Rulemaking No.: R.20-11-003
Exhibit No.: SCE-01
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(U 338-E)

Direct Testimony of Southern California Edison Company

Before the

Public Utilities Commission of the State of California

Rosemead, California

January 11, 2021

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I.

INTRODUCTION & BACKGROUND

A. Regulatory Background

From August 14 through 19, 2020, California experienced an extreme heat event where temperatures were 10 to 20 degrees above average. The extreme heat event caused a sharp, sustained increase in energy demand while simultaneously triggering energy supply issues for the California energy grid. On August 14, 2020, the California Independent System Operator (CAISO) declared a Stage 3 Emergency and issued rotating outage orders, which resulted in 491,600 customers across the state experiencing power outages for up to 150 minutes. On August 15, 2020, the CAISO again declared a Stage 3 Emergency and issued rotating outage orders, which resulted in 321,000 customers losing power for up to 90 minutes.

Following the rotating outages, Governor Gavin Newsom directed the California Energy Commission (CEC), the CAISO, and the California Public Utilities Commission (Commission or CPUC) to publish a report identifying the root cause of the events leading to the outages. On October 6, 2020, the CEC, the CAISO, and the Commission submitted to Governor Newsom a Preliminary Root Cause Analysis report preliminarily identifying several factors that contributed to the emergency and making preliminary recommendations to ensure reliability for 2021 and beyond.

The Commission instituted this rulemaking to identify and execute all actions within its authority to ensure reliable electric service if an extreme heat event occurs in the summer of 2021. In particular, this rulemaking will address how to decrease energy demand and increase energy supply during the peak demand and net peak demand hours in the event that a heat storm similar to the August 2020 storm occurs in summer 2021. This rulemaking primarily focuses on those actions that the Commission can adopt by April 2021 and that parties can implement before or during the summer of 2021.

The December 18, 2020 Administrative Law Judge's Ruling Introducing a Staff Report and Questions to the Record and Seeking Responses From Parties in Opening and Reply Testimonies (December 18 ALJ Ruling) includes an Energy Division staff proposal for addressing summer 2021 reliability needs, as well as staff guidance and questions for parties to consider when developing their proposals for submission in opening testimony on January 11, 2021.

B. Overview of SCE's Proposals

To best use the limited time available and enable this rulemaking to achieve its goal of enhancing system reliability for summer 2021, SCE's proposals focus on those actions that are feasible and implementable by this summer, that can provide flexible, significant, and reliable load reduction or increased supply during times of system need, and that are affordable and can be implemented equitably from a cost allocation standpoint.

1. Demand Response Proposals

Of the two options of reducing energy demand or increasing energy supply, the options that reduce demand are more likely to be achievable in meaningful quantity by the summer of 2021. SCE's demand response (DR) proposals focus on load reduction options that can achieve meaningful, beneficial reliability impacts on the grid in the limited time available. Specifically, SCE's DR proposals include:

- An Emergency Load Reduction Program (ELRP) pilot that allows participation by eligible directly enrolled (bundled and unbundled) large non-residential customers and aggregators, including those already participating in the Base Interruptible Program (BIP) and the Agricultural & Pumping Interruptible (AP-I) program.
- Enabling more participation in DR programs by allowing year-round enrollment in the BIP and the AP-I program, temporarily exempting customers enrolled in the BIP and the AP-I program from the Prohibited Resources (PR) policy for an interim period, increasing BIP incentives, and elimination of the two percent reliability cap.
- Expanding the Smart Energy Program (SEP) by permanently modifying the medical baseline exclusion, implementing new acquisition tactics and opportunities, and considering eligibility for all residential customers for summer 2022.

- Mitigating customer attrition and increasing program enrollment in the Summer Discount Plan (SDP) program by offering a sign-up bonus, increasing program incentives, and modifying tariffs to provide dispatch flexibility.
- Expanding the Capacity Bidding Program (CBP) to include all residential accounts and increasing CBP capacity rates.
- Encouraging participation in the Automated Demand Response Technology Incentive Program (ADR) by removing the 60/40 incentive payment split, increasing the enrollment duration requirement, and allowing customers enrolled in the ELRP pilot and BIP to be eligible for incentives.
- Extending and expanding the Virtual Power Plant (VPP) pilot to acquire additional vendors and customers.
- Commencing an education campaign for Critical Peak Pricing (CPP) customers to improve CPP performance.
- Upgrading DR systems and technology to better support future grid emergencies.
- Performing an Evaluation, Measurement, and Verification (EM&V) study to quantify systematic differences between Commission-approved load impact methods and CAISO-approved baseline methods.

2. Expedited Procurement Proposal

On December 28, 2020, President Batjer issued an Assigned Commissioner's Ruling Directing the State's Three Large Electric Investor-Owned Utilities to Seek Contracts for Additional Power Capacity to Be Available by the Summer of 2021 or 2022 (December 28 ACR). The December 28 ACR directs Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and SCE (collectively, the investor-owned utilities or IOUs) to seek contracts for capacity, available for the net peak demand and peak demand periods in summer 2021 and/or summer 2022, that conform with the parameters outlined in the December 28 ACR.[1] The December 28 ACR provides that

[1] *See* December 28 ACR, pp. 2-5.

the IOUs shall procure on behalf of all customers in their service territories with the costs and benefits allocated to all benefitting customers through the Cost Allocation Mechanism (CAM) and that the IOUs shall submit the contracts that conform with the December 28 ACR for Commission consideration through advice letters by no later than February 15, 2021.[2] The December 28 ACR notes that the "substance of this ruling will be brought to the full Commission in the form of a proposed decision."[3]

On January 8, 2021, Administrative Law Judge Stevens issued a Proposed Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Seek Contracts for Additional Power Capacity for Summer 2021 Reliability (January 8 PD). Like the December 28 ACR, the January 8 PD directs the IOUs to seek contracts for capacity that is available to serve peak and net peak demand in the summer of 2021 and to procure on behalf of all customers in their service territories with the costs and benefits allocated to all benefitting customers through the CAM.[4] The January 8 PD also requires the IOUs to submit the contracts that conform with the decision for Commission consideration as advice letter submittals by February 15, 2021.[5] The main differences between the December 28 ACR and the January 8 PD are that the January 8 PD does not include procurement for summer 2022 or include firm forward imported energy contracts as one of the resource types that may be considered. The January 8 PD states that it "focuses on the actions that are … most urgently needed in order to practically deliver the intended benefit by summer 2021," and that "[w]hile we believe swift action is needed to ensure firm forward imported energy contracts can be executed for summer 2021 and to ensure intended benefits are provided for summer 2022, we believe these benefits can be reasonably realized through consideration in a subsequent decision in this proceeding."[6]

SCE supports the January 8 PD. In SCE's expedited procurement proposal, SCE recommends the Commission authorize the IOUs to procure incremental firm import energy on behalf of

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[2] *See id.*, pp. 3-5.
[3] *Id.*, p. 2.
[4] *See* January 8 PD, pp. 1, 11-12, Ordering Paragraph (OP) 1-2.
[5] *See id.*, p. 12, OP 3.
[6] *Id.*, p. 4.

all customers in their service territories under the CAM, after the monthly resource adequacy (RA) showings where unused intertie capacity is available. Waiting until after the RA showings (e.g., after April 17, 2021 for showing month June 2021) will ensure that the IOUs do not inadvertently procure the same imports that otherwise would have been RA resources resulting in no incremental firm energy imports for the CAISO system. Moreover, after the monthly RA showings are completed, the IOUs would be able to ascertain the true unused intertie capacity by tie-point and procure accordingly to avoid congestion and maximize the incremental energy that can flow to the CAISO system when needed.

C. Organization of SCE's Testimony

SCE's testimony is organized into seven chapters. This Chapter I includes regulatory background, an overview of SCE's proposals, and a description of the organization of this testimony. Chapter II includes SCE's DR proposals. SCE incorporates the December 18 ALJ Ruling's staff guidance and questions related to its DR proposals in those proposals. Chapter III includes SCE's response to other staff guidance and questions related to CPP. Chapter IV includes SCE's response to other staff guidance and questions related to DR. Chapter V includes SCE's response to the Energy Division staff proposal regarding a Flex Alert Paid Media Campaign. Chapter VI includes SCE's expedited procurement proposal. Finally, Chapter VII includes SCE's response to staff guidance and questions regarding expedited procurement.

II.

SCE'S DR PROPOSALS

A. Introduction

SCE has developed these proposals for actions SCE believes will be the most impactful to grow SCE's DR portfolio and are feasible to be implemented by summer of 2021, while minimizing customer impacts due to the recent grid emergencies of 2020.

1. SCE's Proposals Include the Initiatives That Are Most Effective in Enhancing System Reliability

SCE considered all options to decrease energy demand during peak demand and net peak demand hours. However, due to the limited time available before summer 2021, SCE focused its efforts on proposals that can produce the greatest load impacts to provide grid reliability. SCE objectively assessed the overall effectiveness of various approaches and focused its resources on areas that can be optimally deployed to achieve maximum peak and net peak load reductions when and where they are most needed on the grid.

2. SCE's Proposals Are Implementable by Summer of 2021

This rulemaking is appropriately focused on those actions that the Commission can adopt by April 2021 and that parties can implement before or during the summer of 2021.[7] SCE is currently undergoing the replacement of its enterprise Customer Service System (CSS) with an SAP customer relationship and billing systems through the Customer Service Re-Platform (CSRP) project. Since January 2019, SCE has been in a business freeze which will extend through the stabilization phase of the CSRP project through the fourth quarter (Q4) of 2021. A stabilization period is required to ensure that the new system is working as expected and to safeguard against potential negative impacts to operations when temporary increases in work volumes and average handle times are expected. Implementing any new scope or code changes during this time can introduce significant risk to existing work and particularly increase the risk of billing system issues. As a result of CSRP, SCE is limited in the

[7] *See* Assigned Commissioner's Scoping Memo and Ruling, R.20-11-003, December 21, 2020, pp. 1-2.

proposals that can be implemented in time for summer 2021 and will not be able to develop any new solutions to support grid emergencies until after stabilization, which is expected to occur in early 2022.

B. Proposals by Megawatt Impact

1. ELRP Pilot

SCE proposes an out-of-market, non-RA DR pilot program (i.e., an energy-only program) designed to compensate customers for their demonstrated energy load reduction (i.e., pay-for-performance) during grid reliability events. The ELRP pilot would also allow customers to use their back-up generation, if they have it and can use it within their air quality permit requirements.[8] The Commission should approve SCE's ELRP pilot proposal until the immediate identified emergency conditions have been addressed through longer-term procurement of new resources. SCE estimates this pilot program could provide approximately 200 megawatts (MW) of additional hourly energy by summer 2021.

