Rulemaking No.: R.20-11-003
Exhibit No.: SCE-04
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SOUTHERN CALIFORNIA
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(U 338-E)

Direct Testimony of Southern California Edison Company-Phase 2.

Before the

Public Utilities Commission of the State of California

Rosemead, California
September 1, 2021

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I.

INTRODUCTION & BACKGROUND

Southern California Edison Company (SCE) submits this testimony pursuant to: (i) the instructions in the Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2 (the Phase 2 Scoping Memo), issued in Rulemaking (R.) 20-11-003 on August 10, 2021; (ii) the Guidance to Parties for Proposals to Reduce Demand or Increase Supply (the Guidance Document) provided in Administrative Law Judge (ALJ) Brian Stevens's email ruling issued August 11, 2021; (iii) ALJ Stevens's email ruling issued August 12, 2021 regarding the California Energy Commission's (CEC) Draft Preliminary 2022 Summer Supply Stack Analysis (the Draft 2022 Summer Stack Analysis); and (iv) ALJ Stevens's email ruling issued August 16, 2021 providing for comment the Energy Division (ED) Staff Concept Paper Proposals for Summer 2022 and 2023 Reliability Enhancements (the ED Staff Concept Proposals). This submission provides SCE's testimony regarding its program and policy proposals for Phase 2 of this rulemaking, and to the extent not addressed in connection with SCE's proposals, SCE's comments on the ED Staff Concept Proposals and the Draft 2022 Summer Stack Analysis.

A. Background

The California Public Utilities Commission (the Commission) issued Decision (D.) 21-02-028 and D.21-03-056 in Phase 1 of this rulemaking on February 17, 2021 and March 26, 2021, respectively, and issued D.21-06-027 on June 25, 2021 to modify D.21-03-056 to add a day-of trigger for Group A participants in the Emergency Load Reduction Program (ELRP). These Phase 1 decisions direct the investor-owned utilities (IOUs) to take a variety of specific actions on behalf of all benefitting customers to decrease peak and net peak demand and increase peak and net peak supply to avert the potential need for rotating outages, similar to the events that occurred in summer 2020, in the summers of 2021 and 2022. SCE is actively implementing and administering the actions authorized in Phase 1 of this rulemaking to help maintain electric system reliability.

On July 30, 2021, Governor Newsom issued a Proclamation of a State of Emergency (the Emergency Proclamation), which announced immediate action to make energy supply more resilient by (1) implementing new measures to support demand reduction, including through the establishment of a new demand reduction programs to be operated by the utilities and the suspension under specific circumstances of restrictions on prohibited resources (PR); and (2) accelerating plans for new clean energy and storage projects.[1] Among other directives, the Emergency Proclamation requests that the Commission (along with the California Independent System Operator (CAISO)) work with the state's load-serving entities (LSEs) on accelerating plans for new clean energy and storage projects, and expedite approval of demand response (DR) programs and storage and clean energy projects, with the goals of ensuring a safe and reliable electricity supply, reducing strain on the energy infrastructure, and ensuring increased clean energy capacity.[2]

The Phase 2 Scoping Memo expanded the scope of this rulemaking to include consideration of the following goals and programs:

(1) "Increase peak and net peak supply resources in 2022 and 2023" – including through expedited generation and energy storage procurement, updates to resource adequacy (RA) requirements, CAISO's Capacity Procurement Mechanism authority, analysis of need/net-short, Integrated Resource Planning (IRP) procurement, planning reserve margin (PRM) adjustment for 2022 and/or 2023, interconnection, and other opportunities to increase supply.

(2) "Reduce peak and net peak demand in 2022 and 2023" – including through Flex Alert, Critical Peak Pricing, ELRP, modifications to existing supply-side DR programs, new DR

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[1] *See* https://www.gov.ca.gov/2021/07/30/governor-newsom-signs-emergencyproclamation-to-expedite-clean-energy-projects-and-relieve-demand-on-the-electrical-gridduring-extreme-weather-events-this-summer-as-climate-crisis-threatens-western-s/ (Press Release); https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf (Emergency Proclamation).

[2] *See* Emergency Proclamation, ¶¶ 2, 13.

programs or pilots, electric vehicle participation, measures to minimize loss of DR enrollment, rate structures, and other opportunities to reduce demand or net demand.

(3) "[Establish a] Memorandum or Balancing Accounts to cover cost of programs in 2022 and 2023."[3]

The Guidance Document provided additional direction on the elements parties should address (where applicable) with respect to proposals for new programs and policies, and/or modifications to existing programs and policies, that could reduce demand or increase supply at net peak, as well as procurement mechanisms and resources not previously accepted in this proceeding.

The Draft 2022 Summer Stack Analysis estimated the potential gap between supply and demand for July through September 2022 under average (15 percent PRM) and extreme weather conditions (22.5 percent PRM), showing a shortfall of up to 5,200 megawatt (MW) in the CAISO balancing authority under the 22.5 percent PRM demand curve.

Finally, the ED Staff Concept Proposals includes proposals in the areas of demand reduction, smart thermostats, and utility-scale storage, imports, and generation.

A. Overview of SCE's Proposals

1. DR Proposals

As detailed below, SCE proposes new and/or modified DR programming in eight areas: (1) a Whole Home Savings Program (WHSP) , with accompanying modifications to existing residential DR programs to effectuate a "whole house" approach to achieving demand reduction during times of stress on the grid; (2) modifications to SCE's Summer Discount Plan (SDP) Program; (3) modifications to SCE's Smart Energy Program (SEP); (4) modifications to the Programmable Communicating Thermostat (PCT) Incentive Program; (5) extension of SCE's VPP Phase II Pilot until 2023; (6) modification of the ELRP to allow for dual participation with additional DR programs, a lower minimum threshold for Sub-Group A.1. participants, removal

[3] *See* Phase 2 Scoping Memo, pp. 4-5.

of the 50 percent and 200 percent payment requirements (e.g. the ELRP payment collar), increase the ELRP compensation rate to $2 per kilowatt-hour (kWh) and a nomination requirement for Group B participants; (7) modifications to the Automated Demand Response (ADR) Technology Incentive program; and (8) modifications to Time-of-Use (TOU) pricing. SCE also proposes modifications to the Prohibited Resource (PR) policy and modifications to event parameters to align all reliability DR programs and ensure all programs can be dispatched concurrently when needed.

2. <u>Procurement Proposals</u>

As discussed in this testimony, SCE is actively pursuing a variety of supply-side strategies in support of the Governor's Emergency Proclamation. SCE believes that these efforts, in addition to continued emergency procurement authority for IOUs to procure on behalf of all benefitting customers, represent the most effective solution to increase peak and net peak supply consistent with the Governor's Emergency Proclamation. SCE recommends a few areas where additional regulatory action by the Commission could help to meet the objectives of the Emergency Proclamation related to imports, contracting with once-through cooling units through 2023, and utility-owned storage. Additionally, SCE suggests that the Commission should narrow the scope of supply-side efforts to summer 2022, given the lack of any demonstrated system reliability need for summer 2023 and ongoing procurement efforts that are already underway for summer 2023.

II.

SCE'S PHASE 2 PROPOSALS

SCE proposes the following new and/or modified programs, policies, and mechanisms. SCE believes these proposed initiatives will be most impactful with respect to the Commission's goals of reducing net peak demand and increasing net peak supply in the summers of 2022 and 2023. SCE will continue to evaluate its activities and consider initiatives that decrease net peak demand and increase net peak supply to help alleviate the reliability risks identified in the Emergency Proclamation.

New Programs or Modifications to Existing Demand Response Programs

The emergency reliability events of 2020 created a sense of urgency and need for an acceleration and focus on SCE's Demand Response strategy and long-term vision. This vision was originally intended to be introduced in SCE's 2023-2027 Demand Response Application, but is now introduced as part of this Phase II Reliability OIR in order for the Commission, stakeholders and interested parties to better understand the context and direction the following SCE proposals are intended to launch and support. Demand Response (DR) plays a critical role in ensuring continued safe and reliable service during the transition from the current state to a decarbonized resource supply mix. While this proceeding attempts to adopt measures and actions to address the capacity shortfall issues raised by Governor's existing Emergency Proclamation issued on July 30, 2021, they should not continue indefinitely. Demand response should be rethought. Asking customers to turn off their power multiple times in the year, even if compensated, will lead to the perception that the grid is unreliable. With this perception, customers may not adopt the building and vehicle electrification technologies needed to decarbonize society.

Using technologies available today to run reliable programs that help mitigate peak demand while customers' comfort and businesses are not noticeably impacted can be thought of as demand optimization. Through these technologies, utilities and customers can engage in reliable programs that help mitigate peak demand while customers' comfort and businesses are not noticeably impacted. This outcome can be thought of as demand optimization. Traditional emergency demand response programs can be retained for use on an infrequent basis for true emergencies, however there must be a shift to demand optimization and that function is best left to the load serving entity/utilities in partnership with customers, third-parties and developers of behind-the-meter technology and innovation. Key principles to move from traditional demand response to demand optimization include:

- Increase the number of participating customers through automated programs at scale to minimize the impact on individual customers by increasing program success and decreasing the risk of customer attrition. Customers can set levels of comfort and not have to take proactive steps during grid emergencies.
- Maximize participation for residential and small business customers with the addition of smaller in-home connected devices, with negligible impacts on customers.
- Increase function and capability of load-serving entities/utilities to better manage their demand across their distribution service territory in order to flatten utility demand needs to the CAISO/statewide grid operator, avoid repeated CAISO system uncertainty and avoid exponentially expensive costs to serve said steep load curves at the CAISO level (i.e. control costs for customers-at-large).
- While minimizing customer impact is key, it continues to be important for the state, utilities, and other stakeholders to educate customers on the benefits of conservation so that they can take meaningful action in their lives beyond demand response or demand optimization programs.

In consideration of the above, SCE's vision for the future of DR is a single demand response program offered to all residential customers that will allow for greater grid flexibility and allow customers to optimize capacity and energy incentive payments. Customers will no longer be required to choose between competing IOU programs or forced to choose one smart connected appliance or device over another to participate in demand response (e.g., battery storage system versus smart thermostat). SCE's proposals reflect a significant first step in achieving this vision that will further support a Clean Energy future, in which increased electrification and opportunities to manage multiple end-use devices are made available to customers.

As a first step toward achieving this vision, SCE recommends that the Commission approve the following proposals in support of meaningful engagement and expansion of DR participation in the residential segment of its customer base:

- Adopt SCE's Whole Home Savings Program (WHSP) Pilot as an alternative to the Staff Concept Paper's residential ELRP;
- Transition SDP to a reliability only program; and
- Allow dual participation for residential customers in the WHSP Pilot, SDP, SEP, and VPP Phase II Pilot.

SCE proposes a tiered dispatch regime to achieve increasingly greater MW reductions. The first to be dispatched will be the behavioral WHSP Pilot triggered by a Flex Alert or CAISO Alert. Following the dispatch of the behavioral program, SCE will then dispatch smart controlled devices through the Smart Energy Program where customers have the ability to opt out or override events. Finally, if conditions worsen, SCE can dispatch the Summer Discount Plan Program to provide firm load reduction achieved by a utility direct load control device.

1. Whole Home Savings Program (WHSP) Pilot

As an alternative to the Staff's Concept Paper proposal for a default residential ELRP program, SCE proposes a Whole Home Savings Program Pilot ("WHSP Pilot") which would be an out-of-market, non-RA, residential behavioral DR program that compensates customers for their demonstrated energy load reduction during grid reliability events. For purposes of this testimony, SCE will reference this program as the WHSP Pilot, however, if approved, SCE will determine a program name that is understandable and most accurately conveys the action that is needed from customers.

a) Target Customer Population and Enrollment

SCE has learned from past experience that mass defaults into behavioral DR programs do not garner the expected customer actions and results in extensive free ridership. In D.13-07-003, the Commission directed SCE to modify its Peak Time Rebate (PTR) Program, (originally a program where all bundled residential customers were defaulted into it similar to the residential ELRP proposed by staff), to be an opt-in program to eliminate incentive payments to customers who were not actively participating (i.e., free ridership).[4] The Commission cited PTR consumer surveys indicating that PTR customers choosing to receive utility alerts experienced increased awareness of the program and also provided increased load reduction.[5] In contrast, the 2012 program results showed that customers who were defaulted onto PTR without notification did not significantly reduce load.[6] As all customers are eligible for bill credits, this also resulted in widespread free ridership. To proactively address free ridership, SCE proposes to auto enroll high usage customers who have opted in to receive transactional emails, with the option to de enroll. Based on SCE's PTR experience, customers who already have opted in to some type of notifications with the utility are more engaged and will provide more load reduction than those customers who are not enrolled in notifications. In addition to automatically enrolling high usage customers, SCE plans to cross-promote this program with SDP and SEP. SCE estimates this collective approach could result in the enrollment of up to two million service accounts in those programs.

b) Dual Participation

SCE proposes that residential customers enrolled in the WHSP Pilot may also participate in technology-specific or market-integrated DR programs or pilots to avoid

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[4] Based on the 2013 Staff Report "Lessons Learned From Summer 2012 Southern California Investor Owned Utilities' Demand Response Programs," Staff recommended modifying the PTR program from a default program to an optional program, in which only customers who chose to receive event alerts would qualify for bill credits. See D.13-07-003, pp. 23-25.

[5] *Id.*

[6] *Id.*

cannibalization of those programs and increase energy reduction potential through dual enrollment. This includes aggregator or third-party administered programs, such as DRAM and CBP residential, SCE's VPP Pilot, Summer Discount Program, Smart Energy Program, etc. Allowing dual participation is perhaps one of the most critical first steps toward SCE's long-term vision of a whole home demand response rate/tariff/program that would provide customers a mechanism to monetize their collective behind-the-meter energy investments including A/C devices, batteries, smart appliances, EV's, pool pumps, etc. Current rules that force customers to decide between technology to participate in a DR program result in stranded load reduction potential in the devices not utilized and standing idle in times of need. SCE's proposed WHSP Pilot represents a first-generation attempt at creating an energy program for all devices to be able to support the distribution grid.

c) Event Trigger

SCE proposes that WHSP events be triggered on a day-ahead basis for all participants when CAISO has declared a Flex Alert or a CAISO Grid Alert only. WHSP will only be dispatched after CAISO has informed SCE that this resource is needed a day ahead through a Flex Alert or CAISO Grid Alert and cannot be dispatched based on "day of" conditions. SCE will provide customers with at least one day-ahead notification and day-of pre-event reminder.

d) Program Parameters

Customer research and focus groups conducted in 2021 found that the duration and frequency of events affect the customer and correlate to customer performance and resiliency. Customers are willing to participate in DR events until the lack of convenience exceeds the benefits received. In addition, the SEP load impact evaluation stated "ex ante results show the largest impact during the first event hour with decaying impacts each subsequent hour."[7] In consideration of these observations, SCE recommends the following availability to

[7] 2020 Smart Energy Program Load Impact Evaluation, p. 60.

maximize performance, reduce customer non-performance, increase customer engagement and trust, and limit IT and resource complexity:

- Limit event dispatches to one event per day; max 2 events per week;
- Static 2-hour events with a maximum of 30 events per calendar year;[8]
- Available May 1 through Oct 31;[9] and
- Available seven days per week.

e) Program Incentive

SCE recommends that residential customers should be compensated $2 per kilowatt-hour ($2/kWh) in parity with ED staffs' proposal and equity with the energy compensation for non-residential emergency programs. A customer's verified load reduction will be calculated using a Meter Before / Meter After method. The table below provides an example of how that calculation will performed (the hours of dispatch in the example are only for illustrative purposes, the static 2-hour event period will be determined in the future).

Time	**Meter Data (hourly usage)**	**Calculated Hourly Load Reduction (kWh)**	**Compensation ($)**
Hour Ending (HE) 3pm *(hour before dispatch; 2-3pm)*	3.0 kWh	Not Applicable	None
HE 4pm *(WSHP Event Hour 1; 3-4pm)*	2.0 kWh	**1.0 kWh** (3.0 kWh – 2.0 kWh)	**$2.00** (1.0 kWh x $2/kWh)
HE 5pm *(WSHP Event Hour 2; 4-5pm)*	1.5 kWh	**1.5 kWh** (3.0 kWh – 1.5 kWh)	**$3.00** (1.5 kWh x $2/kWh)
TOTAL		**2.5 kWh**	**$5.00**

SCE estimates that the WHSP Pilot, with an enrolled population of approximately two million customers, as proposed, could reduce electric demand by 100-160

[8] SCE is still determining the two static hours WHSP will be available for dispatch and will work with stakeholders to determine the appropriate hours.

[9] SCE recommends that for 2022, the WHSP Pilot be available from July to October 31 to allow SCE to develop internal systems and processes.

MW during the net peak period based on past performance of an average load reduction per customer of between 0.05 kW and 0.08 kW from SCE's Save Power Day program.

f) WHSP Pilot Marketing, Education and Outreach

As a complement to the Statewide Flex Alert campaign, the WSHP event marketing and outreach will generate public awareness about the critical role customers play in supporting a safe and reliable grid, especially when the energy supply is constrained due to various factors. SCE will use a variety of marketing tactics to bring awareness and educate its customers, as well as maximize enrollments and successful participation in the various DR programs.

Ongoing engagement with customers about energy conservation will involve personalized communications, enabled by marketing automation, to drive down energy usage during WHSP and reliability events. SCE's approach will leverage customer data to place DR events in the context of a customer's broader energy usage, providing them with the personalized information and tools they need to lower their energy usage during events. Channels that will be used to deliver personalized messaging may include, but are not limited to, email, text/SMS, SCE DR Mobile App push notifications, and mobile-optimized web. Further, SCE will use technology solutions including marketing automation to ensure that during DR events other non-essential notifications from SCE are deprioritized to maximize the effectiveness of DR and minimize customer confusion.

Working in tandem with the Statewide Flex Alert campaign, the SCE Mass Media Campaign (Campaign) will leverage customer segmentation to raise awareness regarding the need for conservation and the various SCE DR programs and incentives. The Campaign may include, but is not limited to, a variety of new digital creative assets, including video, to be utilized in paid, earned, and owned channels (social ads, digital banners, and search engine marketing (SEM)). Building on the Campaign, SCE will use customer segmentation to drive outreach to increase DR program enrollment in the Smart Energy Program, Summer Discount Plan Program, and the WHSP Pilot.

g) Pilot Incremental Funding Request

The final approach to implementing the WHSP Pilot has yet to be determined. The budget estimates provided are pending a detailed evaluation of the methods and capabilities of implementation. SCE is considering all available options including full utility implementation, outsourcing, or a combination of approaches. SCE's forecasted labor cost assumes that SCE will be administering all aspects of the WHSP Pilot. If SCE does not administer the entire pilot, SCE's forecasted labor cost will be lower. Non-Labor costs assume the participation of up to two million customers. These costs include measurement and evaluation, market research, IT upgrades to facilitate the extraction and transmission of billing data required to calculate verified load reduction, technology upgrades to systems (e.g., DR Mobile App, SCE.com) to manage the expected increase in volume and utilization, vendor costs to support the calculation of bill credits, event notifications, and marketing, education, and outreach (ME&O) to facilitate awareness and program participation. Table II-1 outlines SCE's 2022 and 2023 WHSP Pilot incremental funding request.

