Decision 21-03-056 March 25, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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.	Rulemaking 20-11-003

DECISION DIRECTING PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY TO TAKE ACTIONS TO PREPARE FOR POTENTIAL EXTREME WEATHER IN THE SUMMERS OF 2021 AND 2022

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DECISION DIRECTING PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY TO TAKE ACTIONS TO PREPARE FOR POTENTIAL EXTREME WEATHER IN THE SUMMERS OF 2021 AND 2022

Summary

Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are directed to take specific actions to decrease peak and net peak demand and increase peak and net peak supply to avert the potential need for rotating outages that are similar to the events that occurred in summer 2020 in the summers of 2021 and 2022. These actions are outlined in detail in Attachment 1 to this decision.

A Flex Alert paid media campaign program is authorized to encourage ratepayers to voluntarily reduce demand during moments of a stressed grid in California. Modifications to the Critical Peak Pricing program are instituted to ensure that the program is more effective and aligned with the times of need.

We establish an Emergency Load Reduction Program as another tool that can provide emergency load reduction and serve as an insurance policy against the need for future rotating outages. Modifications to the existing demand response programs are instituted to make the programs more effective and more aligned with grid needs.

Modifications to the planning reserve margin are instituted to provide a more appropriate reserve for electricity capacity supply side resources during the moments the grid is most stressed. We continue authorizations for supply side procurement to ensure adequate capacity is procured and secured to avert the potential for rotating outages.

We discuss how electric vehicle deployment may integrate into the demand side programs developed in this decision.

1. Background

On November 19, 2020, the Commission instituted this rulemaking. A prehearing conference was held remotely on December 15, 2020, and a scoping ruling was filed and served in this proceeding on December 18, 2020.

On December 11, 2020, the assigned Administrative Law Judge (ALJ) issued a ruling that identified the potential need for additional capacity to be procured by summer 2021 and sought comments from parties on the parameters the Commission could set on such procurement to deem it per se reasonable. On December 18, 2020, numerous parties to this proceeding filed comments in response to the December 11, 2020 ruling.

Additionally, on December 18, 2020, the assigned ALJ issued a ruling that contained a staff proposal and guided questions that relate to issues scoped into this proceeding. Parties were directed to address the staff proposal and questions in their opening and reply testimony served to parties in this proceeding.

On December 28, 2020, President Batjer issued an Assigned Commissioner Ruling (ACR) directing the large electric investor-owned utilities (IOUs) to seek contracts for capacity available for the peak and net peak demand in summer 2021 or summer 2022 and set parameters for that procurement and provided guidance on submitting the resulting contracts to the Commission for approval.

On January 8, 2021, the assigned ALJ mailed a proposed decision that addressed the same issues as the ACR and refined the issues to focus on capacity procurement for the summer of 2021 only. The Commission adopted Decision (D.) 21-02-028 on February 11, 2021.

Parties served opening testimony on the service list of this proceeding by January 11, 2021, and reply testimony was served by January 19, 2021.

Opening briefs were filed on February 5, 2021, and reply briefs were filed on February 12, 2021.

A Final Oral Argument was held on March 19, 2021 before a quorum of Commissioners.

2. Issues Before the Commission

This decision addresses two main issues: how to decrease energy demand and increase energy supply during peak demand and net demand peak hours in the event that an extreme heat event similar to the August 2020 event occurs in the summer of 2021 or 2022. More specifically, addressed in this decision are the following scoped issues:

1. Flex Alert program authorization and design
2. Modifications to and expansion of Critical Peak Pricing (CPP) Program
3. The development of an Emergency Load Reduction Program (ELRP)
4. Modifications to existing demand response (DR) programs
5. Expedited Integrated Resource Plan (IRP) procurement
6. Modifications to the planning reserve margin (PRM)
7. Parameters for supply side capacity procurement
8. Expanded electric vehicle participation

In addition to the issues enumerated, the umbrella issues of (1) safety, (2) reliability, (3) load and supply impact, and (4) cost allocation are addressed.

3. Flex Alert

This decision adopts a Flex Alert paid media campaign program to be in place for the summer of 2021. With consideration of the totality of the record, the parameters of the adopted Flex Alert program are outlined in Attachment 1 of this decision.