Due to CSRP and the schedule needed to implement an ELRP pilot by the summer of 2021, SCE's ELRP proposal will need to leverage existing systems or processes that do not impact the CSRP project. With CSRP limitations, SCE plans to initially restrict participation to eligible directly enrolled (bundled and unbundled) large non-residential customers and aggregators and only allow dual participation with BIP and AP-I.[9]

Grid needs and emergencies are fluid and dynamic and cannot always be predicted; therefore, the ability to call events on a day-ahead (DA) and day-of (DO) basis would provide the most flexibility. This type of flexibility is best suited for an energy, pay-for-performance, non-penalty DR

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[8] Regardless of Commission program guidelines that may provide compensation to certain customers to run on-site generation during emergency DR events, local Air Pollution Control Districts (APCDs) and Air Quality Management Districts (AQMDs) regulate the use of stationary generators in California. There are 35 local districts across the state, each with a separate set of rules that may or may not impact a generator to be used during an emergency DR event. Similar to actions taken in summer of 2020, additional coordination with state and local agencies will be required in order to see the full potential load reduction that would result from any Commission program or policy. SCE is not proposing that any Commission-approved program would trump existing APCD or AQMD requirements.

[9] Eligible large non-residential service accounts must have a peak demand of greater than or equal to 200 kilowatts (kW) with an SCE approved interval meter. Participating aggregators can only add and nominate eligible large non-residential customers in their ELRP portfolio.

program, such as ELRP. Accordingly, SCE proposes to initiate an ELRP event in any one of the following circumstances to allow flexibility to call events when needed:

1. After the CAISO has publicly declared an Alert, Warning, Stage 1, Stage 2, Stage 3, Transmission Emergency, or Probable Load Interruption; or
2. Upon determination by SCE's grid control center of the need to implement load reductions in SCE's service territory; or
3. At the discretion of SCE for program evaluation or system contingencies.

Similar to the closed Demand Bidding Program, SCE recommends the ELRP should be employed as an "emergency avoidance program" and an "emergency response program" "within a comprehensive portfolio of load management programs to support system reliability."[10] With the ELRP being dispatched as needed and notifying participants either DA or DO, there is no reason to specify whether the ELRP should be dispatched before or after the BIP. For example, after the August 14, 2020 grid emergency events, the same grid issues were anticipated for the next five days (August 15-19). In this instance, ELRP notifications could be issued in the DA to allow participants to plan and provide load reductions when needed, which could mitigate or prevent the need for reliability DR resources for those days and possibly alleviate customer fatigue. Alternatively, Transmission Emergency Notices generally cannot be anticipated; therefore, the ELRP could be dispatched to provide immediate system reliability.

Since ELRP events or dispatch notifications would be DA (CAISO DA Alert Notice) or DO (CAISO Warning, Stage 1, Stage 2, Stage 3, Transmission Emergency, or Probable Load Interruption Notices), it is unclear how ELRP comports with the Commission's dual participation rules. D.09-08-027,[11] D.12-04-045,[12] D.17-12-003,[13] and D.18-11-029[14] only allow dual participation between two DR programs, one capacity program and one energy program as long as each program has a

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[10] Decision (D.) 02-07-035, p. 5. *See also id.*, Conclusion of Law 2.
[11] *See* D.09-08-027, pp. 154-155, OP 30.
[12] *See* D.12-04-045, pp. 47-56.
[13] *See* D.17-12-003, pp. 31-35.
[14] *See* D.18-11-029, pp. 13-22.

different notification type (e.g., DA energy program and DO capacity program). When the DR dual participation rules were established, there were no DR programs that have both DA and DO notifications such as what is being proposed for the ELRP pilot. To allow dual participation between the ELRP pilot and the BIP and AP-I program, the ELRP pilot should be designated as a DA energy DR program.

SCE proposes an incentive energy rate of $0.75 for each kilowatt-hour (kWh) of Recorded Reduction which should attract customers to the program and for consistency purposes, is similar to the rate proposed in SDG&E's Advice 3615-E.[15] Energy payments shall only be issued if the service account's Recorded Reduction is at least 50 percent, but not greater than 200 percent, of the participant's nominated kW demand reduction amount, which would mitigate payments to free riders or gamers.

SCE is conducting additional analyses of the 2020 grid emergencies to determine an appropriate baseline methodology. Until such time, SCE proposes that a customer's AEB is calculated by multiplying the energy baseline (EB) by the DO adjustment (DOA). The AEB shall be no more than 40 percent higher than the EB after adjustment. The EB will be calculated on an hourly basis using the average of the previous 10 calendar days and shall exclude days when the customer was subject to a BIP or ELRP event. The DOA is a ratio of (a) the average load of the first three hours of the four hours prior to the event to (b) the average load of the same hours from the last 10 calendar days. The DOA value shall not be less than 1.00 or greater than 1.40.

The ELRP incentive energy rate is an after-the-fact "pay-for-performance" compensation rate. ELRP payments will also be consistent with D.09-08-027 and other Commission decisions that address double payment. In situations where an ELRP event's hours overlap with a BIP or AP-I event's

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[15] Recorded Reduction equals the difference between the sum of an ELRP participant's service account's Adjusted Energy Baseline (AEB) and their recorded kW during each hour of an ELRP event. The Recorded Reduction cannot be less than zero for purposes of calculating ELRP energy payments.

hours, participants will only receive a payment[16] under the capacity program (e.g., there will be no ELRP payments for overlapping hours).[17]

a) ELRP Incremental Funding Request

Table II-1 summarizes SCE's incremental funding request for its ELRP pilot proposal for 2021 and 2022. Funding for the ELRP pilot for 2023 and beyond will be included in SCE's 2023-2027 DR Application due on November 1, 2021.

Table II-1
ELRP Incremental Funding Request
(in millions)

Cost Type	**2021**	**2022**	**Total**
Admin – Labor	$ 0.14	$ 0.13	$ 0.27
Admin – Non-Labor	$ 0.43	$ 0.13	$ 0.56
Participant Incentives	$ 9.00	$ 9.00	$ 18.00
TOTAL INCREMENTAL BUDGET	**$ 9.57**	**$ 9.26**	**$ 18.83**

(1) Labor

SCE is requesting an additional $140,000 for program management, analytical support, and overhead for the ELRP pilot for 2021. Should the ELRP pilot be authorized for 2022, SCE requests $126,000 for these labor costs or $267,000 for both years.

(2) Incentives

In Q4 of each year, after all service accounts have been billed, SCE will issue ELRP energy payments as a bill credit for directly enrolled customers and as a check to aggregators. SCE requests $9 million for participant incentives for summer 2021 (10 event days, six hours per event, 200 MW (or 200,000 kW) per hour, $0.75/kWh). Should there be additional events,

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16 This position assumes SCE's proposal to suspend the PR policy under the BIP and AP-I program is adopted. If that proposal is not adopted, then consideration should be given to accommodate incremental ELRP compensation for ELRP actions that may transcend overlapping hours and accommodate complex operating scenarios for customers trying to manage operating loads and on-site generation during system emergency situations.

17 *See* D.09-08-027, p. 155.

event hours, or Recorded Reduction beyond SCE's estimates, SCE requests the Commission authorize contingency funding to ensure there is sufficient funding to pay participants; otherwise, SCE will need to limit enrollment or limit events to ensure the budget is not exceeded. Should the pilot be approved for 2022, SCE requests the same incentive funding.

(3) System Enhancements and Upgrades

For directly enrolled customers, SCE proposes to develop and use an online microsite that will allow customers to electronically accept the program terms and conditions as part of the enrollment process. The proposed ELRP microsite will leverage an existing process that uses a similar microsite to help mitigate the CSRP implementation schedule. For aggregators, SCE plans to leverage the existing APX system that manages the CBP with minor modifications to support the ELRP pilot. Other system modifications and changes include the Demand Response Automation Server (DRAS), the DR Event Website, the DR Mobile App, event notifications, automated dispatch, and settlement engines. SCE is requesting $267,000 to make these system enhancements to support the ELRP pilot. An additional $10,000 will be needed for notifications in 2022.

(4) Marketing, Education, and Outreach (ME&O)

With the limited amount of time to implement this pilot, marketing, education, and outreach (ME&O) to non-residential customers will be mostly performed by SCE's Business Customer Division Account Managers and aggregators. SCE is requesting approximately $45,000 to develop informational materials, such as SCE DR information webpage(s), program fact sheets, the DR Brochure, and sending emails that will be used to inform customers about the pilot. Incremental ME&O costs for 2022 would be $4,000 to make updates to materials and to send emails.

(5) EM&V

Incremental costs to evaluate the ELRP pilot are estimated to be $120,000 for each evaluation. The evaluation should inform the load impacts of the pilot and whether it should be extended in duration to 2022 and following years.

2. **BIP and AP-I Program**

Each year between November 1 and December 1 (i.e., the November Window), SCE offers BIP and AP-I participants a window to unenroll from the programs and allows BIP participants to change their Firm Service Level (FSL). During the 2020 November Window, 32 AP-I customers and 48 BIP customers disenrolled from their respective program for a total loss of approximately 36 MW. Another 47 BIP participants elected to increase their FSL for another loss of 12 MW. SCE expects that these MW losses are attributed to the record number of events held in August and September 2020.

To increase enrollment and load reduction in time for summer 2021, SCE proposes: (a) permanently allowing year-round enrollment in the BIP and AP-I program; (b) allowing BIP and AP-I customers to be temporarily exempted from the PR policy;[18] (c) increasing BIP incentives; and (d) eliminating the two percent DR reliability cap.

a) Allow Year-Round Enrollment

Of special concern is the gap between the November Window and the April lottery (enrollment) window where potential MW sit unused and are unable to be allocated. Moving from the current April lottery process to year-round enrollment enables maximum participation of the interested participants to apply and enroll prior to the hottest summer months when DR is needed most.[19] SCE recommends no changes to the current unenrollment window in November,[20] but requests that D.18-11-029, OP 5 be deleted and allowing year-round enrollment onto the programs.

b) Temporary Exemption to the PR Policy

SCE proposes the Commission authorize temporary tariff changes to both the BIP and AP-I program to permit PR use by these customers within their air quality permits (absent an emergency order of the Governor specifying otherwise) until the immediate identified emergency

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[18] 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.

[19] Year-round enrollment allows customers to enroll onto the BIP or AP-I program at any time, but customers will only receive bill credits (e.g., capacity incentives) for the time that they are enrolled with no retroactive payments.

