginal costs associated with the FERC-jurisdictional facilities and activities are excluded from marginal cost revenues and the revenue allocation process because FERC—not the CPUC— has jurisdiction and is responsible for determining revenue requirements and rates associated with these facilities and activities.

In this Application, SCE's marginal costs are intended to represent conditions expected to occur during the period from 2018 through 2020. In particular, electricity supply marginal costs are based on a three-year forecast (expressed in constant 2018 dollars). Thus, upon implementation of the rates requested in this Application, there is no need to true-up SCE's marginal costs in annual rate design proceedings.

3. <u>Cost Drivers</u>

A more detailed discussion of the three cost drivers identified above—electricity usage, delivery related design demand, and number of customers—follows below.

a) <u>Electricity Usage</u>

The cost associated with a change in customer electricity usage includes energy-related and capacity-related components. Because SCE buys and sells power in the electricity market in which its service area is located, the market clearing price of this power is an appropriate measure of energy-related marginal generation costs. As described further in Section I.C.1., *energy*-related generation marginal costs are forecast through production simulation models of market clearing prices. *Capacity*-related generation marginal costs are measured by annualizing the expected costs of a utility-built combustion turbine (CT) as a proxy.[12] Because CTs operate during periods of higher market prices and are able to earn energy rents (operating profits in excess of variable operating costs) that recover a portion of their fixed costs, these energy rents are deducted from the annualized CT proxy costs to determine capacity-related marginal generation costs standing alone.

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[12] SCE uses the RECC approach to derive the annualized basis of long run capacity related costs.

Energy-related generation marginal costs are aggregated and averaged for each TOU period. Capacity-related generation marginal costs are assigned to TOU periods using a loss-of-load expectation (LOLE) measure, also derived from a simulation model.[13] SCE's LOLE methodology is described in Section I.C.1(a)(2).

b) Design Demand

Design demand, as a cost driver, is a function of both the *amount* and the *configuration* of planned capacity that system planners determine is necessary to serve the additional demand expected on the distribution system. When connecting a large customer, planners may consider the customer's electrical equipment and the expected utilization of this equipment (*i.e.*, customer site diversity of use) in order to size the customer's facilities "upstream" of the final line transformer. For smaller customers, planning standards have been developed to identify expected peak demand, and consider the diversity of appliance use within the customers' premises and diversity between customers served from shared facilities. Planners appropriately account for demand coincidence when planning for capacity at different stages of power transformation on the distribution grid.

Before SCE's 2012 GRC, the design demand value was assumed to be equal to the maximum amount of demand or usage placed on the system. However, the decision (D.13-03-031) adopting the revenue allocation and marginal cost settlement in Phase 2 of SCE's 2012 GRC incorporated a new methodology, called "planned capacity," which represents the capacity that SCE's grid would carry under normal operating conditions. SCE believes that the planned capacity amount is a more appropriate measure because it accurately reflects the "cost-to-growth" ratio when (a) there is a large amount of capacity being added to alleviate stress on distribution equipment (substations and circuits) that are operating at or near rated levels, or (b) freed up installed capacity made available during years of stagnant or declining growth experienced during the most recent

13 This is also called loss-of-load probability, or LOLP.

recession beginning in 2008.[14] SCE uses planned capacity in determining the incremental cost of installed capacity for design demand marginal costs in this testimony.

The amount and configuration of planned capacity has the greatest impact on the costs experienced on the distribution system. Power is typically delivered to the transmission system from regional generators or regional interties at 220 kV or higher voltages. In order to safely and reliably deliver power to SCE's customers, electricity typically goes through three stages of power transformation: from 220 kV to 66 kV (or other subtransmission voltages), from 66 kV to 12 kV (or other primary distribution voltages), and from distribution primary voltages to between 120 and 480 volts at the customer premises (secondary voltage). The need for additional capacity is often studied independently at each of these stages in order to accommodate incremental load. Additional substation facilities are required as a result of increases in transformer capacity. An increase in design demand may also result in an increase in the size and/or number of distribution circuits serving a local area.[15] The use of planned capacity to set the cost-to-growth ratio recognizes that incremental assets originally installed to meet incremental load growth needs are still in place during periods of negative load growth.

In this Application, SCE has refined the assessment of design demand marginal costs by functionalizing such costs into *peak* and *grid*, with an added layer of granularity consisting of individually computing such costs both by asset *type* and asset *category*, as discussed in Section I.C.2.[16]

Design demand, or planned capacity, does not fully reflect the evolution of SCE's distribution system over time. Design demand is related to a customer's maximum expected usage at the time of service installation, but maximum usage may vary over time. In older neighborhoods, for example, transformer capacity and distribution circuit routings may have been

[14] Freeing up of available capacity caused by a drop in recorded peak load experienced during recessions, or dramatic conservation efforts as seen during the 2001 energy crisis, distort the average cost models by inflating the cost-to-growth ratio.

[15] Distribution circuits are lines connecting customers in an area to a nearby substation.

[16] Asset *categories* include distribution and subtransmission: asset *types* include substations and circuits.

reconfigured over time to keep up with increasing demand. Keeping track of the contribution of an individual customer to the delivery capacity and configuration built to serve an area is subjective and unwieldy. In addition, the time when maximum usage occurs varies by climate zone and by the mix of customers in an area. Thus, system peak demand (a measure appropriate for the capacity component of generation marginal costs) and design demand are not necessarily coincident. However, to appropriately account for the time-varying nature when peak usage impacts the portion of distribution design demand marginal costs that are capacity related, SCE proposes in this Application to use the PLRF methodology to identify the hours of the year when distribution assets tend to experience peak capacity constraints.[17] For grid-related design demand costs, SCE continues to use the EDF method.[18] Both of these are discussed in detail in Section I.C.2.

c) Number and Type of Customers

Finally, the number and type of customers is a cost driver because each customer requires *access* (defined by the final line transformer and a service drop) to the delivery system and a meter to measure consumption.[19] Because access to the delivery system entails investment in long-life capital equipment when providing such service, SCE uses a long-run estimate of marginal costs for this component of the customer marginal costs. In addition, SCE incurs short-run marginal costs in managing its relationship with customers, including handling customer

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17 The PLRF methodology is a deterministic variant of the LOLE methodology used for generation capacity, and uses the same conceptual framework of identifying hours of the year when expected load may result in an expected capacity constraint on the system. Since the distribution system is geographically disparate, the PLRF methodology is applied to each individual substation and circuit to take into account load diversity on the system.

18 Ideally, given the split of design demand into peak-capacity related costs and grid-related costs, the EDF should be modified to measure customer load diversity on the portion of the system being functionalized as *grid,* namely, subtransmission circuits, primary distribution radial lines and secondary distribution voltage lines. However, in this Application, SCE continues to use the current EDF method for determining circuit- and subtransmission-level cost contribution as a sufficient proxy for allocating grid-related costs to customers.

19 Technically, this description refers to a service account. Some customers, such as a firm owning a chain of retail stores or a large facility with several points of service at a single site, have more than one service account. For the vast majority of customers, the terms "customer account" and "service account" are synonymous, so we use the term "customer" in this testimony. In rare instances, where customer usage is highly predictable, SCE provides unmetered service.

communications, metering, and maintaining records and billing, which are also included in the estimate of customer marginal costs.

The cost of providing a customer *access* to the delivery system varies by type of customer, reflecting differences in size, service voltage, metering requirements, and other factors. The change in facilities cost for providing *access* to a small increment or decrement in the number of customers is identified through customer cost studies. These studies are performed for the typical customer in each rate group (e.g., for single-family and multi-family residential dwellings), resulting in more than one customer cost study being performed. The customer cost studies identify facilities directly associated with the customer connection to the grid, such as the meter, service drop, protection equipment, and final line transformer. Final line transformers are a critical element of providing a customer access when connecting to the delivery system. They are associated with the distribution 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.[20] With respect to final line transformers, the study accounts for the specific service configuration, *e.g.*, if a transformer is shared (a typical urban residential tract design illustrates a transformer service configuration that is shared by approximately 22 customers) or whether multiple transformers are required to serve accounts (three-phase accounts).

The short-run customer service component of marginal customer costs also includes activities such as handling customer communications, measuring usage, maintaining records, and billing. SCE identifies the specific activities and assets directly attributable to providing the particular services and then calculates the associated marginal costs. These marginal costs are calculated by customer type and size.

4. TOU Considerations

a) Generation Marginal Costs

Generation marginal costs vary by hour, primarily because different

[20] 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).

generation units are "on the margin" each hour based on the level of customer demand and the costs associated with maintaining sufficient resource capacity to meet reliability targets. Generation marginal costs are averaged by corresponding TOU period, in SCE's TOU rate schedules.[21] These TOU periods vary seasonally (summer and winter) and hourly (on-peak, mid-peak, off-peak and super-off-peak), and are intended to group together hours with similar marginal costs. SCE periodically reviews the appropriateness of its TOU periods in conjunction with its marginal cost studies and recommends changes when appropriate.[22] In SCE's 2016 Rate Design Window Application (2016 RDW), SCE submitted testimony in support of its proposal to implement new TOU periods based on an updated marginal cost analysis of generation energy and capacity costs, as well as an assessment of the time-differentiation of certain distribution system costs.[23] The TOU periods proposed in the 2016 RDW serve as the basis for the marginal cost and revenue allocation studies performed herein. Further, in A.17-04-015, SCE also proposed new default TOU rates for residential customers that contain updated TOU periods that generally align with SCE's 2016 RDW proposal.

An analysis of SCE's current TOU periods is provided in Appendix D, along with an assessment of how the existing TOU periods fare under the dead band tolerance range proposal put forth by SCE in Advice 3581-E to comply with the requirements of D.17-01-006.[24]

b) <u>Delivery-Related Design Demand Marginal Costs</u>

The peak-capacity portion of delivery-related marginal costs should be time-differentiated to align how distribution system capacity costs vary with differences in how customers

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[21] Generation marginal energy costs are averaged across TOU periods. Generation marginal capacity costs expressed in relative percentages of LOLEs in each hour are summed across TOU periods to arrive at the annual estimate of such costs in $/kW-Yr.

[22] As outlined in Exhibit SCE-01, on September 1, 2016, SCE filed Application (A.)16-09-003, *Application of Southern California Edison Company for Approval of Its 2016 Rate Design Window Proposals* (2016 RDW).

[23] *See generally* Exhibit SCE-1 in A.16-09-003.

[24] Exhibit SCE-01 provides more background on the dead band tolerance range filing and it applicability to this Application.

impose demand for peak capacity on the distribution system. For instance, if peak demands on subtransmission and distribution facilities were consistently experienced only on hot summer days throughout SCE's service area, it would improve pricing accuracy to recover peak capacity-related marginal costs based on how customers' demands affect system constraints during those high-cost days. This allows a customer who uses electricity predominantly in the lower cost periods to pay proportionately less, because if that customer's peak load were to increase or decrease, there would be no impact on distribution system capacity requirements. The PLRF methodology described in Section I.C.2 identifies the time-sensitive nature of distribution system peaks and uses the results to time differentiate peak-capacity related costs on the distribution system.

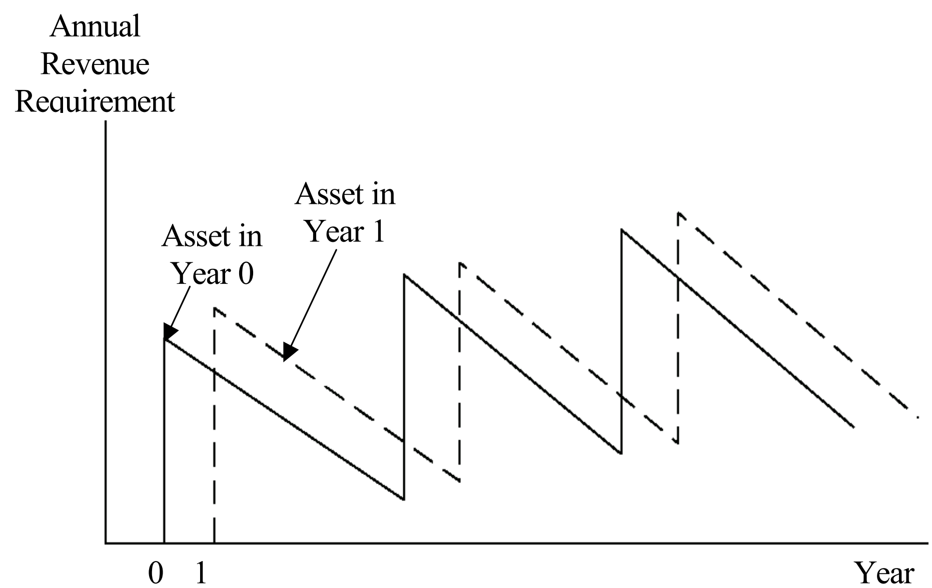
5. Annual Cost Of Capital Investments – RECC Methodology

When computing marginal costs, SCE estimates the opportunity cost of capital investments using the RECC methodology. Under this approach, which is illustrated in Figure I-1, the present worth of the annual revenue requirements[25] for an asset and its subsequent replacements are computed, and then compared to the present worth of an equivalent asset and its replacements installed one year later. The first scenario is building the asset today, and the second scenario is building the asset a year from today. The only difference between these two scenarios is that, in the second scenario, SCE would defer the opportunity to use the asset in the first year. Thus, the difference in present worth between the two scenarios measures the implied economic (opportunity) cost of using the asset during the first year. The resulting annual charge, when escalated at the rate of inflation over time and then discounted, yields the original cost (in terms of revenue requirement) of the investment. As shown in Figure I-2, the net present value (NPV) of the two payment streams are the same, but the RECC results in the same real payment over time. This conclusion is important because, in real terms, the charge for an asset is the same over time and, assuming electricity customers value the service they receive, the charge should be the same regardless of the age of the equipment. Therefore, the proper charge can be calculated for both existing and new customers by

[25] The revenue requirement includes depreciation, return on investment, income taxes, property taxes, administrative and general (A&G), insurance, and salvage costs.

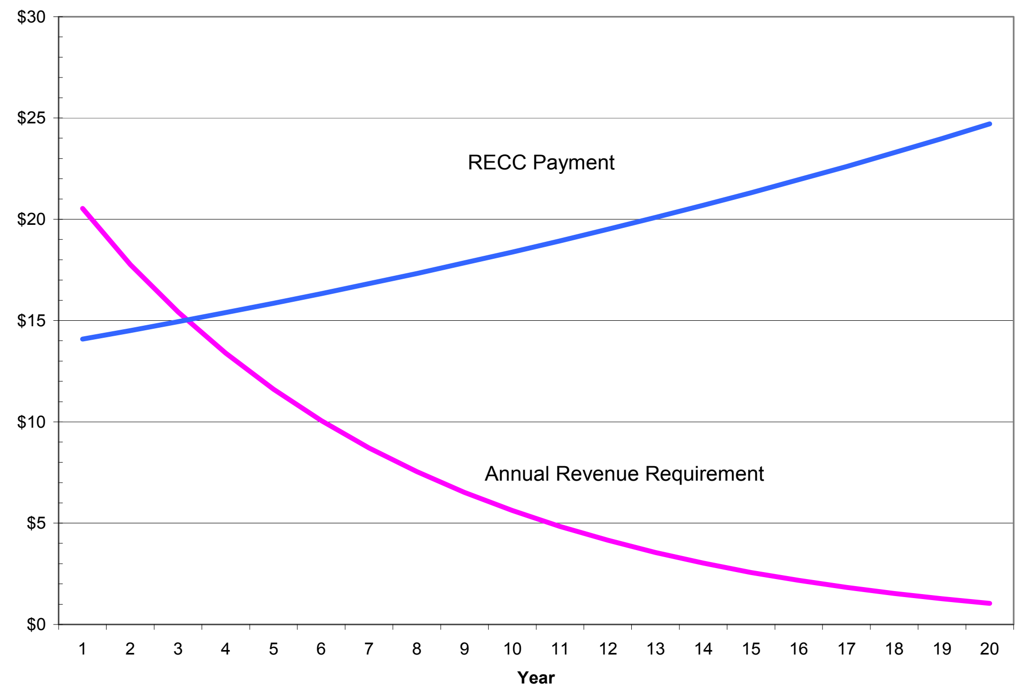
applying the RECC to the *real* cost of the equipment. This RECC approach is documented in work prepared by the National Economic Research Associates for an Electric Utility Rate Design Study, which was funded by various parties including the National Association of Regulatory Utility Commissioners.[26]

Figure I-1
Illustration of the RECC Methodology



[26] NERA #15 Topic 1.3, "A Framework for Marginal Cost-Based Time Differentiated Pricing in the United States," February 1977, pp. 90-94, and Appendix C. *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.

Figure I-2
Annual Payment for $100 Capital Investment,
10 Percent Discount Rate and 3 Percent Annual Inflation



SCE continues to advocate for using the RECC method (rental value) as a more appropriate measure of long-run customer marginal costs compared to the NCO method.[27] The NCO method includes only the cost of *new* customer interconnections, spreading these costs across both existing and new customers. By ignoring the economic value of existing interconnection facilities, the NCO method systematically understates marginal costs. Simply because an asset is already installed and thus "sunk" does not mean the asset loses its economic value. As long as the interconnection has value to the customer, there is a price at which the customer is willing to "buy"

[27] In Pacific Gas and Electric Company's (PG&E's) 2016 GRC Phase 2 proceeding (A.16-03-013), SCE presented discussion on the differences between the RECC and NCO methods. SCE maintains that the RECC method accurately estimates the economic cost of providing a customer *access* to the distribution grid. In the A.16-03-013 proceeding, the Commission's Energy Division introduced the Adjusted Rental Method (ARM2) as an alternative approach that could be used when determining a reasonable fixed charge for the residential class. SCE generally supports the ARM2 as a viable compromise between the RECC and the NCO methods for the purposes of deriving the *access* portion of a fixed charge for the residential class.

and the utility is willing to "sell" interconnection service. Because the NCO method ignores this basic economic principle, it is not a valid marginal cost methodology.

Another major difference is the NCO's value of new customer costs where, under certain conditions, the NCO method can create unreasonable results. For example, assume that a customer class is expected to *grow* by 10 newly added similarly situated customers and *decline* by 15 departing customers for a net *reduction* of five customers. The NCO method would yield either a zero or negative marginal cost, depending on how the method is applied. However, the basic premise of marginal costs is to derive an estimate of the change in cost for a postulated increment or decrement in service provided, which in this case is a single customer. If the utility were to model such a scenario, the marginal cost of providing access to the grid, to each of the newly added 10, similarly situated customers, would essentially be the same. The NCO method therefore inappropriately discounts or exaggerates the marginal cost of providing access to each new customer, in relative proportion, to the ratio of the number of new customers added to number of existing customers connected to the grid. Changes in the growth forecast can yield declining costs one year and increasing costs the next, yet the underlying cost structure remains unchanged. This sensitivity demonstrates a weakness in the theoretical foundation of the NCO method.