3.1 Background of the Flex Alert Proposal

The December 18, 2020 ruling in this proceeding contained a staff proposal for the program authorization and design of a paid media Flex Alert campaign program with the following characteristics:

- Electric IOUs participation in a paid media Flex Alert campaign using ratepayer funds for the purpose of mitigating the need for rotating outages;
- Contract management would occur through a contract between one electric IOU and a marketing agency;
- Solicitations for marketing vendors would occur in the early spring of 2021 with the intention of launching the program for the summer of 2021; and
- The contract would be in place for the summers of 2021 and 2022.

The December 18, 2020 ruling proposed parameters regarding budget, administration, content and delivery channels, oversight, and the interface with other programs. That ruling also posed six specific questions to the parties of this proceeding to address in opening and reply prepared testimony. Numerous parties addressed this proposal and the associated questions in their opening and reply prepared testimony that was admitted to the evidentiary record of this proceeding.

3.2 Party positions on the Flex Alert Proposal

There is support in the evidentiary record for the implementation of a Flex Alert paid media campaign to be authorized in this decision for the summers of 2021 and 2022.

The California Independent System Operator (CAISO) indicated support for the Commission directing the implementation of a paid media Flex Alert program. It indicated a Flex Alert program would

> educate consumers regarding the positive impacts of conservation, help them understand grid conditions and inform consumers when conservation is needed because electricity supplies are short. Long-term support and funding of the program can establish and sustain a trusted brand and consumer tool that is essential to overall grid reliability. An ongoing consumer awareness and participation program that reaches millions of California consumers each year is an essential part of reaching our collective clean energy goals.[1]

SCE supports the implementation of a Flex Alert paid media campaign. Southern California Edison Company (SCE) recommends that the IOUs be authorized to use their own media agencies to implement a paid media Flex Alert campaign.[2] SCE also supports developing a study that assesses the baseline awareness of Flex Alert.[3]

SCE indicated in testimony that if the Commission does not adopt the direction for the IOUs to utilize their existing media agencies, SCE recommends that the contracting go to the existing time of use statewide marketing education and outreach vendor, DDB Worldwide Communications Group, Inc. (DDB San Francisco) solely for the 2021 implementation.[4] It then recommends that for 2022 the Commission should evaluate the effectiveness of the 2021 implementation and focus on a competitive solicitation for 2022 and future implementations.[5]

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[1] Exhibit CAISO-1 at 7.

[2] Exhibit SCE-1 at 44.

[3] Exhibit SCE-1 at 45.

[4] Exhibit SCE-1 at 45.

[5] Exhibit SCE-1 at 45.

"SCE estimates a budget of $4 million to $5 million within SCE's service territory is needed for the campaign to achieve broad awareness. This is aligned with staff's proposed $12 million statewide for the entire Flex Alert Campaign."[6]

Pioneer Community Energy supports the development of a Flex Alert paid media campaign for the summers of 2021 and 2022. Pioneer Community Energy supports a contract length of "two years (with a performance clause option to cancel after 1 year) because Pioneer believes the capacity shortages will continue into 2022."[7] Pioneer Community Energy asserts that the Commission's "staff's recommendation of $12 million for a statewide campaign seems reasonable (about one-half of the [current budget for] Marketing, Education, and Outreach)."[8]

Pacific Gas and Electric Company (PG&E) proposed that the campaign be funded from the Statewide Marketing, Education and Outreach Expenditure Balancing Account.[9] SCE recommended "tracking and recording its funding portion for the Flex Alert marketing campaign in SCE's Statewide Marketing, Education, and Outreach Balancing Account and recovered through the Public Purpose Programs Charge rate, which is consistent with cost recovery for Flex Alert funding for 2013, 2014, and 2015."[10] San Diego Gas & Electric Company (SDG&E) proposed that tracking and recording its portion of the funding for the Flex Alert marketing campaign be handled through SDG&E's Advanced Metering and DR Memorandum Account, collected through distribution rates

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6 Exhibit SCE-1 at 46.

7 Exhibit PIO-1 at 2.

8 Exhibit PIO-1 at 2.

9 Exhibit PGE-1 at 1-13.

10 Exhibit SCE-1 at 46.

via the Rewards and Penalties Balancing Account, in line with other SDG&E DR activities. The DR Coalition states that funding for the Flex Alert campaign should come from the IOUs' DR program budgets and the associated cost recovery mechanisms.[11]

There was not strong opposition to the establishment of a paid media Flex Alert program in this proceeding, although California Large Energy Consumers Association (CLECA) expressed some concern about cost allocation.