[20] Customers can only de-enroll from the BIP or AP-I program during the November Window, which means customers cannot choose when to de-enroll any time outside the November Window.

conditions have been addressed through longer-term procurement of new resources to meet load needs. SCE estimates temporarily eliminating PR provisions from interruptible tariffs could add 16 additional DR MW from existing interruptible customers and potentially bring back 50 MW of customers that unenrolled after the implementation of the PR policy, which was implemented by the IOUs in 2019 following the issuance of D.14-12-024, D.16-09-056, and Resolution E-4906, while ensuring that air quality permit limits are still respected.

c) Increase BIP Incentives

SCE plans to increase BIP incentives by 20 percent to retain and attract more customers to the program.[21] Table II-2 below summarizes BIP incentive factors that are planned for implementation in SCE's next consolidated rate change scheduled for February 1, 2021. Attrition of customers following the significant number of dispatches in the summer of 2020 is evidence that a higher BIP incentive is necessary to maintain and grow the capacity in this program.

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[21] SCE does not propose any other changes to incentive levels, including establishing different incentives for partial year enrollment. SCE anticipates having a sufficient BIP incentive budget, authorized in D.17-12-003, to accommodate a 20 percent increase.

Table II-2
BIP Incentive Rate Factors

TOU BIP (Option A, or 15MIN) - $/Average kW-month Year 2021			
Program	**below 2 kV**	**2 kV to 50 kV**	**above 50 kV**
Summer Average On Peak kW	(26.11)	(26.11)	(17.84)
Summer Average Mid Peak kW	(2.04)	(1.70)	(0.86)
Winter Average Mid Peak kW	(10.97)	(10.26)	(6.46)
Excess Energy Charge - $/kWh	14.98186	14.69333	14.18881

TOU BIP (Option B, or 30MIN) - $/Average kW-month Year 2021			
Program	**below 2 kV**	**2 kV to 50 kV**	**above 50 kV**
Summer Average On Peak kW	(23.54)	(23.14)	(15.37)
Summer Average Mid Peak kW	(1.84)	(1.50)	(0.73)
Winter Average Mid Peak kW	(9.89)	(9.07)	(5.54)
Excess Energy Charge - $/kWh	13.51232	13.22378	12.71927

d) Eliminate the Two Percent Reliability Cap

The increased participation and MW that could result from the changes listed above and the increased BIP incentives may cause SCE to reach its two percent DR reliability cap allocated MW and cause SCE to cap enrollment. SCE proposes the Commission permanently eliminate the two percent DR reliability cap established in D.10-06-034,[22] given that it is no longer needed since the Commission modified the DR Maximum Cumulative Capacity (MCC) bucket which limits the amount of DR that counts towards load-serving entities' (LSEs) RA obligations.[23]

SCE is confident that increasing BIP incentives, combined with the proposals listed above, will drive increased participation in the BIP and AP-I program, adding valuable MW to the programs, and can be easily implemented by summer 2021. If any of these recommended changes are approved, SCE will conduct outreach to inform existing customers of the changes, and also inform past

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[22] *See* D.10-06-034, OP 1.e.
[23] D.20-06-031, OP 19, adopted an 8.3 percent DR MCC bucket for LSEs, which includes all DR RA allocations through the CAM and IOUs' DR programs.

customers to see if they would be interested in re-enrolling. Marketing efforts will be minimal and will not require any additional funding. SCE does not recommend major program design changes at this time (such as different tiers of the programs) because attempting to make major program changes by summer 2021 would be systematically and operationally challenging due to CSRP. SCE plans to re-evaluate program design and will consider various options for its 2023-2027 DR Application.

3. 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.[24] 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 program is available for dispatch year-round, but enrolled participants only receive program incentives (bill credits) from June through September, up to $40 annually.

In 2020, the SEP was dispatched for up to 35 hours over 14 event days throughout the summer, including six emergency triggered reliability events. For each event, approximately 44,400 participants were dispatched with a total average of 22 MW of peak load reduction.[25] The SEP lost approximately 10,300 customers to attrition in 2020 (from January through November) primarily due to migration to community choice aggregators (CCAs) and account closures, with a small subset (less than one percent) occurring from customers requesting to de-enroll during August and September. Historically, event-related attrition on the SEP has been minimal due to the design of the program. In 2018 and 2019, event-related attrition was less than four percent; therefore, targeting certain end-use customers could lead to larger sustained aggregate capacity as the program continues to scale.

SEP attrition has significantly increased due to the expansion of CCAs in SCE's service territory and the current tariff limitation restricting the SEP to bundled service customers only.

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[24] Bundled service customers are customers who have their delivery and generation-related services provided by SCE.

[25] Based on SCE 1-in-2 August System Peak ex-ante per participant value of 0.5 kW.

When cities migrate to CCA service, SCE must remove or de-enroll those customers from the SEP and the thermostat enrollment incentive becomes a stranded asset. Few customers opt-out of CCA service to keep their bundled service status and remain enrolled in the SEP. In 2020, nearly 30 percent of SEP customers lost to attrition were attributed to new CCA service and the remaining 70 percent were due to service account closures. Since 2018, SCE has had to remove over 14,000 customers from the SEP, an estimated loss of approximately 7 MW of DR capacity, due to CCA migration. In addition, as smart thermostat adoption rates continue to increase, CCA customers that are not offered a DR program to participate in are lost DR MW.

The SEP could add up to 47,000 enrollments (about 23.5 MW of DR capacity) by 2022 by removing enrollment barriers, such as the CCA restriction, and modifying the medical baseline exclusion, as well as implementing new acquisition tactics and opportunities. If approved, these changes could help meet near- and long-term grid needs.

a) <u>Modify Medical Baseline Exclusion</u>

The SEP inherited from the Peak Time Rebate (PTR) program a provision that prohibited medical baseline customers from joining the program. Considering the SEP is a smart thermostat program, SCE does not believe all types of medical baseline allocations should be excluded from participating. SCE proposes to permanently modify the medical baseline exclusion to only those with a medical need for air conditioning. This approach aligns with the medical baseline exclusion for the SDP program and will help reach more customers for 2021 and future years.

b) <u>Optimize New Acquisition Opportunities</u>

In 2021 and 2022, SCE plans to implement strategies, such as customized and targeted marketing and leveraging Integrated Demand-Side Management (IDSM) opportunities, that could increase customer program enrollment. For instance, SCE can recruit customers to apply for the SEP by: (1) developing customized marketing to target customers that de-enrolled from the SDP program, current thermostat owners such as customers who previously received an energy efficiency (EE) thermostat rebate or had a smart thermostat installed at their home through one of SCE's EE direct install programs, or customers that have moved into a premise where a smart thermostat is likely to be already installed; and (2) working with thermostat vendors to increase their ME&O to thermostat owners where SCE does not have visibility. For the immediate term, these activities will be focused on bundled residential customers until SCE can update its billing systems to expand to all residential customers. SCE also plans to explore opportunities to implement SEP pre-enrollment at point of sale through the SCE Marketplace by 2022.

c) <u>Eliminate CCA / Electric Service Provider (ESP) Restriction by Converting SEP from Generation to Distribution Funding</u>

In 2014, the SEP was integrated as a new enrollment option within SCE's legacy PTR program per Advice 3001-E.[26] As the PTR energy program evolved into the SEP capacity program, the CCA/ESP restriction was never removed. This was because when the PTR program was initially proposed in SCE's SmartConnect Application (Application (A.) 08-03-002), it was originally designed to be an energy-only DR program that used residential customers' SmartConnect (smart meter) to determine the customer's PTR performance and pay customers for their demonstrated load reduction. Because PTR program was originally structured as a bundled generation incentive, that meant only bundled customers were eligible to receive an incentive. Over the last several years, SCE has implemented program changes to improve the program's load impacts and has changed the original behavioral PTR DR energy program to the current DLC SEP DR capacity program that provides grid reliability.

Prior to the SEP transitioning to a capacity payment program, the SEP was approved for a new acquisition expansion effort in response to Aliso Canyon remediation action pursuant to D.16-06-029, which quickly scaled the program to nearly 50,000 participants by 2017 while the other PTR options were decommissioned (due to lack of cost-effectiveness, flexibility, and low customer savings). Soon after achieving the new SEP acquisition targets, CCA activity was further expanded between 2017 and 2020 resulting in a loss of over 14,000 SEP enrollments and limiting SCE's DR MW capacity growth in these areas. In parallel with the increase in CCA activity, SCE

[26] Prior to 2018, the SEP was known as Peak Time Rebate with Enabling Technology Direct Load Control (PTR-ET-DLC).

implemented SEP design changes in 2019 to improve the program and enable integration into the CAISO wholesale energy market where it is now available to help address economical and reliability needs.[27]

To date, SEP is the only market integrated DR resource in SCE's portfolio that is limited to bundled service customers. SCE supports CCA expansion and would like to work with CCAs and their customers to offer and enroll them in the SEP if a controllable thermostat DR program is not offered by their CCA (or ESP). Modifying the SEP to allow unbundled residential customers will also allow LSEs to receive a portion of the program's DR RA credit. Due to CSRP, expanding SEP to all residential customers is not possible for 2021, but will be considered for implementation in summer 2022. SCE requests $2.87 million for additional funding for labor, non-labor vendor support, participant incentives, and ME&O. If the Commission approves this proposal and SCE is able to implement this change by summer 2022, SCE will include this funding in its distribution DR revenue requirement for 2022.

(1) Customer Impacts through Revenue Recovery

The revenue recovery for the SEP would need to be changed from bundled service customers only, which is recovered via Generation charges, to all customers (i.e., bundled and departing load customers) via Distribution charges. The revenue will continue to be allocated on the basis of system generation marginal costs even though recovery occurs through Distribution charges. According to the 2021 estimated program spend for the SEP, the rate impacts would change from $0.00018/kWh bundled to $0.00011/kWh system, which is based upon a bundled residential customer that uses 20,000 kWh a year and would be an $1.40 annual bill decrease.

Through 2020, SCE has spent $16 million of its authorized funds and as noted in SCE's DR 2018-2022 Mid-Cycle Status Report (MCR) advice letter, had planned to fund shift unspent funds from SDP and ADR, as needed, to meet its enrollment projections through 2022.[28] The SEP proposals above seek to expand enrollments beyond what was estimated in the MCR to help

[27] *See* SCE Advice 3944-E, submitted on January 31, 2019 and effective as of March 22, 2019.
[28] *See* SCE Advice 4182-E, p. B-21.

provide grid reliability by summer 2021 and 2022. Furthermore, the unspent funds that were available from the SDP will be used to help grow enrollments in that program and will no longer be available to fund shift to the SEP. Therefore, SCE requests an additional $6.20 million[29] to cover the costs of these SEP proposals, program administration, and customer incentives through 2022 and smart thermostat rebates will continue to be funded from SCE's Technology Incentive Program.[30] SCE's incremental funding requests for the SEP medical baseline and IDSM proposals are provided in Table II-3. SCE does not include its incremental funding for eliminating the CCA/ESP restriction in the incremental funding request due to the uncertainty of implementation by summer 2022.