C. Marginal Cost Methodology

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

1. Electricity Usage Marginal Costs

The Commission has a long-standing policy of developing marginal generation costs using the deferral value[28] of a CT proxy for estimating the long-run marginal cost of capacity, and a system marginal energy cost for estimating the short-run marginal cost of energy. This is an

[28] That is, the annual cost of acquiring CT capacity in a single year is the full lifecycle cost of a CT (with replacement) procured at the beginning of the year, minus the full cost of a CT procured at the beginning of the next year. This is calculated using the RECC methodology.

appropriate approach in California's current hybrid market, where energy procurement is transacted largely through market transactions, and capacity requirements are met through a combination of utility long-term procurement and annual resource adequacy (RA) requirements. The marginal cost analysis presented here is intended to represent conditions expected to occur during 2018 through 2021.

a) Generation Capacity Marginal Cost

Generation capacity marginal costs (GCMCs) have historically reflected the capacity cost of meeting system peak conditions. However, as the use of intermittent renewable energy resources has expanded throughout California, multiple parties have identified the need to enhance the RA program, or the system capacity framework, to include physical attributes for "flexible capacity."[29]

As the electric system evolves and California progresses towards meeting its 50 percent Renewables Portfolio Standard (RPS) requirement, the need for flexible capacity will increase and require the utilities to assess the costs directly associated with the procurement of flexible capacity. For this reason, flexible capacity costs should be recognized as a cost driver relevant to TOU period and price determinations, and these costs should be determined using a marginal cost methodology consistent with the framework adopted in the CPUC's RA program.

In this section, SCE first describes the methodology for quantifying the annual generation capacity marginal cost. SCE continues to use a single proxy CT resource when deriving the marginal cost of generation capacity, but now functionalizes such costs between peak and flex capacity based on the relative level of peak and ramp demand modeled for the system. This annual cost is then allocated to each hour using the LOLE methodology to estimate the hourly marginal cost of generation capacity expected for both peak and ramp system needs.

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29 The Commission formally adopted a policy framework for incorporating flexible capacity needs as a part of the local capacity requirements for LSEs in 2013, and began including flexible capacity requirements in the 2015 RA program.

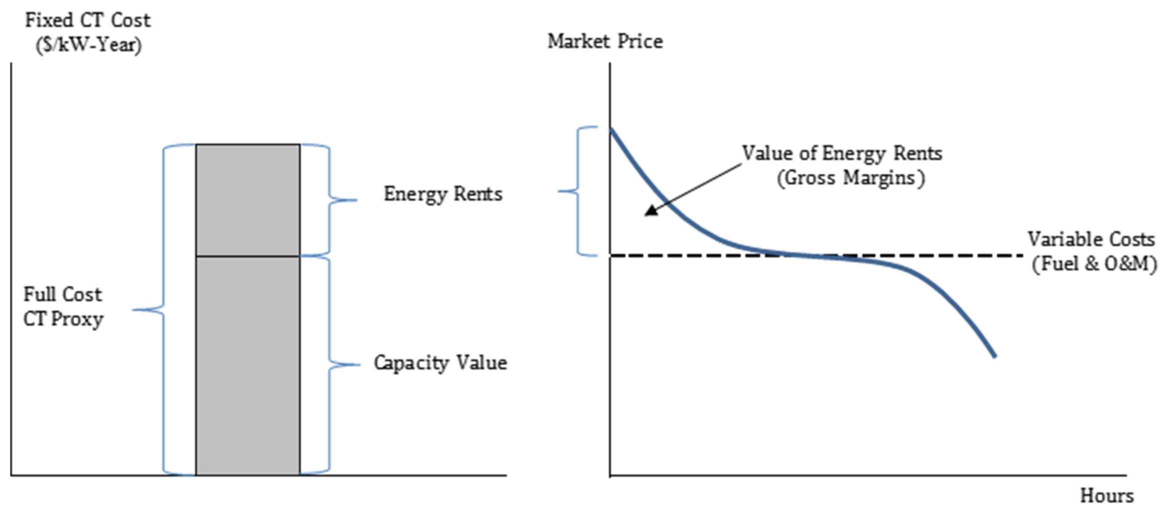
(1) Proxy Resource and Valuation

SCE bases the GCMC on the deferral value of a new build CT proxy resource.[30] The proxy is the estimated installed cost (in $/kW) for a new SCE-owned generation unit in the southern California region, including all permitting, financing, development costs and inflation during the construction period. The annualized cost ($/kW-Yr) is then calculated using the RECC methodology, to which fixed operations and maintenance (O&M) costs and property taxes are added to get the total annualized GCMC.

Due to the separation of capacity and energy prices, the CT proxy cost must be adjusted for any energy rents forecast to be obtained in the market to avoid overstating the isolated capacity value of the CT proxy. Energy rents are the operating profits that a proxy CT is able to earn from energy-related market awards when market prices are above the CT's variable operating costs, which principally consist of fuel, emission costs, and variable O&M. Because these energy rents reduce the CT's fixed costs that need to be recovered in capacity markets, energy rents are also known as energy-related capital costs (ERCC). For example, if the marginal energy price forecast is $90 per MWh, but the variable operating cost of a CT proxy is $60 per MWh for that same hour, then the CT would realize a $30 per MWh contribution to its fixed costs and the value of energy rents (or ERCC) would be subtracted from the full CT proxy. Figure I-3 illustrates this calculation.

[30] This is typically thought of as the long-run value of capacity, while the short-run value of capacity represents the present day value of RA capacity. SCE has traditionally used the long-run value of capacity to determine revenue allocation and to set rates.

Figure I-3
CT Proxy Valuation



Following this approach, the annualized value of 30 years of energy rent revenues is divided by the CT's nameplate capacity, which provides an energy rent value in $/kW-year. That value is then subtracted from the CT proxy's capacity value.

CTs have historically been the generators used to provide marginal system capacity. As the need for flexible, marginal capacity increases, CTs should continue to be considered the generator of choice for this exercise due to their relatively low marginal cost, ability for fast dispatch, fast start-up times, and ramping capabilities.

The long-run value of capacity is typically used to quantify the cost associated with the need for an additional MW of capacity to prevent a shortfall. However, with the increased supply of energy from RPS-eligible resources, California ISO-level grid operating constraints will evolve into a balance of capacity resources needed for both peak and ramping system needs. While SCE has used the long-run value of capacity in this proceeding consistent with previous GRC filings, SCE is proposing in this Application a joint allocation method for peak and flex (ramp) capacity needs, premised on the fact that a similar type of flexible CT resource will effectively meet both of these needs in the future.

SCE used the instant cost of an advanced 200 MW CT (LMS100) from the California Energy Commission's (CEC's) March 2015 "Estimated Cost of New Renewable and Fossil Generation in California" report.[31] Using the methodology discussed above for this CT proxy and the marginal energy costs (MECs), SCE derived a CT proxy cost of $141.2 ($/kW-Yr) (2018$) and an annual marginal generation capacity cost of $134.5 ($/kW-Yr) (2018$) as shown, respectively, in Table I-4 and Table I-5.

Table I-4
Generation Capacity CT Proxy Costs
(2018$)

1	Combustion Turbine Installed (w/ AFUDC) Cost (2018 COD)	$/kW	1,145.0
2	Real Economic Carrying Charge Rate	%	8.9%
3	Annualized CT Installed Cost (line 1 * 2)	$/kW-yr.	102.0
4	Fixed O&M	$/kW-yr.	26.5
5	Property Tax	$/kW-yr.	7.4
6	Full CT Proxy Cost (line 3 + 4 + 5) EOY	$/kW-yr.	135.9
7	Full CT Proxy Cost Mid-Year Payment Line 6 * (1 + 7.9%)^(1/2)	$/kW-yr.	141.2

[31] March 2015 "Estimated Cost of New Renewable and Fossil Generation in California," p. 137. The report is *available at* http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf.

Table I-5
Generation Capacity Marginal Costs
(2018$)

1	Full CT Proxy Cost (mid-year payment)	$/kW-yr.	141.2
2	Less Energy Rents	$/kW-yr.	(15.8)
3	Incremental Capacity Cost (line 1 - 2)	$/kW-yr.	125.4
4	7.3% General Plant Loader (line 3 * 7.3%)	$/kW-yr.	9.2
5	Generation Capacity Value Marginal Cost (line 3 + 4) at the generator level	$/kW-yr.	134.5

The marginal capacity cost calculated above is an annualized number and is not differentiated by TOU periods. SCE allocates the marginal capacity cost using relative LOLE values to indicate time-differentiated capacity value based on TOU period definitions.[32] This is a valid approach to assigning capacity costs to TOU periods. LOLE is closely related to Expected Unserved Energy (EUE),[33] which identifies the potential amount of generation-related outages (in MWh of unserved energy), that would occur in a time period when considering uncertainty in customer loads, resource availability and other market conditions. If available generation increases by one MW, then LOLE is equal to the change in EUE that occurs as a result.[34] Thus, relative LOLE measures the expected improvement in reliability that occurs in a time period as a result of an increase in available generation or a decrease in customer load. The capacity value allocation by percentage is shown in Table I-6 for both peak and ramp. LOLE development is discussed in the next section.

[32] This approach is a standard utility practice and has been used in prior SCE GRC proceedings.

[33] EUE is also called energy not served, or ENS.

[34] For example, if the likelihood of rolling blackouts due to a generation resource shortage is 10 percent in a particular hour (the LOLE) and the utility adds 100 MW of additional generation resources, then the amount of expected unserved energy (the EUE) would go down by 10 MW (10 percent times 100 MW times one hour). Mathematically, LOLE is the first derivative of EUE with respect to a change in available resources.

Table I-6
Categorization of Generation Capacity Unit Marginal Costs

TOU 2018 MCC Percentages	Annual
Combined	100%
Peak Allocation	61%
Ramp Allocation	39%

(2) System Peak and Ramp Capacity Allocation

One method to value generation capacity for purposes of establishing marginal costs is to determine the likelihood that the electric system will be unable to serve customer demand in any given hour. There is always some likelihood, however small, that the system will be unable to serve demand due to insufficient availability of generation relative to the electricity demanded by customers. The risk of a generation capacity constraints can be reduced by having the requisite amount of generation available than forecast peak demand, but this additional generation capacity imposes costs on customers. Determining the optimum supply-and-demand balance requires the study of expected system operations using a probabilistic risk-assessment approach. Analysis of a system's LOLE is one appropriate risk-assessment approach. LOLE is a measure of system reliability that predicts the ability (or inability) to deliver energy to the load. An LOLE analysis can provide insight into the planning reserve margin required for each LSE in a region.[35]

The LOLE provides a method for allocating annualized capacity marginal cost across hours in proportion to when the loss of load (*i.e.*, insufficient capacity to serve demand) is likely to occur.[36] If the LOLE is greatest in the summer period primarily due to load conditions, particularly during the on-peak period, then most of the value SCE attributes to capacity

[35] In D.04-10-035, the Commission directed LSEs under its jurisdiction to plan based upon meeting a 15 to 17 percent RA requirement. This implicitly reflects a balancing of customer risks and costs.

[36] The purpose of SCE's LOLE analysis is not to forecast the precise timing of future low-reserve margin events, nor is it to forecast the absolute magnitude of any single loss-of-load event. Rather, it is intended to be a relative distribution of risk used to allocate capacity value across hours based on a 1 in 10 planning scenario.

will be assigned to that period, because that is the period for which SCE may have the highest probability of facing a capacity constraint. Similarly, if the relative probability for a loss of load event is nearly zero during the winter super-off-peak period, SCE will assign very little capacity value to that period.

Typically, the LOLE has only been run to test for probability of LOLE for peak. In this Application, SCE proposes to functionalize capacity marginal cost between peak and ramping/flex services. In recognition of the year-round need for ramping capacity on the grid, the California ISO developed an interim solution to ensure the availability of enough flexible generation in the markets. The mechanism, known as the "flexible resource adequacy criteria and must offer obligations" (FRAC-MOO), established the interim definition of flexibility that has developed into a market product. Although the FRAC-MOO proposal has yet to be accepted as the final solution for California's flexibility needs,[37] SCE used its definitions and rules to define and characterize flexible resources for valuation purposes here. In this context, "flexible capacity" is the ability of certain generation resources to sustain or increase output during the greatest upward three-hour net load ramp in each month.

There are two parts (supply and demand) to the flexible shortfall calculation in FRAC-MOO: (1) calculation of the Effective Flexible Capacity (EFC) (supply), and (2) definition of the flexible capacity need (demand). A generation resource's ability to qualify as "flexible capacity" is defined by its EFC. EFC is similar to the concept of Net Qualifying Capacity (NQC) in the RA program, in that both programs define how much of a generator's capacity can be counted on for reliability purposes. While NQC is a peak capacity program that defines the amount of a generator's capacity that can be used to meet system peak requirements, EFC defines the

[37] The CPUC is looking to establish a durable flexible product in Track 2 of the RA Proceeding. *See* R.14-10-010, Assigned Commissioner and Administrative Law Judge's Phase 2 Scoping Memo and Ruling, December 23, 2015, pp. 3-5.

amount of a generator's capacity that can be used to meet a three-hour upward net load ramp on the system.[38]

Once the overall monthly flexible need is determined, it is further refined into three categories, as defined by the FRAC-MOO proposal: (1) base ramp – the largest morning upward ramp, (2) peak ramp – the overall flexible need less the base ramp, and (3) super-peak ramp – up to 5 percent of the maximum upward three-hour net load ramp of the month.[39] Categories 1 and 2 were evaluated in the LOLE tool to determine the probability of LOLE due to ramp. Figure I-4 illustrates these three categories and the two types of ramp.[40]

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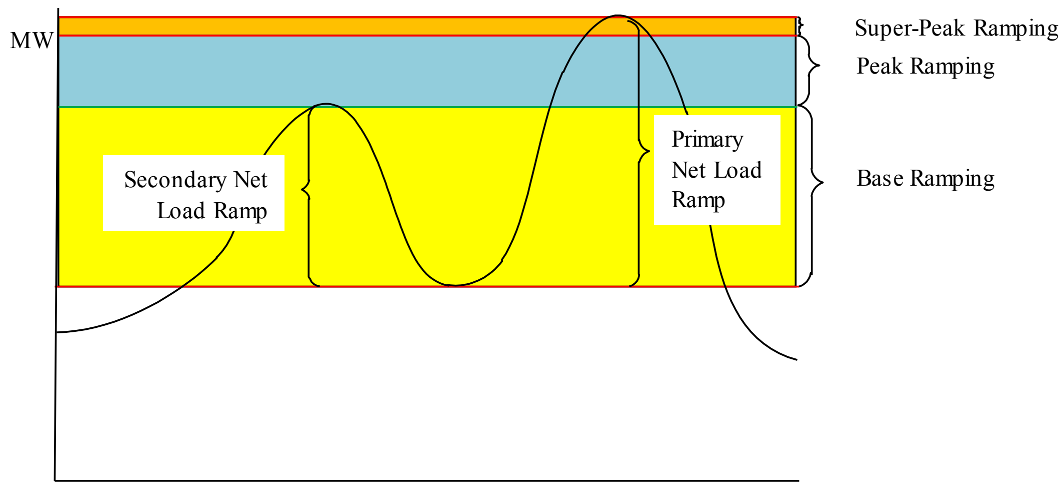
[38] Additional information on determining EFC can be found *at* https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx [as of April 29, 2016].

[39] ISO definitions of generator characteristics necessary to meet each of these ramping categories can be found on the FRAC-MOO website. SCE did not evaluate LOLE ramp for super-peak ramp and assumed any ramp in or before hour-ending (HE) 11 pacific standard time (PST) was considered a base ramp. Additionally, the latest list of ISO generator categories and EFC values can be found on the ISO's website *at* https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=9A94E71F-5542-49E8-BFBF-B9E00A2EC11B [as of April 29, 2016].

[40] "Flexible Resource Adequacy Capacity Requirement Amendment," Collanton, Roder E. et al. Aug 1, 2014, p. 27, *available at* https://www.caiso.com/Documents/Aug1_2014_TariffAmendment-FlexibleResourceAdequacyCapacityRequirement_ER14-2574-000.pdf.

Figure I-4
Graphical Depiction of Peak Ramp Need Used in the LOLE Model



(a) LOLE Methodology

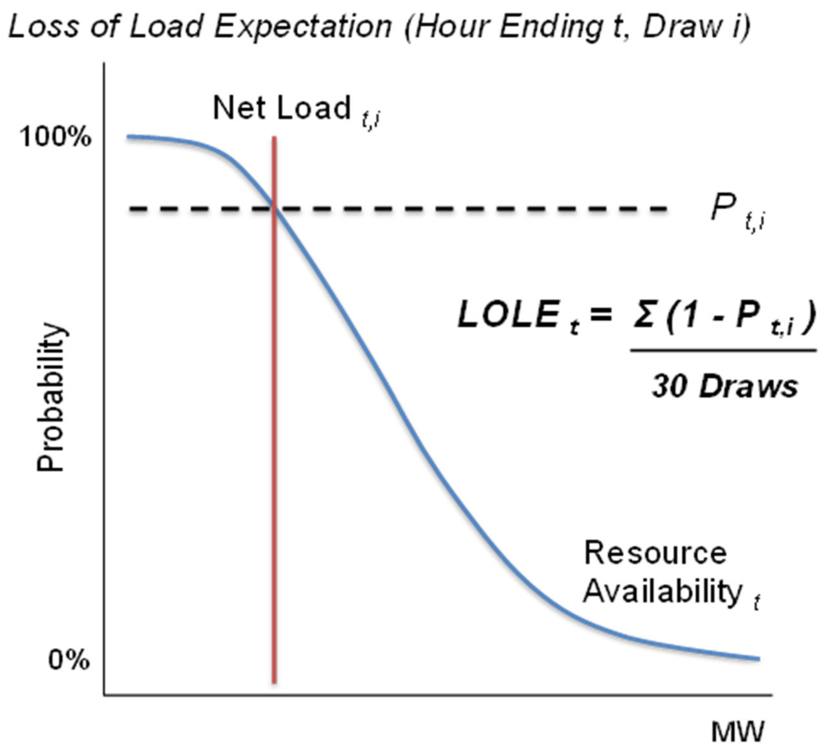
The LOLE methodology uses a Monte Carlo analysis to determine the times in the year with the highest relative probability of a loss of load event occurring.[41] The inputs to the analysis for load and intermittent resources are 30 years of forecasted SCE managed load data without distributed generation photovoltaic (DG PV) shaped to 30 historical weather years, an annual wind curve, and a combined annual RPS solar and DG PV curve. The non-intermittent resources are the resources believed to be in SCE's service territory sized to both the reported ISO EFC and NQC. An annual maintenance curve is then calculated using the NQC of the resources. This maintenance curve is scaled down proportionally from NQC to EFC to create maintenance curves for the fleet's EFC. A distribution of monthly forced outages is also calculated such that the NQC on forced outage is correlated to the EFC on forced outage. The loads, intermittent resources, non-intermittent resources and outages are then input to the LOLE tool.