Table II-1
Whole Home Savings Program Pilot Funding Request
(in millions)

Line No	Cost Type	2022	2023	Total
1	Admin – Labor	$ 1.00	$ 0.80	$ 1.80
2	Admin – Non-Labor			
3	ME&O	$ 5.40	$ 1.60	$ 7.00
4	Event Notifications	$ 2.70	$ 2.70	$ 5.40
5	Systems & Technology	$ 13.50	$ 7.40	$ 20.90
6	Measurement & Evaluation	$ 0.20	$ 0.20	$ 0.40
7	Participant Incentives	$ 19.20	$ 19.20	$ 38.40
8	TOTAL INCREMENTAL BUDGET	$ 42.00	$ 31.90	$ 73.90

1 h) Whole Home Savings Program Pilot Guidance Document Elements[10]

Table II-2
Guidance Document Elements – Whole Home Savings Program Pilot

General Program Design	
i. Program trigger	WHSP Pilot will be triggered when CAISO issues a Flex Alert or a Grid Alert Notice
ii. Demonstration that program will deliver benefits during net peak	WHSP Pilot can provide benefits during net peak hours, 7 days/week.
iii. Program performance requirements	WHSP Pilot is a non-penalty, pay for performance pilot.
iv. Compensation structure	SCE recommends an energy payment of $2.00 per kilowatt per hour (kWh) reduction using a Meter Before/Meter After calculation method.
v. Program eligibility and enrollment	All residential customers are eligible to participate in WHSP Pilot, but high usage customers who have signed up to receive Transactional Emails will be defaulted onto the pilot.
vi. Measurement and verification, if needed	Conduct annual measurement and verification for Program Years (PY) 2022 and 2023 (which will be published in April 2023 and 2024, respectively) to align with other DR load impact evaluations.
Program Administration	SCE will administer the pilot.
Program Marketing, Education & Outreach	SCE plans to target high usage customers who have not signed up to receive Transactional Emails. SCE will utilize a variety of marketing tactics to bring awareness and educate customers about the pilot, as well as maximize enrollments to existing DR programs. • Generate public awareness about the critical role our customers play in supporting a safe and reliable grid, especially when the energy supply is constrained due to various factors. • Educate customers of the various DR programs and their incentives through mass media, paid media, social and search engine marketing. • Ongoing engagement with customers through personalized communications via marketing automation driven by customer and data insights. • Utilize targeted segmentation to maximize enrollments for each of the participating DR programs and the pilot – Smart Energy Program, Summer Discount Plan Program, and WHSP Pilot.

[10] For ease of reference in this document, SCE is addressing the elements identified in the Guidance Document in table format.

	• Utilize analytics and customer behavior to cross-promote other applicable DR programs to maximize participation.
Program Budget	Please see Table II-1
Implementation Timeline	SCE estimates that the WHSP Pilot will be fully implementable by July 2022.
Program Duration	SCE proposes that this Pilot be available from July through October 31 for 2022 and May 1 through October 31 for 2023.
Estimated megawatt contribution/load impact (including whether load impact will reduce the demand at net peak hours, and whether and how much the load impact may reduce the impact of any existing programs)	SCE estimates that the Pilot can reduce usage up to 100-160 MW based on the historical per customer average load reduction between 0.05 kW and 0.08 kW from a similar historical program.
Potential interaction with other existing programs (i.e., dual participation issues)	SCE proposes there be no restrictions to participating in WHSP Pilot as this would be the only energy-based demand response program offered in SCE territory for residential customers.
Prior similar program experience in California or elsewhere	From 2012-2017, SCE offered the Peak Time Rebate (PTR) Program (also known as Save Power Day), which was designed to provide residential customers bill credits for lowering their energy usage (behavioral) during PTR events. WHSP Pilot builds on lessons learned from PTR and introduces an improved program concept by focusing on high energy users.
Program funding and cost recovery mechanisms	Please see Section II.D. Cost Recovery
Potential risks of proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) with discussion of each potential risk	Considerable IT work will be needed to meet the July 2022 operation date while SCE is still undergoing CSRP implementation and stabilization. As customer awareness is critical to success, ME&O efforts need to be a priority.
Estimated megawatt contribution/load impact (including whether load impact will reduce the demand at net peak hours, and whether and how much the load impact may reduce the impact of any existing programs)	SCE estimates that WHSP Pilot can reduce usage up to 100-160 MW based on past performance of an average load reduction per customer of between 0.05 kW and 0.08 kW with an enrolled population of two (2) million customers.

2. Summer Discount Plan (SDP) Program

The SDP program is one of SCE's longest standing DR programs, having provided reliability-based DR since the early 1980s. The program has a history of fast and reliable load shed and, since 2015, operates as both a reliability and price responsive program in the CAISO wholesale market. The SDP program offers bill credits to residential and commercial customers who allow their air conditioning (A/C) units to be cycled off during curtailment events. Participating customers allow SCE to install radio frequency load switches at their residence/business to periodically turn or cycle off a customer's A/C compressor during grid emergencies or high wholesale energy prices. For compensation, SDP customers receive a credit on their electric bills for their participation each year from the first of June to the first of October.

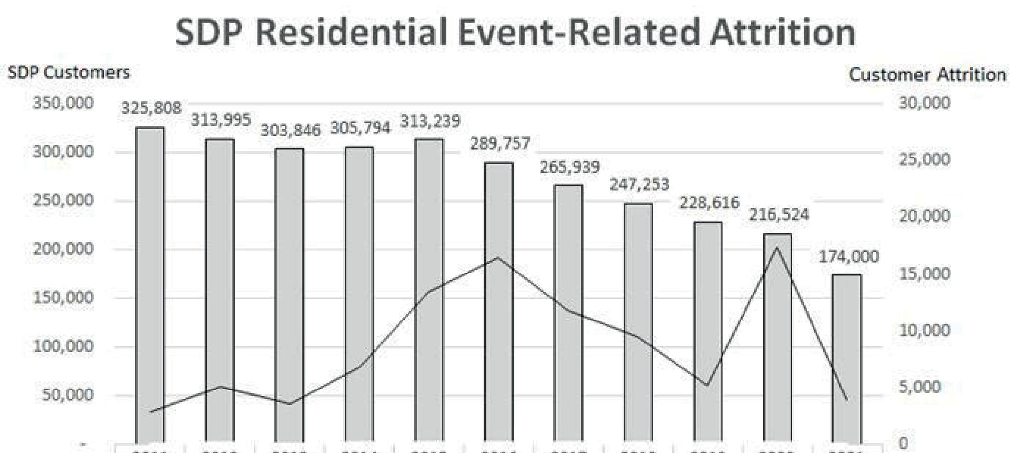
SCE proposes the following modifications to SDP: (1) remove SDP from the CAISO wholesale energy market to recruit customers into the program and recover lost MW due to attrition, and reduce customer attrition from the program; and (2) allow dual participation with SEP and specified DR Pilots.

a) <u>Remove SDP from the CAISO Wholesale Energy Market</u>

SCE proposes to remove SDP from the CAISO market to allow dual participation with SEP (discussed further below), reduce attrition, preserve the current capacity enrolled in the program for emergency/reliability dispatch only, and allow dual participation with other non market-integrated DR pilots including the VPP Phase II Pilot, WSHP and ELRP for Commercial SDP customers. To allow dual participation with SEP, the SDP program must be removed from the CAISO market, due to CAISO bidding rules (a service account can only be registered in the CAISO market under a single Resource ID). Dual participation will also allow SCE and third-party providers to market program options together to provide customer choice, or the option to choose multiple programs. Additionally, allowing dual participation for SDP Commercial with ELRP could provide an opportunity for additional ELRP participation that SCE has identified via customer outreach and marketing.

SCE will dispatch SDP after CAISO has issued a Stage 1/2/3 Emergency Notice and all necessary steps have been taken to prevent the degradation of CAISO operating reserves similar to the triggers established for the California State Emergency Program (CSEP). Additionally, SCE would reserve the ability to dispatch upon determination by SCE's grid control center of the need to reduce load within SCE's service territory, to test load control devices, and for program measurement & evaluation. SDP is a direct load control program that ranks highest among SCE's residential programs in load reduction per service account.[11] Since market integration in 2015, SDP has seen a decrease in participation that can be attributed to increased event dispatches and hours, as well as decreasing incentive rates. SDP began event dispatch simulations in 2012 to prepare systems for market integration in 2015. Prior to 2012, SDP had over 325,000 residential customers enrolled in the program. From 2012 to 2020 the number of residential, event-related unenrollments totaled over 89,000; equivalent to 80 MW of lost capacity (see figure II-1 below). Decreasing incentives and customer fatigue further contributed to attrition as customers who have relocated are no longer continuing their participation. Currently SDP has approximately 174,000 actively enrolled residential participants, which is only 55% of SDP participation at the start of 2012.

Figure II-1



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Active Enrollments	325,80	313,99	303,84	305,79	313,23	289,75	265,93	247,25	228,61	216,52	174,00
Estimated MW Lost	2.7	4.8	3.4	6.4	12.6	15.4	9.9	8.1	4.4	14.7	3.3
Event Related Attrition	2,867	5,058	3,571	6,835	13,405	16,380	11,739	9,511	5,136	17,402	3,876
Total Event Hours	5	22	17	30	35	20	24	20	20	31	5

Note: Estimated MW lost is based on 2011-2020 ex ante load impact results: SCE weather, 1-in-2 year, average kW per SA.
Participation numbers for 2021 reflect activity through August 2021. To date SDP has ~174k customers enrolled.

[11] According to the 2020 SDP Load Impact Evaluation, the average load reduction per service account is 0.87 kW.

Transitioning SDP back to a reliability-only resource will provide an opportunity to revamp marketing of this program in order to promote to customers that they will only forgo their comfort if there is a grid emergency, rather than current messaging which allows for 20 hours of 'economic' dispatch. Further, in Phase I of this proceeding SCE implemented the approved $50 sign up bonus but is forecasting only about 8,000 enrollments in 2021, well below the 25,000-30,000 as originally estimated. Customers appreciate the summer bill credits that offset their electric costs, but the discomfort during extended and consecutive SDP events should be limited to grid emergency needs in order to attract and retain this resource. The ability to communicate this message clearly through ME&O can only bolster efforts to enroll customers.

b) Allow SDP Participants to Dual Participate With SEP and Specified DR Pilots

SCE proposes changes to dual participation limitations for SDP customers, which will expand the target customers for enrollment and increase the ability for these programs to contribute load reduction in alignment with grid needs. Over the last several years, there has been greater customer adoption of Distributed Energy Resources (DERs) and internet-of-things (IOT), but Commission and CAISO policies and rules force customers to choose one DR program or pilot over another, thus leaving additional DR resources stranded or left on the table.

Removing SDP from the CAISO wholesale energy market and allowing customers to dual enroll in SEP would create a two-stage DR resource for those participating customers, as well as provide an opportunity to distribute smart thermostats to SDP customers and bolster MW participating in DR via smart thermostats. See Section II.3.a. for further details of combining SDP and SEP into a single resource.

SCE believes these changes will increase enrollments and decrease attrition. SDP and SEP would benefit from dual participation as this would open up a new target audience of approximately 221,000 residential A/C users (174,000 SDP-R and 47,000 SEP participants) that are already participating in DR and may be open to participating on a different scale. Dual enrolled participants would also benefit from increased incentives for their commitment to participate in DR events that may occur both during and outside of CAISO grid emergencies. Once dual participation is available, SCE plans to market and promote dual enrollment opportunities to existing DR participants as well as new customers.

SCE also proposes to allow SDP participants to dual participate in other DR pilots such as WHSP, VPP Phase II Pilot, and the ELRP Pilot. As noted earlier in this section, these pilots allow for control of different technologies or non-A/C end uses. For example, the VPP Phase II Pilot is intended to control solar-paired battery energy storage and other DERs. Prohibiting SDP customers participation in the VPP Phase II Pilot limits the pilot's ability to recruit and enroll customers and test the use of VPP DERs during grid emergencies. This proposal also supports SCE's vison for a single DR program for residential customers. Residential customers who choose to participate in these DR programs should qualify and receive the full benefits from each program and will enable customers to maximize and optimize their load during DR events and grid emergencies. SCE does not anticipate the need for incremental funding to implement its SDP proposal at this time. But should enrollments in SDP sharply increase, SCE may require additional funding to support and operate these additional enrollments.

c) SDP Dispatch Trigger

SDP would be available out-of-market for CAISO Stage 1, 2, and 3 grid emergencies, SCE local emergencies, and for measurement and evaluation. For those customers dual enrolled in SDP and SEP that are triggered simultaneously for emergency purposes, SDP would take priority for its ability to curtail the A/C load during an event, thus maximizing load reduction during a grid emergency.

d) SDP Guidance Document Elements

Table II-3
Guidance Document Elements - SDP

General Program Design	
i. Program trigger	• After the California Independent System Operator (CAISO) has issued a Stage 1 Emergency and has taken all necessary steps to prevent the further degradation of its operating reserves; or • After the CAISO has declared a Stage 2 Emergency; or • After the CAISO has declared a Stage 3 Emergency; or • Upon determination by SCE's grid control center of the need to implement load reductions in SCE's service territory; or • For testing of the control device; or • For measurement and verification.
ii. Demonstration that program will deliver benefits during net peak	SDP will provide benefits as events will be called in response to system emergencies which are most likely to be the result of a lack of supply or grid constraints during the net peak hours.
iii. Program performance requirements	SDP-R - All customers served under this Schedule must register a minimum of 1.5kWh of electric usage one hour prior to the start of SDP event or one hour after the end of SDP event for no less than one SDP event in a calendar year. SDP-C - All customers served under this Schedule must register a minimum of 0.2 kWh of electric usage per air conditioner tonnage enrolled in the SDP program during the hour prior to the start of the SDP event or the hour after the end of the SDP event for no less than one SDP event in each calendar year

iv. Compensation structure	Incentive Methodology - $ per tonnage of central air conditioning load per Summer Season day - in no event shall the amount of credit exceed the amount of Distribution and Conservaton Incentive Adjustments (CIA) portion of the Energy Charge plus the total charge for generation of the customer's bill as calculated under the customer's otherwise applicable tariff (OAT). <u>SDP-Residential Override</u> • 100% Cycling Strategy: $(0.164) per Summer Season day per connected ton of central air conditioning for 100% cycling • 50% Cycling Strategy: $(0.083) per Summer Season day per connected ton of central air conditioning for 50% cycling <u>SDP-Commercial</u> • 30% Cycling Strategy: $(0.58) per Summer Season month per Connected Tonnage of air conditioning for 30% cycling • 50% Cycling Strategy: $(2.90) per Summer Season month per Connected Tonnage of air conditioning for 50% cycling • 100% Cycling Strategy: $(8.24) per Summer Season month per Connected Tonnage of air conditioning for 100% cycling
v. Program eligibility and enrollment	• Minimum Electric Usage Threshold - Any customer removed from this Schedule due to not meeting the minimum electric usage threshold is not eligible to re-enroll during the subsequent 12 months. • Existing and new customers receiving service under this Schedule must have an Edison SmartConnect® meter installed and program ready to participate. • Customer Option Change: At the Customer’s request, subject to device availability, Customers may change their Option (Standard or Override) one time within each 12-month period of service.
vi. Measurement and verification, if needed	SDP is subject to Load Impact Protocols in which an annual evaluation is performed to calculate and report ex post and ex ante load impacts on an aggregate and per customer scale, based on varying system/weather conditions.
Program Administration	SCE administers the Summer Discount Plan
Program Marketing, Education & Outreach	Marketing efforts will be enhanced to utilize customer data to better segment and target outreach to customers and locations with high usage on an annual basis, and a four-touch marketing strategy where program information is delivered to SDP customers via direct mail and email. Communications happen throughout the year, providing program details, billing, and SDP incentive information, SDP event readiness, tips on how to stay cool during the summer, and a year-end appreciation for program participation, and support for grid reliability. SCE also leverages the DR Mobile App and social media platforms to give customers notification of dispatched events and give them a form to provide their feedback. In addition, the personalized and integrated marketing through automation will further cross-promote SDP to customers who are on other DR programs. This approach will maximize enrollments to the various DR programs and incentives we offer our customers.

Potential risks of proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) with discussion of each potential risk	Enabling dual participation is contingent on obtaining SCE IT support to implement by 2022.	

3. Smart Energy Program (SEP)

The SEP is a direct load control (DLC) program of enabling technologies that can be controlled by SCE-approved third-party vendors for eligible bundled residential customers.[12] Presently, enabling technologies are limited to specified Wi-Fi enabled smart thermostats, but SCE anticipates expanding the program to other enabling technologies in the future. SEP participants also have the flexibility to opt out of events at any time by resetting their thermostats' temperature. The SEP is available for dispatch year-round, but enrolled participants only receive program incentives (bill credits) from June through September, up to $40 annually.

SCE proposes the following modifications to the SEP: (1) allow dual participation with SDP, VPP Phase II Pilot, and WHSP Pilot; (2) increase the marketing, education, and outreach budget; and (3) reinstate the pre-cooling strategy. If approved, SCE estimates that these modifications may provide 15 MW of incremental load reduction for SEP in 2022 and 2023.

a) Allow SEP Participants to Dual Participate With SDP, VPP Phase II Pilot and SCE's Proposed WHSP Pilot

As discussed, SCE is requesting that SDP be removed from the CAISO wholesale energy market and made available only for emergency/reliability dispatch purposes. If this change is approved, SCE plans to market SEP to all SDP customers. Under this approach, SDP customers who elect to dual participate with SEP will be available for economic dispatch via a set temperature adjustment to their smart thermostat, which they will have the ability to adjust at any time[13]. During emergency/reliability dispatch, dual participants will be curtailed

[12] Bundled service customers are customers who have their delivery and generation-related services provided by SCE. In 2022, SCE will be able to offer SEP to all residential customers as approved in Commission D.21-03-056.