Table II-3
SEP Incremental Funding Request
(in millions)

Cost Type	**2021**	**2022**	**Total**
Admin – Labor	$ 0.44	$ 0.00	$ 0.44
Admin – Non-Labor	$ 2.89	$ 0.00	$ 2.89
TOTAL INCREMENTAL BUDGET	**$ 3.33**	**$ 0.00**	**$ 3.33**

4. 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 operates as both a reliability and price responsive program in the CAISO wholesale markets. The SDP program offers credit to residential and commercial customers who allow their air conditioning (A/C) units to cycle off during curtailment events. Participating customers allow SCE to install radio frequency load switches at their residence/business to periodically turn-off or cycle-off a customer's A/C compressor during periods of peak energy demand, system emergencies, or at times of high

29 Total amount including funding for modifying Medical Baseline provision and IDSM opportunities ($3.33 million) and for removing CCA/ESP prohibition ($2.87 million).

30 SEP administration and incentive budgets approved in D.17-12-003 and D.18-03-041 are estimated to be sufficient to cover incremental costs for these proposals in 2021 but cannot cover incremental costs in 2022.

wholesale energy prices. SDP customers can reduce their energy bills by receiving a credit on their electric bills each year from the first of June to the first of October.

In 2020, SDP was dispatched for an average of 30 hours per customer over 13 event days. Approximately 210,000 SDP participants were dispatched during this time and delivered an average load reduction of 195 MW. SDP was dispatched for five economic events, three measurement and evaluation events, and seven days of reliability events. SDP customers were dispatched for up to 26 hours during these reliability events, and the length of the events ranged from one hour and 45 minutes to six hours and eight minutes.

As of November 2020, approximately 17,000 SDP customers de-enrolled from the program in 2020 due to event-related attrition, which has led to a loss of approximately 14 MW of capacity.[31] A survey of those customers indicated that their top reasons for opting out of the program were due to COVID-19 restrictions, length of event dispatches, consecutive days, and the incentive was not worth the discomfort or inconvenience. To mitigate further customer attrition and increase program enrollment, SCE proposes to: (a) offer a sign-up bonus; (b) increase program incentives; and (c) modify tariffs to provide dispatch flexibility. SCE estimates $200,000 will be needed for incremental labor to process these applications and scheduling of device installations for the new enrollments as a result of the incentive increase and sign-up bonus. SCE plans to use its existing administrative budget to pay for these incremental labor costs.

a) Offer A Sign-Up Bonus

SCE is proposing to market and pay a sign-up bonus of $50, for up to 30,000 service accounts, to increase SDP enrollment ($1.5 million for each year 2021 and 2022), which could provide up to 48 MW of incremental load reduction. Additional enrollments will also require installation of SDP load control devices. SCE will not have enough existing funding for the installation of 60,000 new devices; therefore, for 2022, SCE seeks $3.64 million, in addition to the $1.5 million for the sign-up bonus, for the purchase and installation of SDP load control devices.

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[31] Average ex ante per customer is 0.8 kW.

b) Increase Residential SDP Incentives

The SDP program has demonstrated that it is an effective resource, especially during system emergencies, and provides immediate grid reliability and support in times of both energy and capacity shortfalls. Over the last three years, SDP incentives have decreased by 30 percent.[32] In SCE's MCR advice letter, SCE reported declining enrollment due to incentive reductions and requested to halt further decreases to SDP incentives.[33] To mitigate further attrition from the program and potentially increase program enrollment, SCE proposes to increase SDP residential incentives by 25 percent from current levels and use the SDP contingency incentives authorized in D.17-12-003 and D.18-03-041. Based on current enrollment and the increased enrollment levels expected from the sign-up bonus, SCE estimates SDP residential incentive costs for 2021 and 2022 will be approximately $38.9 million and $40.0 million, respectively.

SCE is focusing on changes that can provide the greatest amount of load reduction during the net peak demand period; therefore, SCE does not plan to make any modifications to SDP commercial incentives and will keep SDP commercial incentives at 2020 rates. Should the Commission see value in increasing incentives to SDP commercial customers as well, SCE would need an additional $2.5 million for each year.

c) Adding Dispatch Flexibility to Address Customer Fatigue

Current SDP tariff provisions require a minimum of 20 event dispatch hours each year which may be from a combination of economic or reliability CAISO dispatches. Once the program has achieved the 20-hour minimum, the program is only available for emergency purposes.
SCE proposes modifications to the SDP program to improve the customer experience and preserve program enrollment by revising the SDP tariffs to remove the minimum dispatch requirement, while preserving the maximums of 20 economic hours and 180 emergency hours annually. This proposed modification effectively establishes an annual target for event dispatch hours while allowing the program to assess the impacts that SDP events have on customer enrollment and make real-time

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[32] Incentives decreased in 2018, 2019, and 2020 from $200 to $180, $160, and $140, respectively.
[33] *See* SCE Advice 4182-E, p. B-31.

decisions to improve the customer experience, preserve customer retention, and preserve the capacity and value of this DR resource. These modifications will result in parity with SCE and other IOU DR programs. SCE's incremental funding requests for the SDP program are provided in Table II-4.

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

Cost Type	2021	2022	Total
Admin – Labor	$ 0.00	$ 0.00	$ 0.00
Admin – Non-Labor	$ 1.50	$ 5.14	$ 6.64
TOTAL INCREMENTAL BUDGET	**$ 1.50**	**$ 5.14**	**$ 6.64**

5. CBP

The CBP is a statewide price-responsive program developed in 2006 that provides its participants (self-aggregated customers or third-party DR aggregators) monthly capacity payments based on the amount of load reduction elected each month, plus additional energy payments based on the kWh reduction when an event is called. The program allows for the flexibility for a participant to adjust their nomination each month, and to select the option in which it wants to nominate its load. SCE proposes the following changes to the CBP to increase program enrollment and capacity: (a) expand CBP to include residential accounts; and (b) increase CBP capacity rates. SCE does not anticipate needing any incremental funding for these proposals.

a) Expanding CBP to Include Residential Accounts

In SCE's MCR advice letter, SCE requested Commission approval to add residential accounts to CBP instead of conducting a one-year residential CBP pilot and add a 5-in-10 baseline for residential accounts.[34] SCE estimates expanding the CBP to residential accounts and aggregators could add more CBP capacity, particularly during the net peak load hours. No incremental funding is needed for this proposal, but SCE requires Commission approval of SCE's MCR advice letter

[34] *See* SCE Advice 4182-E, pp. B-18-B-19, E-7-E-8.

before SCE can start on implementation; as such, SCE requests Commission approval for this proposal in its MCR advice letter or in a Commission decision issued in this proceeding.

b) Increasing CBP Capacity Rates

SCE has not changed CBP capacity rates since 2013. SCE proposes a 20 percent increase to CBP DA and DO annual dollar per kW ($/kW-year) capacity rates for 2021 and 2022 to $79.24/kW-year and $91.09/kW-year, respectively, to attract aggregators to the program. This increase is reasonable considering that the CBP is dispatched more often and for more hours in a year than any other SCE DR program and could add more capacity to the program.

6. 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 ensure customers provide reliable load shed during DR program events.

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 $25,000 in incentives and has about $1.3 million reserved for projects in-flight. SCE plans to use $3.3 million in unspent ADR incentive funds to cover an expected SEP thermostat incentive budget shortfall.[35] The remaining $12.8 million remains available (unspent uncommitted) for the next two years of this funding cycle.

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. SCE does not anticipate needing any incremental funding for these proposals.

[35] The Technology Incentive Program budget includes ADR and smart thermostat incentives.

a) Remove 60/40 Incentive Payment Split

In D.12-04-045, the Commission adopted changes to IOUs' ADR programs, including splitting ADR Customized incentives 60/40 (60 percent of the eligible incentive is paid upfront and the remaining performance incentive, up to 40 percent, is paid after one year, based upon the customer's DR calculated performance).[36] Under current ADR rules, 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.

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 it was rejected 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.[37] Energy Solutions found that applications decreased substantially due to changes and the implementation of the 60/40 incentive structure.[38] 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 business models and adds uncertainty to customers financial planning. The ADR program would instead benefit from a redesign of this incentive structure.[39]

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[36] *See* D.12-04-045, OP 58.

[37] 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.

[38] *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.").

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

b) Increase Enrollment Requirement to Five Years

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 only if the proposal to remove the 60/40 incentive payment split is adopted. The Energy Solutions report showed that most ADR customers maintained their DR program enrollment longer than the existing three-year requirement.[40]

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 percent of accounts stayed 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 do become ongoing DR participants.[41]

c) ADR Incentives Eligibility

SCE proposes to allow customers enrolled in the ELRP pilot and the 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's load would 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."[42] SCE recommends that the Commission reconsider and allow BIP to be eligible for ADR incentives to automate customer's load. SCE does not require incremental funding for this proposal.

7. VPP Phase II Pilot

In May 2020, SCE launched Phase I of its VPP pilot with Sunrun Inc. (Sunrun), which is expected to conclude in May 2021. The pilot tests various dispatch scenarios, including high-demand events, such as heat storms or other stresses to the grid, that sends a signal to Sunrun to dispatch energy

[40] *See id.*, p. 6.
[41] *See id.*, pp. 42-43.
[42] D.16-06-029, p. 47.

from its 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. The bundling of these battery systems creates a VPP.

The VPP Phase I pilot, targeted to residential customers, has recruited 336 customers (a 22 percent uptake rate) and 275 customers (18 percent) are currently active in the pilot. Sixty-one (61) of the recruited customers were not eligible to participate in the VPP pilot because they are currently enrolled in an existing DR program. One customer has de-enrolled from the VPP pilot. Under this pilot, customers are compensated with a one-time payment for their participation, and not on a pay-for-performance basis.

Intermittently, the VPP pilot has achieved 95 percent of the dispatch goals to date and customers have contributed averages of 1.48 kW and 4.3 kWh per dispatch across the five most recent dispatches. SCE proposes to create Phase II of the VPP pilot which will expand to acquire additional vendors and customers. SCE estimates up to 1,500 customers will enroll in the VPP Phase II pilot and would be able to provide approximately 5 to 7.5 MW of additional capacity to the grid by the third quarter of 2021.[43]

a) VPP Phase II Pilot Incremental Funding Request

Table II-5 summarizes SCE's incremental funding request for its VPP Phase II pilot proposal for 2021 and 2022.