41 The relative probability is set to a 1-in-10 planning criteria. This is the average of all the probabilities in the simulation divided by the number of days in 10 years.

The LOLE tool uses annual loads by day and the annual wind and solar shapes by month and randomly samples them to generate net load curves. The resulting curves are then removed from the available resources stack by month. The remaining stack is then compared to the distribution of forced outages to determine the probability of not being able to serve load. This process is done for every day of the year. This approach provides a reasonable estimate of the relative risk of being unable to serve some portion of system load in any given period. Figure I-5 illustrates this process. As the resources required to serve load and or ramp increases (MW X-axis), the probability of being able to serve that load decreases (Probability Y-axis). The hourly LOLE is then normalized over all hours of the year such that the sum of the normalized LOLE equals one. If the sum of LOLE does not equal one, then the LOLE product being evaluated for, peak or net load ramp, must be scaled up or down and re-evaluated until the normalized LOLE equals one.

This process is used for both LOLE peak and ramp separately to determine the 1-in-10 event hours for peak and ramp. The results are then combined using the ratio of maximum average net load peak versus maximum average net load ramp when the probability of an LOLE occurring was greater than zero.

Figure I-5
Illustration of Hourly LOLE Calculation



(b) Results

The data indicates LOLE probabilities concentrated in September and March for the years 2018-2021. While SCE has used 2018 as the basis of functionalizing generation capacity marginal costs between peak and ramp, SCE has used the hourly dispersion of test year 2021 LOLEs to aggregate generation capacity marginal costs by TOU periods. The high probability of LOLE in September goes from 6 p.m. to 8 p.m. due to high loads outside of hours with high RPS production. The winter and spring capacity needs are driven by large ramps ending on the weekends from 5 p.m. to 7 p.m. The hourly dispersion of LOLE peak and LOLE ramp for weekdays and weekends is shown in Table I-7 and Table I-8.[42]

[42] The ramp hours represent the last hour of the three-hour ramp.

Table I-7
Relative Loss of Load Expectation – Peak (PST)[43]
(Part 1 of 2)

		Weekday LOLE Peak 2021												
HE		1-13	14	15	16	17	18	19	20	21	22	23	24	Total
Month	1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	6	0%	0%	0%	0%	0%	0%	0%	2%	2%	0%	0%	0%	4%
	7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
	8	0%	0%	0%	0%	0%	0%	0%	9%	3%	0%	0%	0%	12%
	9	0%	0%	0%	0%	0%	0%	40%	31%	6%	0%	0%	0%	77%
	10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total		**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**40%**	**42%**	**11%**	**0%**	**0%**	**0%**	**94%**

		Weekend LOLE Peak 2021												
HE		1-13	14	15	16	17	18	19	20	21	22	23	24	Total
Month	1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	9	0%	0%	0%	0%	0%	0%	4%	1%	0%	0%	0%	0%	5%
	10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total		**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**4%**	**2%**	**1%**	**0%**	**0%**	**0%**	**6%**

[43] Hours are illustrated as PST in the heat map, and should be shifted appropriately for representation in clock/prevailing time.

Table I-8
Relative Loss of Load Expectation – Ramp (PST)[44]
(Part 2 of 2)

		Weekday LOLE Ramp 2021												
HE		**1-13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**Total**
Month	**1**	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
	4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total		**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**1%**

		Weekend LOLE Ramp 2021												
HE		**1-13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**Total**
Month	**1**	0%	0%	0%	0%	0%	17%	1%	0%	0%	0%	0%	0%	18%
	2	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	1%
	3	0%	0%	0%	0%	0%	4%	36%	27%	0%	0%	0%	0%	67%
	4	0%	0%	0%	0%	0%	0%	0%	13%	0%	0%	0%	0%	13%
	5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total		**0%**	**0%**	**0%**	**0%**	**0%**	**22%**	**38%**	**40%**	**0%**	**0%**	**0%**	**0%**	**99%**

Table I-9 shows the maximum average demand for net load peak and ramp during LOLE events for 2018 through 2021. In this Application, SCE proposes to use an approximate 60/40 percent split for peak versus flex capacity, which is reflective of the relative proportion of peak and ramp MW for the test year 2018.[45]

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[44] The heat maps only show the proportionate allocation of ramp in the third hour of the three-hour ramping event.

[45] The ratio between peak and ramp was derived by taking the maximum of the monthly average ramps (MW) and the maximum of the monthly average net load peaks (MW) that occurred during peak and ramp LOLE events. Given the evolving nature of ramp constraints on the system SCE chose a near term estimate based on the year 2018 when functionalizing generation capacity marginal costs.

Table I-9
Split of Generation Capacity Marginal Cost Between Peak and Flex

Year	Max Avg Net Load Peak	% LOLE Peak	Max Avg Ramp	% LOLE Ramp
2018	20,462	61%	7,977	39%
2019	20,240	56%	8,811	44%
2020	19,964	51%	9,776	49%
2021	19,486	49%	10,024	51%

b) Marginal Energy Costs (MECs)

(1) Methodology and Data Sources

MECs equal the hourly long-term marginal market-clearing price of the ISO wholesale power market. The long-term marginal energy price forecast is based on fundamental power price forecast from SCE's internal PLEXOS production simulation model. In this Application, SCE is using MECs for 2021.

SCE uses PLEXOS, a commercial software program with a mixed integer programming (MIP) optimization engine, to perform the fundamental market simulations and model the ISO day-ahead market auction. PLEXOS models the commitment and dispatch of available generation resources to meet demand and reserve requirements at least cost subject to transmission and individual generation resource constraints. The forecasted hourly energy prices from the simulations reflect the level of hourly net load served by dispatchable generation resources and their production cost.

The PLEXOS model used to forecast MECs is a California-only nodal model based on the full network model (FNM) published by the ISO on a regular basis. The PLEXOS model contains the following inputs:

- Gross load projections, which include the effects of on-site load impacts due to DERs, including DR, energy efficiency (EE) and DG such as rooftop solar, based on SCE's internal load forecast;

- Natural gas price forecasts for each "hub" based on SCE's internal forecasts, which SCE updates on a regular basis;
- Greenhouse gas (GHG) compliance cost forecasts based on SCE's internal forecasts, which SCE updates on a regular basis;
- Transmission line and interface limitations based on the transmission capability of the interties and the ISO FNM;
- RPS trajectory for major LSEs including SCE, PG&E and San Diego Gas & Electric Company (SDG&E) based on the RPS calculator; and,
- Generation profiles for the investor-owned utilities' (IOUs')[46] RPS-eligible wind and solar resources based on the RPS calculator.

The forecast energy prices consist of the costs of incremental fuel, variable O&M, GHG compliance, startup, and no-load fuel costs. The energy prices include the costs related to congestion and line losses.

(2) Key Assumptions

The PLEXOS Model includes the following assumptions:

- 90 percent of renewable generation is scheduled in the ISO 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.

[46] The IOUs include SCE, PG&E and SDG&E.

Table I-10
Generation Energy Marginal Costs 2021
Average ¢/kWh (2018$)

Cost Component	**Annual**	**Summer**			**Winter**		
		On-Peak	**Mid-Peak**	**Off-Peak**	**Mid-Peak**	**Off-Peak**	**Super-Off-Peak**
Energy (¢/kWh)	3.654	4.884	4.397	3.559	4.622	3.906	2.475

2. <u>Distribution Marginal Costs</u>

Distribution marginal costs are typically categorized into two categories: (1) design demand and (2) customer-related costs. Customer-related costs are designed to collect some "fixed" portion of a utility's distribution costs,[47] which include the costs of connecting a new customer to the grid, and are not considered to be dependent on the level of demand or usage on the system. Capital-related marginal costs associated with providing service to customers are also included in customer-related costs and include the final line transformer, service drop and customer meter. The remaining portion of distribution marginal costs are associated with design demand, or the amount and configuration of distribution capacity, and are typically considered "load driven" costs applicable to the delivery of electricity to a customer site. To maintain service reliability and meet the demand needs of customers, SCE expands, upgrades, and reinforces all levels of its electric system, including transmission, sub-transmission and distribution assets. SCE uses peak load data and load growth forecasts to evaluate whether existing distribution facilities will exceed their loading thresholds (also known as "planning load limits" or "PLLs") under normal and abnormal conditions,[48] and plans infrastructure projects to mitigate existing and forecasted constraints.[49]

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[47] Customer charges are collected as fixed charges on a per-customer, per-month basis for non-residential customers. While SCE does have fixed customer charges for residential customers, those are currently established at less than $1 per month for the default tiered rates (with monthly minimum delivery bills for residential customers established at $10 and $5 for non-CARE and CARE customers, respectively, as established in D.15-07-001).

[48] Abnormal conditions include, for example, planned facility outages for maintenance, unplanned facility outages due to equipment failures, and facilities removed from service because of a fault on the system.

[49] This planning process is described in detail in SCE's 2018 GRC Phase 1 Application (A.)16-09-001, *see* Transmission and Distribution Volume 3 – System Planning Projects.

In past GRCs, SCE used load-driven capacity need at the time of a typical circuit peak as the main cost driver for determining design demand marginal cost. Appendix B describes the conceptual framework for implementing this approach using EDFs, with the resulting cost and revenue responsibility recovered from rate groups using a non-time-differentiated facilities-related demand (FRD) charge. SCE recognizes, however, that California's policy of promoting customer choice through the adoption of customer or third-party-sited DERs will significantly change the landscape of the distribution system of the future and, in turn, will affect the drivers of delivery-related marginal costs. Prior to the advent of DERs, viewing the entire portion of the distribution system as a peak capacity resource may have been appropriate because the utility was the singular source of distribution capacity investments. Now, with the increased proliferation of DERs, SCE expects to see a paradigm shift where the distribution grid increasingly serves two different functions: (1) a peak capacity function to meet time-sensitive peak customer demand; and (2) a grid or network function that enables the bi-directional transfer of energy to and from customers.[50] Further, the implementation of mandatory TOU for commercial and industrial customers, technological advances in metering for small and large customers, and the availability of time-variant load data has provided the much needed foundation to reassess and analyze the allocation and recovery of distribution delivery costs.

In SCE's 2016 RDW proceeding, SCE proposed the time-differentiation of distribution costs and indicated that a more comprehensive evaluation of these costs would be addressed in this Application.[51] In the following sections, SCE describes a refined approach for

[50] Because of the time-dependent nature when load materializes on the distribution system, the functionality with which distribution system assets support peak capacity needs is therefore also time-dependent. While SCE does not dispute some relevance of time sensitivity for grid-related assets, the general criteria with which the gird portion of the system has been designed and configured over time has caused those assets to primarily meet the needs of connectivity and the potential to share load-carrying capability. To capture the relatively minor time-dependent nature of such costs, SCE continues to use the EDF methodology when determining rate group contributions to such costs, but proposes to recover these costs through non-time-differentiated FRD charges.

[51] Exhibit SCE-1 in A.16-09-003, pp. 34-35.

determining distribution marginal costs that draws on the principles of marginal cost pricing, supplemented by the experiential criteria used by SCE's system planners.

a) Design Demand Marginal Costs [52]

Design demand marginal costs are the marginal costs of the distribution system facilities employed in the delivery of power to SCE's customers. Such costs have typically been computed using the incremental cost of adding capacity from the NERA regression method described below.

(1) FERC Basis of Recording Costs

As SCE refines its cost methodology in this Application, FERC classification is still being used as the basis of categorizing costs by asset type.[53] The basis of SCE's proposed FERC-account based identification of costs for distribution plant is as follows:

- The cost of assets recorded to FERC accounts 361 (Substation Structures and Improvements) and 362 (Substation Equipment) are classified as substation assets.
- The cost of assets recorded in FERC accounts 364 through 367 are classified as distribution circuits.

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[52] In addition to the distribution design demand marginal cost components outlined in this section that represent SCE's cost of incremental load-carrying capacity, *SCE also spends a significant amount of resources managing an installed level of capacity*. This includes capital expenditures for infrastructure replacement, reliability, grid modernization and automation, to name a few, which allow SCE to effectively operate the system. While such spend is recognizably different from the capital expenditures needed for incremental capacity, it is as important, because there is a significant amount of resources needed to continually *manage* and *operate* this installed base of capacity. The estimate of the opportunity costs for such spend could be functionalized as a *grid* cost and used in the revenue allocation process. While SCE has analyzed these costs in this GRC, they have not been included in the marginal cost analysis presented herein.

[53] *Asset* types are distribution substations, distribution circuits, subtransmission substations and subtransmission circuits.

- The cost of land is recorded to FERC account 360. For the purposes of this analysis, these costs have been grouped as substation-related costs.[54]

A description of each FERC account is listed in Table I-11.[55]

Table I-11
FERC Account Descriptions – Distribution Plant

FERC Acct #'s	Asset Type	FERC Description
360	Land/Subs	Land and Land Rights
361	Land/Subs	Structure and Improvements
362	Land/Subs	Station Equipment
364	Lines	Poles, Towers, and Fixture
365	Lines	Overhead Conductors and Devices
366	Lines	Underground Conduit
367	Lines	Underground Conductors and Devices

Subtransmission (66 kV and 115 kV) capital expenditures are recorded to FERC accounts 350 through 359. Only the non-ISO allocated portions of costs recorded to these accounts are included in the analysis of distribution-related marginal costs.[56]

- The cost of assets recorded to FERC accounts 352 (Substation Structures and Improvements) and 353 (Substation Equipment) are classified as substation assets.

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[54] Land costs for distribution substations and lines could be categorized as fixed since the cost incurred for the land is essential for the physical connectivity provided by the grid. However, given that a large portion of distribution land costs are primarily driven by the siting of distribution substations assets, for the purposes of this analysis, land costs have been aggregated with the cost of substations.

[55] More detailed descriptions can be found under Title 18 of the Code of Federal Regulations, Part 101 *available at* https://www.gpo.gov/.

[56] Consistent with FERC ratemaking, ISO-jurisdictional costs are used for the determination of FERC authorized revenues in the transmission ratemaking proceedings filed with FERC. In this Application, only the non-ISO jurisdictional costs are included when computing marginal costs for the subtransmission system.

- The cost of assets recorded in FERC accounts 354 through 358 are classified as subtransmission circuits.
- The cost of land is recorded to FERC account 350 (Land and Land Rights) and 359 (Roads, Trails and Rights of Way). For the purposes of this analysis, costs recorded in account 350 have been grouped as substation-related costs and those recorded in 359 have been grouped as subtransmission circuit-related costs.
- A description of each FERC account is listed in Table I-12.[57]

Table I-12
FERC Account Descriptions – Transmission Plant

FERC Acct #'s	Asset Type	FERC Description
350	Land/Subs	Land and Land Rights
352	Land/Subs	Structure and Improvements
353	Land/Subs	Station Equipment
354	Lines	Poles and Fixture
355	Lines	Overhead Conductors and Devices
356	Lines	Underground Conduit
357	Lines	Underground Conductors and Devices
359	Lines	Roads and Trails

(2) NERA Regression Method

Consistent with past GRCs, SCE applies a regression methodology to ten years of historical and five years of forecast capital expenditure data to determine the incremental cost of adding delivery related capacity on the distribution system. This method uses established FERC accounting to categorize expenditures by asset type as identified in SCE's FERC

[57] More detailed descriptions can be found under Title 18 of the Code of Federal Regulations, Part 101 *available at* https://www.gpo.gov/.

Form 1 filing.[58] For historical years, SCE adjusts replacement capital from reported plant balances in its FERC Form-1 to determine the estimate of load-growth-driven capital expenditures for each year. For the five forecast years, load growth capital expenditures for both the distribution and subtransmission cost components are taken from the work papers that supplement SCE's Transmission and Distribution Volume 3 – System Planning Capital Projects testimony proposed in A.16-09-001.[59] To normalize the basis of costs between historical and forecast periods, forecast capital expenditures are analyzed on a closed-to-plant basis and include capitalized allowed funds used during construction (AFUDC) and A&G overhead.[60]

The regression model aligns cumulative capital expenditure (independent variable) to cumulative planned capacity (dependent variable) to derive the incremental cost of capacity additions as expressed in $/kW.[61] To minimize cost-to-growth distortions caused by expansionary or recessionary business cycles, SCE switched from using "recorded load" to "planned capacity" in its 2012 GRC Application.[62] Regression calculations use the Ordinary Least Squares (OLS) method to deduce a trend line through 15 years of cumulative expenditure and planned

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[58] SCE's FERC Form 1 filing captures invested capital by asset class and by FERC account. A detailed classification of the different FERC accounts have been described in Section I.2.a.1. above.

[59] Projects discretely identified as load growth are only considered in the analysis. All projects not related to load growth (*i.e.*, grid reliability, infrastructure replacement projects, grid modernization, automation, etc.) are excluded from this analysis. Additionally, capital expenditures related to construction projects that have an operational date beyond the forecast period are also excluded.

[60] This is an accounting term used to describe when the construction project is completed and is ready for service. At time of completion, all costs are moved from a construction work in-process (CWIP) account to general rate base account for "plant-in-service." SCE-10, Vol.2 Revision 1, April 2014, Chapter 1 provides a good description.

[61] SCE used B-bank substation nameplate capacity as the proxy for "planned capacity." Circuit capacity was not identified in SCE's 2015 GRC due to time and resource constraints. As a result, the costs of substations and circuits combined as a sum were then regressed against substation nameplate capacity as the single dependent variable. The slope value of the regression is what SCE uses when computing the incremental cost of distribution design demand. In this GRC, SCE uses both substation and circuit PLLs when determining incremental cost for each asset type (asset types are distribution substations, distribution circuits, subtransmission substations and subtransmission circuits).

[62] Planned capacity was a better fit in the regression when used as a dependent variable. *See* SCE-02, A.14-06-014, p. 33, line 6.

capacity (MW). In a regression analysis that uses time series data, autocorrelation or serial correlation of the errors may be a problem because they violate the OLS assumption that the error terms are uncorrelated. SCE checked for serial correlation and determined that this problem does not exist. The slope value derived from the regression trend line is then multiplied by the RECC factor to estimate the capital portion of the marginal cost of adding new capacity on the distribution system.[63] In addition to the capital component, an O&M cost component is also added to compute the total marginal cost for each cost component (distribution and subtransmission).[64] The sum of the capital and O&M portions described above result in the following delivery-related design demand marginal costs.