[13] SCE will maintain the discretion to remove any SEP participant from the program if they override all events dispatched in a calendar year when such overrides consistently occur within the first event hour.

through SCE's SDP direct load control switch where they will be cycled off and on, based on their SDP enrollment choice. Additionally, SCE proposes to allow dual participation with the WHSP Pilot and the VPP Phase II Pilot. These changes support SCE's vison for a single DR program for residential customers as discussed above. SCE does not propose any changes to SEP customer incentives. Customers who choose to participate in all programs may qualify to receive the full benefits from each program, which is appropriate as each measure of participation represents an increasing level of kWh reduction commitment from thermostat-only to A/C switch that is reflected in *ex ante* load impact values of 0.5kW to 0.87kW respectively. Currently, SCE systems do not support dual participation and will need to be modified. SCE plans to implement this change in 2022 contingent on securing the funding and resources necessary to implement this change. Funding for these system changes is being requested through the WHSP Pilot proposal.

b) Increase Program Marketing, Education and Outreach

SCE's marketing, education, and outreach (ME&O) budget allocation for SEP during the 2018 – 2022 period was approximately $0.53 million per year. This limited marketing, education and outreach budget only allows SCE to promote SEP via digital marketing (e.g., email, social media, and web banner ads). Although digital advertising is a valuable marketing tactic, SCE's reach of eligible customers is limited due to SCE not having email addresses for all customers. The approach to digital marketing has also resulted in SCE continually marketing to the same groups of customers leaving other potential enrollees unaware of SEP. The cost for other acquisition tactics, such as direct mail letters, has been too costly for the current budget. SCE proposes to increase SEP's marketing, education, and outreach budget to reach a broader audience through targeted marketing channels and leveraging marketing automation technology to improve ME&O effectiveness. SCE's proposed incremental budget request is in Table II-4 below.

c) Reinstate Pre-cooling

In A.17-01-018, SCE noted that integrating into the CAISO wholesale market would eliminate pre-cooling prior to SEP events. This is because the program would be offered as an RDRR resource and available for dispatch within 20 minutes. When D.17-12-003 was issued, all active participants were notified of the program change ahead of any events called in 2018. Both the 2019 and 2020 load impact studies recommended SCE consider reinstating pre-cooling where applicable. "Pre-cooling of homes can also help slow the deterioration of load impacts by extending the amount of time it takes the home to warm to its event setpoint. Pre-cooling can also reduce participant opt-outs through increased participant comfort."[14] Although pre-cooling would continue to not be available for RDRR events, SEP is also offered as a day-ahead economic resource in the CAISO market. These types of economic events would allow SCE to pre-cool customer homes prior to events and help mitigate thermostat overrides and/or postpone when homes may reach their adjusted temperature offset – resulting in the A/C turning back on during an event. SCE will work with its authorized thermostat service providers to develop a pre-cooling strategy that could be implemented in a TOU environment.

d) SEP Incremental Funding Request

Table II-4 summarizes SCE's incremental funding request for the SEP proposal for 2022 and 2023.

[14] 2020 Smart Energy Program Load Impact Evaluation, p. 30.

Table II-4
SEP Incremental Funding Request
(in millions)

Line No	**Cost Type**	**2022**	**2023**	**Total**
1	Admin – Labor	$ -	$ 0.18	$ 0.18
2	Admin – Non-Labor			
3	Vendor Fees	$ 0.28	$ 3.84	$ 4.12
4	ME&O	$ 1.27	$ 0.98	$ 2.25
5	System Costs	$ 1.60	$ -	$ 1.60
6	Participant Incentives	$ 0.55	$ 2.92	$ 3.47
7	TOTAL INCREMENTAL BUDGET	$ 3.70	$ 7.92	$ 11.62

e) <u>SEP Guidance Document Elements</u>

Table II-5
Guidance Document Elements - SEP

General Program Design	
i. Program trigger	SCE may, at its discretion, call an SEP Event based on any one of the following criteria: a) After the California Independent System Operator (CAISO) has (i) publicly declared a Warning, Stage 1, Stage 2, Stage 3, or Transmission Emergency and (ii) has taken all necessary steps to prevent the further degradation of its operating resources according to Operating Procedure 4420; b) Upon determination by SCE's grid control center of the need to implement load reductions in SCE's service territory; c) At the discretion of SCE's energy operations center in response to a CAISO economic award in the wholesale market, or high wholesale energy prices; or d) At the discretion of SCE for program evaluation or system contingencies.

ii.	**Demonstration that program will deliver benefits during net peak**	SEP will provide benefits during net peak because events may be called in response to emergencies, overworked electrical grids, high wholesale energy prices.
iii.	**Program performance requirements**	At SCE's discretion, customers may be removed from SEP for overriding all SEP events dispatched in a calendar year, when such overrides consistently occur within the first hour of events.
iv.	**Compensation structure**	Customers earn a fixed daily capacity credit of $0.3275 per day from June 1 through September 30.
v.	**Program eligibility and enrollment**	Enabling Technology Requirements: • Qualified Wi-Fi-enabled smart thermostat connected to a working central A/C • Must have an internet connection Program eligibility: • Residential "Bundled Service" customer with an eligible Edison SmartConnect® meter.[15] • Receive service under rate schedule D, D-CARE, D-FERA, TOU-D or TOU-D-T • Must NOT be enrolled in any of the following programs, rate schedules, rate options, or services:[16] o Capacity Bidding Program (CBP) o Critical Peak Pricing (CPP) o Demand Response programs or rates offered by Non-Utility Demand Response Service Providers o Medical Baseline Allocation for air conditioning o Domestic Multiple (DM) o Domestic Multiple Service 1 (DMS-1) o Domestic Multiple Service 2 (DMS-2) o Domestic Multiple Service 3 (DMS-3) o Community Choice Aggregation (CCA) Service o Direct Access (DA) Service Enrollment: • All customers enrolled in SEP must register a minimum of 1.5kWh of electric usage one hour prior to the start of an SEP event or one hour after the end an SEP event for no less than one SEP event in a calendar year.
vi.	**Measurement and verification, if needed**	Performed through the annual load impact studies.[17]
Program Administration		SEP is administered by SCE in partnership with two SCE-approved third-party vendors, Resideo Technologies and EnergyHub Inc.
Program Marketing, Education & Outreach		ME&O is performed by both SCE and thermostat manufacturers participating in the program in conjunction with the SCE-approved third-party vendors.

Program Budget	SCE's SEP authorized budget for 2018 – 2022 under D.17-12-003 is \$8.018 million for program administration and \$12.412 million for customer incentives. D.21-03-056 authorized an additional \$4.854 million in incremental funds for program administration and \$1.320 million for customer incentives. See above for SCE's incremental funding request.
Implementation Timeline	SCE to implement all SEP proposals in 2022.
Program Duration	SEP is a year-round program.
Estimated megawatt contribution/load impact (including whether load impact will reduce the demand at net peak hours, and whether and how much the load impact may reduce the impact of any existing programs)	SCE estimates that the proposed modifications to SEP would result in 22 MW.
Potential interaction with other existing programs (i.e., dual participation issues)	Currently SEP does not dual participate with any other DR programs. By 2022, SCE expects to allow dual participation with SDP, VPP Phase II Pilot and WHSP Pilot contingent upon Commission approval.
Prior similar program experience in California or elsewhere	SCE has experience marketing a larger PCT Incentive amount for SEP that attracted higher volumes of customers. Other utilities have begun launching a free thermostat offer via their Marketplace store that resulted in over 90% of consumers pre-enrolling in DR.
Program funding and cost recovery mechanisms	Please see Section II.D. Cost Recovery.
Potential risks of proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) with discussion of each potential risk	Enabling dual participation between SEP, SDP and DR pilots is contingent on obtaining IT support to implement by 2022.

4. Programmable Communicating Thermostat (PCT) Incentive Program

The Programmable Communicating Thermostat Incentive program was approved in D.17-12-003 and provides eligible residential and small and medium business (SMB) customers with a one-time \$75 incentive (in the form of a bill credit) for the purchase and installation of a smart thermostat. To qualify, customers must own an eligible thermostat

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[15] D.21-03-056.

[16] SCE proposes to allow dual participation for SEP, SDP and SCE's proposed new WHSP Pilot. If the Commission does not approve SCE's request, dual participation with SDP will not be allowed.

[17] D.10-04-006.

supported by one of SCE's authorized thermostats service providers and/or must be enrolled in a qualifying DR program. Currently, PCT incentives are available for eligible customers participating in SEP, CPP, CBP residential or DRAM.

SCE proposes the following modifications to the PCT Incentive Program: (1) temporarily increase the PCT Incentive from $75 to $125 for 2022 and 2023;and (2) activate DR pre-enrollment through SCE Marketplace and use PCT incentives to apply an instant discount at point of sale.

a) <u>Temporarily Increase the PCT Incentive to $125</u>

Currently, SCE's PCT Incentive Program gives eligible customers who enroll in a qualifying DR program and own a qualifying smart thermostat a one-time $75 bill credit. To encourage more DR participation, SCE proposes to increase the PCT Incentive to $125 for all qualifying programs. The proposed incentive aligns with the rebate amount SCE offered from 2016-2019 under the SEP program. SCE stacked PCT's $75 rebate with a $50 energy efficiency thermostat rebate offer. Over an 18-month period between July 2016 through December 2017, SCE marketed a savings opportunity of up to $125 in rebates to customers and enrolled approximately 45,000 new customers onto the program, which resulted in approximately 22 MW of DR load reduction capacity. Since the energy efficiency thermostat rebate has been discontinued, SCE proposes to increase the PCT incentive to $125 to attract new customers.

b) <u>Activate DR Pre-enrollment Through SCE Marketplace and Use PCT Incentives to Apply an Instant Discount at Point of Sale</u>

During the 2022 and 2023 period, SCE plans to activate DR pre-enrollment within the SCE Marketplace website. This feature will give customers buying a qualifying smart thermostat through the Marketplace the option to pre-enroll in SEP at the point of sale and remove the extra administrative step customers must take after installing their thermostat. To generate interest and help increase program enrollments, SCE proposes to have the flexibility within the PCT Incentive Program to apply the PCT incentive in the Marketplace as an instant rebate for qualifying customers. The modification expands SCE's new enrollment acquisition strategy by removing an adoption barrier some customers may have with paying the full upfront cost of a thermostat. Customers who choose to forgo the DR pre-enrollment will not qualify for the instant rebate but may be eligible to receive the PCT Incentive as an SCE bill credit following successful enrollment in SEP through the traditional enrollment flow. Logistically, SCE will pay the cost of the instant rebate to the Marketplace vendor with the customer being the beneficiary of such transaction. SCE recognizes D.18-11-029 authorized SCE to limit Auto DR incentive payments specifically to customers and not any third parties. Although Auto DR and the PCT Incentive Program are under the same umbrella of the Technology Incentive Program, the PCT Incentive Program is a separate program from Auto DR and was not considered in D.18-11-029. Therefore, SCE proposes to implement this program modification specifically for the PCT Incentive Program and be able to utilize program funds to provide instant rebates via Marketplace to qualifying customers.

c) <u>PCT Incentive Program Incremental Funding Request</u>

Table II- summarizes SCE's incremental funding request for the PCT Incentive Program proposal for 2022 and 2023.

Table II-6
PCT Incentive Program Incremental Funding Request
(in millions)

Line No	Cost Type	2022	2023	Total
1	Admin – Labor	$ -	$ -	$ -
2	Admin – Non-Labor			
3	System Costs	$ 0.98	$ -	$ 0.98
4	Participant Incentives	$ 1.88	$ 5.50	$ 7.38
5	TOTAL INCREMENTAL BUDGET	$ 2.86	$ 5.50	$ 8.36

d) PCT Incentive Program Guidance Document Elements

Table II-7
Guidance Document Elements – PCT Incentive Program

General Program Design	
i. Program trigger	No trigger for PCT Incentive Program specifically. Eligible customers must be enrolled in a qualifying DR program, which each have their own specific dispatch triggers.
ii. Demonstration that program will deliver benefits during net peak	Qualifying DR programs (SEP, CPP, CBP Residential and DRAM) all deliver benefits during net peak. Customers who enroll their qualifying thermostat into a qualifying SCE program will have their thermostat setpoint temporarily adjusted up to four degrees during the program's DR event to help reduce load. Customers can override their thermostat adjustment at anytime.
iii. Program performance requirements	N/A
iv. Compensation structure	One-time $75 PCT Incentive applied as a bill credit. SCE is proposing to increase this one time $75 PCT incentive to $125.
v. Program eligibility and enrollment	Customers must own a qualifying smart thermostat that is installed, connected, and registered with their thermostat provider. Customers must also enroll or be enrolled in a qualifying DR program.
vi. Measurement and verification, if needed	N/A

Program Administration	SCE administers the PCT Incentive Program.
Program Marketing, Education & Outreach	SCE conducts its own program marketing, education, and outreach for and through its SCE administered programs (SEP, CPP and CBP residential). Third Parties participating in DRAM will conduct their own program marketing, education, and outreach.
Program Budget	SCE's PCT Incentive Program budget for 2018-2022 was approved in D.17-12-003 as part of the $43.639 million under the Technology Incentive Program. The allocation for the PCT Incentive Program is specifically $11.25 million.
Implementation Timeline	Q1, 2022 – SCE will be able to implement the temporary rebate increase. Implementation for splitting the PCT Incentive across two payments and enabling DR pre-enrollment with an instant rebate through Marketplace may have some system dependencies that make it difficult to pinpoint. SCE will implement as soon as possible but could be delayed until 2023.
Program Duration	D.17-12-003 approved PCT incentive Program through 2022.
Estimated megawatt contribution/load impact (including whether load impact will reduce the demand at net peak hours, and whether and how much the load impact may reduce the impact of any existing programs)	SCE does not have an estimated MW load impact at this time. PCT Incentive Program offers customers a $75 bill credit to help offset the cost of installing a smart thermostat that may be dispatched during DR events with no manual intervention. SCE is proposing to increase the $75 bill credit to $125. PCT Incentive Program customers must enroll or be enrolled in a qualifying DR program.
Potential interaction with other existing programs (i.e., dual participation issues)	N/A
Prior similar program experience in California or elsewhere	N/A
Program funding and cost recovery mechanisms	See Section II.D. Cost Recovery.
Potential risks of proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) with discussion of each potential risk	There could be delays with implementation for splitting the rebate or activating a DR pre-enrollment offer with instant rebate through Marketplace due to internal and external system dependencies and/or developing and coordinating process and procedures between various parties.

5. Extension of Virtual Power Plant (VPP) Phase II Pilot

D.21-03-056 approved SCE's VPP Phase II Pilot. SCE's VPP Phase II Pilot tests various scenarios, including high-demand events, such as heat storms or other stressors on the grid, for dispatching energy from solar-paired battery systems in SCE's territory to provide load reduction in support of the grid. Solar-paired battery systems help make the grid more flexible and reliable with little to no impact to the residential customer.

SCE requests to extend the VPP Phase II Pilot through 2023. SCE is seeking to expand its VPP effort to include additional partners, approaches, technologies, and megawatts. SCE will expand its collaboration to include companies such as Tesla that have 80 to 100 MW of available capacity in SCE's service Territory. SCE will also test an alternate compensation structure (pay-for-performance) to potentially improve customer participation in a VPP Pilot. Customers will receive compensation for a minimum of 20 hours and a maximum of 60 hours under the pay-for-performance construct. This extension seeks to incorporate and operationalize a diverse fleet of underlying VPP technologies, such as solar-paired batteries, and other nascent technologies that are currently not used, but are capable of demand response. Ultimately, SCE seeks to access an additional 80 – 100 MW of additional capacity during grid emergencies by expanding our collaborations across partnerships and technologies while leveraging alternate approaches to help enable more customers to become grid partners.

a) VPP Phase II Pilot Incremental Funding Request

Table II-8
VPP Phase II Pilot Incremental Funding Request
(in millions)

Line No	Cost Type	2022	2023	Total
1	Admin (Labor)	$ 0.12	$ 0.30	$ 0.42
2	Admin (non labor)			$ -
3	Vendor Fees	$ 0.37	$ 0.42	$ 0.78
4	Marketing, Education & Outreach	$ 0.10	$ 0.14	$ 0.24
5	Measurement & Evaluation	$ 0.10	$ 0.10	$ 0.20
6	Systems & Technology	$ -	$ -	$ -
7	Participation Incentives	$ 1.36	$ 2.19	$ 3.55
8	Total Incremental Funding	$ 2.05	$ 3.14	$ 5.19

b) VPP Phase II Pilot Guidance Document Elements

Table II-9
Guidance Document Elements - VPP Phase II

General Program Design	
i. Program trigger	Dispatches can be triggered with 0–24-hour advance notice. Potential triggers include but are not limited to: CAISO Warnings or CAISO Emergency notices, CAISO Alerts, High Temperatures, and load trending above forecast.
ii. Demonstration that program will deliver benefits during net peak	Existing VPP Pilot was successfully dispatched using multiple triggers and dispatch profiles. The Pilot was dispatched 50 times from August 25, 2020 to May 31, 2021 during net peak hours. SCE has begun dispatching VPP as part of existing Summer Reliability effort and expects contribution of approximately 10 MW of capacity across 50 to 100 dispatches as needed.
iii. Program performance requirements	VPP aggregators will be required to connect to SCE's Demand Response Automation System (DRAS). DRAS utilizes Open ADR signals which SCE sends to either aggregators or connected VPP technologies to dispatch on SCE's command (or command of other market actors such as the CAISO). Automated demand response consists of fully automated signaling from SCE, CAISO, or other entities to provide automated connectivity to customer end-use control systems and strategies. OpenADR provides a foundation for interoperable information exchange to facilitate automated demand response.

iv.	**Compensation structure**	SCE will price VPP incentive to align with current market rates. Current market rates for incentives fall in the range of $1 to $2 per kWh of incremental load reduction. Even though SCE will price its incentive in this range, SCE has observed that some VPP participants prefer a "flat fee" incentive while others prefer a "pay-for-performance" incentive. For example, an existing VPP aggregator may prefer a pay-for-performance structure because of the belief that it better incentivizes behavior compared to a flat fee structure, and gives customers greater flexibility to adjust the desired participation level of their underlying technology. Certain customers may opt to set a 20% battery reserve (i.e., use 80% of their battery for the VPP offering), while other customers may opt to set a 50% battery participation threshold.
v.	**Program eligibility and enrollment**	A customer must have a solar-paired battery system or other DR capable technologies not currently utilized by DR programs to establish eligibility to participate in Phase II of SCE's Virtual Power Plant Pilot (VPP II). Solar-paired battery customers must have established Permission to Operate (PTO) in order to establish eligibility to participate in the VPP Pilot. Because the VPP Phase 2 Pilot examines the controllability of non-A/C load, VPP participants should also be allowed to enroll in SCE's Summer Discount Program (SDP), Smart Energy Program (SEP) and SCE's WHSP. The respective programs each utilize different and separate underlying technologies to reduce demand (E.g. Batteries vs. HVAC and Thermostats) that do not conflict or overlap with VPP II technologies. VPP participants are not allowed dual enrollment in other DR programs that leverage the same underlying technology, such as ELRP, for which dual enrollment should still be prohibited. SCE anticipates that it will increase the incremental MWs available to the VPP by as much as 10% by allowing SDP, SEP & WHSP customers to dual participate with VPP.
vi.	**Measurement and verification, if needed**	SCE will conduct M&V to understand load impacts. SCE also seeks to study additional areas to improve the overall customer experience and to fine tune customer and program economics (i.e., optimizing the customer incentive and program design to maximize program enrollment).
Program Administration		SCE will administer the VPP Phase II Pilot.
Program Marketing, Education & Outreach		SCE will leverage a co-branded approach to marketing, education, and outreach. Co-branding has proven to be effective in SCE's existing VPP efforts. SCE has seen a 22% enrollment uptake leveraging a co-marketing/branding approach.
Program Budget		Please see table above.
Implementation Timeline		Q4 2021 • Finalize VPP extension design with input from internal and external stakeholders (e.g., CPUC, Technology Vendors and Suppliers, etc.) • Launch RFP and or other contracting to solicit and validate VPP II vendor partners Q1 2022 • Finalize vendor participation (e.g., procurement and contracting, IT & Cyber, etc.) • Engage M&V partner for load impact assessment Q2 2022 • Launch customer marketing & enrollment efforts

	• Complete system integration and testing with selected participating vendors • Begin dispatching VPP <u>Q3 2022</u> • VPP Dispatching and intermittent M&V and reporting
Program Duration	The VPP Phase II Pilot is a 2-year program and is designed to be operational during the summers of 2022 and 2023.
Estimated megawatt contribution/load impact (including whether load impact will reduce the demand at net peak hours, and whether and how much the load impact may reduce the impact of any existing programs)	SCE estimates that its VPP Phase II Pilot will reduce net peak demand by 20–30 MW during net peak hours and does not anticipate VPP operations to reduce load impacts from other programs. Furthermore, the VPP is focused on Nascent technologies, such as solar paired batteries, that do not participate in existing programs.
Potential interaction with other existing programs (i.e., dual participation issues)	Although SCE is proposing dual participation with other programs (SEP, SDP & WHSP Pilot), SCE does not anticipate dual participation issues with other programs because the different programs utilize different underlying technologies relative to the VPP pilot (E.g. Solar-Paired battery systems versus smart thermostat versus utility direct load control device).
Prior similar program experience in California or elsewhere	SCE initiated its VPP efforts in 2019. Initial VPP Pilot effort was an exclusive partnership with Sunrun. Based on success of initial VPP Pilot, extension was granted in D.21-03-056. To date, SCE has contracted with six technology vendors and anticipates enrolling 1,500 customers into VPP Phase II Pilot for a total capacity of 11.8 MW.
Program funding and cost recovery mechanisms	Please see Section II.D. Cost Recovery
Potential risks of proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) with discussion of each potential risk	Potential risks include the inability of new technologies to connect to SCE's DRAS system. SCE will likely have to engage a 3rd party technology partner capable of connecting disparate systems to SCE's DRAS.