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[43] This capacity is considered incremental because VPP pilot eligibility does not allow customers to be enrolled in a DR program.

Table II-5
VPP Phase II Pilot Incremental Funding Request
(in millions)

Cost Type	**2021**	**2022**	**Total**
Admin – Labor	$ 0.25	$ 0.19	$ 0.44
Admin – Non-Labor	$ 0.46	$ 0.05	$ 0.51
Participant Incentives	$ 0.00	$ 0.38	$ 0.38
TOTAL INCREMENTAL BUDGET	**$ 0.71**	**$ 0.62**	**$ 1.33**

(1) Labor and Non-Labor

SCE is requesting an additional $444,000 for additional labor to administer and manage the pilot and analytical support. Non-labor costs, such as vendor costs, to operate the pilot are estimated to be $225,000.

(2) Participant Incentives

Similar to the VPP Phase I pilot, customers that are recruited and eligible to participate in the pilot would receive a $250 participation incentive to allow SCE and approved vendors to send VPP technologies an automated dispatch signal for energy curtailment for a period of up to 12 months. SCE is requesting $375,000 for participant incentives.

(3) Systems and Marketing

SCE will need to make updates and modifications to its DRAS to enable and send DR events signals to VPP enabling technologies for curtailment which will cost approximately $50,000. Additionally, similar to the VPP Phase I pilot, SCE plans to co-market with authorized vendors to enroll new participants onto the VPP Phase II pilot. Based upon marketing costs incurred for VPP Phase I, SCE estimates $137,000 will be needed to enroll up to 1,500 additional pilot participants.

(4) EM&V

The pilot is intended to evaluate performance reliability and characteristics, system integration, and technology to understand how to integrate a cohort of diverse technologies. EM&V costs to evaluate the pilot are estimated to be $100,000.

8. CPP

CPP is a dynamic pricing rate and all SCE bundled non-residential customers are defaulted onto CPP. CPP is available year-round but bill credits are only issued during the summer, typically when CPP events occur. SCE is interested in making changes to CPP, such as allowing it to be dispatched on weekends and holidays, but is unable to make any significant changes to CPP in the near-term due to CSRP. SCE intends to evaluate possible CPP changes in its 2021 General Rate Case (GRC) Phase 2 application, but for now proposes to educate and inform CPP customers on ways to improve their CPP performance and actions they can take when the CAISO issues Flex Alerts, Alerts, or Warnings, which could help for summer reliability for 2021 and 2022. To administer this CPP marketing campaign, SCE requests $450,000 annually.

Table II-6
CPP Incremental Funding Request
(in millions)

Cost Type	**2021**	**2022**	**Total**
Admin – Labor	$ 0.00	$ 0.00	$ 0.00
Admin – Non-Labor	$ 0.45	$ 0.45	$ 0.90
TOTAL INCREMENTAL BUDGET	**$ 0.45**	**$ 0.45**	**$ 0.90**

9. DR Systems and Technology

To better support future grid emergencies, SCE requests $106,000 to make upgrades to its DR systems and technology infrastructure to: (a) extend the legacy Alhambra Control Platform for one additional year; (b) enhance the DR Event Website and DR Mobile App; and (C) create a test rack to confirm when a DR event has taken place.

a) Extending the Alhambra Control Platform

In Q4 of 2020, SCE moved its Alhambra Control Platform (ACP), the system that manages SDP and AP-I devices, to the Amazon Cloud. Testing and launching of SDP and AP-I events from the new ACP cloud have not been performed to the same extent SDP and AP-I events occurred in summer 2020. SCE requests funding to allow SCE to run the legacy ACP in parallel (e.g., back-up) with the ACP cloud to ensure successful dispatch of SDP and AP-I resources for potential grid emergencies in 2021.

b) Enhancing the DR Event Website and DR Mobile App

During the system-wide grid emergencies in 2020, SCE experienced a large spike in call volumes and website hits. SCE received many questions about why SCE's DR programs were being dispatched and how long the events would last. To mitigate the call volumes to SCE's call center, SCE is proposing two upgrades to SCE's DR Event Website and DR Mobile App:

1. Implementing a banner at the top of the DR Website and DR Mobile App to educate the customers of the emergencies.
2. Implement ad-hoc templates for the DR Mobile App to send messages faster and more efficiently to customers.

c) Test Rack for Smart Thermostats

SCE developed a test rack that can confirm enabling DR technology devices, such as SDP and AP-I load control devices and BIP Remote Terminal Units, have successfully received event signals. SCE proposes to develop a test rack for all supported smart thermostats, that support the Bring Your Own Device (BYOD) model for SEP, CPP, and CBP, to ensure successful curtailment during emergency events.

Table II-7
DR Systems and Technology Incremental Funding Request
(in millions)

Cost Type	2021	2022	Total
Admin – Labor	$ 0.00	$ 0.00	$ 0.00
Admin – Non-Labor	$ 0.11	$ 0.00	$ 0.00
TOTAL INCREMENTAL BUDGET	**$ 0.11**	**$ 0.00**	**$ 0.11**

10. EM&V

SCE recommends performing a study to quantify systematic differences between Commission-approved load impact methods and CAISO-approved baseline methods as a solution to staff's question regarding Demand Response Performance Improvements in connection with the August 2020 heat waves.[44] SCE identified several possibilities for performance variations between SCE's DR program results and the CAISO's results. If approved, this study would allow SCE to better plan for DR resources by improving SCE's ability to evaluate discrepancies that may occur due to methodological differences in the settlement data and load impact/regression data reported in SCE's April 1 Load Impact filings. SCE requests $120,000 for this study.

Table II-8
EM&V Incremental Funding Request
(in millions)

Cost Type	**2021**	**2022**	**Total**
Admin – Labor	$ 0.00	$ 0.00	$ 0.00
Admin – Non-Labor	$ 0.12	$ 0.00	$ 0.12
TOTAL INCREMENTAL BUDGET	**$ 0.12**	**$ 0.00**	**$ 0.12**

C. Cost Recovery Proposal

1. Overview

In this proceeding, SCE is requesting DR *incremental* funding for 2021 and 2022, which is an increase to the DR funding amounts authorized in the 2018-2022 DR Program Cycle.[45] In addition, SCE proposes to record and recover the incremental CPP funding that was not forecasted in SCE's 2021 GRC, A.19-08-013, in SCE's Demand Response Programs Balancing Account (DRPBA).[46] Cost allocation will be consistent with the allocation of DR program costs and incentives established in SCE 2018 GRC Phase 2 proceeding.[47] As is standard practice, the allocation of costs and incentives will be updated in each GRC Phase 2 cycle.

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[44] *See* December 18 ALJ Ruling, Attachment 1, p. 8. SCE's response to the question is further discussed in Chapter IV.B.

[45] 2018-2022 DR Program Budgets approved in D.17-12-003 and D.18-03-041.

[46] *See* D.12-04-045, p. 138 ("We direct that funding for these [CPP and Real-Time Pricing] programs after this DR cycle not be included in future DR applications.").

[47] A.17-06-030.

2. Revenue Requirement for DR Proposals

SCE requests that the Commission adopt a total revenue requirement of $31.62 million, including Franchise Fees and Uncollectibles (FF&U)[48] expense, to fund the incremental 2021-2022 DR proposals in this proceeding. SCE proposes to include the annualized incremental DR Program revenue requirement in the amount of $15.81 million in rates in both 2021 and 2022, as shown in Table II-9, Line No. 16 below. The total annualized incremental DR Program revenue requirement includes a Distribution and Generation revenue requirement of $13.67 million and $2.14 million, respectively. SCE requests that the revenue requirement adopted in this proceeding be made effective January 11, 2021, the date of the submission of this testimony and the concurrent filing of the Motion of Southern California Edison Company for Order Approving Memorandum Account to Track Costs Incurred Pursuant to Rulemaking 20-11-003.

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[48] Total incremental DR revenue requirement includes FF&U, which is based on the FF&U factors adopted in SCE's most recent GRC.

Table II-9
Proposed Incremental DR Program Revenue Requirement
(in millions)

Line No.		2021	2022	2021-2022 Annualized
1.	**Distribution - DR Program Incremental Funding**			
2.	ELRP	$9.57	$9.26	$9.42
3.	SDP	$1.50	$5.14	$3.32
4.	VPP	$0.71	$0.62	$0.67
5.	DR Systems & Technology	$0.11	$0.00	$0.06
6.	EM&V	$0.12	$0.00	$0.06
7.	**Total Distribution - DR Program Incremental Funding**	$12.01	$15.02	$13.52
8.	FF&U	$0.14	$0.17	$0.15
9.	**Total Distribution Incremental DR Revenue Requirement**	**$12.15**	**$15.19**	**$13.67**
10.	**Generation - DR Program Incremental Funding**			
11.	SEP	$3.33	$0.00	$1.67
12.	CPP	$0.45	$0.45	$0.45
13.	**Total Generation - DR Program Incremental Funding**	$3.78	$0.45	$2.12
14.	FF&U	$0.04	$0.01	$0.02
15.	**Total Generation Incremental DR Revenue Requirement**	**$3.82**	**$0.46**	**$2.14**
16.	**TOTAL INCREMENTAL DR REVENUE REQUIREMENT**	**$15.97**	**$15.65**	**$15.81**

As shown on Line No. 9 of Table II-9 , SCE proposes to include the annualized Distribution DR Program incremental funding of $13.67 million in the Distribution incremental DR revenue requirement and consolidate into distribution rate levels each year of the two-year period starting in 2021.

As shown on Line No. 15 of Table II-9, SCE proposes to include the annualized Generation DR Program incremental funding of $2.14 million in the Generation DR revenue requirement and consolidate into generation rate levels each year of the two-year period starting in 2021.

Of the Generation DR Program incremental funding, $0.45 million as shown on Line No. 12 of Table II-9, is associated with the CPP marketing campaign to encourage customers to take action and reduce their energy usage when a CAISO Flex Alert, Alert, or Warning notice is issued. SCE did not request funding for this CPP marketing campaign in its 2021 GRC, and therefore the incremental funding is addressed in this proceeding. SCE proposes that the incremental CPP funding be recorded in the DRPBA, included in the Generation revenue requirement, and consolidated into Generation rates.

3. Ratemaking

SCE's proposed 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 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 because it is necessary to record for recovery purposes those DR Programs that are offered to, and thus whose costs are recovered from, both bundled service and departing load customers (i.e., Distribution sub-account), and bundled service customers only (i.e., Generation sub-account). Over the two-year period (2021-2022), any over- or under-collection recorded in the DRPBA for the DR Program will carry over to the next year.