> While Flex Alerts are clearly useful in encouraging conservation, when there is a statewide reliability challenge for the CAISO-controlled grid it is inequitable for only customers served by the IOUs to pay for these media announcements. Customers of all load-serving entities (LSEs) served by the CAISO grid should pay for the messaging and indeed all receive the messaging. The Flex Alert program is managed by the CAISO, and the cost of the program should be recovered in its grid management charge. The [California Public Utilities Commission] (CPUC) and the CAISO should coordinate any necessary enhancements to the Flex Alert Program.[12]

SDG&E indicated its position on the record about the timing involved with implementation. "While SDG&E's preferred practice for a project of this scale is to solicit a vendor through a competitive bidding process, SDG&E recognizes there may not be enough time to thoughtfully and accurately complete a request for proposal process, onboard a new vendor, and develop an effective Flex Alert campaign strategy and related assets in order to launch in the summer of 2021."[13]

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[11] Exhibit DRC-1 at 11.

[12] Exhibit CLECA-1 at 4.

[13] Exhibit SDGE-2 at 2.

3.3 Adopted Flex Alert Direction

The adopted Commission direction and guidance for the directed paid media Flex Alert campaign program is included in Attachment 1 of this decision.

Based on the record, we find that it is in the public and ratepayer interest to direct the implementation of a statewide Flex Alert program available for the summers of 2021 and 2022. As outlined in Attachment 1, due to the immediate need for program planning and administration to begin in time for summer 2021, SCE shall develop a new contract with the existing time-of-use Statewide Marketing, Education and Outreach vendor DDB San Francisco. SCE shall create a 2-year contract and conduct a performance assessment during year two (2022) and shall provide the assessment to stakeholders through the service list as well as to Energy Division. The contract shall be executed within 30 days of the effective date of this decision to allow for adequate program implementation for the 2021 summer months. Given the complexity of the implementation and tight timing, SCE is directed to coordinate with the Commission's Energy Division throughout the contracting, implementation, and program administration.

SCE, PG&E, and SDG&E are directed to fund the paid-media Flex Alert campaign with funds collected from all benefitting customers (*i.e.*, bundled IOU, community choice aggregator (CCA), and Direct Access customers) using Public Purpose Program balancing accounts. Further, this decision authorizes a budget of $12 million per year, for two years, to support the Statewide Flex Alert Paid Media campaign. As requested by PG&E in its opening comments, up to 3% of the annual Flex Alert budget is authorized to cover IOU administration costs.

4. Critical Peak Pricing

This decision adopts modifications and expansions to the CPP program, to be in place for the summer of 2021. With consideration of the totality of the record, the parameters of the adopted modifications and expansions to CPP are outlined in Attachment 1 of this decision.

4.1 Background

CPP is a retail rate mechanism whereby a utility or LSE charges a higher price for consumption of electricity during peak hours on selected days, referred to as critical peak days or event days. Currently the three large electric IOUs all have active CPP programs, although the design elements for each individual large electric IOU differ.

The December 18, 2020 ruling in this proceeding contained specific questions regarding a potential modification and expansion of the CPP program that parties were directed to address in their prepared testimony. The questions posed in the ruling included elements of program design, marketing and education, budgetary issues, and non-IOU LSE issues.

This decision adopts modifications and expansions to the CPP program, to be in place for the summer of 2021. With consideration of the totality of the record, the parameters of the adopted modifications and expansions to CPP are outlined in Attachment 1 of this decision.

4.2. Party Input and Positions on Expansion and Modification of CPP

Numerous parties provided input and insight into how CPP could be modified and expanded to more effectively align with the times and conditions when the grid most needs the associated load reduction.

The issue of event window timing and days of availability was raised in the prepared testimony of many parties. The CAISO, for instance, in concurrence with CLECA, stated that it believes all CPP event windows should be at least from 4:00 PM to 9:00 PM to address the net peak period.[14] The CAISO also indicated it believes that CPP should be available on weekends.[15] SCE indicated that it would like to include holidays and weekends but indicated that complexity of modifications to its billing system will prevent this modification from occurring quickly.[16] PG&E conversely indicated that it is not possible to make any other changes from what it has already planned for 2021.[17] SDG&E states that it cannot make the time change in 2021 due to its billing system upgrade and references Advice Letter (AL) 3667-E, which provides further details.[18]

The CAISO[19] and Small Business Utility Advocates (SBUA)[20] both also asserted that there should be no maximum number of days that the events can be called, and CAISO believes that the large electric IOUs should be given more flexibility on the use of CPP.