Table I-13
Delivery-Related
Design Demand Marginal Costs (2018$)

Cost Components	**$/kW-yr.**
Distribution	106.8
Subtransmission (Non-ISO)	58.7

In past GRCs, distribution design marginal costs were typically computed only at the level of the asset category described above (distribution and subtransmission). However, because costs experienced on the distribution system also vary by asset type, in this Application, SCE has refined the regression method to further reflect these differences. SCE performed separate regressions for each asset type (distribution substations, distribution circuits, subtransmission substations and subtransmission circuits) with the dependent variable used

[63] The marginal cost of distribution design demand is expressed in $/kW-Yr. The RECC factor for different asset classes is independently calculated and applied to the cost basis for each asset class pertinent to the respective cost component. The RECC factor encapsulates SCE's opportunity cost of invested capital, which, in turn, forms the basis of the capital-related portion of distribution design marginal costs.

[64] Ten years of annual historical O&M divided by an annual level of designed capacity. The data for historical expense is obtained from the FERC Form-1 O&M accounts and was adjusted to include employee pension and benefits to arrive at a fully loaded O&M cost to be included in the marginal cost for design demand.

in each case being planned capacity of each asset type being analyzed.[65] SCE was therefore able to compute discrete costs for incremental capacity for each asset type.[66] Table I-14 summarizes the proposed cost components by asset type and asset category.

Table I-14
Delivery-Related Marginal Costs by Asset Type
(2018$, at applicable voltage levels)

Cost Components	Substation ($/kW-yr.)	Circuits ($/kW-yr.)
Distribution	25.0	103.0
Subtransmission (Non-ISO)	30.3	15.6

(3) Functionalizing Costs Between Grid and Peak

Once the individual cost components of incremental capacity for each asset type have been identified, SCE functionalizes costs between grid and peak based on the criteria outlined below. As discussed above, "peak" refers the distribution system's peak capacity function in meeting time-variant peak customer demand, whereas "grid" refers to the distribution system's function that enables the bi-directional transfer of energy to and from customers. In this Application, SCE proposes a time-dependent charge for the recovery of *Peak* costs, and a non-time-differentiated charge for the recovery of *Grid* costs.

(a) Distribution Circuits

Consistent with the FERC method of using transmission circuit miles to allocate costs between ISO and non-ISO jurisdictional transmission assets, SCE proposes to

[65] Nameplate capacity was used for substations, and the PLL was used for circuits. Since circuits are an amalgamation of different assets, the PLL is akin to the nameplate capacity of a substation. For a substation, a manufacturer's rated nameplate capacity is readily available, but, for a circuit, capacity must be derived and is dependent on the clustering of assets employed in the delivery of power, specific to each circuit. By using cumulative circuit PLLs as the dependent variable in the regression, the incremental cost of circuit capacity was determined for the analysis period.

[66] The analysis period in this Application was maintained at 10 years of historical data and five years of forecast data. For each asset type (substations or circuits) and for each cost component (distribution or subtransmission), SCE computes the respective marginal costs independently. This refinement appropriate reflects the cost-to-capacity relationship used when deriving the respective marginal costs.

use the split between *Main-Line Circuit Miles* and *Radial-Line Circuit Miles (including secondaries)* as the basis of functionalizing distribution circuit marginal costs between peak-capacity-related costs and grid-related costs. A summary of the main-line and radial-line miles is included in Table I-15.

Table I-15
Summary of Circuit Line Miles - 2016

	Line Miles	Formula
Primary Voltage		
Mainline or Backbone	25,087	(a)
Radial	42,498	(b)
Mainline Percent of Combined Mainline and Radial miles	37.10%	(c) = (a)/{(a)+(b)}
Radial Lines Percent of Combined Mainline and Radial miles	62.90%	(d) = (b)/{(a)+(b)}
Circuit		
Primary Voltage	64,021	(e)
Secondary Voltage	27,245	(f)
Circuit Line Miles Split		
Mainline Miles	23,764	(g) = (e) x (c)
Radial and Secondary Miles	67,502	(h) = {(e) x (d)} + (f)
Circuit Mainline Miles % - Peak	26.00%	(i) = (g)/ {(g) + (h)}
Circuit Secondary and Radial Miles % - Grid	74.00%	(j) = (h)/ {(g) + (h)}

(b) Main Line

Primary voltage (4 kV to 33 kV) circuit miles form the basis of apportioning distribution line costs to the peak-capacity component of design demand marginal costs. The main line is the largest sized conductor or cable used for the delivery of power from the substation to a general geographical proximity of load on the distribution grid. These lines primarily accommodate peak coincident load needs and are typically configured and sized to extend from a substation to different load areas.[67]

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

(c) Radial Lines and Secondary Lines

Primary voltage circuit miles, inclusive of secondary voltage (600 V and below) circuit miles, form the basis of apportioning distribution line costs to the grid-related component of design demand marginal costs. Radial lines allow for connectivity to SCE's mainline / backbone system, as described above. These lines typically extend in a radial configuration and traverse assigned right of ways and property lines to deliver power to a customer's premise.

SCE's analysis of 2016 distribution system circuit miles demonstrated that approximately 26 percent of the circuit miles were main circuit miles and 74 percent of the circuit miles on the distribution system were radial and secondary voltage circuit miles. The marginal cost of distribution circuits listed in Table I-14 represent an estimate of the economic (opportunity) cost for adding circuit capacity on SCE's system. While there exists a variety of different configurations when building distribution circuits, for the purposes of marginal cost analysis, the system level split between radial-lines and main-lines is appropriate as the basis of functionalizing distribution system circuit costs between peak and grid. Because mainlines perform the primary function of carrying capacity when delivering power to load centers, these costs were functionalized as peak costs. In contrast, radial lines and secondary voltage lines perform the primary function of delivering power to individual customer premises, and were therefore functionalized as grid costs.[68]

(d) Distribution Substations (B-Banks) and Subtransmission Substations (A-Banks)

Distribution substations play a critical role by transforming high voltage power to low voltage power that is eventually delivered to customer load areas.[69]

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[68] Using line miles as the basis for splitting costs is consistent with the methodology used at the FERC where transmission line miles are used as the basis of ISO and non-ISO jurisdictional costs.

[69] 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).

As utility scale generation became larger to take advantage of economies of scale, substations helped transform supplied power into *transportable* voltages for delivery over the grid. Typically, multiple circuits fan out from each substation to serve geographically dispersed load clusters within each load area. As substations are generally planned and designed for a peak level of coincident load experienced on supporting circuits, substation costs have been functionalized as a peak cost.

(e) Subtransmission Circuits

SCE's subtransmission system is uniquely configured as a radial grid and has generally evolved over time based on the following design criteria:

- Subtransmission lines are designed for the non-coincident peak load of the B-banks they connect; and,
- Any B-bank with greater than 28 MVA in load requires two subtransmission lines for reliability reasons.

The subtransmission system configuration and design has been largely influenced by inter-connectivity, energy transfer and contingency planning in order to alleviate the risk of dropping load such that, in the event of a contingency, connected subtransmission circuits are able to share load carrying capacity. The majority of the capacity planned on the subtransmission system is therefore governed by the ability to accommodate: (i) directional power flows in normal and contingency scenarios; and (ii) congestion management on the subtransmission network.[70] 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.* Further, over time the system has evolved with a design and configuration that primarily functions as a network that allows the transfer of energy in the event of a contingency. This predominance of subtransmission circuits to act as a

[70] When SCE performed this analysis, subtransmission circuit hourly load data was not available. While subtransmission circuits are required to accommodate peak load needs, the configuration of the system lends itself to predominantly function in the role of a grid or network. As such, classifying subtransmission circuits as grid costs is appropriate for the purposes of this analysis.

grid/network under normal operating and load conditions has generally resulted in the *de minimus* functionality of the system as a peak capacity resource. Therefore, SCE has functionalized subtransmission circuit marginal costs as grid costs.[71]

Table I-16
Functionalized Distribution Marginal Cost by Asset Category and Asset Type

Cost Component -- Asset Category	**Grid ($/kW-yr.)**	**Peak ($/kW-yr.)**
Distribution - Substations	n/a	25.0
Distribution - Circuits	76.2	26.8
Subtransmission (Non-ISO) - Substations	n/a	30.3
Subtransmission (Non-ISO) - Circuits	15.6	n/a
Total	**91.8**	**82.2**

The figures above indicate that approximately 47 percent of the design demand marginal costs are peak-capacity related that could appropriately be allocated on a time-variant basis.

(4) Relating Design Demand Distribution 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. Both methods are discussed below.

[71] The historical context of distribution system marginal costs, typically defined as the incremental cost of adding new capacity driven by base case load growth, should not be indiscriminately transposed on the subtransmission system. The two systems function with very different operating constraints. While planning for load growth is critical, the primary driver of subtransmission system costs is contingency-driven reliability planning. This emphasis on contingency planning necessitates a sufficiently integrated network that has the robust capability of moving power between load centers, especially in the event of an operating contingency.

(a) PLRF Methodology for Peak Capacity-Driven Costs

In the 2016 RDW, SCE introduced the Peak Load Risk factor (PLRF) methodology as the basis of assigning a time-sensitive allocation of peak capacity-related costs.[72] In the section below, SCE describes the methodology and its application in this GRC.

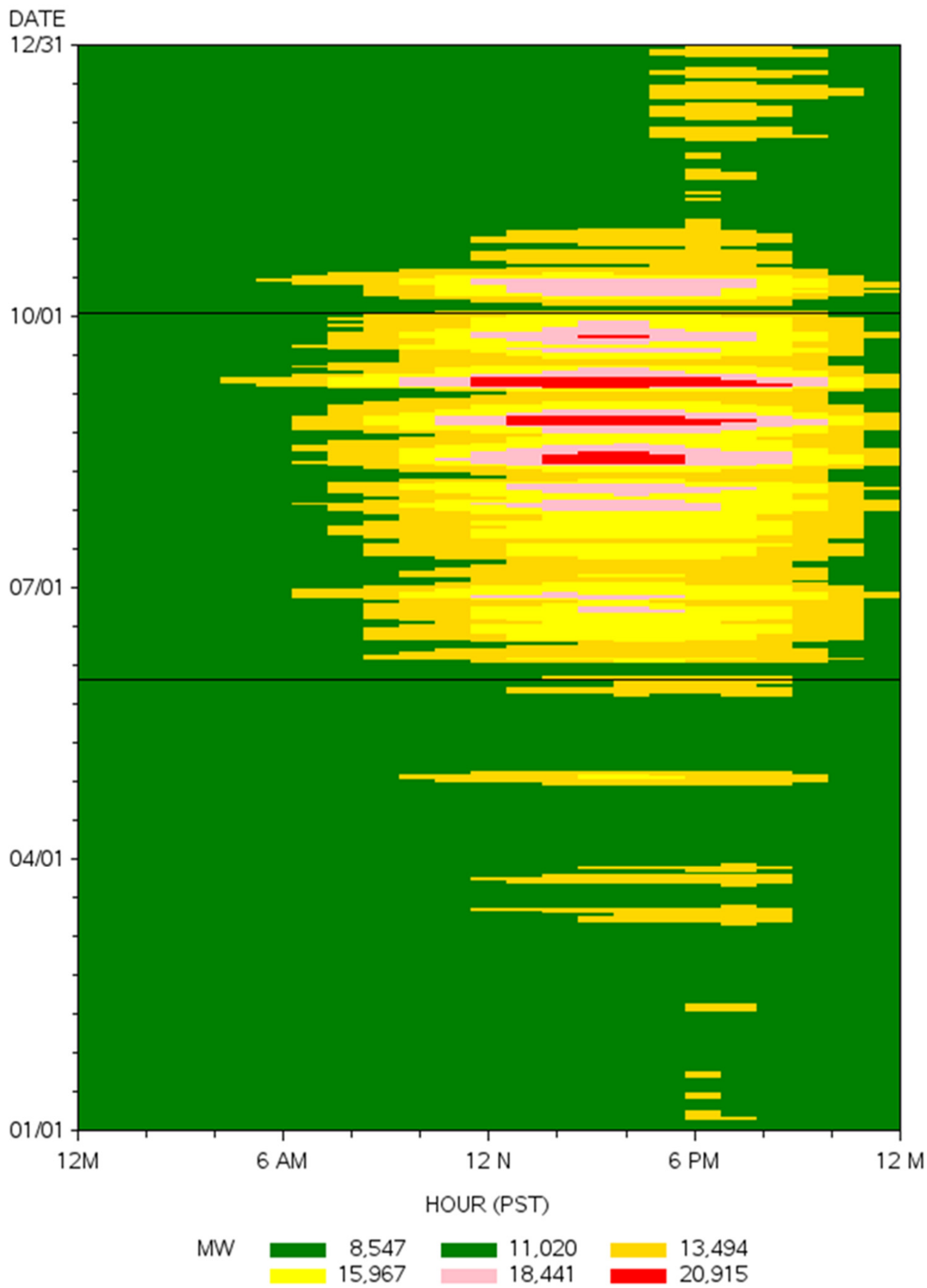
As discussed above, SCE's distribution system is comprised of a network of substations (B-banks) that convert sub-transmission voltages (66 kV and 115 kV) carried from the A-banks to distribution voltages (33 kV and below), and includes distribution circuits used for the delivery of power from B-banks to specific customer load points. Figure I-6 is a contour map of circuit load levels in 2015, 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.[73] 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.[74]

72 A.16-09-003, Exhibit SCE-1, pp. 38-43.

73 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.

74 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-7.

Figure I-6
Contour Map of Hourly Coincident Circuit Load (Year 2015)



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 PLL of all circuits connected to a single substation. In this Application, SCE uses this same criteria when assessing the time periods during which distribution circuits may have a capacity constraint. The results are then used to determine the time-varying nature of peak capacity-related costs for distribution circuits.[75]

Distribution Substations (B-banks): Distribution substations are designed to meet the total load of connected circuits at an individual substation. The recorded load is similarly compared to a threshold, defined as 90 percent of the individual substation PLL. Any load greater than or equal to the threshold will be considered for an upgrade. The results are then used to determine the time-varying nature of peak capacity-related costs for distribution substations.

Sub-Transmission Substations (A-banks): Sub-transmission assets typically constitute A-banks and subtransmission circuits. A-banks are planned to account for peak load needs in a similar manner as distribution B-banks. However, as discussed in the cost section above, due to the sizeable impact of losing load in the event of a sub-transmission contingency, the system has specifically been designed to accommodate load carrying capacity for such contingencies. This contingency driven planning results in a very small percentage of sub-transmission A-banks experiencing capacity constraints when the same 90 percent planning criteria threshold is used. To accommodate this issue, SCE therefore uses a proxy threshold of 90 percent of A-bank annual peak load.[76] The results are then used to determine the time-varying nature of peak capacity-related costs for sub-transmission substations.

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

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[75] 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.

[76] 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 planers 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.

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.

(i) 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.

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

where i= 1 to 8760th hour, j=1 to nth asset.[77]

Second, the number of peak load occurrences are then summed for all assets in each hour (equation 2, below),[78] and a relative ratio is determined for these hourly peak load values (equation 3).[79] This relative ratio is called the PLRF.

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

[78] 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.

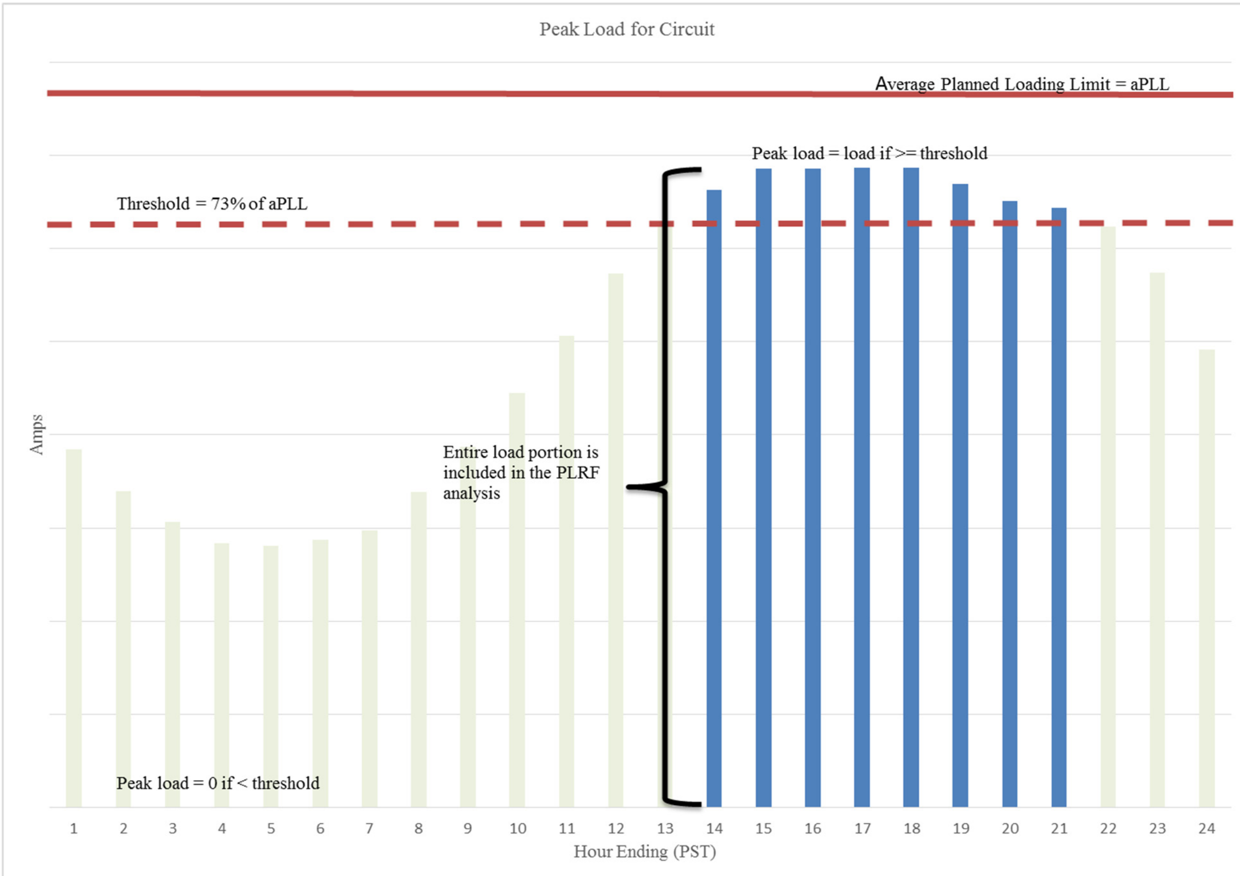
[79] This relative ratio defines the percentage load in an hour to the sum of the total peak load for each hour in the year, given the specified threshold.