SCE will include reasonableness review of the DRPBA recorded amounts associated with the 2021-2022 DR Program proposals in this proceeding in its 2023 Energy Resource Recovery Account (ERRA) Review proceeding. SCE will propose disposition of any over-collection associated with the

DR Program incremental funding remaining in the DRPBA at the end of 2022 in the ERRA Review proceeding. Entries recorded in the BRRBA are also reviewed in the ERRA Review proceeding.

III.

SCE'S RESPONSE TO CPP GUIDANCE QUESTIONS

The purpose of this Chapter is to provide SCE's response to staff's CPP design questions and certain questions regarding CPP expansion to non-IOU LSEs included with the December 18 ALJ Ruling. In Chapter II.B.8, SCE provides its proposal to increase customer participation in CPP.

A. CPP Design Questions

1. Several parties raised concerns that some CPP rate schedules have event windows that are not aligned with the net peak period. Should CPP rate schedules be adjusted such that their event windows be aligned with the net peak period? Please specify the rate schedules and the specific time frame of the adjusted event window (for example, 4pm-9pm)?

Since 2019, SCE's CPP event window has been 4pm-9pm;[49] therefore, SCE CPP event dispatches are during the net peak period.

2. Should CPP have a maximum number of events? Provide the pros and cons of removing the current maximum?

CPP should have a maximum number of call events. Increasing the number of events will potentially weigh program valuation against customer fatigue from being called too frequently. Reducing call duration may be a potential way to reduce the effects of customer fatigue while still retaining the overall coincidence of timing CPP events with SCE's peak periods. Because CPP is triggered based on the expectation of peak prices in wholesale energy markets, optimizing the number of call events to align with the frequency of such periods is important because it potentially increases the responsiveness of the DR program.

3. Should SCE and SDG&E be directed to offer CPP to residential customers, as PG&E does?

SCE already offers CPP to its bundled residential customers. CPP is an event-based time-of-use (TOU) rate schedule that is available to all bundled customers. All non-residential bundled

[49] On February 27, 2019 and March 22, 2019, SCE submitted Advice 3957-E and Advice 3957-E-A, respectively, modifying its rate factors and tariffs to implement the final decisions adopted by the Commission in SCE's 2016 Rate Design Window and 2018 GRC Phase 2 applications.

customers are defaulted on CPP, whereas bundled residential customers on a TOU Domestic (Schedule TOU-D) or a TOU Tiered Domestic (Schedule TOU-D-T) rate can opt-in to CPP.

4. Should Net Energy Metering (NEM) non-residential customers in SCE's and SDG&E's territories be allowed to participate in non-residential CPP? (For example, see PG&E's CPP tariff—Peak Day Pricing—which permits this.)

SCE's CPP allows NEM customers, residential and non-residential, to participate in CPP. See CPP Special Condition in each TOU tariff that states "Customers served under this Schedule are eligible for service under Net Energy Metering Schedules."

5. Should general-service customers with qualifying distributed energy resources be allowed to enroll in CPP in SCE and PG&E's territory? (For example, see SDG&E's rate schedule DG-R.)

SCE is unaware of any exclusions in CPP tariffs that do not allow customers with qualifying distributed energy resources to enroll or participate in CPP. CPP participants would be allowed to use distributed energy resources such as solar and energy battery storage in facilitating the customer's CPP performance down to zero.

B. <u>CPP Expansion to Non-IOU LSEs Questions</u>

5. Since CCAs' bills are collected through the IOU billing system, what billing system changes would the IOUs need to make to implement CPP rates for CCAs?

Assuming any approved CPP rate option and associated incentives and event charges for customers served by a CCA will be designed to capture such incentives, charges, and any awarded bill protection guarantees through the Generation component of rate factors, SCE believes there will be minimal billing system changes required.

SCE currently receives monthly CCA calculated generation costs and line item descriptions to be displayed on the customer's monthly billing statement via an Electronic Data Interchange. Considering the line item description is free form, SCE does not foresee any significant system changes or associated billing concerns. CCAs would be leveraging the same process to submit CPP-related incentives, event charges, and/or potential bill protection credits, as long as such cost components continue to be allocated to Generation and are appropriately identified by pre-existing charge codes.

SCE would not display any type of tracking or informational notes on the SCE bill statement. If any designed CPP rate has costs allocated to the Delivery component of the bill, SCE believes the complexity, number of system changes, and the development of new program and operational processes and procedures would increase significantly.

a) Is it feasible to implement these changes by summer 2021?

Yes, based on the assumptions noted above.

b) Are there interim billing solutions that could be administered by the IOUs or non-IOU LSEs, if changes to the IOU billing system are not feasible by summer 2021?

No interim billing solutions will need to be administered by SCE as long as the assumptions noted above are incorporated into any CPP rate option and the CPP-related incentives, rates, and program are administered by the CCAs. This includes, but is not limited to, exchanging pre-defined customer specific data and formatted interval usage, triggering events, providing proper notification, and/or adhering to eligibility and applicability rules defined in SCE's approved tariffs.

IV.

SCE'S RESPONSE TO DR-RELATED GUIDANCE QUESTIONS

The purpose of this Chapter is to provide SCE's response to several of staff's DR-related questions included with the December 18 ALJ Ruling, including questions regarding Proxy Demand Resources (PDR) in CAISO markets, DR performance improvements, cost-effectiveness, and expanding electric vehicle (EV) participation in DR programs. SCE's DR proposals are included in Chapter II of this testimony and address additional staff questions related to DR included with the December 18 ALJ Ruling.

A. PDR in CAISO Markets

10. For PDR resources that are procured for Resource Adequacy (IOU, DRAM and third-party non- DRAM PDR resources) and are able to dispatch only in response to CAISO Day-Ahead Market awards, should the CPUC adopt a bid price cap for these resources bidding in the CAISO Day-Ahead market for the purpose of increasing the probability of these resources being utilized and dispatched during periods of grid stress experienced in Real-Time Market? If so, what should that bid price cap be set at and why?

SCE does not recommend the Commission adopt a DA bid price cap for PDR resources at this time. In D.19-12-040, the Commission recently determined that a minimum dispatch requirement that includes a penalty structure is more effective than a bid cap in increasing Demand Response Auction Mechanism (DRAM) dispatch in the CAISO market, and thus declined to require sellers to offer PDR resources to the CAISO below a certain percent of the bid cap.[50] The requirements of that decision are scheduled to be implemented beginning with 2021 DRAM resources. It is prudent to allow this new requirement to take effect before revisiting the bid cap requirement that was recently considered and rejected.

11. What are the potential positive and negative consequences of the Day-Ahead market bid price cap?

Without properly vetting what the correct DA bid price cap should be, it is unclear whether a bid cap will lead to the most optimized dispatch of PDR resources. An "incorrect" bid

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[50] *See* D.19-12-040, pp. 17-23.

cap could result in resources being dispatch too quickly, potentially making them unavailable during the times of higher value. For example, resources with limited dispatches would not allow SCE to use opportunity costs to optimize dispatches, which would result in increasing costs to customers. Moreover, resources that bid at the contract price would not be able to fully recover their costs if the bid cap is below the contract price.[51] For these reasons, SCE is concerned that an "incorrect" bid price cap would not lead to more dispatches, but rather less optimal dispatches of PDR resources in the CAISO market.

B. DR Performance Improvements

12. Based on preliminary settlement data received by the CPUC, demand response resources (IOU and third-party operated) did not always deliver up to their commitments during the 2020 heat waves. This information will be made public in the Final Root Cause Analysis on the August 14 and 15 rotating outages that is anticipated to issue before end of 2020. Please provide:

a) Reasons for the results.

According to SCE's preliminary data, SCE's DR programs demonstrated strong performance and delivered crucial MW during the 2020 heat waves and possibly prevented additional outages from occurring or the need for additional MW during outage events. While Figure 4.5 of the Preliminary Root Cause Analysis report appears to indicate that the combined IOU DR allocation or RA credit received for the month of August was higher than CAISO preliminary settlement data (which is IOU bid data),[52] it is unclear which DR program or utility attributed to this difference. Program performance and solutions attempting to remedy differences should be evaluated by IOU and program, rather than averaged or aggregated across

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[51] Because the contracts for existing programs were established without a bid cap, there is a potential that the bid cap could be set at a level lower than the contract anticipated. Any change such as a bid cap should be introduced on a going forward basis for new contracts where the impact of the cap can be contemplated appropriately within the program design, including the contract with the third-party provider.

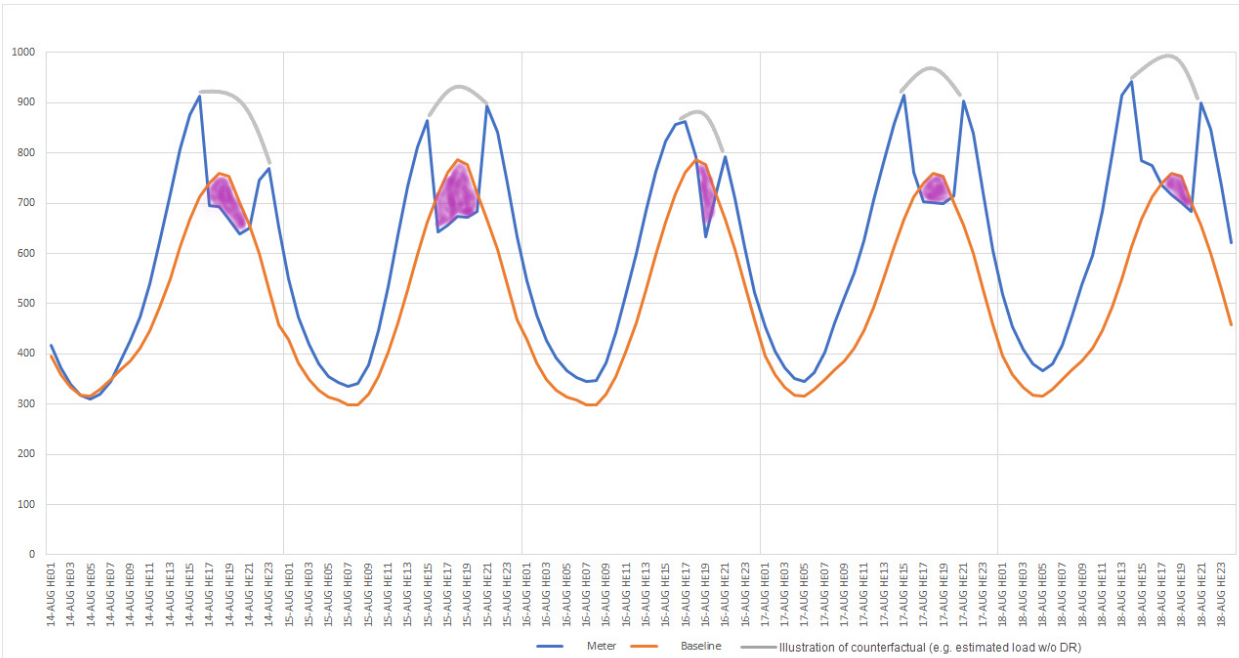
[52] *See* CAISO, Commission, CEC, Preliminary Root Cause Analysis, Mid-August 2020 Heat Storm, October 6, 2020, p. 54, available at: http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf.

all IOUs, otherwise changes that may resolve issues for one IOU program may cause issues for others.