6. <u>Emergency Load Reduction Program (ELRP)</u>

D.21-03-056 adopted the ELRP as a five-year pilot program designed to obtain additional load reduction beyond existing DR programs at times when the CAISO issued a Grid Alert, Warning or Emergency. The program pays customers $1 for every kilowatt hour (kWh) of actual savings, defined as incremental load reduction (ILR). To expand ELRP to attract additional customers, increase load reduction, and remove administrative inefficiencies, SCE proposes to: (1) modify the BIP-ELRP dual participation policy to allow BIP customers to participate in ELRP events during non-overlapping hours; (2) allow dual participation for ELRP

(Sub-Group A.1.) with Critical Peak Pricing (CPP) , Real-time Pricing (RTP) and SDP; (3) expand ELRP eligibility for Sub-Group A.1. by lowering the "Minimum Size Threshold" from 200 kW to 100 kW; and (4) require Group B participants to nominate load reduction. SCE plans to continue to evaluate modifications to ELRP to improve program performance and administrative inefficiencies, and will submit a Tier 2 Advice Letter by December 31, 2021 to address other ELRP program enrollment, program efficiency, potential ways to increase load reduction through the ELRP, and program value and cost, as allowed in D.21-03-056.[18]

a) Allow BIP-ELRP Dual Participation During Non-Overlapping Events

D.21-03-056 defines incremental load reduction (ILR) "as the load reduction achieved during an ELRP event incremental to the non-event applicable baseline and any other existing commitment. Only ILR is eligible for compensation under ELRP."[19] In the case of BIP participants, only load reduction below the participant's BIP Firm Service Level (FSL) is counted towards the participants ILR and is eligible to receive ELRP incentives for the period when a BIP event overlaps with an ELRP (e.g. Special Consideration #1).[20] SCE proposes to allow BIP-ELRP dual participants to receive compensation for ELRP events that *do not* overlap with BIP events. SCE proposes the following changes to D.21-03-056, Attachment 1, Special Consideration #1.a. and #1.b.:

1. *In the case of overlapping BIP and ELRP events, only the incremental reduction below the customer's pre-committed firm service level (FSL) is counted in ILR.*
   a. *Load reduction by dual-enrolled BIP customers during an ELRP event outside of a BIP event is ~~excluded from~~ counted in ILR ~~(and not eligible for ELRP compensation)~~.*

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[18] D.21-03-056, Attachment 1, p. 15.

[19] D.21-03-056, Attachment 1, p. 9.

[20] *Id.*, Special Consideration #1, p. 10.

b. Load reduction by dual-enrolled BIP customers during an ELRP event on a day with no BIP event is ~~excluded from~~ counted in ILR ~~(and not eligible for ELRP compensation)~~.

b) Allow ELRP Participants to Dual Participate in CPP, RTP and SDP

D.21-03-056 prohibits Sub-Group A.1. customers from simultaneous enrollment in another DR program offered by an IOU, demand response provider (DRP) or CCA, with the exception that dual enrollment in BIP or the Agricultural & Pumping Interruptible (AP-I) program is permitted.[21] SCE recommends that ELRP Sub-Group A.1. participants be allowed to dual participate with Critical Peak Pricing (CPP) and Real Time Pricing (RTP) as these customers may be able to contribute additional ILR (from their back-up generation or other load reduction measures) during grid emergencies that is not permitted during CPP events or for purposes of RTP. CPP and RTP are dynamic rates and not traditional DR programs and should be allowed to dual participate in ELRP. In addition, SCE has had to reject potential ELRP participants because they were currently enrolled in CPP,[22] most of whom were defaulted onto the rate. Since bundled non-residential customers are defaulted onto CPP, this prohibition reduces the potential for maximum participation or would cause additional administrative burden on the customer to participate in ELRP because they would have to request to be removed from the rate before they could participate in ELRP, a non-penalty program. Allowing ELRP dual participation with CPP and RTP will increase ELRP participation and the resources available for grid emergencies.

SCE also recommends that ELRP Sub-Group A.1 participants be allowed to dual participate with SDP. SDP installs a load controlling device on or near customers air conditioning unit that allows SCE to cycle off the customers air conditioner during emergency events. Since SDP only focuses on a customer's air conditioning unit, the customers may be able

[21] D.21-03-056, Attachment 1, p. 5.

[22] As required by the Commission, all SCE non-residential customers are defaulted to CPP enrollment. Thus, many potential ELRP participants were rejected by SCE.

to contribute additional ILR (from their back-up generation or other load reduction measures) during grid emergencies. And since ELRP participants are only compensated when there is an event, customers may be reluctant to forego their guaranteed SDP incentive payment for an uncertain ELRP incentive payment.

Allowing ELRP dual participation with CPP, RTP and SDP will increase ELRP participation and the resources available for grid emergencies and remove barriers that prevent commercial SDP customers from participating in ELRP, where other DR programs are allowed to dual participate with ELRP.[23]

c) Expand ELRP Eligibility to 100kW or Greater

As discussed in the Commission's Staff Concept Paper, Sub-Group A.1 customers must meet specific Minimum Size Thresholds, which vary by IOUs. Under the Decision as it currently stands, a Sub-Group A.1 participant served by SCE must have a registered demand reaching or exceeding 200 kW to participate in ELRP. SCE proposes to decrease the demand threshold to 100 kW to increase the number of customers that can participate in ELRP.

d) Remove the 50 percent and 200 percent payment requirements (e.g. the ELRP payment collar) and increase the ELRP compensation rate to $2 per kilowatt-hour (kWh)

SCE supports the Commission's Staff Concept Paper to remove the payment collar and increase the ELRP compensation/incentive rate to $2 per kWh in an effort to attract and increase customer enrollment and participation. While SCE does not have ELRP performance data at this time, SCE anticipates that customers' ELRP event results may not reach the 50 percent threshold or may exceed the 200 percent threshold of their bid amount which could discourage customers from participating in subsequent ELRP events. To address these

[23] D.21-03-056 allows BIP, BIP-Agg, API-I, CPP, RTP, CBP, DRAM, 3rd Party DRPs' PDRs, and exporting DERs to participate in ELRP. The only remaining non-residential DR program that is currently not allowed to participate in ELRP is SDP-C.

potential barriers, SCE recommends removing the ELRP payment collar. In addition, increasing the ELRP compensation rate $2/kWh would provide parity with the California State Emergency Program (CSEP) and should attract those participants to ELRP after CSEP closes on October 31, 2021. But unlike Staff's Concept Paper, SCE recommends this incentive increase apply to all ELRP groups, not just Sub-Groups A.1. and A.2.[24] Since ELRP is a non-penalty, pay-for-performance program, SCE does not support or recommend the higher compensation rate be applied to "customers who commit to providing a certain load reduction performance level." This would likely require creating or applying a collar which SCE and the Staff Concept Paper are recommending be removed. If future data or results determine reimplementation of the collar or changes to the compensation mechanics, SCE could propose further changes through the annual advice letter process authorized in D.21-03-056.

e) Require Group B Participants to Nominate Load Reduction Quantity

In D.21-03-056, The Commission required Group A participants to nominate an estimated target load reduction quantity to be achieved during an ELRP event, but did not establish the same requirement for Group B participants.[25] SCE recommends that the Commission also require Group B participants to nominate an estimated target load reduction for planning purposes. For all DR programs, it is CAISO's expectation that the IOUs provide CAISO Operations an estimate of MWs available daily. SCE has been unable to provide CAISO an accurate expectation of MWs available through its ELRP Pilot because Group B participants are not required to nominate their incremental load reduction.

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24 CPUC Staff Concept Paper emailed on August 16, 2021, Section 1.a.

25 D.21-03-056, Attachment 1, pp. 4, 7.

f) ELRP Incremental Funding Request

If the 2023-2027 DR Application deadline (currently set at November 1, 2021) is extended, SCE requests the Commission's authorization for one additional year of funding (2023) at the same annual amount approved in D.21-03-056.[26]

g) ELRP Guidance Document Elements

Table II-10
Guidance Document Elements - ELRP

General Program Design		
i.	**Program trigger**	ELRP utilizes both day-ahead (DA) and day-of (DO) event triggers. ELRP may be activated after CAISO issues or declares an Alert, Warning, or Emergency Notice, as defined by "Alert, Warning, Emergency (AWE)" process in CAISO Operating Procedure 4420.
ii.	**Demonstration that program will deliver benefits during net peak**	ELRP will provide benefits during net peak because events will be called during times of forecasted or actual stress on CAISO transmission system.
iii.	**Program performance requirements**	Participation is voluntary; no financial penalties for customers not meeting Energy Bid amount during event.
iv.	**Compensation structure**	$2 per kWh
v.	**Program eligibility and enrollment**	Eligible participants are divided into several sub-groups. All customers must be located in SCE's service territory and must have SCE-approved interval or SmartConnect meter that can measure energy consumption, at least hourly, and if applicable, can measure exported energy.
vi.	**Measurement and verification, if needed**	SCE plans to conduct M&V to understand load impacts.
Program Administration		SCE administers its ELRP pilot.
Program Marketing, Education & Outreach		SCE conducts its own program marketing, education, and outreach to eligible customers.
Program Budget		If SCE's 2023-2027 DR Application filing is delayed, SCE requests incremental funding for 2023 at 2021 and 2022 levels (e.g. $2.9 million for administration and $33.8 million for customer compensation).

[26] D.21-03-056 approves $2.9 million for administration and $33.8 million for customer compensation for SCE.

Implementation Timeline	SCE will be able to implement the changes recommended by May 2022.
Program Duration	An ELRP event can be dispatched in May through October each year for the five-year pilot period (2021-2025).
Estimated megawatt contribution/load impact (including whether load impact will reduce the demand at net peak hours, and whether and how much the load impact may reduce the impact of any existing programs)	SCE does not know the estimated MW impacts at this time.
Potential interaction with other existing programs (i.e., dual participation issues)	SCE proposes (1) allowing BIP customers to participate in ELRP events for non-overlapping hours and (2) allow dual participation for ELRP with CPP, RTP, and SDP.
Prior similar program experience in California or elsewhere	n/a
Program funding and cost recovery mechanisms	SCE recommends using funding and cost recovery mechanism approved in D.21-03-056.
Potential risks of proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) with discussion of each potential risk	The potential risks of not adopting SCE's proposed modifications is a lack of participation and low MW contributions.

7. Auto Demand Response (ADR)

ADR control incentives offset ADR control costs incurred by customers who wish to enroll in DR programs utilizing software and systems to effectuate load drop with no manual intervention. The ADR control automates participation in DR events to allow customers to provide reliable load shed during DR program events. To mitigate customer attrition and increase program enrollment, SCE proposes to: (a) remove the 60/40 incentive payment split; (b) increase the DR enrollment requirement to five years; and (c) allow ELRP and BIP customers to be eligible for ADR incentive payments.

a) Remove 60/40 Incentive Payment Split

In D.12-04-045, the Commission adopted changes to the IOUs' ADR programs, including splitting ADR customized incentives 60/40 (i.e., 60 percent of the eligible incentive is paid upfront, and the remaining performance incentive, up to 40 percent, is paid after one year, based on the customer's DR calculated performance).[27] Under current ADR rules,

[27] *See* D.12-04-045, Ordering Paragraph (OP) 58.

customers may be subject to a prorated clawback amount of the incentives they received under the 60 percent incentive payment if they do not remain enrolled on a qualifying DR program for at least three years. Because SCE has seen a drop off in applicants since the 60/40 payment structure was implemented, SCE proposes to remove the 60/40 payment split for ADR Customized incentives to attract more DR customers and automate their DR participation.

As a replacement for the 60/40 payment split, SCE proposes to issue customers 100 percent of their eligible incentive payment after the ADR control installation is verified and tested. SCE made this proposal in SCE's 2017 Bridge Funding Proposal, but the Commission rejected SCE's proposal due to a lack of evidence that the 60/40 incentive payment split led to a decrease in program interest. However, in 2020, the IOUs jointly hired Energy Solutions to conduct research on ADR incentives.[28] Energy Solutions found that applications decreased substantially due to changing the incentive structure to 60/40.[29] Energy Solutions found that the current 60/40 incentive split between installation and performance is a major barrier to participation as it does not align with customer business models and adds uncertainty to customers' financial planning. The ADR program participation would benefit from a redesign of this incentive structure.[30]

b) <u>Increase Enrollment Requirement to Five Years</u>

In an effort to mitigate DR program attrition associated with providing upfront incentives, SCE proposes to increase the enrollment requirement from three to five years for customized incentives, provided that the proposal to remove the 60/40 incentive payment

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[28] Energy Solutions' Automated Demand Response Non-Residential Incentive Structure Research Project Report was included as Attachment 2 to the IOUs' joint updates to the Auto Demand Response Control Incentive Guidelines and Adopted Policies, SCE Advice 4278-E, PG&E Advice 5931-E, and SDG&E Advice 3597-E, submitted on August 28, 2020.

[29] *See* Energy Solutions, Automated Demand Response Non-Residential Incentive Structure Research Project Report, August 6, 2020, p. 6 ("Historically, participation in paid ADR MW peaked in 2012, after which applications decreased substantially. Research indicated the trend was due to changes in incentive structure.").

[30] *See id.*, p. 7.

split is adopted. The Energy Solutions report showed that most ADR customers maintained their DR program enrollment longer than the existing three-year requirement.[31]

Energy Solutions found that once an account is enrolled in a DR program after receiving an ADR incentive, they tend to remain enrolled for at least three years, and almost 60% of accounts remained enrolled in DR for five or more years after incentive payment. These results show that the ADR incentive program is a strong driver of sustained engagement with DR programs and that most customers that receive the incentive become ongoing DR participants.[32]

c) ADR Incentives Eligibility

SCE proposes to allow customers enrolled in the ELRP pilot and BIP to be eligible for ADR incentives due to the expectation that reliability events will be called more frequently in the next few years and automation of customer load is expected to provide quick and reliable MW in response to grid emergencies. If adopted, the Commission would need to modify D.16-06-029, which states that "Given the infrequent dispatch of BIP, we do not consider the Commission's investment in ADR devices recoverable through a reliability program."[33] SCE recommends that the Commission reconsider its prior decision and allow BIP to be eligible for ADR incentives to automate customer's load reductions.

d) Program Budget

In D.17-12-003, the Commission authorized $17.5 million for ADR Customized and Express incentives for business customers. To date, the program has issued approximately $94,000 in incentives. SCE plans to use $3.3 million in unspent ADR incentive funds to cover an expected SEP thermostat incentive budget shortfall. SCE does not anticipate needing any incremental funding for these proposals.

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[31] *See id.*, p. 6.

[32] *See id.*, pp. 42-43.

[33] D.16-06-029, p. 47.

e) ADR Guidance Document Elements

Table II-11
Guidance Document Elements - ADR

General Program Design	
i. Program trigger	No trigger for ADR specifically. ADR customers must be enrolled in a qualifying DR program, which each have their own specific triggers.
ii. Demonstration that program will deliver benefits during net peak	Qualifying DR programs (BIP, CBP, CPP, DRAM, ELRP, and RTP) all deliver benefits during net peak.
iii. Program performance requirements	Remain enrolled in a qualifying DR program for 5 years.
iv. Compensation structure	ADR offers customers incentives to offset the cost of installing load control equipment. Express incentives offer up to \$300/kW or up to 100% of project cost. Customized incentives offer \$300/kW or up to 75% of project cost.
v. Program eligibility and enrollment	Non-residential customers who install qualifying ADR controls and remain enrolled in a qualifying DR program for 5 years.
vi. Measurement and verification, if needed	N/A
Program Administration	SCE administers the ADR Program.
Program Marketing, Education & Outreach	SCE conducts its own program marketing, education, and outreach to eligible customers.
Program Budget	SCE's ADR budget for 2018-2022 was approved in D.17-12-003.
Implementation Timeline	SCE will be able to implement these changes by the end of 2021.
Program Duration	D.17-12-003 approved ADR through 2022.
Estimated megawatt contribution/load impact (including whether load impact will reduce the demand at net peak hours, and whether and how much the load impact may reduce the impact of any existing programs)	SCE does not know the estimated MW impacts at this time. ADR offers customers incentives to offset the cost of installing controls to effectuate load drop with no manual intervention. ADR customers must be enrolled in a qualifying DR program. Adding incentives for automating load drop for customers on BIP and the ELRP pilot would provide quick and reliable MW in response to grid emergencies.
Potential interaction with other existing programs (i.e., dual participation issues)	SCE proposes to allow customers enrolled in the ELRP pilot and BIP to be eligible for ADR incentives.
Prior similar program experience in California or elsewhere	N/A
Program funding and cost recovery mechanisms	No additional funds are required for the proposed changes. SCE will continue to use the same funding and cost recovery mechanism approved in D.17-12-003.
Potential risks of proposal (e.g., delay, lack of participation, low	Paying 100% incentives after the ADR control installation is verified and tested for customized incentives presents risk of

megawatt contribution, etc.) with discussion of each potential risk	nonperformance. Risk will be minimized by requiring customers to remain enrolled in a qualifying DR program for 5 years. SCE will be able to clawback incentive payments if customers do not remain enrolled in qualifying DR program.