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

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

The steps described above for calculating the PLRFs are further illustrated in the Figure I-7 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-7
Illustration of PLRF Methodology Applied to Circuit Data



(ii) <u>Analysis Based on Future Test Year 2021</u>

SCE uses an analysis of forecast system conditions in 2021 to capture the effect of the forecast distributed generation (DG) on distribution system peak loads.[80] SCE expects that the increased penetration of DG will shift the timing of circuit peak demands to later in the day, similar to the ISO system-level duck curve, except that it will also be observed on the distribution circuits and substations (*i.e.*, "ducklings"). SCE forecasted 2021 hourly circuit load using a two-step process:

[80] The inclusion of behind the meter distributed generation (DG) is appropriate as it is expected to be the predominant distributed energy resource affecting the load shape on the distribution system.

1. SCE forecast the penetration of DG on each circuit by applying a system-level growth rate of DG installations to the current level of DG penetration on each circuit.

2. SCE netted this forecast 2021 hourly DG shape against 2015 hourly load for each circuit.[81]

This method accounts for the impact of increased DG penetration on hourly circuit load while isolating the effects of load growth on circuits.

Figure I-8 illustrates the average hourly weekday profile for the years 2015 and 2021 after including expected DG penetration in the year 2021.[82]

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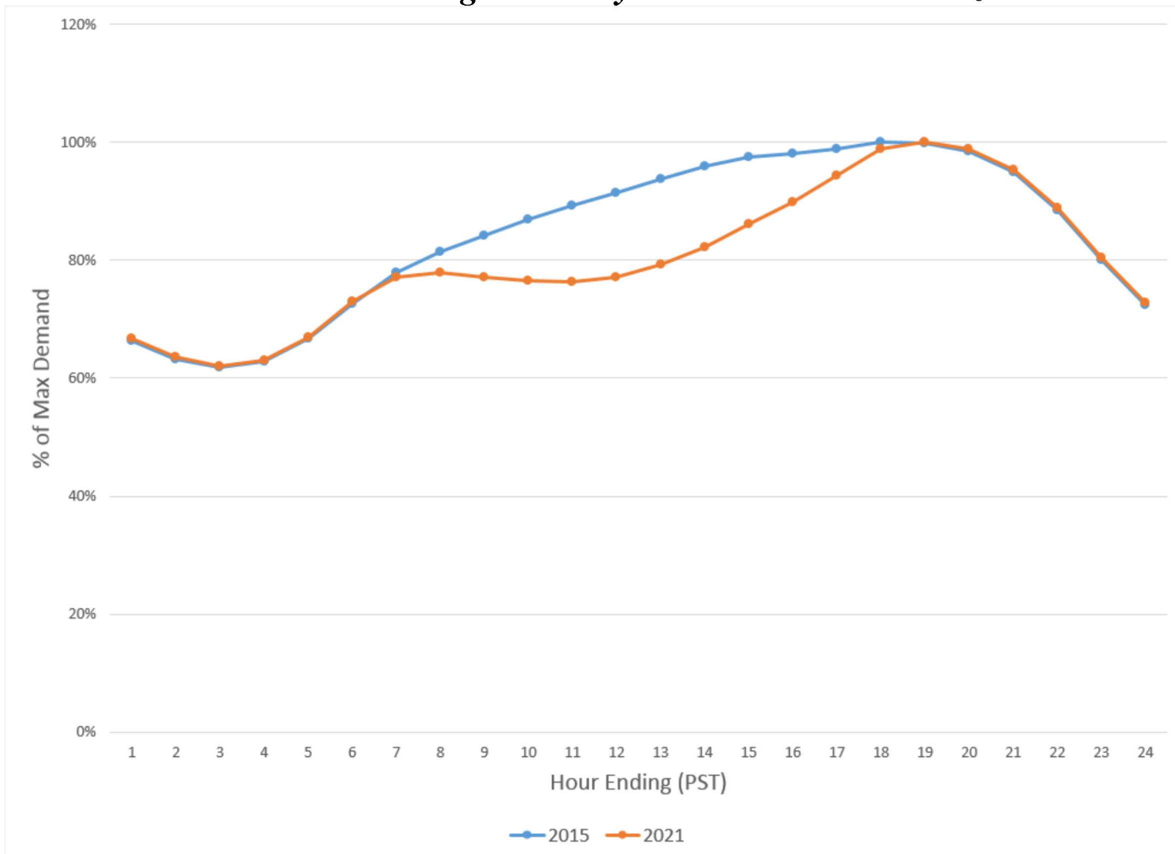
[81] By netting against 2015 hourly load, by circuit, SCE held constant the possible effects of load growth on the *shape* of the hourly circuit load. By using a solar shape based on an estimate of the levels of DG penetration expected in the year 2021, SCE isolated the effect of increased DG penetration on the hourly *shape* of circuit load. This analysis accounted for the varying levels of penetration expected on each circuit. The average customer driven load shape on each circuit is expected to be fairly constant in the forecast period. By including the expectation of DG penetration in this analysis, SCE attempts to model the impact of distribution level *mini-duck curves* on the time-sensitive nature of peak capacity constraints on the distribution system.

[82] Average weekday hourly load for both years was normalized to the maximum value of average hourly load in 2015. For purposes of showing the effect of expected DG penetration, the average profiles for 2015 and 2021 are plotted using 2015 day type.

Figure I-8
2015 vs. 2021 Average Weekday Circuit Load - Normalized



PLRF values are then calculated based on this netted load shape. To adjust for season and day type for 2021, the forecast 2021 “managed load” and recorded 2015 managed load were both sorted and paired by season, day type, and ranked load. SCE defines managed load as the difference between gross load minus the forecast of DG, plus the forecast of EV load.

(iii) Results

Distribution Circuits: When the 2021 circuit PLRF percentages are summed by season and day type as shown in Figure I-9, the timing of circuit peak demands happen at either 6 p.m. or 7 p.m.. The concentration of high PLRF percentages in the late afternoon hours aligns with the proposed peak TOU period.[83] Each line represents the relative

[83] *i.e.*, 4 p.m. to 9 p.m. as proposed in the 2016 RDW.

proportion of peak capacity constrained load when aggregated by hour and expressed as a percentage.

Figure I-9
2021 Forecast Circuit PLRF Percentages by Season and Day Type

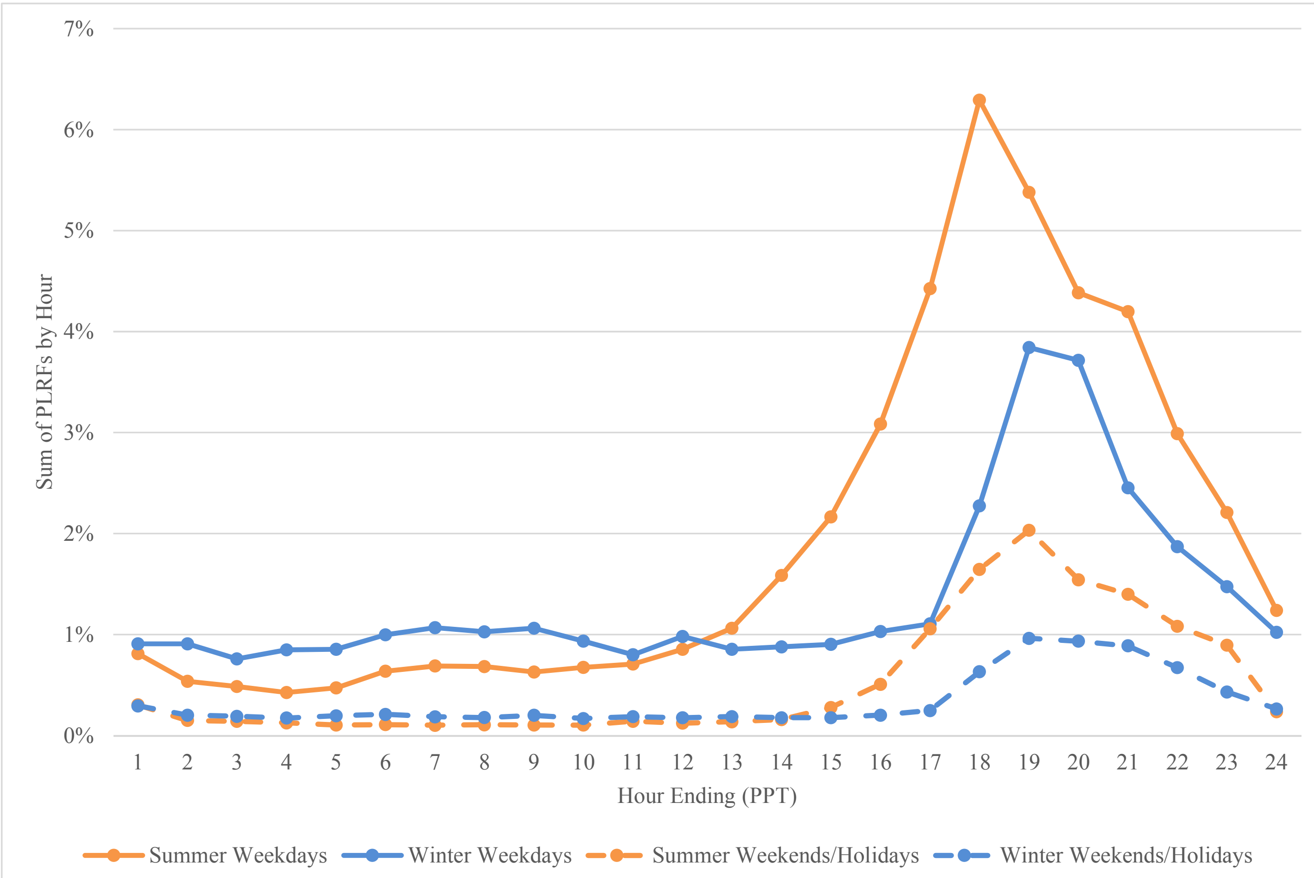


Table I-17 shows the circuit PLRFs aggregated by SCE's proposed TOU periods as filed in A.16-09-003. The circuit PLRF percentages are then multiplied by the peak-capacity-driven portion of marginal distribution circuit costs (*i.e.,* $26.8/kW-Yr) to compute the time-dependent allocation of such costs by TOU period.

Table I-17
2021 Forecast Circuit PLRF Percentages by Proposed Time-of-Use Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	25%	25%	42%	9%	100%
Summer	25%	8%	27%	n/a	59%
Winter	n/a	17%	15%	9%	41%

Distribution Substations (B-banks): Test-year 2021 B-bank data is comprised of 2015 B-bank data that accounts for 2021 DG penetration on each B-bank. Figure I-10 illustrates the dispersion of 2021 B-bank PLRF for summer and 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 show a similar concentration of capacity constrained hours expected in the modeled year when compared to the plot of the distribution circuits.

Figure I-10
2021 Forecast B-Bank PLRF Percentages by Season and Day Type

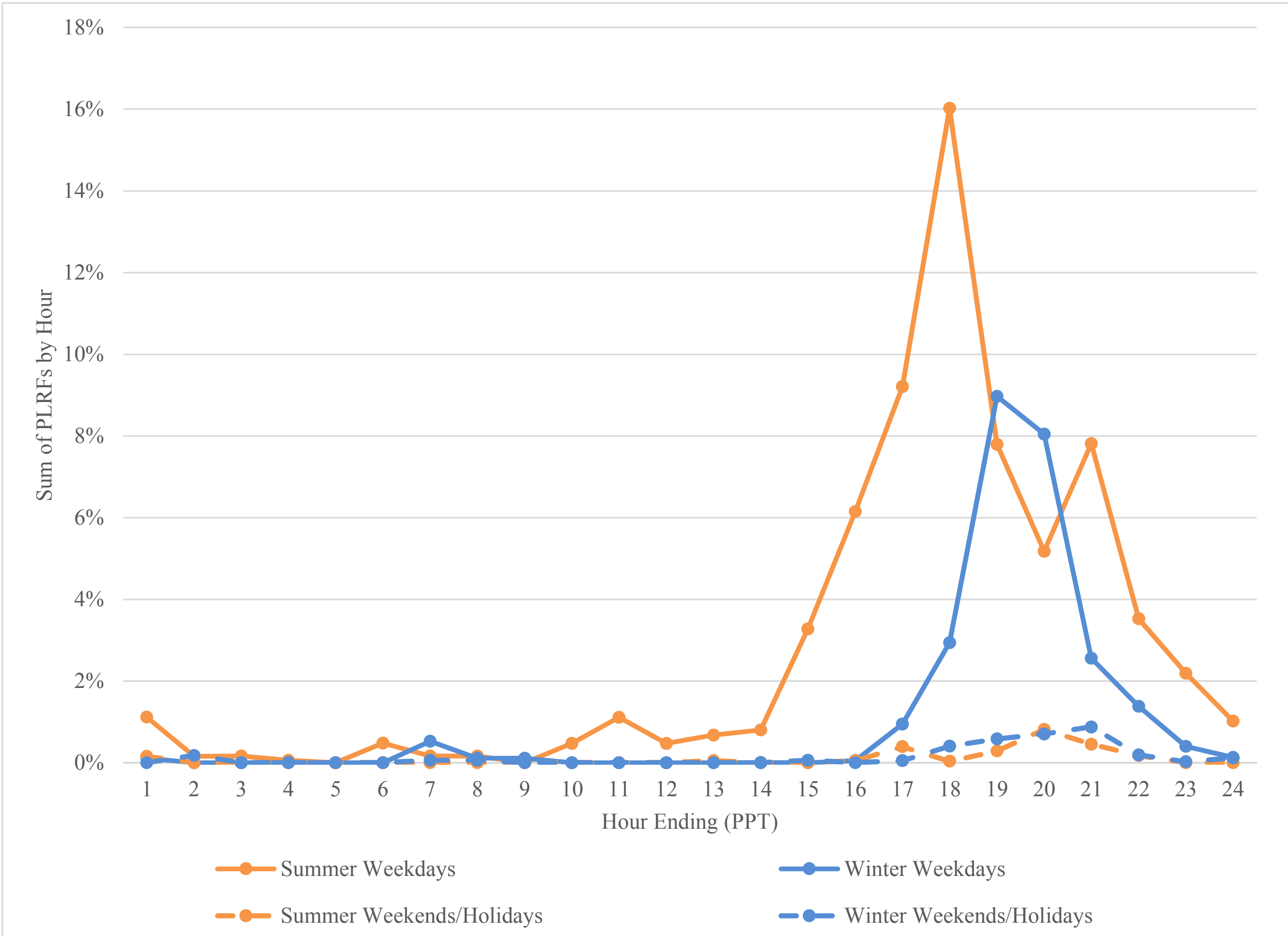


Table I-18 depicts the same PLRF percentages when aggregated by SCE's proposed TOU periods and shows that the results at the B-bank level are directionally aligned with the circuit PLRFs. The B-bank PLRF percentages are then multiplied by the specific peak-capacity-driven portion of the respective marginal distribution costs (*i.e.,* $25.0/kW-Yr) to determine the time-dependent allocation of such costs by TOU period.

Table I-18
2021 Forecast B-Bank PLRF Percentages by Proposed TOU Periods

Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	46%	28%	26%	0%	100%
Summer	46%	2%	22%	n/a	70%
Winter	n/a	26%	3%	0%	30%

Subtransmission Substations (A-banks): Since DG penetrations are not observed at the A-bank level, test-year 2021 A-bank data is comprised of 2015 A-bank data adjusted to 2021 season and day type. Figure I-11 illustrates the dispersion of 2021 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 shows a higher concentration of capacity constrained hours in the summer months of the modeled year.

Figure I-11
2021 Forecast A-Bank PLRF Percentages by Season and Day Type

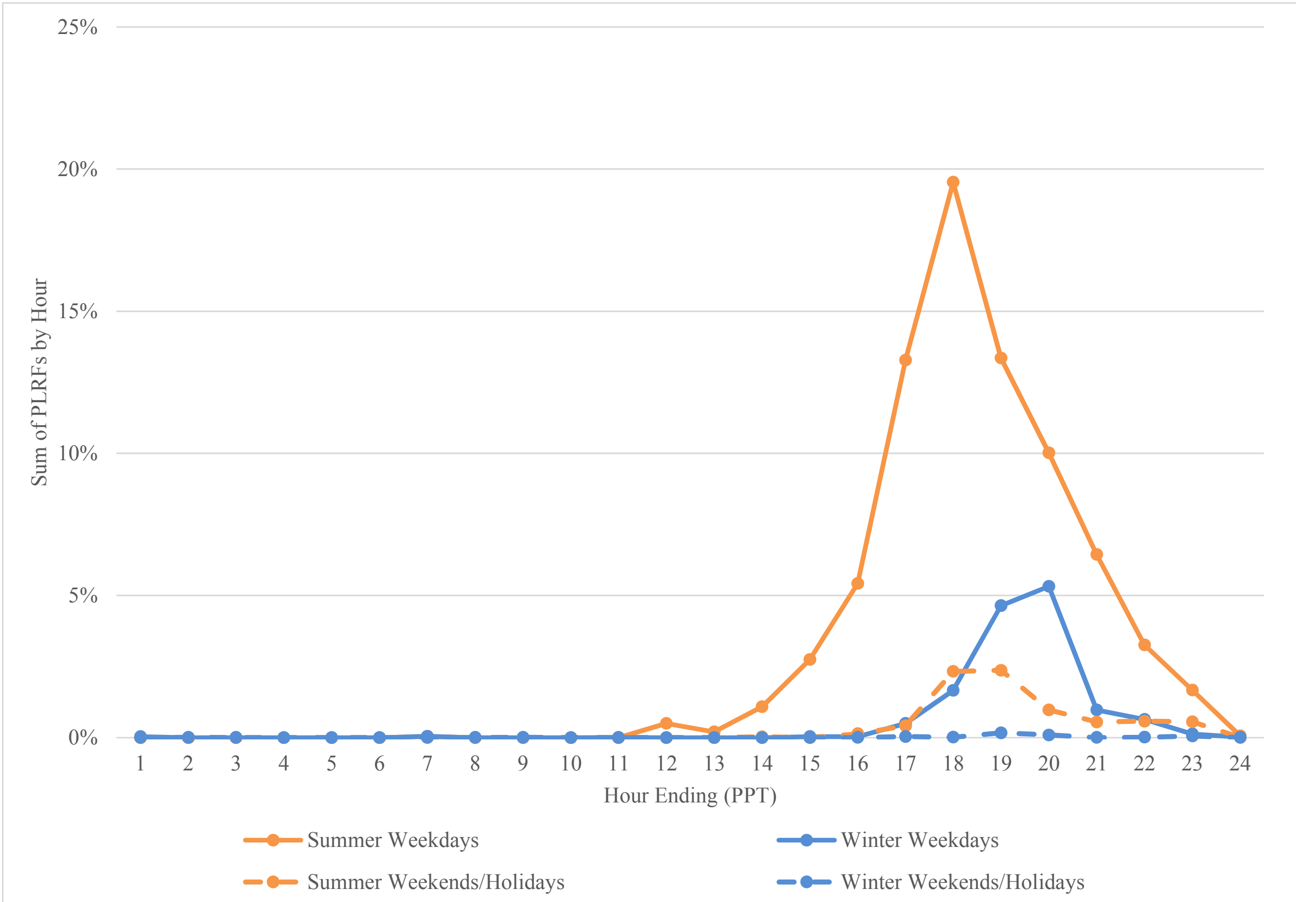


Table I-19 depicts the same PLRF percentages when aggregated by SCE's proposed TOU periods and shows that the results at the A-bank level are generally different from the PLRFs at the B-bank and distribution circuit level. The A-bank PLRF percentages are then multiplied by the specific peak-capacity-driven portion of the respective marginal distribution costs (*i.e.,* \$30.3/kW-Yr) to determine the time-dependent allocation of such costs by TOU period.