SCE identifies the following differences in DR data:

- The IOUs' DR Load Impact Reports are used to determine a DR program's RA allocation for each month. DR Load Impact Reports use a regression analysis to determine a program's average load impacts, whereas CAISO settlements use a baseline calculation, such as a 10-in-10 or 5-in-10 baseline. These different methods will cause a difference in results.
- The CAISO included the 15 percent planning reserve margin adder and transmission and distribution losses to the RA allocations, but SCE's bids and meter settlements do not include those adders.
- Baselines used to calculate the wholesale market settlement under-represent the actual performance of SCE's DR resources. For example, in the illustration in Figure IV-1 below, the blue line illustrates the actual load of DR customers (the grey line is an estimate of what the load would have been if not for the DR event). The orange line is the CAISO baseline for those same customers. As the figure below demonstrates, the CAISO baseline (orange line) is biased because it relies on prior days' data where there were no dispatches and the temperatures were lower. The DO adjustment is intended to help adjust the baseline for weather differences but it is only limited to 20 percent, which is not enough to adjust the baseline to actual levels for these heat wave days.

Figure IV-1
Illustration of DR Program Meter Performance Versus CAISO Baseline Performance



The area above the blue line and below the orange line (the purple shaded region) is the calculated CAISO performance. The purple area dramatically undercounts the actual grid impacts that this DR program and resource provided, which is represented by the total area above the blue line and below the grey line.

In addition, on August 11, 2020, SCE provided the following response to CAISO Board of Governors member Borenstein's question "Are programs bidding in at their Resource Adequacy (RA) value?"[53] SCE provided the following written response to the CAISO:

> While the [DR] RA value is determined based on the year ahead forecast, SCE's market bids are based on the latest day ahead forecasts. These can differ for several reasons, including program enrollment, ambient temperature and customer loads, program design and capabilities, as well as CAISO integration issues.

[53] At the July 22, 2020 CAISO Board of Governors meeting, the Board of Governors voted on agenda item seven (7) "Decision on slow demand response and proxy demand resources proposal." During public comment, Board of Governors member Severin Borenstein requested information regarding DR studies and several other questions.

Program enrollment: SCE bids are updated for actual customer enrollment changes, if more customers enroll than forecast, bids will increase, or vice versa.

Temperature and loads: RA values are based on the 1-in-2 weather and load forecast, while SCE bids are based on the current weather and load conditions at the time of bid creation. For weather-sensitive programs, this translates into bids higher than RA value at times of higher temperatures (loads), and bids lower than the RA value at times of lower temperatures (loads).

Program design: The RA value is a single number for a given month based on the load impact studies and is generally an average of the forecast program capabilities over the CAISO's Availability Assessment Hours (AAH). SCE bids are over the full day and reflect the programs' capability over each hour – so to the extent there is a shape to the program capabilities, it will be reflected in the bids.

CAISO integration issues: While the CAISO has made great strides in improving the rules and modelling capabilities to integrate DR resources, there are still many areas where the Scheduling Coordinator (SC) has to make imperfect choices – i.e. the CAISO models and rules do not allow for fully accurate resource registration. As such, SCs have to make trade-offs, which can result in market bids being lower than the actual resource capabilities.

b) Solutions that address the reasons you provide.

One solution to this issue would be an evaluation of the impact and difference between the load impact protocols and settlements baselines. See Chapter II.B.10 for SCE's EM&V proposal.

C. <u>Cost-Effectiveness</u>

13. IOU DR programs are required to demonstrate cost-effectiveness using the methods described in the Demand Response Cost-Effectiveness Protocols. Considering the acute reliability needs being considered in this proceeding, should the CPUC waive cost-effectiveness analyses and requirements for any DR program changes that might be ordered in this proceeding? Please provide a rationale for your position.

Generally, SCE is very supportive of the Commission only approving programs that are cost effective and beneficial to customers. However, SCE supports the Commission waiving cost-effectiveness analysis as the DR Reporting Template and DR Cost-Effectiveness Protocols have not been updated to reflect the latest avoided cost and cost-effectiveness updates. SCE does not support using the existing DR Reporting Template and DR Cost-Effectiveness Protocols for these proposals.

D. Expanding EV Participation in DR Programs

1. Should the CPUC revise EV programs and/or incentives designed to manage and/or dispatch EV loads in order to respond to a reliability event in Summer 2021?

- ***If so, what program, rate, or incentive should be revised and how?***
- ***Should these revisions be offered to all EV customers, or would offering them to a subset be sufficient to achieve reliability objectives?***
- ***Please provide examples or data to justify your proposal, including any examples of EV participation in a similar program or incentive, as well as estimated impacts for Summer 2021 reliability.***

SCE believes that DR should be end-use and technology neutral to the extent capacity goals and cost-effectiveness can be achieved through a neutral program. Technology-specific programs should be pursued in those cases where a specific technology offers a unique service and reflects unique cost savings that are not being accounted for in existing programs. Currently, EV customers are eligible to participate in multiple DR programs or pilots such as CBP, DRAM, and SCE's Charge Ready DR pilot (CRDRP).[54] Due to the limited time available and because of the planned expansion of Charge Ready 2 EV participation in SCE's CRDRP and all the other available DR programs, SCE recommends encouraging EV customers to participate in existing DR programs rather than exploring or creating short-term measures to expand EV participation. SCE will continue to explore and evaluate solutions that encourage EV participation in DR activities.

[54] SCE Advice 4244-E requests Commission approval to extend the CRDRP through 2022 and specifies that Charge Ready 2 customers, authorized in D.20-08-045, will be eligible to participate in the ongoing pilot until implementation of a full-scale DR program in 2022.

V.

SCE'S RESPONSE TO STAFF PROPOSAL ON FLEX ALERT PAID MEDIA CAMPAIGN

The purpose of this Chapter is to provide SCE's response to the Energy Division staff proposal on a Flex Alert Paid Media Campaign included with the December 18 ALJ Ruling, including the staff questions on the proposal.

1. Should the CPUC direct an IOU to develop a new contract with the existing time-of use Statewide Marketing, Education and Outreach vendor, or direct an IOU to develop a solicitation to competitively source a new vendor?

Should the Commission adopt the Energy Division staff proposal for a Flex Alert Paid Media Campaign for summer 2021 and 2022, considering the limited time to implement a marketing campaign and activities for summer 2021, SCE recommends that each IOU use their own media agencies to implement the statewide Flex Alert Paid Media Campaign. The IOUs will work in coordination with the Commission, the CEC, and the CAISO to develop common messages. This approach is similar to the statewide Public Safety Power Shutoffs (PSPS) campaign that allowed the IOUs to work with their own agencies to maximize local expertise.[55] This approach will better allow the IOUs to provide support during any grid emergency by summer 2021.

SCE notes that the Commission may need to address how authorizing IOU ratepayer funding in this proceeding for a Flex Alert marketing campaign comports with D.13-04-021, Finding of Fact 8, which states: "It is logical that the entity controlling the Flex Alert program also be responsible for administering and securing funding for the program, and that the funding is provided by all customers who benefit from the conservation and load reduction due to Flex Alerts, not just the ratepayers of the investor-owned utilities."

2. Should the contract be for at least two summers (2021 and 2022) or should it be longer?

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[55] *See* D.19-05-042.

SCE supports funding the Flex Alert marketing campaign for at least two summers (2021 and 2022) using its own media agencies. If the Commission does not adopt SCE's proposal to use its own media agencies, SCE recommends using the existing TOU statewide ME&O vendor, DDB Worldwide Communications Group, Inc., for 2021 only. After the summer of 2021, the Commission should evaluate the effectiveness of the campaign so that improvements can be made for the summer of 2022 and a competitive solicitation can be performed. Because there is more time to determine appropriate funding for 2023 and beyond, SCE recommends that the Commission assess the impact of the 2021 and 2022 Flex Alert campaigns and then determine the appropriate funding level for 2023 based on the results of the assessment.

3. What should be the campaign priorities and strategies for the new Flex Alert program, and what budget estimates seem reasonable to address those priorities?

SCE recommends a coordinated study and analysis between the IOUs, the CAISO, and the Commission to establish a baseline understanding of customer awareness of Flex Alert and existing program outreach prior to setting new priorities and strategies for the proposed Flex Alert campaign. Developing recommendations for the proposed campaign based on data and insights will lead to the most effective use of funds and resources. Absent a baseline study and insights, Flex Alert campaign priorities and strategies should focus on a call to action asking Californians to reduce load on critical days. SCE envisions that the Flex Alert campaign could continue to focus on broad communications to all Californians to raise awareness of the need to conserve energy during the Flex Alert, while the IOUs will continue to focus on targeted notifications to their customers with specific calls-to-action applicable to the customer and the IOU service territory.

SCE recommends that Flex Alert campaign messaging should be carefully coordinated with the IOUs' messages in addition to CAISO's messages. When the CAISO issues a Flex Alert, SCE will send targeted emails and texts messages to its customers notifying them of CAISO's Flex Alert and asking customers to conserve energy during the Flex Alert period. Using this approach will minimize confusion that may result from receiving multiple, redundant emails or texts from SCE and the Flex Alert vendor.

SCE supports Energy Division staff's proposal to determine the annual budget through consultation with the stakeholders,[56] and suggests a budget allocation that is appropriate for a social media and texting marketing tactics. SCE estimates a budget of $4 million to $5 million within SCE's service territory is needed for the campaign to achieve broad awareness, with no more than five percent of that budget allocated toward paid social media advertising. This is aligned with staff's proposed $12 million statewide for the entire Flex Alert Campaign.[57]

4. What should the cost recovery mechanism be for funding the Flex Alert campaign?

SCE recommends tracking and recording its funding portion for the Flex Alert marketing campaign in SCE's Statewide Marketing, Education, and Outreach Balancing Account (SME&OBA) and recovered through the Public Purpose Programs Charge (PPPC) rate, which is consistent with cost recovery for Flex Alert funding for 2013, 2014, and 2015.