8. Leveraging Time-Of-Use Rates and Alerts

To encourage customers to limit energy usage during net peak periods, SCE proposes an acquisition campaign to: (1) enroll more customers in Time-of-Use (TOU) rates;[34] (2) enroll more EV customers in TOU-D-PRIME, SCE's electrification rate; and (3) enroll additional customers in TOU text alerts. TOU rates result in load shifts out of peak periods. In the past, SCE has launched campaigns to target customers for TOU rate options. SCE plans to mimic these prior campaigns to acquire more customers by continuing education and outreach for customer groups in the following categories discussed below.

a) Enroll More Residential Customers in TOU Rates

In D.19-07-004,[35] the Commission directed the IOUs to transition select residential customers to TOU rates. By Spring of 2022, SCE anticipates moving approximately 2.3 million additional residential customers to a TOU rate. However, the directive excludes certain groups of customers, such as those who started service after October 2020, as well as CARE/FERA customers in hot climate zones and Medical Baseline customers. Many of these excluded customers are not on TOU rates, but may benefit from being on those rates. SCE proposes to target these groups of customers via a TOU acquisition campaign, similar to what was conducted with customers during the "Test and Learn" campaign effort prior to the TOU transition from 2017-2020. This outreach could be in addition to the Annual Rate Comparison Letter and could contain a stronger call to action to enroll. Recent load impact studies conducted on the TOU default rates found that moving customers to these rates provided a summer

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34 As described below, SCE's proposal to enroll more customer in TOU rates is targeted at residential customers. The majority of SCE's non-residential customers are already enrolled on a TOU rate.

35 *See* D.19-07-004, Phase IIB Decision Addressing Residential Default Time-Of-Use Rate Design Proposals and Transition Implementation, July 11, 2009.

weekday peak period load reduction of 0.016 kW per customer for TOU-D-4-9PM, and 0.019 kW per customer for TOU-D-5-8PM.[36] Marketing to customers may include sending direct mail and emails. Additionally, SCE intends to cross-promote TOU by leveraging existing contacts with Community-Based Organizations (CBOs), and SCE plans to investigate the possibility of integrating the benefits of TOU with communications regarding low income and/or demand response programs (e.g., SEP and SDP).

b) Enroll New EV Owners in TOU-D-PRIME

SCE proposes to roll out an acquisition campaign targeting customers who have purchased an electric vehicle (EV). SCE can leverage interval usage data to conduct a propensity model to identify potential EV customers who charge at home. This would simulate a previous successful acquisition campaign targeting EV customers to move to TOU-D-PRIME, SCE's electrification rate, to encourage load shifting. A recent load impact study showed that EV customers that enrolled in TOU-D-PRIME reduced their peak period electricity demand by 0.43 kW (27.1%).[37] The load shifts realized by EV customers on this rate are relatively significant, possibly because it is simple to set charging times for EVs to off-peak hours on a one-time basis ("set it and forget it"). SCE proposes marketing to these customers through multiple channels, which may include direct mail, email, and educational information at drive events and auto shows.

c) Enrolling Customers in TOU Text Alerts

SCE conducted a pilot study in 2017 that found that residential customers who receive TOU text alerts at the start of their TOU peak period are able to reduce their electricity usage during peak times, and this behavior was persistent beyond the study period. In the study, customers reduced their usage by 7.2% (0.015 kWh).[38] TOU text alerts act as a

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[36] Nexant 2020 Load Impact Evaluation of SCE's Default TOU Pilot, p. 2.

[37] Nexant SCE TOU-D-PRIME Ex Post Load Impacts, July 22, 2021, p. 3.

[38] The timing of behavioral reminders affects customer's energy usage: early findings from a TOU text alert study, 2019.

reminder and can encourage additional load shift. SCE proposes to develop a marketing campaign to enroll customers to receive TOU text alerts. The target audience would be both residential and small business customers. For residential customers, the text alert enrollment option would likely be a component of the TOU acquisition campaign, as this approach was previously found to be the most effective. For business customers, this would not be part of a TOU acquisition campaign, but tactics may include a dedicated campaign or inclusion in part of a larger campaign.

d) Program Budget

Table II-12
TOU Price Leveraging Incremental Funding Request
(in millions)

Line No.	Cost Type	2022	2023	Total
1	Admin - Labor	$ 0.26	$ 0.16	$ 0.42
2	Admin - Non-Labor			
3	ME&O	$ 0.88	$ 0.52	$ 1.40
4	TOTAL INCREMENTAL BUDGET	$ 1.14	$ 0.68	$ 1.82

e) TOU Acquisition Guidance Document Elements

Table II-13
Guidance Document Elements - TOU

General Program Design	Increased enrollment into existing TOU rates and TOU Text Alerts.
i. Program trigger	No trigger for TOU. For TOU Text Alerts, the trigger is the start of the peak period, which for most customers is weekdays at 4pm.
ii. Demonstration that program will deliver benefits during net peak	Previous load impact studies and other pilot studies have shown that customers enrolled in TOU and TOU Text Alerts shift their load from peak times. Load impact for each recommendation is cited above.
iii. Program performance requirements	n/a
iv. Compensation structure	Customers who shift load are rewarded with lower kWh rates during off peak times.
v. Program eligibility and enrollment	All customers are eligible for TOU rates. For TOU-D-PRIME, customer must be residential and attest to owning an EV. For TOU Text Alerts, customer must take service on a TOU rate.

vi. Measurement and verification, if needed	n/a
Program Administration	Internal to SCE.
Program Marketing, Education & Outreach	SCE will leverage the approach previously used in prior TOU acquisition campaigns. SCE will continue to leverage statewide marketing and CBOs for TOU rate options whenever possible.
Program Budget	Please see table above.
Implementation Timeline	TOU acquisition and EV TOU-D-PRIME Acquisitions: Three campaigns: Spring 2022, Fall 2022, and Spring 2023 (assuming a Commission decision in this proceeding authorizing SCE's proposed modifications by Jan 2022) TOU Text Alerts for residential customers will likely mimic the above campaign dates.
Program Duration	Year-round
Estimated megawatt contribution/load impact (including whether load impact will reduce the demand at net peak hours, and whether and how much the load impact may reduce the impact of any existing programs)	400 kW load reduction at peak hours plus 65.8MWh annual conservation
Potential interaction with other existing programs (i.e., dual participation issues)	None known, but potential for increased load reduction when customer is on multiple programs due to interactive behavioral effects.
Prior similar program experience in California or elsewhere	Prior experience at SCE
Program funding and cost recovery mechanisms	See Section II.D. Cost Recovery
Potential risks of proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) with discussion of each potential risk	Low MW contribution

B. NEW POLICIES OR MODIFICATIONS TO EXISTING POLICIES

1. Modifications to the Commission's Prohibited Resource (PR) Policy

SCE is fully committed to the state's ambitious greenhouse gas reduction goals and to an increasingly clean grid that will enable the state's success. However, to provide for grid reliability during extreme heat events, and to increase load reduction when there are capacity constraints, SCE proposes to temporarily allow BIP and AP-I customers to be exempted from the Commission's PR policy to better address forecasted system capacity shortfalls, only for the summer of 2022.[39] Absent an emergency order of the Governor specifying otherwise, SCE proposes the Commission authorize temporary tariff changes to both the BIP and AP-I programs to permit PR use by these customers within their air quality permits.

a) Duration

SCE recommends that the temporary removal of the PR provision be applicable in 2022. SCE anticipates that the temporary modification to the PR policy will only be necessary in 2022 because SCE will have additional resources available to meet needs by 2023. BIP and AP-I customers commit to participation on the programs on an annual basis for year-long commitments that are revisited each November. Thus, SCE requests this rule be in effect for the 2022 calendar year in order to harmonize with current program participation rules, obtain MW commitments in order to facilitate accurate program MW capacity forecasts and compensate customers at appropriate incentive levels.

b) Justification

Temporarily removing the PR policy will lead to an estimated additional 66 MW of load reduction that California can rely on during extreme events.

c) Estimate of Policy's Impact

SCE is not suggesting that through this proceeding customers should be given a waiver of local air permit requirements. The Governor would still need to provide an air quality permit exemption by emergency order as was done in 2020 and 2021 for customers to use PR above air quality permit limitations. Instead, SCE is recommending that BIP and AP-I customers be exempted from the Commission's PR policy in this very narrow circumstance. SCE estimates that temporarily eliminating PR provisions from interruptible tariffs, could add 16

[39] D.16-09-056 prohibits the following list of resources to be used for load reduction during DR events: distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas, in topping cycle Combined Heat and Power (CHP) or non-CHP configuration. *See* D.16-09-056, OP 3.

additional DR MW from existing interruptible customers and potentially bring back 50 MW of customers that unenrolled after the implementation of the PR policy.

d) Implementation Requirements

If the Commission adopts SCE's proposal, SCE will modify its BIP and AP-I tariffs temporarily. Once SCE's BIP and AP-I tariffs are modified, SCE will allow BIP customers to adjust their Firm Service Level (FSL) for 2022 via their annual customer contracts.

e) Potential Risk of Proposal

Even if the Commission allows a temporary suspension of the PR policy, it is uncertain whether customers will re-enroll in BIP and AP-I because their air quality permits do not allow them to use the PRs above air quality permit limitations without an emergency order to do so. As stated above, the Governor would still need to issue an emergency order to allow for use of PR above air quality permit limitations and the uncertainty of whether the order will be issued and how air quality management districts implement the order could lead to lack of interest in enrolling.

f) Statutory and/or Regulatory Justification

In 2019, the IOUs implemented the Commission's PR policy pursuant to D.14-12-024, D.16-09-056 and Resolution E-4906. As such, the Commission has the authority to temporarily suspend the PR policy.

2. Modifications to DR Programs to Enhance Market Integration

Recent CAISO tariff changes stemming from CAISO's Reliability Demand Response Resources (RDRRs) Summer Reliability enhancements have created conditions that pose multiple risks for SCE and its customers. The changes create a scenario whereby the RDRR resource fleet could experience multiple on/off dispatches and scattered and overlapping resource dispatch instructions during CAISO System Emergencies. SCE has raised these issues to the CAISO, however, the CAISO is moving forward in activating market features for RDRRs. Current CAISO market enhancements do not recognize program limitations and, as such, customers run the risk of receiving dispatch targets that conflict with program tariffs, as well as scattered/on-off-/overlapping dispatch instructions. Customer resources that are tasked with the responsibility of preserving reliability should not be subject to miscommunication and disregard of program tariff rules. This leads to customer confusion, frustration, and potentially reduced participation.

If the CAISO declares a system emergency and determines RDRR is needed in order to balance real-time threats to the systemwide grid, SCE's demand response and corporate safety objectives take on a new focus and definition: properly execute the dispatch of RDRR customer resources in order to minimize or avoid rotating outages.

In order to meet this objective, in an actual real-time CAISO declared emergency the best operational scenario is for the RDRR fleet to be called in the largest MW blocks possible (either all at once, or by SLAP as SLAP is the largest single unit of MW per CAISO market integration rules). Keeping the fleet together from a CAISO-integration perspective makes it possible for SCE to monitor and manage program constraints, manage and direct rotating outage blocks, issue DR/outage notifications through SCE channels (e.g. SCE.com and SCE DR Alerts App) and ensure our Customer Call Center as well as our Business Customer Division have consistent information to manage customer interactions and inquiries. At present, CAISO's enhancement project poses multiple risks including SCE-violation of DR program tariff rules as well as introducing the risk that SCE is not able to properly administer RDRR events and meet the real-time corporate objective to minimize or avoid rotating outages.

In order to mitigate those risks, SCE proposes changes to the event parameters to align its reliability DR programs to create two sets of RDRR resources that represent the non-residential and residential segments and will result in large CAISO aggregations by SLAP. The intent of this change is to collapse SCE's current RDRR resource fleet from 69 to potentially as few as 12[40]. To that end, SCE requests modifications to Reliability Program Event Parameters

[40] These changes will not impact SCE's ability to dispatch RDRR resources at the local level (e.g. A-bank) to manage distribution level emergencies via its Grid Control Center team.

such that BIP and AP-I parameters match, and SDP and SEP parameters match, in order to simplify RDRR market integration and ensure all programs can be dispatched concurrently when needed. The proposed changes below reflect program parameters that maximize availability of the RDRR fleet:

Program	BIP	AP-I	SDP**	SEP
Events per day	1	1	Multiple*	Multiple*
Event hours per day	6	6	6	~~4~~ 6 (change)
Event hours per year	180	~~150~~ 180 (change)	180	180
Events per calendar month	10	10 (add)	-	-
Events per calendar week	-	~~4~~ (remove)	-	-
Events per calendar year	-	~~25~~ (remove)	-	-
Event hours per calendar month	-	~~40~~ (remove)	-	-

* *SDP and SEP tariffs allow multiple starts per day should an emergency event dispatch be needed when the program is scheduled for an economic dispatch; therefore, SCE is not proposing any changes and to continue to allow multiple event dispatches per day if needed.* *** SDP Residential and Commercial parameters are aligned; SCE does not propose any changes.*

a) Applicability

SCE proposes this change to be effective immediately.

b) Justification

As stated above, recent CAISO tariff changes stemming from CAISO's RDRR enhancements have imposed a risk to SCE and customers by potentially experiencing multiple on/off dispatches and scattered and overlapping resource dispatch instructions during System Emergencies. In addition, these changes would also allow SCE to register resources more effectively into the CAISO market. For example, all emergency DR programs were dispatched on consecutive days in August and September of 2020, including SEP. However, the SEP was restored ahead of the other DR programs who were still providing valuable load relief during these emergencies because the tariff limits event dispatches to four hours per event.

c) Estimate of Policy's Impact

SCE does not have an estimated MW impact resulting from this policy changes but anticipated that this modification should mitigate or reduce attrition rates which will result in maintaining current MW.

d) Implementation Requirements

As discussed above, to ensure that program parameters can be dispatched concurrently when needed, Reliability Program Event parameters, such that that BIP and API parameters match, and SDP and SEP parameters match, in order to simplify RDRR market integration.

e) Potential Risk of Proposal

SCE has not identified any potential risk of adopting this proposal.

f) Statutory and/or Regulatory Justification

CAISO Tariff ER21-1536 will need to be modified.

C. PROCUREMENT MECHANISMS/RESOURCES NOT PREVIOUSLY ACCEPTED IN THIS PROCEEDING

1. SCE is Already Actively Pursuing Supply-Side Procurement to Alleviate the Reliability Risks Identified in the Emergency Proclamation

To address the risks to California's electric system reliability in the summers of 2021 and 2022 resulting from the increasing effects of climate change, the Emergency Proclamation requests that the Commission "work with the State's load serving entities on accelerating plans for the construction, procurement, and rapid deployment of new clean energy and storage projects to mitigate the risk of capacity shortages and increase the availability of carbon-free energy at all times of day."[41] The Emergency Proclamation also requests that the Commission expedite its actions, "to the maximum extent necessary to meet the purposes and directives of this proclamation, including by expanding and expediting approval of … storage and clean energy projects, to ensure that California has a safe and reliable electricity supply through October 31, 2021, to reduce strain on the energy infrastructure, and to ensure increased clean energy capacity by October 31, 2022."[42]

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41 Emergency Proclamation, p. 2.

42 *Id.*, p. 13.

Consistent with the procurement authorizations already provided to the IOUs in Phase 1 of this proceeding and other proceedings, SCE is actively pursuing additional supply-side procurement for summer 2022 to help alleviate the reliability risks identified in the Emergency Proclamation. In D.21-03-056, the Commission directed the IOUs to continue their procurement efforts on behalf of all benefitting customers and endeavor to meet and exceed their respective incremental procurement targets to achieve an "effective" increase in the PRM from 15 percent to 17.5 percent for the months of May through October in 2021 and 2022.[43] This results in a minimum target of 450 MW for SCE.[44] The IOUs are encouraged to exceed their respective targets by up to 50 percent, known as the upper end target.[45] The Commission clarified that the upper end target is a "soft cap" for all resources, including non-RA resources such as DR programs authorized in this rulemaking, but is a "hard cap" for incremental supply-side generation and in-front-of-the meter storage resources.[46] As such, SCE already has authority to procure up to 675 MW of supply-side generation and in-front-of-the-meter storage resources for summer 2022 on behalf of all benefitting customers.

SCE is pursuing a variety of strategies to procure supply-side generation and storage to achieve the D.21-03-056 targets and in support of the Emergency Proclamation. These include bilateral procurement opportunities from third-party providers and increasing the capacity/output of generation and storage resources already under contract. Moreover, SCE is procuring incremental imports that can contribute to the net peak and help to mitigate reliability risks in the summer months of 2021 and 2022.

In addition to procuring RA imports, in anticipation of heat wave or supply-constrained days, SCE has developed a strategy to procure non-RA imports to support reliability mostly in the daily market, but also monthly or balance-of-the month. These are additional

43 D.21-03-056, OP 14, Attachment 1, pp. 20-22.

44 *See id.*, Attachment 1, p. 20.

45 *See id.*, Attachment 1, pp. 20-21.

46 *See id.*, Attachment 1, p. 21.

purchases beyond RA compliance, and outside of the T-30 window, but otherwise contribute to system reliability (e.g., these imports attest to being sourced outside of the CAISO balancing authority and there is available maximum import capability to support deliverability). This strategy helps to ensure that there is available intertie capacity and that the imports procured by SCE provide energy that will provide reliability benefits. Further, by procuring these imports after LSEs' RA showings, SCE ensures that it is not competing with other LSEs and inadvertently procuring the same imports that otherwise would have been RA resources. SCE already has authority to pursue this import strategy, and its other procurement efforts for summer 2022, pursuant to D.21-03-056. However, SCE suggests that the Commission work with the CAISO to determine whether there is a way to put non-RA imports on supply plans so the resources are treated as RA for CAISO market mechanisms.

SCE is also engaged in a 2021 Mid-term Reliability Request for Offers (RFO) to meets its share of the mid-term reliability procurement ordered by the Commission in D.21-06-035. SCE is reviewing offers from the Fast Track of that RFO, which is targeted at meeting SCE's share of the 2,000 MW and 6,000 MW targets that the Commission required to come online on August 1, 2023 and June 1, 2024, respectively. SCE is exploring opportunities to expedite any mid-term reliability projects to come online by summer 2022. However, the market for new resources able to come online by summer 2022 is already limited, and when combined with the lengthy CAISO interconnection queue, there are a limited number of resources that may be able to come online by summer 2022. As the ED Staff Concept Proposals recognize, "there will be significant challenges associated with LSEs successfully accelerating the online dates of significant quantities of IRP resources by summer 2022."

2. The Supply-Side Procurement Actions Considered in this Rulemaking Should Focus on Summer 2022

The Phase 2 Scoping Memo expands the scope of this rulemaking to include increasing peak and net peak supply in 2022 and 2023.[47] SCE suggests that the Commission focus on actions that can increase peak and net peak supply in summer 2022 only.

Governor Newsom issued the Emergency Proclamation to "free up energy supply to meet demand during extreme heat events and wildfires that are becoming more intense and to expedite deployment of clean energy resources *this year and next year*."[48] The directives in the Emergency Proclamation are focused on 2021 and 2022, and do not specifically address 2023.

Moreover, LSEs are already procuring a substantial amount of resources expected to be online by summer 2023 under existing procurement authorizations in the IRP proceeding, including 3,300 MW pursuant to D.19-11-016 to be online by August 1, 2023[49] and an additional 2,000 MW to be online by August 1, 2023 that was recently required in D.21-06-035.[50] Under Commission staff's stack analysis of CAISO system needs in the IRP proceeding, there was no reliability need in 2023 under any scenario[51] and, assuming Redondo Beach Generating Station Units 5, 6, and 8 (Redondo Beach) receive an extension of its compliance deadline from the State Water Resources Control Board, these once-through cooling units and Diablo Canyon will continue to operate in 2023. Indeed, in D.21-06-035, the Commission acknowledged parties' concerns that a reliability need was not shown in 2023 and that a large amount of accelerated

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[47] *See* Phase 2 Scoping Memo, p. 4.