Table I-19
2021 Forecast A-Bank PLRF Percentages by Proposed TOU Periods

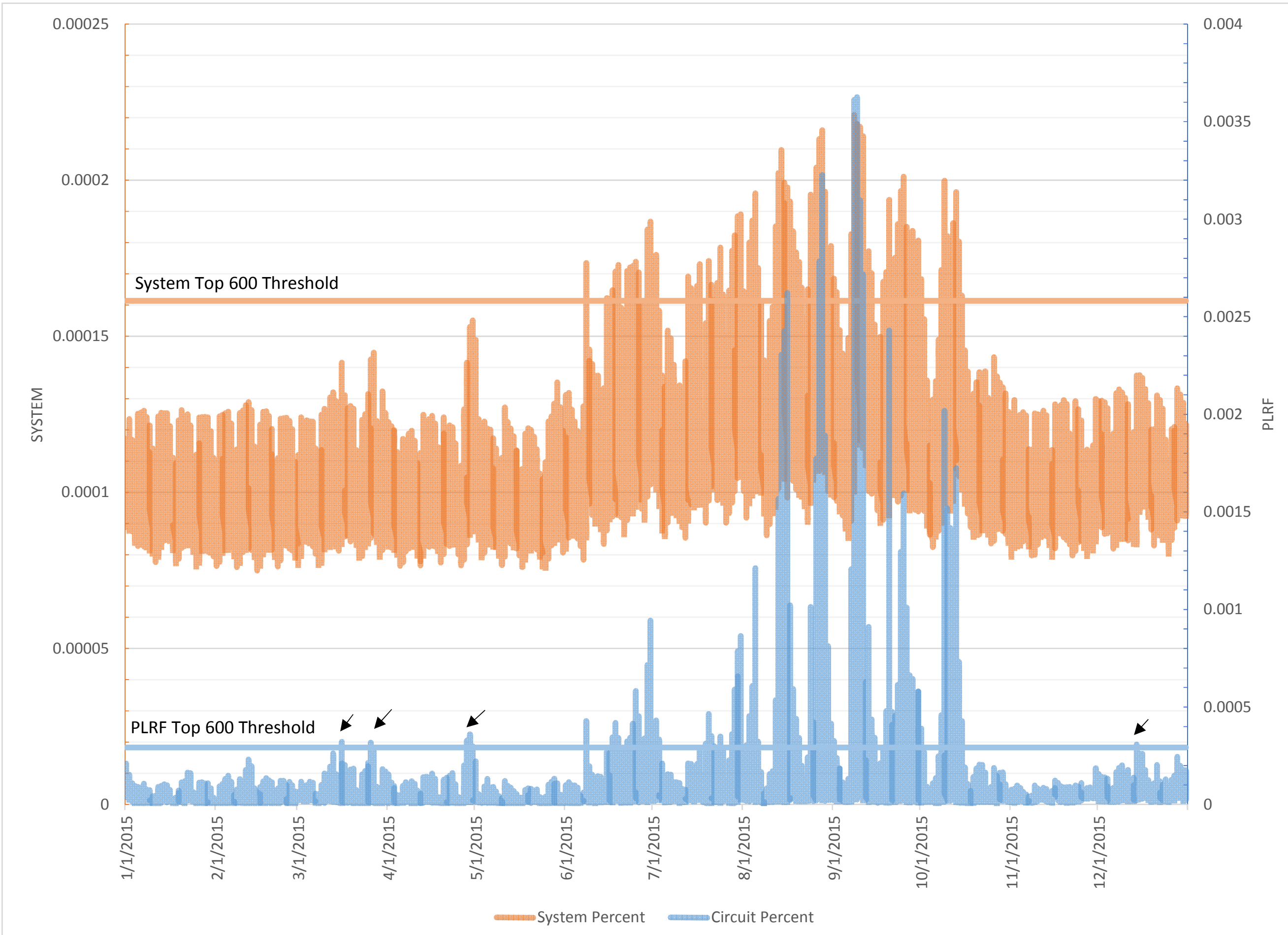
Season	On-Peak	Mid-Peak	Off-Peak	Super Off-Peak	Total
Annual	63%	20%	17%	0%	100%
Summer	63%	7%	16%	n/a	86%
Winter	n/a	13%	1%	0%	14%

(iv) 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-12. Based on 2015 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.[84] 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.

[84] 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 600 hours for the system and the top 600 hours for the PLRF values was drawn.

Figure I-12
Circuit PLRF and System Load Percentages in 2015



To see the effect at the regional level, the heat map in Table I-20 is derived from applying the PLRF methodology to the 2015 distribution circuit data. The percentage represented in each cell of the map is the sum of the individual circuit PLRF percentages by month, and also by planning region.[85] 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.

[85] 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.

Table I-20
Circuit PLRFs Across Planning Regions in 2015

Month	Desert	Metro East	Metro West	North Coast	Orange	Rurals	San Jacinto	San Joaquin
1	0.0%	0.1%	1.2%	0.6%	0.5%	0.6%	0.2%	0.1%
2	0.1%	0.3%	1.2%	0.6%	0.5%	0.4%	0.2%	0.1%
3	0.1%	0.4%	1.9%	1.1%	0.9%	0.4%	0.3%	0.2%
4	0.3%	0.4%	1.0%	0.9%	0.8%	0.4%	0.3%	0.1%
5	0.0%	0.1%	0.6%	0.8%	0.3%	0.5%	0.2%	0.3%
6	0.9%	1.2%	1.2%	1.2%	0.7%	0.7%	0.6%	1.1%
7	0.6%	1.1%	2.2%	1.1%	1.0%	0.6%	0.4%	1.5%
8	3.0%	4.8%	4.8%	2.0%	3.2%	1.1%	1.4%	1.1%
9	1.5%	5.3%	7.3%	2.3%	4.9%	0.6%	1.1%	0.3%
10	0.5%	1.6%	5.0%	1.6%	2.2%	0.5%	0.5%	0.0%
11	0.1%	0.1%	1.1%	0.5%	0.1%	0.9%	0.4%	0.0%
12	0.1%	0.4%	1.6%	0.6%	0.5%	1.3%	0.5%	0.1%

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

SCE has over 4,600 distribution circuits, each of which typically provide service to customers in a variety of rate groups. Distribution circuit EDFs are calculated as follows. First, the number of customers by rate group is determined for each circuit, and is used to develop a profile of the number of customers by rate group on a typical distribution circuit. These profiles are calculated for each type of customer, using an average of the circuits weighted by the number of customers of the particular type. For example, the typical TOU-8 (large customer) distribution circuit serves fewer residential and small business customers because the design demand of the large customer leaves less capacity available for others.[86] Next, a Monte Carlo simulation method is used to randomly populate each typical circuit type with customers from SCE's load research samples. This step is performed for each circuit type. Next, individual customers on each simulated circuit are selected, and the contribution of the customer to the circuit peak is determined. For example, if the Monte Carlo simulation is for a typical TOU-8 customer distribution circuit, the effect of one of the TOU-8 customer's load on the circuit is calculated. Finally, the second and third steps are repeated a sufficient number of times to produce statistically valid results. A similar approach is used to determine EDFs for subtransmission (*e.g.*, 66 kV) circuits. Due to the greater geographic area typically served by these higher voltage circuits, a single typical customer profile is used for all customer types.

Distribution circuit EDFs vary from around 28 percent to 37 percent for residential and small agricultural customers to 61 to 76 percent for medium and large 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

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86 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.

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 260 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 is included in Appendix B of this exhibit.

3. **Customer Marginal Costs**

Customer marginal costs include: (1) the investment-related equipment costs associated with connecting a customer to the grid and related ongoing O&M costs; and (2) the customer expenses related to services such as meter reading, billing and other customer service functions. For calculating the annual capital-related marginal customer cost, SCE used the RECC methodology.

In calculating investment-related costs, the approach includes the cost of long-life equipment directly related to providing access to the grid for a typical customer. For smaller customers, an example is the prorated portion of transformer capacity, service drop and meter because these facilities are dedicated to individual customers. With larger customers, the final line transformer is generally dedicated to an individual customer in addition to the corresponding service drop and meter. Residential and small business customers generally share transformation, and, since this represents the majority of our customers, these costs are attributed to these customers on the prorated basis of the amount of transformation capacity needed to serve a typical customer.

The investment-related costs for each rate group are further broken down into subgroups depending on the specific method of service. These subgroups are, for example, single-phase and three-phase, service voltage, etc., and are based on the average load characteristics for each rate group.

Customer hook-up facilities and associated costs are determined by means of a typical customer cost study. The current typical[87] cost study identifies the equipment required to connect a specific customer type and is used to estimate the costs of final line transformers, service drops, and meters. The annual per customer investment cost is calculated by multiplying the investment-related cost, including overhead and general plant loaders, by a real economic carrying charge yielding the annual customer investment cost. The O&M expenses related to the final line transformer is added to the annual capital cost.[88] The long run marginal customer investment cost for each rate group is the weighted average of these investment costs over any subgroups.

The next step is calculating short-run customer marginal costs for metering (meter services and meter reading), and customer service and billing. Marginal cost estimates for these activities are based on current cost studies that included labor requirements and frequency of each activity. The subject matter experts that compiled these studies, where possible, tried to incorporate known future activities that would be occurring within the next two to three years. Each component is summed to calculate a customer service marginal cost.

For purposes of the customer marginal cost study, customers were grouped into the following categories: residential; small and medium agricultural and pumping (demands less than or equal to 200 kW) and large agriculture and pumping (demands greater than 200 kW); and three commercial groupings of small commercial (demands less than 20 kW), medium commercial (demands between 20 and 200 kW), and large commercial and industrial (demands greater than 200 kW). Each of these categories includes the following components:

- Metering: meter services and meter reading
- Customer Services and Billing: bill presentation, interval data management, field

[87] "Typical" is defined as the most frequent type of customer hook-up.

[88] FLT O&M is based on the 2015 values and was scaled up using the Handy Whitman index and is allocated to rate groups based on each group's percentage of total system FLT cost.

services, billing exceptions, customer inquiry (call center), monthly payment processing, uncollectibles, collections, credit checks, and major account executives.

Service establishment, reconnection, and similar activities are not included as customer marginal costs. Revenue for these services is recovered through separate, usually non-recurring charges.

Generally, a customer who receives single-phase service has lower hook-up costs than a customer who receives service from a three-phase line. Customer marginal costs are disaggregated for single-phase and three-phase, so that these cost differences can be taken into account when designing rates.

The annual investment-related and customer service costs are added together to calculate the total customer marginal cost by rate group. As an example, the cost components for TOU-GS-1 customers are shown in Table I-21.

Table I-21
Customer Marginal Cost Components for GS-1 Customers
(in $/Customer-Year, 2018$)

GS-1 Component	**Single Phase ($/Customer/Yr.)**	**Three Phase ($/Customer/Yr.)**
Final Line Transformer*	49.55	144.29
Service Drop*	22.89	52.82
Meter*	35.51	51.84
Transformer O&M	1.23	3.59
Customer Services (meter reading, billing, etc.)	27.21	27.21
Subtotal	**136.39**	**279.75**
Total Customer Marginal Cost	**136.39**	**279.75**

* includes general plant loader

Since the compilation of data for the 2015 GRC, the company has undergone considerable efforts to streamline costs and thereby become more cost competitive. Decreases in the customer services costs expenses resulted from a combination of reducing the employee count, refining processes, and increasing effectiveness. In addition, several of the rate classes saw a decrease in their investment-related costs. In this Application, SCE updated the unit costs for equipment included in the typical customer cost study. As a result, the cost of some capital equipment updated in this GRC is lower than the cost estimate used in the 2015 GRC.[89] The marginal customer costs for all rate groups are shown in Table I-22.

[89] In the 2015 GRC, SCE did not update the unit cost of capital equipment used in the typical customer cost study. Cost estimates for such equipment were derived by applying standardized Handy Whitman escalation factors to the 2012 GRC levels of cost.

Table I-22
Customer Marginal Costs
(2018$)

Rate Group		Capital ($/Customer/Yr.)	O&M ($/Customer/Yr.)	Total ($/Customer/Yr.)
Domestic				
	Single Family	97.48	26.77	124.25
	Multiple	77.70	26.41	104.11
	TOUs	97.30	26.69	123.99
	Dom-Master Meter	787.95	160.31	948.26
GS-1				
	Single Phase	107.94	28.45	136.39
	Three Phase	248.95	30.81	279.75
TC-1		167.39	27.91	195.30
TOU GS-2				
	Single Phase	787.95	160.31	948.26
	Three Phase	1,504.80	172.53	1,677.33
	Primary	1,091.16	147.97	1,239.13
TOU GS-3				
	Secondary	2,331.26	700.99	3,032.26
	Primary	1,091.16	665.53	1,756.70
TOU-8				
	TOU-8-Sec	3,512.12	724.25	4,236.37
	TOU-8-Pri	1,535.28	665.53	2,200.81
	TOU-8-Sub	14,657.02	665.53	15,322.55
TOU-PA-2				
	Single Phase	373.34	130.71	504.05
	Three Phase	1,077.44	144.53	1,221.96
TOU-PA-3				
	Three Phase	2,851.25	551.84	3,403.09
	Primary	439.52	551.84	991.36
Street Lights (per customer)		107.94	27.64	135.58
Unmetered * (per lamp)				
	LS-1	1.39		
	LS-2	0.57		
	OL	1.60		
	DWL	0.64		

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

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

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

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

Because using the full marginal cost as a basis for the street light facilities rate would have resulted in a substantial increase for LS-1 customers, the Commission-adopted settlement implementing SCE's 2009 GRC Phase 2 Application included a 4.8 percent cap on the annual rate increase. However, this capping methodology was revised in SCE's 2012 GRC Phase 2 Settlement Agreement, such that the non-allocated facilities revenue requirement would equal the recorded street light facilities-related capital and O&M expenses, then allocated to the various types of street light options using the Marginal Cost Revenue Responsibility (MCRR) methodology.[90] This new methodology, utilized in the settlement approved by the Commission in D.13-03-031, is used in this Application to set the current street light facilities rate. This method more closely resembles rate design principles used to set rates in other classes by allocating authorized revenue requirements on an MCRR basis.

[90] D.13-03-031, p. 44. *See also* D.13-03-031, Appendix F, Street Light and Traffic Control Rate Group Settlement Agreement, pp. 5-6.

SCE calculates the cost of street light services based on a typical standard installation to calculate the length of circuits, lamps per circuit, span length, lamp size, and transformer connections. Table I-23 through I-26 show the marginal street light costs. Pursuant to the 2015 GRC Phase 2 Settlement Agreement adopted in D.16-03-030,[91] SCE has proposed a new distribution pole-mounted street lighting rate option for lamps that are mounted on SCE's distribution poles as opposed to being mounted on poles that solely support street lights. Details of this new rate option are included in Exhibit SCE-04. Table I-23 below illustrates the marginal costs of replacements for standard configurations, for streetlights only, as well as streetlights that are mounted on distribution poles.

[91] D.16-06-030, p. 43.