5. How could the Flex Alert campaign be integrated with DR programs and smart thermostats?

SCE does not recommend that the Flex Alert campaign be integrated with DR programs and smart thermostats. As discussed above, SCE recommends that the Flex Alert campaign should focus on broad conservation messages while SCE provides direct targeted messaging. SCE does not recommend that any of the Flex Alert campaign notifications provide specifics on any one DR program. SCE is concerned about creating confusion for DR customers who receive a Flex Alert campaign message and prematurely take action which may create an incorrect expectation that they will receive a DR program incentive. Currently SCE's DR programs have unique methods of notifying participating customers and those communication

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[56] *See* December 28 ALJ Ruling, Attachment 1, p. 2.
[57] *See id.*

methods have proved to be effective. Sending multiple direct messages could cause customer confusion.

However, the Flex Alert campaign can include secondary messages which encourage customers to enroll in a DR program to earn incentives during future conservation events.

6. If the CPUC authorizes a new emergency load reduction program (ELRP) how would the Flex Alert paid media campaign interface with it?

SCE does not recommend co-marketing Flex Alert with DR programs or vice versa. DR programs serve a specific purpose and have specific program parameters and obligations, whereas Flex Alert is a public outreach campaign which calls for energy conservation.

VI.

SCE'S EXPEDITED PROCUREMENT PROPOSAL

A. Introduction

SCE puts forward the following proposal to provide impactful, dependable benefits to grid reliability during peak and net peak periods in the summer 2021 and 2022. SCE supports IOU procurement of incremental firm energy imports on behalf of all customers in their service territories pursuant to the CAM, but seeks to ensure that such imports are incremental to the imports that would already be procured to meet LSEs' RA compliance requirements and provide additional reliability benefits for the grid.

B. Firm Imports Procurement Proposal

The January 8 PD already directs the IOUs to seek CAM procurement on behalf of all customers in their service territories for summer 2021.[58] Unlike the December 28 ACR,[59] the January 8 PD does not include firm forward energy imports among the resource types to be considered for procurement and instead states that while "swift action is needed to ensure firm forward energy contracts can be executed for summer 2021," such import procurement will be considered in a subsequent decision in this proceeding.[60]

SCE generally supports the January 8 PD and agrees that procurement of firm energy imports is a promising method for expediting procurement of incremental supply for the CAISO system because there is limited time to develop new resources before summer 2021. That said, procuring additional imports without having certainty on available intertie capacity may result in energy that will not provide additional reliability benefits. In particular, IOU procurement of firm forward energy imports before knowing how much intertie capacity will already be used for RA procurement in the summer months could lead to inadvertent cannibalization of the same imports that would already have been procured by other LSEs under the RA program and/or may

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[58] *See* January 8 PD, pp. 1, 11-12, OP 1-2.
[59] *See* December 28 ACR, p. 4.
[60] January 8 PD, pp. 4, 11.

be on a congested tie and not provide incremental energy to the CAISO system when needed. It would be difficult to determine whether imports procured before the monthly RA showings for summer 2021 are incremental and would actually enhance grid reliability by increasing supply for the CAISO system.

To address these concerns, the Commission should authorize the IOUs to procure firm energy imports on behalf of all customers in their service territories under the CAM at the conclusion of LSEs' month-ahead RA showings for summer 2021 and 2022, to the extent Maximum Import Capability (MIC) capacity is available. Available MIC should be allocated to each IOU based on the Transmission Access Charge load share of each IOU. For example, at the conclusion of the month-ahead RA showings, beginning in April for June compliance, it will be certain how much of the MIC for the month was utilized by LSEs to meet their RA requirements. If the MIC has not been fully utilized, then the probability of firm energy imports being feasible (i.e., less likely to face congestion to deliver energy within California) is high. In such a case, the IOUs could procure firm energy imports (if available and reasonable) up to the available MIC amount through best efforts with assurance that such imports would not displace RA procurement by LSEs. Additionally, other than the fact the energy was procured beyond the RA filing deadline, these imports would satisfy the Commission's RA compliance rules for imports.

The IOUs could also target their procurement at points where available intertie capacity exists. By waiting until after the RA showings beginning in April 2021 (for June 2021 compliance), the IOUs would be able to ascertain the true unused intertie capacity by tie-point, and procure accordingly, knowing the incremental firm energy imports will be less likely to displace RA resources on the tie when needed during peak and net peak demand hours.

As with the procurement authorized in the January 8 PD, the IOUs' procurement under this proposal would be done on behalf of all customers in their service territories with the costs and benefits allocated to all benefitting customers through the CAM and recorded and recovered via the New System Generation Balancing Account (NSGBA).

The timing of this proposed procurement would not allow for Commission approval through an advice letter process. This import procurement is for reliability purposes and would be authorized for CAM cost recovery and should be deemed per se reasonable and pre-approved if procured consistent within volume limits bounded by the remaining allocated MIC, otherwise consistent with the applicable IOU's Bundled Procurement Plan, and the import meets the requirements for RA imports pursuant to D.20-06-028.[61]

[61] Pursuant to D.20-06-028, a resource-specific import shall count towards RA requirements provided: (1) the resource is either pseudo-tied or dynamically scheduled into the CAISO DA and real-time markets; and (2) the LSE provides a resource-specific resource ID in its RA filing that is listed on a matching CAISO supply plan and on the Commission's Net Qualifying Capacity list. *See* D.20-06-028, OP 1. A non-resource-specific import shall count towards RA requirements provided: (1) the contract is an energy contract with no economic curtailment provisions; (2) the energy must self-schedule (or in the alternative, bid in at a level between negative $150/MWh and $0/MWh) into the CAISO DA and real-time markets at least during the Availability Assessment Hours throughout the RA compliance month, consistent with the MCC buckets; and (3) the energy must be delivered to the LSE in accordance with the governing contract, consistent with the MCC buckets. *See id.*, OP 2. Additionally, the non-resource-specific import energy contract must include: (1) (a) the price denominated in $/MWh or $/kWh, (b) the quantity delivered per hour, and (c) the delivery period; (2) the counterparty of the energy contract must be the LSE and the energy must be delivered and sold to the LSE; and (3) a requirement that the import is not sourced from resources internal to the CAISO Balancing Area. *See id.*, OP 3. Lastly, both resource-specific and non-resource-specific RA imports must be paired with an import allocation right. *See id.*, OP 5.

VII.

SCE'S RESPONSE TO PROCUREMENT-RELATED GUIDANCE QUESTIONS

The purpose of this Chapter is to provide SCE's response to staff's questions regarding expedited Integrated Resource Planning (IRP) procurement included with the December 18 ALJ Ruling.

- ***Should the CPUC offer an incentive to LSEs that voluntarily expedite their 2021 IRP procurement to come online by Summer 2021 (i.e., approximately 6-8 weeks sooner than the August 1st requirement)? For LSEs that support this proposal, please specify the project, resource type, and amount of MW that could be expedited.***
    - ***How should this process be implemented?***
    - ***How should the incentive amount be determined, and how should the costs of the incentive be allocated?***
    - ***Should this proposal be limited to procurement for Summer 2021, or should it also include Summer 2022 and 2023?***

SCE does not support providing additional incentives for expedited IRP procurement for the reasons stated below.

First, there are sufficient incentives for contracted resources to come online prior to August 1, 2021. Given the tightness in the RA market for 2021, market prices for July capacity and energy are projected to be high and provide sufficient incentive for resources to come online and bid into the market. Providing additional financial incentives would add unnecessary costs to customers. SCE's resources contracted pursuant to D.19-11-016 are not prohibited from coming online early to provide incremental capacity prior to August 1, 2021. Indeed, these resources are already incentivized to come online and participate in the market in early June to provide RA on August 1, 2021.

Second, SCE does not believe there is time to complete the development of a new incentive mechanism, as well as determine and approve its pricing and cost allocation, in time to have an impact on procurement for June and July 2021. Such incentives can be challenging to implement without creating inequities and/or distortions in pricing or procurement processes (e.g., demonstration that but for the incentive payment, the resource would not have come online earlier). Such details would have to be fully examined and approved before any negotiations or structuring of contracts could even be contemplated. SCE is concerned a new incentive mechanism, hastily implemented, could unnecessarily introduce distortions to the RA process and create unnecessary costs to customers.

Finally, August and September are the most critical months to focus on for reliability and acceleration of online dates to June and July will only provide marginal benefit. SCE's 2021 Loss of Load Expectation study determined that with the 1,650 MW of capacity procured by LSEs pursuant to D.19-11-016, the 1-in-10 reliability standard is met for 2021.[62] Within that study, the days of potential loss of load were concentrated in August. From an RA compliance standpoint, September remains the most challenging month for LSEs. Developing a new incentive program solely to incentivize June and July procurement would have marginal impacts on addressing net peak load events during summer 2021. The Commission should consider focusing efforts on other mechanisms to improve reliability, including SCE's proposal to procure imports after LSEs' monthly RA showings as discussed in Chapter VI.

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[62] *See* Southern California Edison Company's (U 338-E) Comments on Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021, R.20-11-003, November 30, 2020, pp. 16-17, Appendix A.

Appendix A

Witness Qualifications

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 Demand Response Products team within the Customer Programs and Services department at SCE. 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 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.

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. 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. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

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 2244 Walnut Grove Avenue, Rosemead, California 91770.

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

A. I am currently a Regulatory Advisor in the State Regulatory Operations Revenue Requirement and Forecast Department. My primary responsibility is to manage and support the cost recovery and ratemaking mechanisms to ensure costs are properly recorded and recovered through rate levels in accordance with Commission 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 Masters 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 SCE in 2002. I joined the State 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 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. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF GRANT LITTMAN

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

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

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

A. I am a Principal Manager of Marketing and Digital at SCE. I lead a team responsible for SCE’s marketing communications and the digital customer experience associated with Customer Service programs, rates, and services. I have held this position since March 2018.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Science in Business Administration degree from the University of Southern California. I have worked at SCE for approximately 14 years in Customer Service and Corporate Communications. Prior to my present position, I was a Senior Manager of Digital. In that position, I was responsible for a team that oversaw digital strategy, content management, digital products, and digital analytics. From 2010-2011, I was the Senior Manager of SCE’s Corporate Communications Web team responsible for the strategic planning, governance and day-to-day operations of the three core Edison International websites: edison.com, sce.com, and the enterprise intranet. Prior to that, I joined SCE in 2007 as the Senior E-Channel Manager, responsible for establishing a new functional area within the Customer Experience Management department focused on the development of SCE's digital self-service channels. Prior to joining SCE, I worked at Epson America, Inc. for 10 years in a variety of marketing and product management positions, ultimately leading that company's North America direct-to-consumer e-commerce business.

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. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.