[48] *See* Press Release *available at* https://www.gov.ca.gov/2021/07/30/governor-newsom-signs-emergency-proclamation-to-expedite-clean-energy-projects-and-relieve-demand-on-the-electrical-grid-during-extreme-weather-events-this-summer-as-climate-crisis-threatens-western-s/ (Press Release) (emphasis added).

[49] *See* D.19-11-016, OP 3. Under D.19-11-016, 50 percent of this procurement is required to be online by August 1, 2021 and 75 percent by August 1, 2022. *See id.*

[50] *See* D.21-06-035, OP 1. In D.21-06-035, the Commission also required LSEs to procure an additional 6,000 MW to be online by June 1, 2024, an additional 1,500 MW online by June 1, 2025, and an additional 2,000 MW online by June 1, 2026. *See id.*

[51] *See id.*, pp. 21, 25.

procurement for 2023 may increase costs and decrease procurement flexibility, and thus reduced the accelerated procurement required by August 1, 2023 from 3,000 MW in the proposed decision to 2,000 MW in the final decision.[52] The CEC's Draft Summer 2022 Stack Analysis also does not include an analysis of system needs in 2023.

Based on the lack of any demonstrated system reliability need for summer 2023 in past analyses and the significant incremental capacity already expected to be online by summer 2023, SCE is concerned with considering additional expedited procurement for summer 2023 in this rulemaking, especially given the urgency for 2022 and the need to act on demand-side resources. Additionally, the accelerated schedule for Phase 2 of this rulemaking does not allow for a robust analysis of system reliability needs for 2023 or provide enough time for meaningful stakeholder feedback on that analysis. For all these reasons, the Commission should focus its efforts on increasing supply for summer 2022 only.

3. <u>The Most Effective Solution to Increase Peak and Net Peak Supply Consistent With the Emergency Proclamation is to Maintain the IOUs' Existing Procurement Authority</u>

As explained above, SCE is already actively pursuing strategies for increasing peak and net peak supply for summer 2022 as provided in the Emergency Proclamation. The procurement authority already provided to the IOUs under D.21-03-056 to procure on behalf of all benefitting customers is the most effective tool for pursuing those efforts.

To the extent the Commission considers any other procurement mechanisms in Phase 2 of this rulemaking, those mechanisms should follow a "best efforts" standard similar to the procurement targets in D.21-03-056, as opposed to an increased RA compliance obligation or procurement requirement. A best efforts standard is appropriate because of the uncertainty around how much additional supply is available. As stated in the Emergency Proclamation and found in the CEC's Draft 2022 Summer Stack Analysis, supply conditions are very tight in the

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[52] *See id.*, pp. 24-25, 82.

CAISO balancing authority. There is a limited amount of incremental supply from existing resources available for summer 2022, and the short timeframe before the summer of 2022 (particularly accounting for the time needed to adopt a final decision in this rulemaking authorizing any procurement and the time needed for Commission approval of any resulting procurement contracts) will make it extremely challenging to bring any new resources, that are not already in progress, online by summer 2022. It would be unreasonable to impose a compliance obligation or procurement mandate for a specific amount of capacity or firm energy that the IOUs and/or other LSEs cannot reasonably meet.

While SCE generally believes its existing procurement authority to procure for summer 2022 on behalf of all benefitting customers is the most effective solution for increasing peak and net peak supply for summer 2022, there are a few areas where additional regulatory action by the Commission could help to meet the objectives of the Emergency Proclamation.

First, as addressed above, SCE is already procuring non-RA imports to help enhance system reliability at the peak and net peak under its existing D.21-03-056 authority. However, SCE suggests that the Commission work with the CAISO to determine a process to put monthly imports purchased after T-30 on RA supply plans. Monthly import products are often available in the market closer to the flow date, but after the compliance filing deadline. If these resources meet RA requirements, including being paired with import allocation rights and sourced outside the CAISO balancing authority, there should be a process to reflect them on supply plans.

Second, while the IOUs are authorized to contract with once-through cooling units, including in anticipation of extension of their compliance deadlines, existing Commission decisions also require the IOUs to file a Tier 3 Advice Letter for approval of such contracts in certain circumstances.[53] This makes it difficult for the IOUs to contract with these resources to meet RA requirements and other needs due to the time needed to request and obtain Tier 3

[53] *See* D.19-11-016, pp. 47-48, OP 2.

Advice Letter approval. SCE requests that the Commission authorize the IOUs to contract with once-through cooling units through 2023 under their Bundled Procurement Plan authority without the requirement to file a Tier 3 Advice Letter. This will ensure that the IOUs can contract with these resources for RA needs without the delay and potential uncertainty caused by a Tier 3 Advice Letter process, and thus help to ensure these resources are available for system and local reliability.

Finally, utility-owned energy storage is a promising solution for helping to alleviate the reliability risks identified in the Emergency Proclamation. As noted above, it will be difficult to procure or accelerate the construction of new energy storage capacity before the summer of 2022. The IOUs may be able to develop, construct, and install utility-owned storage resources quickly by utilizing existing IOU substations that can avoid or expedite the challenges associated with new projects (e.g., site control, permitting, interconnection, etc.). These projects could be interconnected to non-CAISO-controlled portions of the electric system under the jurisdiction of this Commission and the operational control of the IOUs and operate outside of the CAISO wholesale market, but would provide reliability by discharging to the grid during the net peak periods and charging during high solar or low load periods. The resources could be located at or near substations where there could be benefits to the overall system, such as within load pockets, local capacity requirement areas, or substations in areas with significant solar generation. Eventually, the IOUs could seek a formal interconnection through the appropriate mechanism.

SCE is actively exploring opportunities to develop, install, and deploy such utility-owned storage for summer 2022. The ED Staff Concept Proposals propose deployment of utility-owned storage on utility-owned (or controlled) properties using a Tier 3 Advice Letter process. However, to deploy utility-owned energy storage resources for summer 2022, SCE would need to begin developing such resources and incurring costs immediately. Waiting for a decision in this rulemaking in November 2021 and then for approval of a Tier 3 Advice Letter would be too late to deploy such resources for summer 2022 because batteries and contractors are in short supply and there would not be enough lead time to construct the resource in a timely fashion. Therefore, SCE recommends that the Commission immediately authorize and provide cost recovery for the IOUs to develop and install utility-owned storage resources and associated upgrades, facilities, or modifications to meet the summer 2022 emergency reliability needs identified in the Emergency Proclamation through a separate resolution or decision.

D. COST RECOVERY OF SCE'S PROPOSAL

In this proceeding, SCE is requesting *incremental* funding for 2022 and 2023 to support the demand response proposals for Phase 2 of the Reliability OIR as addressed herein. The proposed 2022 funding is an increase (and incremental) to the amounts authorized in the 2018-2022 DR Program Cycle[54] and Phase 1 of the 2021-2022 Summer Reliability OIR.[55] SCE is not proposing any change in its currently approved DR ratemaking, and will utilize the existing Demand Response Programs Balancing Account (DRPBA) to ensure that SCE recovers no more than the actual DR costs. SCE requests if the Commission adopts other activities supplemental or in addition to proposals addressed in testimony, any incremental authorized funding should be recorded in the DRPBA. However, if funding is not authorized for recovery in the DRPBA, SCE proposes to track any associated incremental costs in its Summer Reliability Demand Response Program Memorandum Account (SRDRPMA) for review and recovery.[56] In addition, SCE proposes to record and recover the Leveraging TOU Rates incremental funding through the distribution sub-account of the Base Revenue Requirement Balancing Account (BRRBA). SCE proposes to modify the Emergency Load Reduction Program Balancing Account to record costs through 2023. As discussed in Section II.6 of this testimony, SCE request to extend the 2021-2022 ELRP budget approved in D.21-03-056 to 2023.

1. Revenue Requirement for DR Proposals

SCE requests that the Commission adopt a Distribution authorized revenue requirement of $100.19 million, including Franchise Fees and Uncollectibles (FF&U)[57] expense, to fund the incremental 2022-2023 DR proposals in this proceeding. As shown on Line No. 8 of Table II-14 below, SCE proposes to include the annualized Distribution DR Program

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54 2018-2022 DR Program Budgets approved in D.17-12-003 and D.18-03-041.

55 2021-2022 Summer Reliability Phase 1 authorized in D. 21-03-056.

56 SRDRPMA adopted in D. 21-03-056.

57 The total incremental DR authorized revenue requirement includes FF&U, which is based on the FF&U factors adopted in SCE's most recent GRC.

incremental authorized funding of $50.09 million in the Distribution incremental DR revenue requirement and consolidate into distribution rate levels each year of the two-year period starting in 2022.

Additionally, SCE requests a total authorized revenue requirement of $1.84 million, including FF&U expense, to fund the Leveraging TOU Rates proposal and include an annualized incremental authorized revenue requirement in the amount of $0.92 million in distribution rates in both 2022 and 2023, as shown in Table II-15, Line No. 3 below.

Table II-16
Proposed Incremental DR Program Revenue Requirement
(in millions)

Line No.		2022	2023	2022-2023 Annualized
1	**Distribution - DR Program Incremental Funding**			
2	Whole Home Saving Program	$42.00	$31.90	$36.95
3	Smart Energy Program (SEP)	$3.70	$7.92	$5.81
4	Programable Communicating Thermostat (PCT) Incentive Program	$2.86	$5.50	$4.18
5	Virtual Power Plant (VPP)	$2.05	$3.15	$2.60
6	**Total Distribution - DR Program Incremental Funding**	$50.61	$48.47	$49.54
7	FF&U Amount	$0.57	$0.54	$0.55
8	**Total Distribution Incremental DR Revenue Requirement**	**$51.18**	**$49.01**	**$50.09**

Table II-17
Proposed Incremental Leveraging TOU Revenue Requirement
(in millions)

Line No.		2022	2023	2022-2023 Annualized
1	**Leveraging TOU Funding**	$1.14	$0.68	$0.91
2	FF&U Amount	$0.01	$0.01	$0.01
3	**Total Leveraging TOU Revenue Requirement**	**$1.15**	**$0.69**	**$0.92**

2. Ratemaking of DRP Funding

As discussed above, SCE proposes no change to the currently-approved DR Program ratemaking. SCE's current ratemaking associated with the DR Program incremental funding includes: (1) the recovery of the authorized incremental DR Program revenue requirement through the operation of the Base Revenue Requirement Balancing Account (BRRBA); and (2) recording the difference between the authorized incremental DR Program revenue requirement and actual incurred DR Program expenses in the DRPBA. Through this process, customers will ultimately only pay for the incurred DR Program costs.

Through the operation of the BRRBA, SCE records on a monthly basis the difference between the recorded distribution and generation revenue with authorized distribution and generation costs including the authorized DR Program revenue requirement. The BRRBA includes a Distribution sub-account and a Generation sub-account since it is necessary to record over- and under-collections that are refunded to or recovered from both bundled service and departing load customers (i.e., Distribution sub-account) and over- and under-collections that are refunded to or recovered from only bundled service customers (i.e., Generation sub-account). Year-end over- and under-collections recorded in the BRRBA are refunded to or recovered from customers in the subsequent year. Additionally, on a monthly basis, SCE records in the DRPBA the difference between the authorized DR Program revenue requirement and actual DR Program expenses. Like the BRRBA, the DRPBA includes a Distribution sub-account and a Generation sub-account. SCE will include in its 2023 Energy Resource Recovery Account (ERRA) Review proceeding, a compliance review of the DRPBA 2022 recorded amounts associated with the DR Program proposals in this proceeding and propose disposition of any over-collection associated with the DR Program incremental authorized funding remaining in the DRPBA at the end of 2022.

Any over-collection associated with the 2023 proposed funding in this proceeding will remain in the DRPBA at the end of 2023 and a compliance review will occur in a future ERRA Review proceeding.

3. <u>Ratemaking of Leveraging TOU Rates Funding</u>

SCE proposes to modify the BRRBA to record on a monthly basis, the difference between recorded Leveraging TOU Rates funding expenses and authorized Leveraging TOU Rates funding (i.e., the annual funding authorized in this proceeding multiplied by the currently effective Monthly Distribution Percentage (MDP) in the distribution sub account of the BRRBA). The difference (any year-end over- or under-collected balance) will be returned to or recovered from customers in the subsequent year through the consolidation of the BRRBA balance in distribution rate levels. Entries recorded in the BRRBA are reviewed annually by the Commission in SCE's annual ERRA Review proceedings.

III.

SCE's COMMENTS ON STAFF CONCEPTS DOCUMENT

SCE provides the following comments to the Staff Concepts document, which makes suggestions in three overarching areas: A. Demand Reduction; B. Smart Thermostats (SCT); and C. Utility-Scale Storage, Imports, and Generation. SCE has endeavored to respond to all of the Staff Concepts in the time available to prepare this testimony. However, to the extent SCE does not address any particular recommendation, such is not intended to reflect endorsement of that recommendation.

. Demand Reduction Suggestions In Staff Concepts Document

1. Emergency Load Reduction Program Modifications

a) The Commission Should Not Adopt the Staff Proposal to Expand ELRP to Residential Customers

Certain observations and elements of the staff ELRP proposal have merit. For example, SCE agrees that there is currently a lack of residential sector participation in demand response programs and that repeated calling of CAISO Flex Alerts on this sector has diminishing returns both with respect to customer fatigue, and presents equity concerns with a lack of compensation. Repeated and increasing Flex Alerts serve no purpose with respect to customer confidence in the California grid and its stewards, and on the contrary, pose a counternarrative to electrification and achieving the State's environmental goals. SCE considered and incorporated elements of the staff proposal in its WHSP Pilot proposal and does not recommend the Commission adopt Staff's residential ELRP program proposal.

The Staff Concept Paper proposes that all residential customers would be automatically enrolled in ELRP, except customers currently enrolled in supply side DR programs. Though not explicitly stated, the staff proposal implies the traditional rules barring dual participation should be upheld between programs. If adopted, this would be a future recruitment barrier for customers, IOUs, and Demand Response Providers (DRP) because every customer would have to unenroll from the ELRP program before they could enroll on another

DR program. This will result in a cumbersome process for customers and could result in frustration and unwillingness to participate in DR programs. This outcome should be avoided as programs advance toward enabling DR participation by removing unnecessary barriers and enabling a positive customer experience.

The staff proposal posits the mass default of all residential customers would not require customer signup or acknowledgement. SCE does not recommend defaulting all eligible customers into a residential ELRP program because of the potential for free ridership, as well as for the reasons stated earlier in this testimony regarding recruiting these same customers into programs at a later date. On May 1, 2013, pursuant to D.13-04-017, the Commission Staff issued a report entitled Lessons Learned From Summer 2012 Southern California Investor Owned Utilities' Demand Response Programs.[58] This report, among other things, provided an analysis of SCE's PTR Program, a default program offering incentives to encourage residential customers to reduce their electric usage during a PTR event. The analysis found that "customers who actively opted to receive event alerts significantly decreased their load during events while those who were defaulted to receive email event notifications provided an insignificant load impact. Staff contends that this is a case of free ridership, where customers receive incentives without significantly reducing load."[59] Staff also pointed out that all customers qualified for the bill credits, resulting in a situation of free ridership. As a result of this report, in D.13-07-003, the Commission directed SCE to modify its PTR Program to be an opt-in program. In addition, in 2013 and 2014, load impact results showed that the average per customer load reduction was 0.03 kW for the default population and 0.08 kW for those customers who opted into event

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[58] The Commission Staff Report, dated May 1, 2013, described performance of 2012 Demand Response programs of San Diego Gas and Electric Company and SCE, including a report on lessons learned, staff analysis, and recommendations for 2013-2014 program revisions in compliance with OP 31 of D.13-04-017. *See* pp. 36-50 for discussion of Staff analysis and recommendations regarding PTR.

[59] D.13-07-003, pp. 13-15.

notifications.[60] Given these low load impacts, PTR was not cost-effective and SCE discontinued the program in 2017.[61]

The Staff Concept Paper recommends that payments for participation in residential ELRP be based on a meter verified ILR relative to a "simple" baseline. This proposal could be administratively challenging to implement. SCE will be required to develop a baseline for 4.2 million residential customers and calculate the ILR for each customer on a monthly basis. In addition, SCE's billing system, which was upgraded in April 2021, would not be able to support an undertaking of this scale at this time. As of the date of this filing, SCE does not know the magnitude of necessary system enhancements that would be required to support this proposal and does not have a cost estimate to enhance its system to accommodate this proposal. SCE anticipates that, if adopted, this proposal would require SCE to expend significant effort, time, and cost to build the systems needed to administer the program.

Due to challenges around measuring baseline and actual load reduction, it could also result in the program compensating customers where no load reduction was achieved due to customer unawareness of their enrollment status and would create the same "free ridership" concern that was prevalent in the previous PTR program. This is counter to ELRP's program design, which only compensates customers for incremental load reduction, ostensibly to reduce "free ridership."

SCE also notes that automatic enrollment of residential customers in ELRP could raise issues with respect to consumer protection laws, to the extent customers were automatically opted in to receive text messages. As SCE noted in its July 21, 2021 testimony in this rulemaking, the Telephone Consumer Protection Act (TCPA) allows for automated texts

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[60] The 2013 load impact number is for the PTR and PTR-Enabling Technology (PTR-ET) program options combined. For customers that opted into event notifications, the aggregate load drop from 2 to 6 pm was nearly 12 MW, or a 4% load reduction. In comparison, the load drop from defaulted customer was significantly lower.

[61] Decommission of PTR and PTR-ET was approved by the Commission in SCE Advice 3572-E submitted on March 6, 2017.

only for "emergency purposes" or where a consumer has consented to being contacted at a particular number.

b) <u>Electric Vehicle/Vehicle to Grid Integration (EV/VGI) Aggregation Pilot would not provide system relief in 2022 in light of limited/no MW potential and is unnecessary in light of other participation opportunities currently open to EV resources</u>

The Staff Concept Paper proposes an EV/VGI Integration Aggregation Pilot as part of ELRP, which would not result in any meaningful MW contributions to 2022 system reliability based on SCE's current record of interconnected two-way charging stations.

At this time, SCE currently has zero two-way charging stations in service in its service territory. As of September 1, 2021, there is one application in the pipeline for a two-way charging station which is for a V2G demonstration project in the City of Rialto. As a demonstration project, the interconnection of this project is receiving full attention from SCE and it is expected to be online in 2023.

SCE is aware of at least two (2) two-way charging systems that have obtained electrical industry certifications required for operation under Rule 21 and FERC jurisdictional interconnections. However, SCE has not seen activity in its interconnection queue from projects proposing to use this technology.