PG&E took a different position, asserting that removing the limitation on the number of the days the program can be called is not necessary because even with the high heat conditions experienced in 2020, it was able to dispatch the program for those conditions and not hit its max of 15 annual events.[21] PG&E also cites customer fatigue and negative bill impacts as reasons to not remove the

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14 Exhibit CAISO-1 at 10 and Exhibit CLECA-1 at 4.

15 Exhibit CAISO-1 at 11.

16 Exhibit SCE-1 at 28.

17 Exhibit PGE-2 at 2-1.

18 Exhibit SDGE-2 at 5

19 Exhibit CAISO-1 at 11.

20 Exhibit SBUA-1 at 7-8.

21 Exhibit PGE-1 at 2-6.

limitation on the number of days the CPP events can be called. Cal Advocates also asserts that a cap on the number of days that CPP may be called should remain in place, citing the uncertainty of a CPP program that may be called limitlessly.[22]

SCE proposes to spend and recover $450,000 to educate customers on how to perform better during CPP events.[23] Cal Advocates indicated its position in prepared testimony that the Commission should not increase CPP-related marketing fund authorization because CPP is the default rate for eligible non-residential customers.[24] Cal Advocates argues the Commission should focus such funds on increasing residential participation in CPP-related programs.

PG&E asserted that removing the default nature of its CPP program implementation in favor of an opt-in program would make CPP more effective.[25] PG&E requests authorization to recover $500,000 to educate customers about an opt-in implementation of CPP. Solar Energy Industry Association (SEIA) opposes opt-in for large customers but suggests it may be appropriate for small business customers.[26] Cal Advocates indicates a position that funding for customer education is not necessary because the program is currently a default program.[27]

Parties also addressed issues surrounding the implementation of CPP for customers who take generation service from a non-IOU LSE, like a CCA or direct access provider. CalCCA, Pioneer Community Energy, SDG&E, and SCE all

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[22] Exhibit CA-1 at 1-3.

[23] Exhibit SCE-1 at 28.

[24] Exhibit CA-1 at 1-9.

[25] Exhibit PGE-1 at 2-1 and 2-2.

[26] Exhibit SEIA-1 at 14.

[27] Exhibit CA-1 at 1-9.

provided significant insight in testimony about the barriers and potential values that might come from CPP implementation for non-IOU LSEs.

CalCCA put forth a number of challenges for CCAs in implementing CPP. It shared that the CCA Clean Power Alliance found little response for customers to limited mass marketing and other outreach.[28] It also shared that it has been difficult to receive the appropriate interval data from the IOUs to perform the necessary calculations.[29] It also identified hesitations about lessons learned from the implementation of CleanPowerSF's CPP program, namely that customers had concerns about bill protection.[30]

Pioneer Community Energy expressed concerns related to revenue that might occur from the implementation of a non-IOU LSE CPP program.[31] It also indicated that the technical requirements for a CCA to implement CPP is complex, would require significant technical modifications, and would go through a lengthy board approval process.[32]

Numerous parties in their opening comments provided input regarding the CPP program modifications. CAISO supported changing the CPP window to 4:00 pm to 9:00 pm and increasing the event calls to 15.[33] Joint Solar Parties, in their opening comments, recommended that the CPP program be expanded to allow participation by (1) all residential net energy metering customers, and

[28] Exhibit CCCA-1 at 28.

[29] Exhibit CCCA-1 at 26.

[30] Exhibit CCCA-1 at 25.

[31] Exhibit PIO-1 at 6.

[32] Exhibit PIO at 9-10.

[33] CAISO Opening Comments Page 2.

(2) commercial and industrial customers on optional rates.[34] PG&E recommended a revision to grant the funding necessary to enable PG&E to implement the 4:00 pm to 9:00 pm event hours in time for Summer 2022. PG&E argued that work to revise the PDP hours is complex, unplanned, and difficult to implement. PG&E requested a modification to authorize incremental funding for implementation and requested authorization for a budget of $2 million in order to implement the new PDP event hours of 4:00 pm to 9:00 pm, including IT, billing, and administrative costs. PG&E also requested that the surcharge and credit changes related to potential event hours in the 4:00 pm to 9:00 pm event window be addressed and approved in a Tier 2 Advice Letter or in a rate design proceeding.[35] SCE requested deferral of the requirement to include weekends and holidays in its CPP program until June 1, 2022. SCE argued that implementing this change for summer 2021 would require expensive manual billing solutions if this requested modification is not adopted, estimating costs to reach $14 million per year in lieu of system enhancements.