Table I-23
Monthly Street Light Facility Marginal Costs
(2018$)

LS-1: SCE Owned Streetlights

Lamp Type	Watts	Lumens	Wood Pole Streetlights Only			Distribution Pole-Mounted Streetlights		
			Facilities	O&M	Total	Facilities	O&M	Total
			$/lamp/mo.	$/lamp/mo.	$/lamp/mo.	$/lamp/mo.	$/lamp/mo.	$/lamp/mo.
Incandescent	103	1,000	19.14	3.12	22.26	11.88	3.12	15.00
Incandescent	202	2,500	19.14	3.04	22.18	11.88	3.04	14.92
Incandescent	327	4,000	19.14	3.03	22.17	11.88	3.03	14.91
Incandescent	448	6,000	19.08	3.35	22.43	11.83	3.35	15.18
Mercury Vapor	100	4,000	19.14	1.71	20.85	11.88	1.71	13.59
Mercury Vapor	175	7,900	19.08	1.22	20.30	11.83	1.22	13.05
Mercury Vapor	250	12,000	19.20	1.37	20.57	11.78	1.37	13.15
Mercury Vapor	400	21,000	19.88	1.25	21.13	12.46	1.25	13.71
Mercury Vapor	700	41,000	20.07	1.14	21.21	12.65	1.14	13.79
Mercury Vapor	1,000	55,000	20.07	1.93	22.00	12.65	1.93	14.58
High Pressure Sodium	50	4,000	19.14	1.25	20.39	11.88	1.25	13.13
High Pressure Sodium	70	5,800	19.08	1.25	20.33	11.83	1.25	13.08
High Pressure Sodium	100	9,500	19.03	1.24	20.27	11.78	1.24	13.02
High Pressure Sodium	150	16,000	19.54	1.25	20.79	12.11	1.25	13.36
High Pressure Sodium	200	22,000	19.88	1.25	21.13	12.46	1.25	13.71
High Pressure Sodium	250	27,500	19.89	1.26	21.15	12.47	1.26	13.73
High Pressure Sodium	310	37,000	20.07	1.27	21.34	12.65	1.27	13.92
High Pressure Sodium	400	50,000	20.07	1.28	21.35	12.65	1.28	13.93
Low Pressure Sodium	35	4,800	23.61	1.99	25.60	16.36	1.99	18.35
Low Pressure Sodium	55	8,000	23.61	1.99	25.60	16.36	1.99	18.35
Low Pressure Sodium	90	13,500	23.66	2.02	25.68	16.24	2.02	18.26
Low Pressure Sodium	135	22,500	23.19	2.18	25.37	15.77	2.18	17.95
Low Pressure Sodium	180	33,000	23.90	2.40	26.30	16.48	2.40	18.88
Metal Halide	70	5,500	n/a	n/a	n/a	n/a	n/a	n/a
Metal Halide	100	8,500	20.01	2.67	22.68	12.76	2.67	15.43
Metal Halide	150	12,000	20.01	2.18	22.19	12.58	2.18	14.76
Metal Halide	175	12,000	20.01	2.18	22.19	12.58	2.18	14.76
Metal Halide	250	19,500	20.41	1.85	22.26	12.98	1.85	14.83
Metal Halide	400	32,000	20.45	1.38	21.83	13.02	1.38	14.40
Metal Halide	1,000	100,000	22.54	1.61	24.15	15.12	1.61	16.73
Metal Halide	1,500	150,000	n/a	n/a	n/a	n/a	n/a	n/a
LED	25	50*	19.91	0.29	20.20	12.67	0.29	12.96
LED	32	70*	20.06	0.29	20.35	12.82	0.29	13.11
LED	41	100*	20.24	0.29	20.53	12.99	0.29	13.28
LED	88	150*	20.72	0.29	21.01	13.30	0.29	13.59
LED	90	200*	21.38	0.29	21.67	13.97	0.29	14.26
LED	161	250*	22.23	0.29	22.52	14.80	0.29	15.09
LED	157	310*	23.44	0.29	23.73	16.02	0.29	16.31
LED	193	400*	23.80	0.29	24.09	16.38	0.29	16.67
	Tap Devices	Tap Devices	2.84		2.84			

Table I-24
Monthly Street Light Facility Marginal Costs (continued)
(2018$)

LS-2: Customer Owned Streetlights

Rate Option			Facilities $/lamp/mo.	O&M $/lamp/mo.	Total $/lamp/mo.
LS-2 Rate A					
	Series Service		32.56	0.49	33.04
	Multiple Service		1.35	0.39	1.74
LS-2 Rate B					
	Multiple Service		5.62	0.12	5.74
Relamp Service (in addition to costs for LS-2A or LS-2B)					
	Watts	Lumens			
High Pressure Sodium	50	4,000	n/a	0.76	0.76
High Pressure Sodium	70	5,800	n/a	0.76	0.76
High Pressure Sodium	100	9,500	n/a	0.76	0.76
High Pressure Sodium	150	16,000	n/a	0.76	0.76
High Pressure Sodium	200	22,000	n/a	0.76	0.76
High Pressure Sodium	250	27,500	n/a	0.77	0.77
High Pressure Sodium	310	37,000	n/a	0.78	0.78
High Pressure Sodium	400	50,000	n/a	0.79	0.79

LS-3 Metered Service

Rate Option		Facilities $/service account/mo.	O&M $/service account/mo.	Total $/service account/mo.
	Series Service	533.79	5.56	539.35
	Multiple Service	n/a	n/a	n/a

Table I-25
Monthly Street Light Facility Marginal Costs (continued)
(2018$)

OL-1: Outdoor Lighting

Lamp Type	Watts	Lumens	Facilities	O&M	Total
			$/lamp/mo.	$/lamp/mo.	$/lamp/mo.
Mercury Vapor	175	7,900	19.08	1.22	20.30
Mercury Vapor	400	21,000	19.88	1.25	21.13
High Pressure Sodium	50	4,000	19.14	1.25	20.39
High Pressure Sodium	70	5,800	19.08	1.25	20.33
High Pressure Sodium	100	9,500	19.03	1.24	20.27
High Pressure Sodium	150	16,000	19.54	1.25	20.79
High Pressure Sodium	200	22,000	19.88	1.25	21.13
High Pressure Sodium	250	27,500	19.89	1.26	21.15
High Pressure Sodium	310	37,000	20.07	1.27	21.34
High Pressure Sodium	400	50,000	20.07	1.28	21.35
Low Pressure Sodium	35	4,800	23.61	1.99	25.60
Low Pressure Sodium	55	8,000	23.61	1.99	25.60
Low Pressure Sodium	90	13,500	23.66	2.02	25.68
Low Pressure Sodium	135	22,500	23.19	2.18	25.37
Low Pressure Sodium	180	33,000	23.90	2.40	26.30
Metal Halide	70	5,600	n/a	n/a	n/a
Metal Halide	100	8,500	20.01	2.67	22.68
Metal Halide	150	12,000	20.01	2.18	22.19
Metal Halide	175	12,000	20.01	2.18	22.19
Metal Halide	250	19,500	20.41	1.85	22.26
Metal Halide	400	32,000	20.45	1.38	21.83
Metal Halide	1000	100,000	22.54	1.61	24.15
Metal Halide	1500	150,000	n/a	n/a	n/a

Table I-26
Monthly Street Light Facility Marginal Costs (continued)
(2018$)

DWL: Domestic Walkway Lighting

Rate Option		Facilities	O&M	Total
		$/lamp/mo.	$/lamp/mo.	$/lamp/mo.
Rate A: SCE Owned Facilities				
High Pressure Sodium	50	11.73	1.25	12.97
High Pressure Sodium	70	11.73	1.25	12.98
High Pressure Sodium	100	11.73	1.24	12.97
High Pressure Sodium	150	11.73	1.25	12.98
Metal Halide	100	11.73	2.67	14.40
Metal Halide	175	11.73	2.18	13.91
Mercury Vapor	75	11.73	1.29	13.02
Rate B: Customer Owned Facilities				
	Multiple Service	1.35	0.39	1.74
Rate C: Optional Re-lamp Service (in addition to costs for Rate B)				
High Pressure Sodium	50	n/a	0.76	0.76
High Pressure Sodium	70	n/a	0.76	0.76
High Pressure Sodium	100	n/a	0.76	0.76
High Pressure Sodium	150	n/a	0.76	0.76
Metal Halide	100	n/a	2.19	2.19
Metal Halide	175	n/a	1.69	1.69
Mercury Vapor	75	n/a	0.80	0.80

II.

SALES AND CUSTOMER FORECAST

The kilowatt-hour sales forecast for 2018 ("Sales Forecast") forms the basis for the billing determinant forecast discussed below and is used for rate design purposes in this phase of the GRC.[92] The Sales Forecast reflects the energy that SCE expects to deliver to bundled service customers and DA and CCA customers in its service territory during the 2018-2020 period. It excludes sales to public power customers, contractual sales, or interchange energy with other utilities.

Historical sales data are statistically related to the historical values of key economic drivers, electricity prices, and weather conditions. Thus, SCE uses econometric models to construct its sales forecasts for the major revenue classes: residential, commercial, industrial, agriculture and other public authority. Revenue class data are used in the models because they have been defined in a consistent manner throughout the historical period used in the econometric models. The sales forecast for each revenue class is produced monthly and summed up to an annual value.[93] The resulting regression equations, in conjunction with forecasts of the economic drivers including electricity prices and normal weather conditions, are used to predict sales by revenue class. Model-generated forecasts may be modified based on current trends, judgment, and events that are not specifically modeled in the equation.

Table II-27 shows SCE's forecast of grid kilowatt-hour sales and customers for years 2018 through 2020.

[92] The Sales Forecast is discussed in detail in A.16-09-001. *See* SCE-09, Results of Operation (R/O), Vol. 1, Chapter V, pp. 58-70.

[93] 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-27
Forecast Grid Sales and Customers
For Years 2018 Through 2020

Line No.	Rate Group	2018	2019	2020
1	**Grid Sales*(GWH)**			
2	Residential	27,722	27,245	26,584
3	Agricultural	1,499	1,542	1,565
4	Commercial	42,086	42,705	42,826
5	Industrial	7,888	7,731	7,498
6	OPA	4,377	4,248	4,094
7	**Total Retail Sales**	**83,572**	**83,470**	**82,567**
8	**Net Customer Additions**			
9	Residential	34,868	35,374	35,008
10	Agricultural	(117)	(118)	(123)
11	Commercial	7,192	7,245	7,214
12	Industrial	(67)	(95)	(116)
13	OPA	55	97	125
14	**Total Customers**	**41,932**	**42,502**	**42,107**
15	**Customers**			
16	Residential	4,486,121	4,521,495	4,556,502
17	Agricultural	20,948	20,830	20,708
18	Commercial	582,516	589,761	596,975
19	Industrial	10,651	10,556	10,439
20	OPA	46,606	46,703	46,828
21	**Total Customers**	**5,146,843**	**5,189,344**	**5,231,452**

* Grid Sales include bundled service and DA customers.

A forecast of billing determinants for 2018 is required to evaluate the present rate revenues, that is, the revenues that SCE's current rates would be expected to provide in 2018, 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-09 of SCE's 2018 GRC Phase 1 Application.[94] 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.

Present rate revenues are defined as the revenues SCE would expect to collect in a future period (2018) given its current rates and forecast of billing determinants. Present rate revenues are provided for each revenue component, *e.g.*, distribution, transmission, generation, etc., and for each rate group. As with billing determinants, SCE's GRC Phase 1 testimony contains a description of the methodology SCE uses to develop present rate revenues.[95]

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[94] Exhibit SCE-09, Results of Operation (R/O), Vol. 1, Chapter VI, pp. 71-74, in A.16-09-001.

[95] *Id.*, pp. 74-75.

Appendix A

Glossary

Allowance for Funds Used During Construction (AFUDC): the net cost for the period of construction of borrowed funds used for construction purposes.

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.

Coincidence Factor: The ratio of the maximum group coincident demand to the sum of individual customers' non-coincident peak demands.

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.

Competition Transition Charge (CTC): A charge for recovery of costs, delineated in Section 367 and 368 of AB 1890, which were defined to be uneconomic as a result of the restructuring of electric industry.

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.

Consumer Price Index (CPI): A measure of the annual rate of inflation for all urban consumers.

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

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

Demand-Side Management (DSM): Utility sponsored end-user programs or activities that enable the efficient use of energy and/or demand reduction by the end-use customer.

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: 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.

Expected Unserved Energy (EUE): The expected amount of energy that will fail to be supplied per year due to generating capacity deficiencies

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.

Handy-Whitman Index: A measure of the annual rate of inflation in capital investments. Indexes are published for a wide range of industries and investment categories.

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.

Load Serving Entity (LSE): Any entity that procures power to provide to end use customers.

Loss of Load Expectation: The portion of time that available 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

Maximum Likelihood Estimate (MLE): A statistical estimate based on Maximum Likelihood Estimation. Maximum Likelihood Estimation for a given data set and statistical model selects the model parameters to maximize the value of the likelihood function. Parameters selected in this manner will maximize the "agreement" of the observed data and the selected model.

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

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 charge that applies to DA or CCA customers or DA or CCA customers returning to bundled service who are now in Transitional Bundled Service (TBS). The PCIA reflects DA and CCA customes' share of ongoing power costs after 2002.

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.

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 requirement 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.

Western Electricity Coordinating Council (WECC): A nonprofit corporation formed by members of the interconnected western grid with the objectives of maintaining a reliable electric power system, assuring open and non-discriminatory transmission access, and providing a forum for dispute resolution.

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 2003, 2006, 2009, 2012 and 2015 GRCs, 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 4,267 circuits serving 4.9 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 formula[1] (illustrated for the domestic and TOU-GS-1 customer groups):

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[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:

$$\sum_i N(DOM,i) * N(DOM,i) \Big/ \sum_i N(DOM,i)$$

$$\sum_i N(DOM,i) * N(GS1,i) \Big/ \sum_i N(DOM,i)$$

$$\sum_i N(DOM,i) * N(GS2,i) \Big/ \sum_i N(DOM,i)$$

etc.

TOU-GS-1 Customer Distribution:

$$\sum_i N(GS1,i) * N(DOM,i) \Big/ \sum_i N(GS1,i)$$

$$\sum_i N(GS1,i) * N(GS1,i) \Big/ \sum_i N(GS1,i)$$

$$\sum_i N(GS1,i) * N(GS2,i) \Big/ \sum_i N(GS1,i)$$

etc.

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

Circuit	# of Domestic Customers	# of GS-1 Customers	DOM * DOM	GS-1 * GS-1	DOM * GS-1
A	3	1	9	1	3
B	2	1	4	1	2
C	0	2	0	4	0
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:

Typical	Number of Customers	
Circuit	Domestic	TOU-GS-1
Domestic	2.6	1
TOU-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 1,744 domestic, 172 TOU-GS-1, 5 TC-1, 26 TOU-GS-2, 2 TOU-GS-3, 5 TOU-PA-2, and 6 street lighting customers. Therefore, we made repeated random drawings of 1,744 Domestic, 172 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 1,744 customers. This provided 87,200 observations (some of which were duplicates since this is larger than the total residential load research sample of approximately 15,000 accounts).[2] For each of these 87,200 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

[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.

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 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). The EDFs for the TC-1 group (traffic control accounts) are set to 1.00 by definition since these customers have a flat load.

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

	Domestic									TOU-8		TOU-8-S			
Typical Circuit	**Single**	**Multiple**	**Master Metered**	**GS-1**	**TC-1**	**GS-2**	**TOU-GS-3**	**TOU-PA-2**	**TOU-PA-3**	**Secondary**	**Primary**	**Secondary**	**Primary**	**Street Lighting**	**Total**
Domestic	n/a	1,744	n/a	172	5	26	2	5	0	0	0	0	0	6	1,960
- Single	1,158	494	2	140	4	22	2	5	0	0	0	0	0	5	1,832
- Multiple	756	1,122	4	221	5	32	2	4	0	1	0	0	0	7	2,154
- Master-Metered	754	927	11	225	5	32	2	5	0	0	0	0	0	6	1,967
GS-1	728	750	3	243	5	39	3	6	0	1	0	0	0	6	1,784
TC-1	795	631	3	187	7	35	3	4	0	1	0	0	0	7	1,673
GS-2	617	595	2	215	6	47	3	4	0	1	0	0	0	6	1,496
TOU-GS-3	596	510	2	177	5	41	5	3	0	1	0	0	0	6	1,346
TOU-PA-2	604	267	2	124	2	16	1	71	2	0	0	0	0	3	1,092
TOU-PA-3	651	345	1	122	3	20	2	29	3	1	0	0	0	5	1,182
TOU-8-SEC	439	355	1	145	5	39	4	3	0	3	0	0	0	5	999
TOU-8-PRI	454	358	2	126	4	30	3	5	0	1	1	0	0	4	988
TOU-8-S-SEC	426	389	1	126	5	31	3	3	0	1	0	1	0	4	990
TOU-8-S-PRI	362	297	1	111	3	21	2	7	0	1	0	0	1	3	809
Street Lighting	748	671	2	179	5	32	3	3	0	1	0	0	0	15	1,659

Table B-2
Effective Demand Factors

Rate Group	**Effective Demand**		
	12 kV	**66 kV**	**220 kV**
Residential	0.36	0.36	0.36
GS-1	0.37	0.37	0.37
TC-1	1.00	1.00	1.00
GS-2	0.61	0.62	0.62
TOU-GS	0.73	0.70	0.69
TOU-PA-2	0.28	0.25	0.24
TOU-PA-3	0.42	0.36	0.32
Large Power Excluding Standby Accounts:			
TOU-8-Secondary	0.75	0.72	0.68
TOU-8-Primary	0.76	0.68	0.63
TOU-8-Subtran		0.71	0.61
Street Lighting	0.07	0.06	0.06
Large Power Standby Customers Total Load:			
TOU-8-Secondary-Standby	0.73	0.70	0.64
TOU-8-Primary-Standby	0.74	0.62	0.53
TOU-8-Subtran-Standby	n/a	0.36	0.24
Large Power Standby Customers Backup Load:			
TOU-8-Secondary-Standby	0.74	0.69	0.67
TOU-8-Primary-Standby	0.62	0.50	0.41
TOU-8-Subtran-Standby	n/a	0.32	0.20

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 2015, SCE had approximately 260 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 88 of these customers, SCE had data on the generator output and the power sold to the customer by SCE in 15-minute intervals (for 87 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.

To determine the back-up load, Standby customers were divided into two groups:

a) Fully Resourced Customers

In general, these customers' energy needs are met by their own generators. When the customer's generator fails, all energy needs are supplied by SCE. For these customers, back-up load is defined to be equal to their load served by SCE.

b) Partially Resourced Customers

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.

For this Application, SCE is treating Standby customers in the large power rate groups as a separate rate group, and used 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

Marginal Energy Cost Analysis

Major Input Assumptions Applied in the Simulated Marginal Energy Cost (MEC) Analysis

PLEXOS Database Overview

SCE's forecast of the fundamentals-based hourly marginal energy prices were based predominately on the input parameters contained in the 2017 Long-Term Procurement Plan PLEXOS database. The PLEXOS model used in the price forecast is a California-only nodal model based on the Full Network Model (FNM) published by the California Independent System Operator (CAISO) on a regular basis. Specifically, this database contains all the necessary resource, load, fuel, and transmission assumptions throughout the CAISO to develop a price forecast. Where appropriate, SCE updated certain elements of the database to include its own expectations of the market environment or to reflect more recent forecast conditions. For example, natural gas fuel prices from April 2017 were used to update the PLEXOS database, so they reflect more recent forecast conditions.

Forecast *Horizon*

SCE's Plexos model has resource assumptions through 2030. This model serves as the basis for the GRC marginal energy cost analysis. Since the GRC marginal cost analysis relies primarily on the forecast years 2018 through 2021, the description below focuses on this period only.

Inflation

The results from SCE's marginal cost analysis originate in 2018 real dollars. An inflation factor is applied to scale the results into nominal dollars when appropriate. As in prior GRC proceedings, SCE used the gross domestic product implicit price deflator (GDP IPD) from IHS Markit Ltd. as the basis for the inflation rates, shown in the following table.

Table C-1
Annual GDP IPD

Year	Growth Rate
2018	2.23%
2019	2.09%
2020	2.07%
2021	2.05%

Natural Gas Price

The gas price assumption is a blend of market forwards and fundamentals forecasts from two vendors as of Spring 2017. Market forwards are used for the front end.[1] To account for the declining liquidity of the market view, SCE incorporates a fundamental view in the back-end. The two forecasts are then blended together.

Load Forecast

Recent Spring 2017 vintage of SCE's forecasted load for SCE, PG&E and SDG&E are used.

Energy Efficiency

The table below represents SCE's forecast of annual incremental energy efficiency savings from both existing and future programs.

Table C-2
SCE Incremental Annual Energy Efficiency Forecast

Year	GWh
2018	-
2019	543
2020	1,086
2021	1,629

Demand Response

The table below represents SCE's forecast of annual accumulative Demand Response.

Table C-3
SCE Annual Demand Response Forecast

Year	MW
2018	57
2019	56
2020	60
2021	65

Distributed Generation (DG)

Below is the expected SCE annual distributed generation energy production.