Based on this data, SCE does not believe an EV/VGI Integration Aggregation Pilot is, at this time, a prudent use of time and resources as it is not realistic for projects to come online prior to the summer of 2022. Instead, ELRP under Sub-Groups A.1 and A.3 and B.1 are the best options for EV participation in ELRP and pose the most capacity potential with no further incremental costs for program stand-up. It is also worth noting that as of September 1, 2021, SCE has received <u>no</u> interest from EV aggregators in ELRP participation under the one-way charging option, let alone a two-way charging option. Additionally, SCE is concerned that Commission approved tariffs may not be in place in time to support V2G charging. The V2G charging application represents a type of service that is neither entirely retail nor entirely wholesale. SCE's current tariffs related to charging and discharging of stored energy are structured on the basis that the storage device falls entirely within one category or the other (specifically, the "charging" aspect of this system would fall under SCE's retail Rule 2, Rule 15 and Rule26, while the "discharging" is under SCE's Wholesale Distribution Access Tariff interconnection process). An EV/VGI pilot would also require the time to work through metering and data transfer issues in addition to those around disaggregating stored energy, between wholesale and retail, in order to appropriately account for CAISO wholesale costs and revenues, and the retail bill.

In light of these factors, there is no need for an additional EV ELRP option and if it were directed by the CPUC it would likely garner little if any participation with implementation costs that outweigh benefits.

A. <u>DRAM Modifications</u>

The Staff Concepts Document proposes additional auctions for 2022 by adding a partial year supplementary auction for DR capacity to be delivered in the second half of 2022 and a potential expansion of the budget for 2023 DRAM, for which the auction is expected to occur in 2022. The Staff Concept Paper also proposes new requirements for future auctions to improve the reliability of these resources.

SCE respectfully offers the following comments on these concepts.

1. <u>Additional Auctions for 2022</u>

a) <u>The Commission Should Not Order A Partial Year Supplementary Auction</u>

SCE does not support holding a partial year supplementary auction to obtain additional DR capacity through DRAM for the second half of 2022 because the limited information available about the performance of DRAM Resources has raised questions about its performance, and it would be premature to allocate additional funding for the DRAM pilot before those questions can be answered by the in-process evaluation ordered by the Commission.

SCE believes that substantial questions have been raised about whether DRAM is providing the reliability services that have been promised or are indicated by the size of the pilot's contracts over the past several years – either in terms of the megawatts promised or the amount of money that already has been budgeted. Questions about the performance of Resources under contract in the DRAM pilot have been raised by analyses performed by CAISO and others. While it is unclear, without further evaluation, what the actual performance of individual DRAM Resources has been, SCE has seen a wide variation in performance among DRAM Resources, based upon several factors, including the nature of the DRP's program, the type of underlying accounts participating in the DRAM Resource, and geographic variation, among others.

Due to the performance questions that have been raised, the Commission ordered that an Independent Evaluator (IE) perform an evaluation to answer these questions and set aside a budget of $2.8 MM for that work. This substantial evaluation was to be completed by September 1, 2021. However, the IE has encountered data quality issues that have delayed the issuance of the evaluation report, and the preliminary version of that report is now expected to be issued in late December 2021.

Once the evaluation has been completed and the final report has been issued, ED staff and the Commission will need time to review the report. The Commission will then need to determine the future of the DRAM pilot. These necessary steps simply cannot be conducted in time for a supplemental DRAM auction for 2022 deliveries, as an auction would need to be held within the next few months, well before the evaluation report is issued.

In addition, SCE notes that the DRAM pilot has been through several generations and the agreement has, throughout the years, undergone multiple iterations, all aimed at improving the product to make it more reliable and ensure its performance. It is likely that additional changes to the DRAM agreement will be called for after the release of the evaluation report, a further iteration that cannot be drafted, let alone implemented, in time for a supplemental auction for additional DR capacity through DRAM for the second half of 2022.

Therefore, the contracts signed in a proposed supplemental auction would exacerbate the issues SCE has previously seen, related to resource performance and reliability, and would not be able to correct issues to be identified in the evaluation report.

Finally, adding additional funding to the DRAM pilot for further 2022 deliveries could have unintended impacts on contracts already entered into for 2022 deliveries – impacts that could result in no incremental capacity from a supplemental auction. As DRAM is not tied to an identifiable set of customers, a DRP could choose to bid a higher price into the proposed supplemental auction than it was awarded in the initial 2022 auction and then 'move' the customers' accounts and their underlying MWs originally intended to meet the MWs of DRAM contracts awarded in the initial 2022 auction to the higher price of the DRAM contracts potentially awarded in the proposed supplemental 2022 auction. Under the current contract terms, there is no mechanism for the IOUs to stop this or even identify that it was occurring. Thus, a supplemental auction may, in fact, result in higher costs to customers for no additional capacity.

Accordingly, SCE does not support expanding DRAM funding in 2022 or beyond and believes it would be premature to do so until the Commission fully evaluates the pilot's effectiveness and the Commission has an opportunity to weigh in on the near-term and long-term future of DRAM.

b) <u>DRAM 2023 Budget Should Not Be Expanded</u>

SCE also does not support expanding the 2023 DRAM budget (as currently authorized under D.19-07-009). DRAM should not be expanded in 2022 or 2023 because of the questions referenced above regarding its contributions to reliability and the need to examine the pilot's performance by the IE in its evaluation report still pending. Moreover, there is a lack of any demonstrated system reliability need for Summer 2023, and there is significant incremental capacity expected to be online by Summer 2023. For any resource, much less a resource that has open questions from the CAISO and CPUC as to its efficacy, SCE is concerned with considering additional expedited procurement for Summer 2023, resulting in additional costs to customers.

2. Additional Requirements for Future Auctions

SCE addresses the suggestions in the Staff Concept Paper for additional requirements for future solicitations. As noted, SCE does not support a supplemental 2022 DRAM auction, and its position on these additional requirements would be subject to change if the Commission ordered such a supplementary auction.

a) (1) Maximum Bid on Third-Party DR Resources

SCE supports ED's concept proposal to require PDRs participating in the real-time market (RTM) to bid at or below $900/MWh to maintain consistency with the triggering price for the reliability-based demand response programs, including the Base Interruptible Program (BIP).

b) Maintenance of PDR Resource ID on Supply Plan

SCE supports the requirement of a PDR Resource ID being introduced on a Monthly Supply Plan and maintained on the Monthly Supply Plan until removed. This will alleviate administrative burden and confusion for IOUs and CAISO.

c) Penalty for Shortfall in Supply Plan Capacity Relative to Contracted Capacity

SCE supports the proposal that a shortfall in the DR capacity shown on the Monthly Supply Plan relative to the contracted capacity is subject to a penalty if there is a capacity shortfall. SCE has experienced PDR Resource IDs exiting DRAM Monthly Supply Plans, resulting in the need for SCE to procure additional RA to make up for the shortfall in DRAM contracted capacity. The current DRAM contract is not structured to impose penalties when PDR Resource IDs exit the DRAM Monthly Supply Plan, which in many cases results in DRPs not meeting the contract capacity. Adding the proposed contractual change reduces the need for replacement RA procurement and unnecessary cost to ratepayers.

d) Counting Capacity Toward QC Limit Under LIP Processes

SCE does not agree that capacity awarded in the 2022 supplementary auction and the DRAM 2023 auction should be counted toward the Qualifying Capacity limit established for 2022 and 2023 through the 2021 and 2022 Load Impact Protocol (LIP) processes, as this is currently exempted from the DRAM pilot. Further, this issue is currently being addressed through the RA proceeding.

B. Smart Communicating Thermostat (SCT)

1. SCT Related Modifications to Energy Efficiency Programs

a) SCT Measures Should Not Be Limited to Hot Climate Zones

The Staff Concept Paper recommends that SCT measures should only be installed in climate zones with the highest cooling degree days (CDD) (i.e., 10, 11, 13, 14 and 15) and target customers with high AC usage. SCE's Residential Direct Install and Comprehensive Manufactured Homes programs currently target the hottest Climate Zones (10, 13, 14, 15) for program outreach and installation. The cooler Climate Zones (e.g., 8 and 9) are not targeted, but are also not excluded from participating in the program, as there are cost-effective EE savings in those Climate Zones when bundling a Smart Thermostat with other cost-effective HVAC measures, such as Duct Test and Seal. With climate change, Climate Zones 8 and 9, are getting warmer. During the summer months, AC usage can be high in these areas. Therefore, SCE proposes to include Climate Zones 8 and 9 for Smart Thermostat installations when bundling with other measures.

b) SCE Supports Required Enrollment in a Demand Response Program with Any PCT Incentive with Modification

SCE supports the Staff Concept Paper recommendation to require enrollment in a demand response program with any smart thermostat incentive, with one modification. Earlier this year, SCE began integrating Energy Efficiency with Demand Response by leveraging Residential Direct Install's program implementation to enroll eligible customers onto Demand Response's Smart Energy Program (SEP) when installing a Smart

Thermostat in the customer's home. At this time, enrollment in SEP is highly encouraged but not required. Requiring enrollment with any smart thermostat installation makes sense in cases where the customer is eligible to enroll in SEP. However, not all customers are eligible to enroll in SEP, such as customers who are on Medical Baseline Allocation for air conditioning, or who are already enrolled in another Demand Response program that won't be eligible to dual participate with SEP.[62] Excluding customers from receiving a Smart Thermostat because they are ineligible for SEP enrollment could result in lost opportunities for cost-effective energy savings, especially for customers residing in the hotter Climate Zones. SCE proposes to require enrollment in SEP with any smart thermostat installation, with the exception that if a customer does not qualify for SEP, they can still receive a Smart Thermostat installation so long as the measure is cost-effective.

c) <u>SCE Does Not Recommend That a New Statewide Program Relating to Smart Thermostat Adoption Be Developed</u>

The Staff Concept Paper recommends considering directing the IOUs and other EE program administrators to develop a statewide program following ED's suggestions relating to smart thermostats. SCE does not recommend developing a new statewide program. Encompassing these changes in a new statewide program is not the best approach to maximize smart thermostat adoption and DR program enrollment. Rather, SCE submits that its SEP and PCT Incentive Program proposals (described above), along with maintaining SCE's Residential Direct Install and Comprehensive Manufactured Homes program budgets, will maximize adoption of smart thermostats, because SCE already has the program infrastructure in place and has successfully advanced PCT adoption and DR participation in its service territory to date.

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[62] CPP, CBP residential and Demand Response programs or rates offered by Non-Utility Demand Response Service Providers.

On the contrary, SCE is concerned the creation of a statewide program could introduce confusion and interrupt SCE's current PCT activities if the rules and administration of a new program did not match the activities SCE has in place today.

d) SCE Supports Utilizing Combined EE-DR Cost Effectiveness Tests

SCE agrees with the statement in in the Staff Concept paper that, at this time, smart thermostat measures are not cost effective in the Energy Efficiency portfolio. SCE supports ED's effort to develop a cost effectiveness tool for EE-DR that encompasses the load shapes for dual EE-DR programs, and looks forward to using the combined EE-DR Cost Effectiveness Tests to increase the cost-effectiveness of Smart Thermostats for Energy Efficiency programs. That said, we should not wait to have this cost effectiveness test in place to advance the relevant programs proposed for summer 2022 reliability.

2. SCT Modifications to Energy Savings Assistance (ESA) Program

a) SCE Does Not Support ESA Customers Defaulting onto a Residential ELRP Program

The Staff Concept Paper proposes a program that offers ESA customers[63] who have a smart thermostat install in conjunction with central AC measures or separately be set up to automatically participating in the ELRP program. For reasons discussed above, SCE does not support a residential ELRP program and as such does not support automatically defaulting ESA customers that have received a smart thermostat and/or central AC measures onto ELRP.

C. Utility-Scale Storage, Imports, and Generation

SCE appreciates the spirit and intent of ED Staff's observations and proposals to bring new battery and generation resources online by summer 2022. Below are SCE's comments regarding each of the proposals in the ED Staff Concept Proposals related to utility-scale storage, imports, and generation.

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[63] The ESA program is available to residential customers who participate in at least one eligible public assistance program or meet the income guideline qualifications.

1. **<u>The Commission Should Not Introduce Penalties for Delays to D.19-11-016 Procurement</u>**

ED Staff's first supply-side concept is that the "CPUC could apply penalties to Load Serving Entities (LSEs) for not bringing ordered procurement resources online in accordance with Integrated Resource Planning (IRP) decision D.19-11-016."

SCE supports the Commission's reasonable efforts to ensure D.19-11-016 resources timely come online. However, retroactively introducing penalties for delayed D.19-11-016 resources would do little to bring resources online faster and should not be considered. SCE has executed third-party contracts approved by the Commission in Resolution E-5101 and Resolution E-5142 to meet its D.19-11-016 procurement requirements and the requirements of LSEs in SCE's service territory who opted-out of their procurement responsibility. Delays for D.19-11-016 resources to meet the August 1, 2021 online date have been for reasons outside of SCE's control; thus, retroactive penalties for delayed projects would be a third-party responsibility that is not considered in current power purchase contract terms and conditions. SCE's contracts provide for daily liquidated damages for unexcused delays in online dates. Even if penalties for delays beyond this contract requirement were considered during contract negotiations, it would likely result in increased pricing to account for the risk of incurring these penalties, including for situations that are not within the developer's control. Indeed, 2021 was particularly challenging given many delays in the supply chain caused by the global pandemic. It would not be fair to be penalized for delays caused by a once in a lifetime global event.

Similarly, it would be unfair and unreasonable to retroactively introduce LSE penalties for delays in meeting the August 1, 2022 and August 1, 2023 online dates for D.19-11-016 procurement when LSEs have already executed contracts to meet those procurement requirements and any delays are likely to be for reasons outside their control. Project development, by nature, is highly uncertain and projects can be delayed for a number of reasons, including local permitting, transmission interconnection, supplier delays and force majeure, most of which are beyond control of the LSE. LSEs should not be penalized for such failures or delays. Moreover, the IOUs should not be subject to any penalties for procurement on behalf of LSEs that opted out of their procurement requirements or backstop procurement on behalf of other LSEs' customers as long as they make good faith efforts to procure the resources. Because IOUs would be taking on these responsibilities on behalf of other LSEs and their customers, the IOUs should not be penalized if contracts fail or are delayed, particularly given the short timelines to procure backstop resources and bring such resources online.

There is no evidence that penalties are necessary to incentivize procurement toward the D.19-11-016 procurement requirements. ED Staff recently released an update on compliance with D.19-11-016, stating that all 25 LSEs "demonstrated an effort to meet their procurement obligations, especially for Tranche 1 due 8/1/2021," that LSEs were collectively over procured for August 1, 2021 procurement obligations, and that most project delays are expected to be less than six months.[64]

SCE recommends the Commission maintain the process in D.20-12-044 for LSEs to submit biennial compliance filings and apply the trigger mechanism for IOUs to backstop an LSE that fails to meet milestone requirements. Being potentially subject to backstop procurement already incentives LSEs to put forth best efforts to meet their D.19-11-016 procurement requirements on time. Furthermore, D.20-12-044 contemplates reasonable delays, as "Commission staff will evaluate individual circumstances of specific LSEs and specific contracts and recommend to the Commission whether backstop procurement is warranted or whether LSEs should be allowed to continue pursuing contracts that are slightly but reasonably delayed."[65]

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[64] *See* Status Update on Procurement in Compliance with D.19-11-016 (IRP Procurement Order), August 2021, *available at* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/ed_staff_review_of_feb2021_data_in_compliance_with_d1911016.pdf.

[65] D.20-12-044, p. 17.

Retroactively introducing penalties for delayed D.19-11-016 resources will not make delayed projects come online any faster and may only penalize LSEs for delays outside their control. Accordingly, this proposal should not be adopted by the Commission.

2. The Commission Should Not Increase RA Penalties

ED Staff also suggests that the Commission could consider increasing RA penalties by "doubling the penalties for LSEs who may be short in August 2022 and September 2022." SCE does not support this increase to RA penalties. While aligning penalties with the cost of RA is reasonable, RA capacity is becoming more and more scarce in summer months and LSEs and their customers should not be penalized for market-level scarcity when they have made all commercially reasonable efforts to meet their RA obligations.

The Commission recently adopted a new RA penalty structure for 2022 that already applies potential double and triple penalties for repeated RA deficiencies.[66] The Commission should allow time for this penalty structure to work before increasing penalties that will not incent compliance if there is no RA capacity to be procured. If the Commission does increase RA penalties, then it should allow LSEs to file waivers demonstrating that they made commercially reasonable efforts to meet their RA obligations before levying this increased penalty (including for system RA). Additionally, the waiver process for the provider of last resort should continue to apply to this increased penalty.[67]

3. Accelerating Procurement Ordered in IRP Mid-Term Reliability Decisions

ED Staff suggests that the Commission could provide an incentive to LSEs for early compliance with D.21-06-035 mid-term reliability procurement requirements in 2022 instead of 2023.

As discussed above, SCE has been actively pursuing resources that can meet a 2022 online date through bilateral efforts and is exploring whether 2023 projects in its Mid-term

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[66] *See* D.21-06-029, OP 16.

[67] *See* D.20-06-031, OP 21.

Reliability RFO can come online early. Given this activity, the Governor's Emergency Proclamation, and this rulemaking, strong market signals currently exist for projects to come online in 2022 if possible. Notwithstanding this dynamic, the market for new resources able to come online by summer 2022 is small and with the lengthy CAISO interconnection queue, there are a limited number of resources that may be able to come online by summer 2022. As such, SCE does not see the need to increase incentives for accelerating mid-term reliability procurement. Indeed, such incentives may increase costs for those few projects that would have been constructed regardless of such an incentive.

However, if the Commission determines incentives are needed, all LSEs must be subject to the same level of regulatory oversight and approvals as the IOUs' procurement before their procurement qualifies for such an incentive.

4. Emergency Procurement and Cost Recovery via a Non-Bypassable Charge

ED Staff suggests a new non-bypassable charge ("NBC") could be established "for cost recovery of costs associated with emergency procurement that adds additional reserve margin and does not already fit into an existing cost recovery mechanism." ED Staff further states that the existing Cost Allocation Mechanism ("CAM") charge "does not usually allow for cost recovery of procurement which adds to reserve margins or for resources that do not provide firm resource adequacy." SCE disagrees that the CAM cannot be used for emergency procurement that increases reserve margins or does not provide RA. In D.21-03-056, the Commission authorized the use of the CAM for the IOUs' emergency reliability procurement to meet the 17.5 percent "effective" planning reserve margin (and to exceed that by up to 50 percent for supply-side generation and in-front-of-the-meter storage resources) regardless of whether they provide RA.[68]

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[68] *See* D.21-03-056, pp. 44-45, Finding of Fact 72-73, Conclusion of Law 14, OP 14, Attachment 1, p. 21.

SCE does not believe a new NBC is needed. The existing CAM charge has been sufficient, and it is unclear whether an NBC is required to recover yet-to-be determined system reliability procurement costs. The Commission should focus on the measures that will most benefit system reliability in summer 2022 rather than developing a new NBC on the expedited timeframe of Phase 2 of this rulemaking. However, if the Commission does consider a NBC, then such NBC should only be used for IOU cost recovery. If the Commission considers extending a NBC to any other LSEs' procurement, then the Commission must apply the same oversight and approval standards to that procurement that is applied to the IOUs' procurement.

5. Bundled Procurement Rules Modifications

ED Staff propose rule modifications to the bundled procurement rules to "effectively allow IOUs to plan for hydro resources to count for a higher RA value in August and September, during hours when it is most critically needed." Staff appear to see "least cost procurement" as a barrier to reserving hydro capacity for critical periods, and that a rule change is necessary to resolve this constraint.