Both PG&E and SCE also requested additional funding for customer outreach. PG&E requested authorization to augment the $500,000 authorized for outreach (intended to support customer participation) by an additional $135,000 to educate customers about the new PDP event hours of 4:00 pm to 9:00 pm, for a total of $635,000 to provide customer support to increase the load response produced by the PDP program.[36] SCE stated that in 2021, it needs a total of $500,000 to educate customers to improve their CPP performance and to notify them that the CPP event maximum will increase to 15 events per year. In 2022,

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[34] Joint Solar Parties Opening Comments at Page 2.

[35] PG&E Opening Comments at Page 14.

[36] PG&E's Opening Comments at Page 15

SCE will need an additional $500,000 to educate customers and notify them that weekends and holidays have been added as potential CPP event days.[37] Some parties also addressed issues surrounding the implementation of CPP for customers who take generation service from a non-IOU LSE, like a CCA or direct access provider. CalCCA, in its opening briefs stated that it is unlikely that CCAs will be positioned to implement or expand CPP programs for Summer 2021. CalCCA cited that CCAs have encountered difficulty in receiving appropriate and accurate interval data from the IOUs necessary for the calculations to implement a CPP program.[38] City and County of San Francisco (CCSF) requested the Commission direct the IOUs to work with LSEs in their service territories to ensure that high-quality interval data is available in a timely manner to all LSEs to facilitate CPP programs and direct IOUs to share contact data on customers IOUs have identified for enrollment in CPP programs.[39] Utility Consumers Action Network also recommended the Commission direct the IOUs to begin providing non-IOU LSEs with validated interval data on a day after basis commencing prior to Summer 2021 and provide appropriate access to interval meter data to non-IOU LSEs.[40]

4.3. Adopted CPP Expansion and Modification Direction

The direction adopted in this decision regarding CPP modifications is outlined in Attachment 1.

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[37] SCE's Opening Comments at Page 10.

[38] California Community Choice Association Opening Comments at Pages 5 and 6.

[39] CCSF Opening Comments at Page 2.

[40] Utility Consumers' Action Network Opening Comments at Page 2.

PG&E is not directed to modify its CPP event windows for 2021 but is directed to modify its windows for both residential and non-residential customers to the hours of 4:00 p.m. to 9:00 p.m., no later than June 1, 2022. Rushing PG&E to make billing system changes this year by changing the event window could create billing problems for these CPP customers and for PG&E, making this time change while default TOU is in motion creates more complexity and potential confusion for residential customers on SmartRate. PG&E is directed to spend, and authorized to recover, up to $2 million to implement the new event hours of 4:00 pm to 9:00 pm, including IT, billing, and administrative costs.

We have similar concerns for SDG&E, as its billing system is being upgraded and then stabilized in 2021. Therefore, we target 2022 for the implementation of this modification for PG&E and SDG&E. SDG&E shall also implement a 4:00 p.m. to 9:00 p.m. event window no later than June 1, 2022. SCE's CPP event window is already 4:00 p.m. to 9:00 p.m., hence by summer 2022, we will have consistency among the Statewide large electric IOUs.

We do not approve a modification to the program that will eliminate the default nature of enrollment. However, the record indicates that there have been issues with performance in PG&E's service territory for smaller commercial customers who have been defaulted onto the rate. In response, PG&E is also directed to spend, and authorized to recover, up to $635,000 associated with customer education with the focus on improving the performance of its CPP rate program.

SCE is directed to increase the maximum number of events for CPP from 12 to 15 per year. PG&E, SEIA, and Cal Advocates provided a reasonable rationale that the removal of the maximum number of events could negatively impact enrollment of the program. However, SCE reached its maximum number of events in 2020, and based on its monthly DR report, the 12th event was on August 19, 2020. Thus, CPP was not available for the Labor Day heat wave. In response, we are increasing the maximum number of allowable annual events from 12 to 15.