1 NYMEX Henry Hub plus ICE Southern California basis differential as of April 2017.

Table C-4
SCE Annual Distributed Generation Forecast

Year	GWh
2018	10,015
2019	11,601
2020	13,385
2021	14,991

Renewables

SCE's build out assumes compliance with California's Renewables Portfolio Standard, in which SCE plans to meet the statutory requirement that 33 percent of its retail energy sales be served by renewable generation by 2020 and 40 percent by 2024. In the PLEXOS simulation model, 90 percent of wind and solar generation are assumed to be scheduled in the CAISO day-ahead market.

Table C-5
California Central Station Renewable Generation

Year	GWh
2018	49,782
2019	54,042
2020	58,337
2021	60,570

Carbon Emission Costs

The carbon emission cost forecast is derived in a manner similar to SCE's Natural Gas Price Forecast. Fundamental forecasts from three vendors are averaged and blended with short-term market data. The market data used for this forecast is as of Spring 2017.

Table C-6
Carbon Emission Cost
$/short-ton

Year	$ Nominal
2018	13.24
2019	13.86
2020	17.01
2021	23.05

Transmission Assumptions

The PLEXOS model used in the MEC forecast is a California-only nodal model based on the FNM published by the CAISO on a regular basis. All the transmission line and interface definition and enforcement are consistent with CAISO's FNM.

Retirement Assumptions

SCE assumes the retirement of once-through cooling (OTC) generator units including Redondo Beach, Alamitos, Mandalay, Huntington Beach and Ormond Beach over the period 2018-2021 for SCE's area. The MW impact on SCE's system is summarized in the table below.

Table C-7
Generator Retirements in SCE's Area

Year	MW
2018	0
2019	0
2020	5,765
2021	0

Appendix D

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 the "price signals" that utility customers see as a result of their consumption decisions and result in improved economic efficiency in comparison to flat rates, which do not vary by time of day or season.[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 standard TOU periods SCE proposed in its 2016 RDW are as follows:

Table D-1
2016 RDW Proposed Base TOU Periods for Non-Residential Customers

Time-of-Use Period	Summer (June-September)	Winter (October – May)
On-Peak	4:00 p.m. – 9:00 p.m. Non-Holidays, Weekdays	n/a
Mid-Peak	4:00 p.m. – 9:00 p.m. Weekends	4:00 p.m. – 9:00 p.m.
Off-Peak	All other hours	9:00 p.m. – 8:00 a.m.
Super-Off-Peak	n/a	8:00 a.m. – 4:00 p.m.

In each GRC cycle, SCE performs a costing period study to determine whether a change in the TOU rate structure is warranted based on marginal cost considerations. Based on the review of 2021 marginal costs described herein, SCE concludes that the ***proposed*** TOU periods in SCE's 2016 RDW appropriately reflects the distribution of generation and distribution marginal costs on a seasonal and time-of-day basis. This conclusion takes into account the total marginal costs forecast in SCE's service area for the year 2021.

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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.

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 capacity-related distribution marginal costs. The sum of all these costs are referred to as *total marginal costs* in this Appendix. All other marginal cost components are considered non-time differentiated and excluded from the analysis.

SCE's proposed TOU periods maintain the current seasonal definitions of summer and winter. The TOU periods have been defined to 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 load 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. SCE expects that marginal costs in the mid-peak period will be increasingly affected by the need for flexible resources in meeting ramp constraints on the system. The off-peak period reflects times when loads are low, resulting in marginal costs that are generally lower than the peak (on and mid) periods. In SCE's 2016 RDW, SCE introduced a super-off peak period where marginal costs are at their lowest levels, caused by the over-supply of renewable generation expected in that period.

In addition to a visual inspection of how TOU periods align with the hourly and seasonal dispersion of marginal costs, SCE performed a quantitative analysis of "goodness of fit" of the periods defined in SCE's 2016 RDW. By comparing various TOU rate proposals using this goodness-of-fit analysis, the rate structure that best fits the load and pricing patterns can be identified. This analysis is presented in Sections III and IV, below.

III. Cost Analysis

In this section, variations in SCE's TOU periods are investigated. As described in Section II, this analysis is based on total marginal costs for the year 2021, with adjusted R^2 used as the "goodness of fit" measure. The specific scenarios investigated are summarized in Table D-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 a number of dummy 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.[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 dummies being true at the same time. The omitted season/TOU period is Winter Off Peak.[3] The coefficients, the $\beta_i's,$ represent the effect of the interaction term on MW. That is how much MW increases in the Summer On Peak, for example, is given by β_1. The intercept term $\alpha_0$is the MW 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 will look at two TOU period scenarios. The first is the existing TOU-8 time periods (Case A) and the second is the proposed TOU-8 time periods (Case B). Both are analyzed using the regression methodology described above and the adjusted R^2's are compared to determine which model

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2 For additional discussion of measures of "goodness of fit," *see* Greene, William H., Econometric Analysis, 2nd Edition (New York, NY: Prentice Hall, 1993), 191-193.

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

provides a better fit to the data. In presenting results, the adjusted R^2 value of each of these scenarios is presented in Table D-4.

Tables D-2 and D-3 present the regression results for the current and proposed scenarios respectively. These results contain a number of statistics include the adjusted R^2s and the estimated coefficients noted above (the β and α coeffiencts). For example, the intercept (α) for the current scenario represents $0.03666 for the Winter Off Peak period. For the proposed scenario, the intercept has a value of $0.04906 for the Winter Off Peak. Similar interpretations can be applied to the other coefficient estimates. The estimate of the intercept is the average cost of the Winter Off Peak and the remaining coefficient estimates are additional costs relative to the omitted period (Winter Off Peak). Coefficients that have been bolded represent statistical significance at the 95 percent level.

Table D-2
Regression Step Function 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	5	549.03132	109.80626	2328.11	<.0001
Error	8754	412.88633	0.04717		
Corrected Total	8759	961.91765			
Root MSE	0.21718	**R-Square**	0.5708		
Dependent Mean	0.06351	**Adj R-Sq**	0.5705		
Coeff Var	341.93229				

Parameter Estimates					
Variable	**DF**	**Parameter Estimate**	**Standard Error**	**t Value**	**Pr > |t|**
Intercept=Winter Off	1	0.03666	0.0036	10.19	<.0001
Summer Mid	1	0.10531	0.0086	12.24	<.0001
Summer On	1	0.05379	0.01022	5.27	<.0001
Winter Mid	1	0.0064	0.00588	1.09	0.2765
Summer Off	1	0.00517	0.00646	0.8	0.4232
Top 20	1	5.17862	0.0487	106.33	<.0001

Table D-3
Regression Step Function for <u>Proposed</u> 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	561.08932	93.51489	2042.11	<.0001
Error	8753	400.82833	0.04579		
Corrected Total	8759	961.91765			
Root MSE	0.21399	**R-Square**	0.5833		
Dependent Mean	0.06351	**Adj R-Sq**	0.583		
Coeff Var	336.92162				

Parameter Estimates					
Variable	**DF**	**Parameter Estimate**	**Standard Error**	**t Value**	**Pr > |t|**
Intercept=Winter Off	1	0.04096	0.00414	9.9	<.0001
Summer Mid	1	0.034	0.01648	2.06	0.0391
Summer On	1	0.21845	0.01115	19.58	<.0001
Winter Super Off	1	-0.01492	0.00638	-2.34	0.0194
Summer Off	1	0.00243	0.00607	0.4	0.6894
Winter Mid	1	0.01526	0.00742	2.06	0.0397
Top20	1	5.11923	0.04816	106.3	<.0001

Table D-4
Break Analysis on Total Marginal Cost
Current TOU–8 Peak Periods vs. Proposed Peak Periods

Case	**Adjusted R^2 (higher number is better)**
Case A: Summer On-Peak Noon-6 p.m.	0.5705
Case B: Summer On-Peak 4-9 p.m. (RDW Proposal)	0.583

The following graphs provide a graphical representation of the tabulated regression results above.

Figure D-1
Graphical Representation of Regression Analyses on Current TOU Periods Marginal Cost

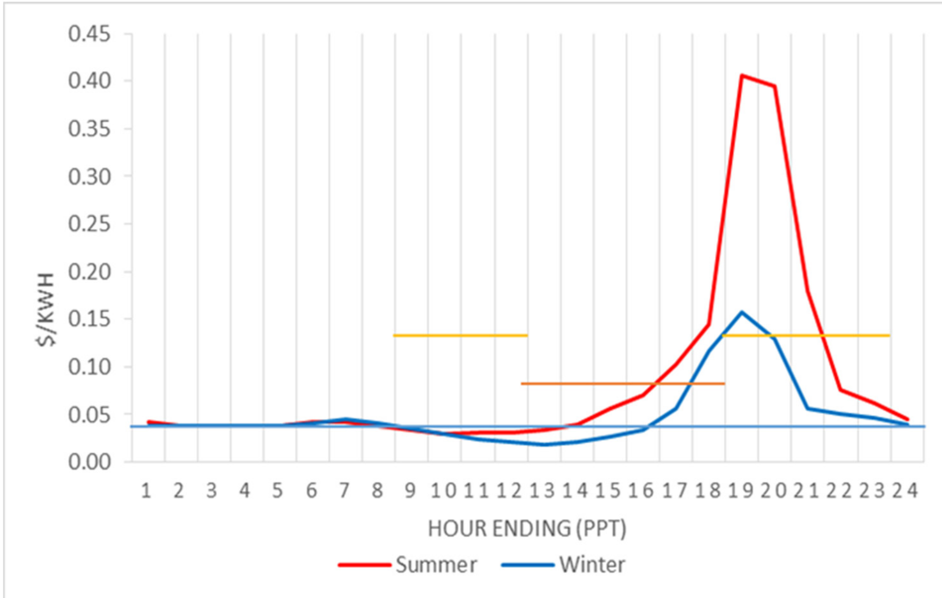
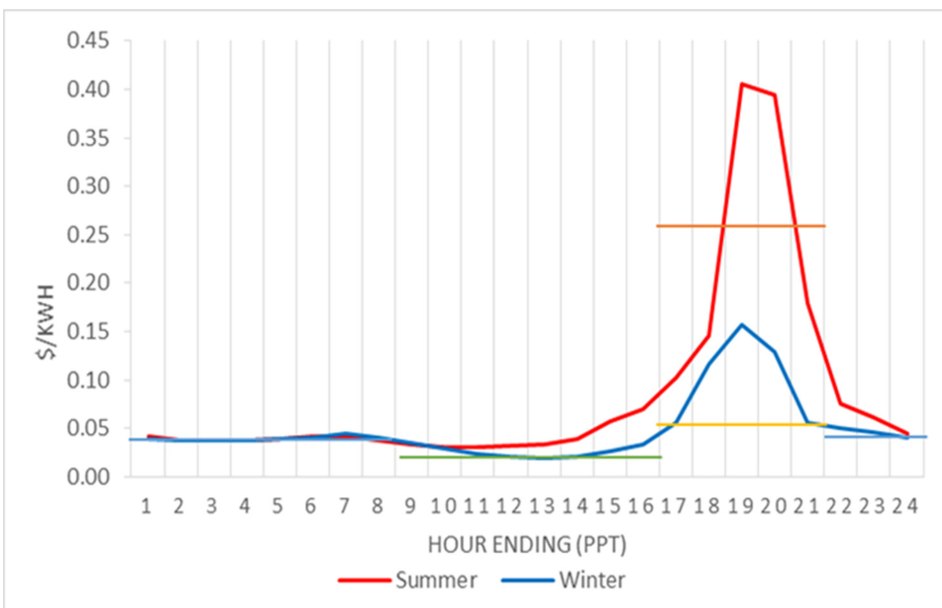


Figure D-2
Graphical Representation of Regression Analyses on Proposed TOU Periods Marginal Cost



The continuous lines show the seasonal average marginal costs and the step lines illustrate the estimates of the regression results. The errors or residuals consist in the differences between the two sets of lines. As demonstrated by the graphs, the lines in the proposed periods are a better fit to each other.

IV. Regression Analysis Recommendations

The results of this analysis support the use of the TOU periods proposed 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. The 2016 RDW proposal outperforms the current TOU periods and yet is still relatively simple for customers to understand.

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 decide whether the TOU periods need to be revised.

In Advice 3581-E, SCE proposed to establish a dead band tolerance range based on the results of a (a) top-20 and top-100 highest-cost hour assessment and (b) lowest 20 and lowest 100 cost hour assessment. If the results showed that less than 75 percent of the top 20 and the top 100 highest cost hours fall within the current on-peak period, the dead band tolerance range is exceeded and a more frequent update to the TOU periods may be warranted. Similarly, if less than 75 percent of the lowest 20 and lowest 100 cost hours fall within the current off-peak (or super-off-peak) period, the dead band tolerance range is exceeded and a more frequent update to the TOU periods may be warranted.

While SCE's proposal is still pending Commission approval as of the date of this filing, in accordance with D.17-01-006, SCE performed an analysis of its proposed dead band tolerance range proposal against existing TOU periods and the TOU periods proposed in the 2016 RDW.

Using the highest 20 and 100 hours ranked by the 2021 total marginal cost as put forward in Table D-5, SCE determined the following results:

[4] A.16-09-003, Exhibit SCE-1, p. 71.

Table D-5
Dead Band Analysis

Measurement Criteria		Current	Proposed		
		Noon to 6 p.m. Summer Weekday	4 p.m to 9 p.m Summer Weekend/Weekday	4 p.m. to 9 p.m. Winter Weekend/Weekday	Total 4 p.m. To 9 p.m.
Top 20 Hours	Number of Hours Captured	0	9	11	20
	% Captured	0%	45%	55%	100%
Top 100 Hours	Number of Hours Captured	18	58	36	94
	% Captured	18%	58%	36%	94%

These results show that 0 percent of the top 20 hours and 18 percent of the top 100 hours are captured by the current on-peak TOU period (*i.e.*, summer, noon to 6:00 p.m.), which breaches the dead band tolerance range, indicating that an update is warranted. The results for the peak periods proposed in the 2016 RDW (*i.e.*, 4:00 to 9:00 p.m.) show that 100 percent of the top 20 and 94 percent of the top 100 hours are captured in the peak period, which is within the tolerance band. Thus, a further update is not warranted (provided the proposed TOU periods are adopted).

Appendix E

NCO Marginal Cost Methodology

Marginal Customer 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.

In the computation of customer access 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 number of average 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 2016 to 2018 customer growth. An annual replacement rate of 3.3 percent was assumed based upon the 30-year depreciation life for final line transformers, which is a large portion of the customer cost. The replacement rate is multiplied by the 2015 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]
4. The customer services (metering, billing, etc.) marginal cost is included. This is identical to SCE's approach.
5. The NCO capital cost is added to the customer services marginal costs to yield the total customer marginal cost.

Several customer groups are forecasted to decline in number over 2016-2018 due to actual decline or rate group switching. The decline creates difficulty because there is negative customer growth. The NCO methodology has problems when there is negative customer growth because it can create negative marginal costs. SCE caps the negative growth at zero and uses the annual replacement rate based on the 2015 customer forecast.

The table below shows the marginal customer costs based on the NCO methodology.

Table E-1
NCO Customer Marginal Cost
(In $/Customer/Year, 2018$)

Rate Group	Total NCO Capital	Total O&M	Annual NCO Customer Cost
Domestic	58.01	26.77	84.78
TOU-GS-1	106.40	29.44	135.84
TC-1	98.28	27.91	126.19
TOU-GS-2	855.25	170.95	1,026.20
TOU-GS-3	1,330.74	683.52	2,014.26
TOU-8			
Secondary	2,191.83	724.25	2,916.08
Primary	634.10	665.53	1,299.63
Sub-Trans	7,060.37	665.53	7,725.90
TOU-PA-2	525.97	142.97	668.93
TOU-PA-3	1,954.71	551.84	2,506.55
Meter Street Lights	67.42	27.64	95.06

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

Appendix F

Marginal Generation Capacity Analysis as Required Pursuant to D.14-03-007 in Regards to the MGCC Factor Applicable to Maritime Entities at the Port of Long Beach

In D.14-03-007, the Commission approved an uncontested settlement agreement proposed by SCE, the City of Long Beach for the Port of Long Beach (the Port) and the Office of Ratepayer Advocates (ORA). The approved settlement agreement authorized rate discounts for existing and future maritime entities' [1] electric usage at the Port, and with certain exceptions, obligated SCE to install 66 kilovolt (kV) electric service facilities without charge for new maritime entities' electric load as an integral part of the Port's electrification and expansion programs.

Pursuant to the approved settlement agreement, a marginal generation capacity cost (MGCC) factor of 50 percent, which functions as an adjustment to the marginal cost of generation capacity used to calculate the marginal cost of service to maritime entities and their contribution to margin (CTM), was adopted for an initial term of six years. In accordance with the approved settlement agreement, the MGCC factor is subject to review in a Tier 2 advice letter filed at the conclusion of SCE's 2018 GRC, and again at the conclusion of alternate GRCs through December 31, 2037.

Continued use of an MGCC factor less than 1.0 beyond the initial 6-year term requires a showing, citing the Commission's most recent Long-Term Procurement Proceeding (LTPP) or other applicable Commission precedent, or provision of the California Public Utilities Code, that it is justified. If the most recent LTPP or other applicable Commission precedent indicates that additional generation capacity is required for reliability purposes in SCE's service area, then the magnitude of an MGCC Factor would be determined according to the timing of the capacity need. To facilitate this review, the approved settlement agreement provides that "[i]n the 2018 GRC Phase 2, for example, SCE would be required to show that there is no forecast need for additional generation capacity for reliability purposes in SCE's service area from 2019 through 2024. If

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[1] Maritime entities are defined as "container, stevedoring and shipping entities located within the real property owned in fee by the City of Long Beach within or adjacent to the Harbor District, including real property in fee acquired by the City of Long Beach within or adjacent to the Harbor District, but excluding Pier H."

additional generation capacity is required, then the magnitude of a MGCC Factor would be determined according to the timing of the capacity need."[2]

Based on the decision in the most recent LTPP, there is no forecast need for additional peak generation capacity for reliability purposes in SCE's service area from 2019 through 2024.[3]

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2 D.14-03-007, Appendix A, p. 10.

3 *See* OP 1 of D.15-10-031, which approved SCE's 2014 Bundled Procurement Plan (BPP) in R.13-12-010. SCE's 2014 BPP requested that the Commission not authorize additional procurement since there was no additional need. *See* Second Revised Phase 1a Testimony of Southern California Edison Company on Resource Need, p. 1, in R.13-12-010. The next time SCE expects to review the need for new resources is in the 2016 LTPP or 2016 Integrated Resource Plan (IRP). Based on the current estimated schedule, the utilities will be making their IRP filings around the end of 2017.