Under existing bundled procurement rules, the IOUs are required to schedule and bid their hydro resources to achieve least cost dispatch. Least cost dispatch principles include bidding opportunity costs for use-limited resources to maximize the customer value. This ensures that resources are awarded when they are needed the most (i.e., when market prices are highest, or system conditions are strained). Thus, there is no need to adjust bundled procurement rules.

IV.

SCE's COMMENTS ON THE CEC's DRAFT 2022 SUMMER SUPPLY STACK ANALYSIS

SCE's comments on the CEC's Draft Summer 2022 Stack Analysis, which were submitted to the CEC on August 20, 2021, are included as Appendix A to this testimony. As explained in those comments, SCE believes the combination of supply and extreme demand assumptions used in the Draft 2022 Stack Analysis represent a very low probability event that, based on historical reliability policy, is overly conservative and should not be used to inform this rulemaking. Instead, the Commission should consider the results of incorporating SCE's proposed assumption changes in the Draft Summer 2022 Stack Analysis, which show the system to be reliable in all hours under the "average weather" scenario and trigger contingencies of up to 2,695 MW, not 5,200 MW, in September under the "extreme demand" scenario. Additionally, policy actions in this rulemaking must ultimately consider the final outcome of the State Water Resources Control Board hearing on the extension of the compliance deadline for Redondo Beach, which, if approved, would further reduce the trigger contingencies by 834 MW.

Appendix A

CEC Comments

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company

Dawn Anaiscourt
Director, Regulatory Affairs

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August 20, 2021

California Energy Commission
Docket Office, MS-4
Re: Docket No. 19-SB-100
1516 Ninth Street
Sacramento, CA 95814-5512
docket@energy.ca.gov

Re: Southern California Edison Company's Comments on the California Energy Commission's Draft Preliminary 2022 Summer Supply Stack Analysis (Draft 2022 Stack Analysis), Docket No. 21-ESR-01

Dear Commissioners:

On August 11, 2021, the California Energy Commission (CEC) provided an "Update on Short-term Reliability Activities" and solicited public comments on the results and assumptions used in its Draft 2022 Stack Analysis. Southern California Edison (SCE) appreciates the efforts of the CEC in undertaking this assessment and the opportunity to provide feedback on the inputs and assumptions.

SCE submits that the Draft 2022 Stack Analysis's finding of a capacity shortfall of up to 5,200 MW is driven by the conservative assumptions used in the analysis. The Draft 2022 Stack Analysis compares an assumed generation supply stack to "average" (15% Planning Reserve Margin (PRM) scenario that is based on a 1-in-2 weather event with 1.5% demand variability) and "extreme" (22.5% PRM scenario that is based on a 1-in-2 weather event with 9% demand variability, which is equivalent to a greater than 1-in-20 weather event)[1] demand scenarios. This combination of supply and extreme demand assumptions represents a very low probability event that, based on historical reliability policy, is overly conservative and should be viewed as an upper-bound sensitivity scenario.

The California Public Utilities Commission (CPUC) has indicated that it may rely on this analysis to evaluate 2022 electrical system reliability in Phase 2 of Rulemaking (R.) 20-11-003 (Emergency Reliability OIR).[2] While SCE agrees that climate change creates significant demand and supply uncertainties, SCE recommends, for purposes of a simple stack analysis to inform the Emergency Reliability OIR, using the CEC's "extreme weather" demand scenario without applying additional conservative assumptions on the generation supply stack. Comparing a demand curve that is based on a 1-in-20 weather event to a conservative supply

[1] The Draft 2022 Stack Analysis describes the 9% weather variability component of the 22.5% PRM as a "greater than 1-in-10 weather event." However, the 2022 1-in-10 forecast is only 6.6%, not 9%, higher than the 1-in-2 weather forecast, while the 1-in-20 forecast is 8.3% higher. As such, a 1-in-2 forecast with a 9% weather variability adder is directly comparable to a 1-in-20, not 1-in-10, weather event.
[2] Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2, dated August 10, 2021, in R.20-11-003.

stack may overestimate the capacity shortfall and can lead to costly over-procurement in a tight market at a time when there is already upward pressure on customer rates. Accordingly, SCE proposes changes to the supply-side assumptions that would increase the supply stack by at least 2,579 MW.[3] If updated to reflect SCE's proposed assumption changes, the analysis would show the system to be reliable in all hours under the "average weather" scenario and trigger contingencies of up to 2,695 MW, not 5,200 MW, in September under the "extreme demand" scenario.

As a more general matter, a deterministic stack analysis provides a snapshot comparison of expected supply on a single forecast peak day to predetermined demand levels and is thus heavily dependent on the underlying assumptions. On the other hand, a stochastic Loss-of-Load Expectation (LOLE) analysis is able to comprehensively account for demand and supply uncertainties by considering hundreds of scenarios and identifying the MW needed to meet the current LOLE standard of 0.1 days/year. SCE urges the state to use an LOLE analysis as a check on the Draft 2022 Stack Analysis findings and inform potential supply- and demand-side actions to address emergency reliability needs in summer 2022.[4] An LOLE analysis will more accurately identify reliability needs and therefore will more appropriately balance reliability with affordability.

Hydroelectric Drought Derate

The Draft 2022 Stack Analysis applies a 1,500 MW derate to California hydroelectric capacity to reflect continued drought conditions into 2022. SCE finds that this deration amount is unnecessary and inconsistent with other CEC assumptions. Qualifying capacity (QC) values for dispatchable hydroelectric resources already reflect their capacity availability during drought conditions.[5] Dispatchable hydroelectric resources can largely be optimized to "reserve" water for use during critical hours. While continuing drought conditions would likely reduce the expected energy output (*i.e.,* GWh production) of the resources in 2022, this ability to optimize reservoir levels ensures that hydroelectric resources can still provide most of their QC value during system peak conditions.[6] Additionally, as described in further detail below, the PRM already includes a 7.5% buffer for portfolio forced outages. Any hydroelectric drought-related derating would be considered "forced" outages and are thus already reflected in both the NQC and demand assumptions. For these reasons, it is unnecessary to further reduce the supply stack by 1,500 MW.

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[3] SCE's comments focus on the September 2022 stack analysis because it is the peak month with the highest trigger contingencies in the Draft 2022 Stack Analysis.
[4] Slide 34 from the CEC's August 11, 2021 Business Meeting notes that it will perform "2022-2026 stochastic analysis to support [Integrated Resource Planning]."
[5] The CPUC recently adopted changes to the QC counting methodology for dispatchable hydroelectric resources in Decision 20-06-031. This new methodology, which is in place for 2022, generates monthly QC values based on the previous ten years of historical offered capacity and thus already incorporates the long-term impact of drought on the hydroelectric resources' overall capacity availability.
[6] As described in the Forced Outage Rates section below, the net qualifying capacity (NQC) for hydroelectric resources already accounts for forced outages—including forced outages related to drought.

Import Assumptions

The Draft 2022 Stack Analysis uses historical average California Independent System Operator (CAISO) resource adequacy (RA) imports to estimate import levels in 2022. The CEC should consider modifying that assumption to include expected economic imports (*i.e.,* imports not under RA contract), which would increase the September import level by 1,079 MW.[7] A total of 7,000 MW of imports is consistent with import levels during the 2020 extreme heat events and reflects the reality that economic imports play a key role in meeting peak demand.[8,9]

Additionally, because RA imports have generally been used to fill load-serving entities' residual RA positions (*i.e.,* difference between the RA requirements, which are set using a 15% PRM, and in-state capacity), there will—by definition—be a significant difference between the extreme demand scenario (22.5% PRM) and a supply stack that only includes imports used to meet RA requirements. This comparison is internally inconsistent because it does not account for the economic imports that are necessary and available to meet demand when it exceeds the forecast that is the basis for the RA requirements. The Draft 2022 Stack Analysis underestimates the contribution of imports to meeting peak demand because average RA import levels are not representative of import availability during peak hours or consistent with historical experience. SCE urges the CEC to revise this assumption to include expected economic imports.

Retirement Assumptions

The Draft 2022 Stack Analysis assumes 834 MW from Redondo Beach Generating Station Units 5, 6, and 8 (Redondo Beach) will retire at the end of 2021 and be unavailable in 2022. On October 19, 2021, the State Water Resources Control Board will consider a proposed amendment to its once-through cooling (OTC) policy extending Redondo Beach's OTC compliance date through December 31, 2023. The joint-agency Statewide Advisory Committee on Cooling Water Intake Structures, which includes representatives from the CEC, CPUC, and CAISO, has approved a report recommending that OTC compliance date extension for Redondo Beach. While it may be appropriate to consider whether Redondo Beach should be excluded from the supply stack given its pending status for 2022, the CEC and CPUC must update this assumption, including when considering any policy actions in the Emergency Reliability OIR where a proposed decision is expected in October, to reflect the final outcome of the State Water Resources Control Board hearing.

Forced Outage Rate

The Draft 2022 Stack Analysis incorporates 7.5% for forced outages in both the average and extreme weather demand PRMs and then compares those scenarios against a generation

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[7] The average 2015-2020 CAISO RA showing for September is 5,921 MW. *See* Table 13 in CAISO's 2021 Summer Loads and Resources Assessment published on May 12, 2021.

[8] To that end, the CAISO recently approved market enhancements that improve incentives for economic imports during tight system conditions. *See* CAISO's Market Enhancements for Summer 2021 Readiness.

[9] Limiting assumed imports to average RA imports is a sensitivity, not a base, scenario in the CAISO's 2021 Summer Loads and Resources Assessment. *See* CAISO's 2021 Summer Loads and Resources Assessment, published on May 12, 2021, pp. 33-35.

supply stack that is developed using resources' net qualifying capacity (NQC), which results in over-counting some forced outage types. Forced outage rates are typically calculated based on deviations from installed capacity. At the same time, NQCs for some important resource types such as hydroelectric and geothermal, already account for historical forced outages. This results in NQCs for these resources that are less than installed capacity. The impact is that NQC, in the aggregate, is lower than the sum of resources' nameplates. Comparing a PRM that incorporates forced outage rates calculated using nameplate capacity against an NQC stack is thus inconsistent. While SCE does not recommend any specific changes to the accounting of forced outages in the Draft 2022 Stack Analysis, SCE notes that these assumptions will lead to more conservative outcomes than intended.

Base Demand

The Draft 2022 Stack Analysis states that the base demand upon which PRM is applied is based on the "2020 CEC IEPR Update Mid Demand Case." It is unclear to SCE whether this refers to the "Baseline Net Load," which does not include any Additional Achievable Energy Efficiency, or the "Managed Net Load," which is the basis for RA requirements. To be consistent with RA requirements, the analysis should use the "Managed Net Load" because using "Baseline Net Load" would overstate the September 7pm-8pm demand by approximately 700 MW.

SCE thanks the CEC for consideration of the above comments. Please do not hesitate to contact me at (415) 929-5518 with any questions or concerns you may have. I am available to discuss these matters further at your convenience.

Very truly yours,

/s/

Dawn Anaiscourt

Appendix B

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY OF KIMWUANA BLEBU

Q. Please state your name and business address for the record.

A. My name is Kimwuana Blebu, and my business address is 8631 Rush Street, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am currently an Advisor in the State Regulatory Operations Revenue Requirement and Forecast Department. My primary responsibility is to manage and support ratemaking mechanisms to ensure costs are properly recorded and recovered through rate levels in accordance with CPUC decisions and resolutions.

Q. Briefly describe your educational and professional background.

A. I received my Bachelors of Science Degree in Finance from California State Polytechnic University, Pomona in 2001 and a Master's degree in Business Administration from the University of La Verne in 2013. I began my career as a Financial Analyst at Edison International, which is the Parent Company of Southern California Edison in 2002. I joined the Regulatory Operations department in 2006.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-The purpose of my testimony in this proceeding is to sponsor portions of SCE's Direct Testimony Phase 2, Testimony preliminarily marked for identification as SCE-04 and titled *Direct Testimony of Southern California Edison Company-Phase 2*. Specifically, I am sponsoring the portions of the testimony where I am identified as the witness in the Table of Contents.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you certify under penalty of perjury that you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, do you certify under penalty of perjury that it represents your best judgment?

A. Yes, it does.

Q. Do you adopt this testimony as your sworn testimony in this proceeding?

A. Yes, I do.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF BRET BUFFINGTON

Q. Please state your name and business address for the record.

A. My name is Brent Buffington. My business address is 8634 Rush Street, Rosemead, CA 91770.

Q. Briefly describe your present responsibilities at Southern California Edison Company (SCE).

A. I am currently employed by Southern California Edison as Principal Manager of Integrated Resource Planning department. I am responsible for all Demand Response programs and operational support activities associated with these programs.

Q. Briefly describe your educational and professional background.

A. I received a B.A. in Mathematical Economics and a M.A. in Economics, from California State University Long Beach. I joined SCE in 2011 and prior to my current role I have held several analytical, operational, and leadership roles in the areas of energy portfolio analysis, demand forecasting, resource adequacy position management, CAISO market operations, and generation asset management.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of SCE's Direct Testimony Phase 2, Testimony preliminarily marked for identification as SCE-04 and titled *Direct Testimony of Southern California Edison Company-Phase 2.* Specifically, I am sponsoring the portions of the testimony where I am identified as the witness in the Table of Contents.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you certify under penalty of perjury that you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, do you certify under penalty of perjury that it represents your best judgment?

A. Yes, it does.

Q. Do you adopt this testimony as your sworn testimony in this proceeding?
A. Yes, I do.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONYOF DAVID B. COHER

Q. Please state your name and business address for the record.

A. My name is David B. Coher, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am a Principal Manager in the Energy Contracts Management division of SCE's Energy Procurement and Management (EPM) department. My responsibilities include representing SCE interests in the administration and management of SCE's long-term energy purchase and sale contracts such as Power Purchase Agreements, enabling agreements, and otherwise.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science Degree in Public Policy and Management from the University of Southern California, in 1999. I also received a Juris Doctorate from the Georgetown University Law Center in 2002. I began working for SCE's Law Department in 2007 and have held a variety of positions with SCE since then, most recently beginning work in this current position in 2017.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-04, entitled *Direct Testimony of Southern California Edison Company-Phase 2,* as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you certify under penalty of perjury that you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, do you certify under penalty of perjury that it represents your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF ERICA KEATING

Q. Please state your name and business address for the record.

A. My name is Erica Keating, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at Southern California Edison Company (SCE).

A. I am currently the Principal Manager of the Customer Demand and Generation Programs Team within the Customer Programs and Services department at SCE. I am responsible for SCE's Demand Response and Customer Generation programs and the operational support activities associated with these programs.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Arts Degree in Communications with minors in History and German from California State University at Fullerton. I completed a graduate degree from California State University at Long Beach where I received a Master of Public Administration. I began my career in 2001 at the city of Rancho Cucamonga as the administrator of the city's capital improvement program, as well as the operations manager for the City's municipal utility. In 2010, I started with SCE as a contracts and Requests for Offers (RFO) originator in the Energy Procurement and Management Department and progressed to senior originator in 2012. In that period of time I oversaw the procurement of SCE's resource adequacy portfolio, led the procurement of conventional generation resources in SCE's Local Capacity Requirements RFO, and more recently was responsible for SCE's Renewables Portfolio Standard RFO. In 2016, I was promoted to Senior Manager of the Large Power Demand Response programs responsible for approximately 1,000 MW of demand response programs. In 2019, I was promoted to Principal Manager of Demand Response Products and in 2021 the Customer Generation Programs group was combined with the Demand Response group.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of SCE's Direct Testimony Phase 2, Testimony preliminarily marked for identification as SCE-04 and titled *Direct Testimony of Southern California Edison Company-Phase 2*. Specifically, I am sponsoring the portions of the testimony where I am identified as the witness in the Table of Contents.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you certify under penalty of perjury that you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, do you certify under penalty of perjury that it represents your best judgment?

A. Yes, it does.

Q. Do you adopt this testimony as your sworn testimony in this proceeding?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY OF EVA MOLNAR

Q. Please state your name and business address for the record.

A. My name is Eva Molnar, and my business address is 1515 Walnut Grove Avenue, Rosemead, California 91770

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Senior Manager of Pricing Implementation, and I have been in this role since March 2016. My responsibilities currently include overseeing the rollout and budget of major rate initiatives, as well as the launch, enhancement, and management of customer energy management tools.

Q. Briefly describe your educational and professional background.

A. I graduated from the Wharton School of Business, University of Pennsylvania in 1994 with a Bachelor of Science in Economics. I received my MBA from Pepperdine University in 2006. I have over 20 years of experience with launching programs, products, and rates for a variety of different businesses. I started SCE in 2006 and have worked at SCE for over 11 years in a variety of different positions in Customer Programs & Services.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE- The purpose of my testimony in this proceeding is to sponsor portions of SCE's Direct Testimony Phase 2, Testimony preliminarily marked for identification as SCE-04 and titled *Direct Testimony of Southern California Edison Company-Phase 2*. Specifically, I am sponsoring the portions of the testimony where I am identified as the witness in the Table of Contents.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you certify under penalty of perjury that you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, do you certify under penalty of perjury that it represents your best judgment?

A. Yes, it does.

Q. Do you adopt this testimony as your sworn testimony in this proceeding?

A. Yes, I do.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF WILLIAM V. WALSH

Q. Please state your name and business address for the record.

A. My name is William V. Walsh, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at Southern California Edison Company (SCE).

A. I am a Vice President, responsible for managing the Energy Procurement & Management Operating Unit at SCE. My organization's responsibilities include contracting for wholesale energy supply, including renewables and energy storage; energy compliance; energy solicitations and valuations; energy contract management and financial settlements, and energy market operations, including the bidding and scheduling of SCE's utility-owned and contracted resources into organized wholesale energy markets.

Q. Briefly describe your educational and professional background.

A. I earned a Bachelor of Arts Degree in Business Economics from the University of California, Los Angeles in 1997. I earned a Juris Doctor Degree from The George Washington Law School in 2000. I was hired by SCE in July 2005 as an Attorney 2. I was promoted to Senior Attorney in 2009 and was responsible for several major energy proceedings including resource adequacy and Renewables Portfolio Standard. From 2010-2011, I served as the Manager 3 of Renewable Procurement and was responsible for leading a team of originators in the procurement of all of SCE's renewable power through competitive solicitations, bilateral opportunities, and standard renewable procurement programs. In 2014, I was promoted to Director and Managing Attorney for the Resource Policy and Planning group responsible for representing SCE at the Commission in all of its energy and resource policy proceedings. I also managed SCE's Power Procurement law group and Contracts and Intellectual Property law group. In 2018, I was promoted to Assistant General Counsel in the SCE's Law Department with responsibility over cybersecurity, litigating the company's positions before the Federal Energy Regulatory Commission, and all transactional work related to SCE's energy procurement, interconnection agreements, and supply management activities. I assumed my current position in February 2020.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of SCE's Direct Testimony preliminarily marked for identification as SCE-01 and titled *Direct Testimony of Southern California Edison Company*. Specifically, I am sponsoring the portions of the testimony where I am identified as the witness in the Table of Contents.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

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

A. Yes, I do.

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

A. Yes, it does.

Q. Do you adopt this testimony as your sworn testimony in this proceeding?

A. Yes, I do.

Q. Insofar as this material is factual in nature, do you certify under penalty of perjury that you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, do you certify under penalty of perjury that it represents your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.