SCE is also directed to include weekends and holidays as potential call days for its CPP program no later than June 1, 2022. SCE is further directed to spend, and authorized to recover, up to 1,000,000 ($500,000 annually for 2021 and 2022) associated with customer education with the focus on improving the performance of its CPP program. Small commercial customers have not performed very well on the tariff, but like our direction to PG&E, SCE can and should educate customers on how to perform better.

Since so few non-IOU LSEs currently offer CPP programs, and most of those programs are still in the pilot phase, we see an opportunity for CCAs and electric service providers (ESPs) to contribute to the reliability of the electric grid during peak demand days by proactively launching and expanding CPP programs. In this decision, we direct PG&E, SCE, and SDG&E to host a workshop on non-IOU CPP programs by April 7, 2021, to facilitate a peer knowledge exchange on the topic for summer 2021 and to identify barriers and solutions to non-IOU LSE program expansion as we look ahead to summer 2022. Recognizing that implementation of new CPP programs may not be feasible by summer 2021, as indicated by the California Community Choice Association (CalCCA) in its opening comments, the workshop may also consider alternative ways that the CCAs and IOUs should coordinate to encourage CCA customer participation in other load shedding programs. The CPUC strongly encourages CCAs and ESPs to take steps to launch or expand existing non-IOU CPP programs by summer 2021 (and by extension, summer 2022) to do their part to contribute to summer reliability by leveraging best practices from the workshop. We also encourage non-IOU LSEs to conduct CPP program load impact and cost effectiveness studies after this summer to inform the development of policies to expand programs in summer 2022.

5. Emergency Load Reduction Program

This decision directs PG&E, SCE, and SDG&E to each develop and administer an ELRP pilot with the attributes described in Attachment 1 of this decision. The purpose of ELRP is to allow the large electric IOUs and CAISO to access additional load reduction during times of high grid stress and emergencies involving inadequate market resources, with the goal of avoiding rotating outages while minimizing costs to ratepayers.

5.1 Background of ELRP

The December 18, 2020 ruling in this proceeding contained specific questions regarding the potential creation of ELRP that parties were directed to address in their prepared testimony. The ruling posed questions about potential program design elements like a trigger mechanism, eligibility, compensation, and administration. CAISO, California Energy Storage Association (CESA), CLECA, DR Coalition, ecobee, Joint DR Parties, PG&E, SCE, and The Utility Reform Network (TURN) provided proposals for how to design ELRP, including which customer types should be eligible to participate, when the program should be triggered, and how participants should be compensated. The ELRP framework adopted in this decision contains elements from those party proposals.

5.2 Pilot Program Duration

The initial duration of the ELRP pilot program will be five years, 2021-2025, with years 2023-2025 subject to revision in the DR application proceeding that is expected to be initiated November 2021. ELRP design aspects that are subject to review and revision include minimizing use of diesel backup generators where there are safe, cost-effective, and feasible alternatives; consideration of local air pollution impacts on disadvantaged communities; and other modifications to make the program more effective and consistent with the state's decarbonization goals. We make this modification in response to comments from the California Environmental Justice Alliance, Union of Concerned Scientists, and Sierra Club. To this end, PG&E, SCE, and SDG&E should collect data on backup generator participation in ELRP, including location, type of fuel used, and the capacity of the generator, for years 2021 and 2022.

There was general party support for an ELRP pilot program duration of five years. For instance, TURN discussed a five-year pilot program duration.[41] Additionally, CLECA indicated that "ELRP should be funded as a pilot for 3-5 years to test its effectiveness and can be paid for out of IOU budgets for DR pilots."[42] CESA and PG&E generally supported this position as well. We considered the totality of the record, and given the weight of the evidence, determine that an initial pilot duration of 5 years is appropriate.

5.3 Out of Market Framework

ELRP capacity will be excluded from the resource adequacy (RA)/ California Energy Commission peak forecast framework with no CAISO market

[41] Exhibit TURN-1 at 18.

[42] Exhibit CLECA-1 at 8.

obligations. ELRP should be out-of-market (*i.e.*, not integrated into the CAISO's market), so that it does not interfere with the RA program and instead provides compensation for energy (or load reduction) beyond what is provided by RA resources.[43] In other words, ELRP should be viewed principally as an insurance policy made available during emergency conditions to supplement the reliability already provided by the RA program.[44]

5.4 Adopted Program Parameters

The following program parameters will apply to the ELRP pilot.

- Program availability: May – October; seven days a week; 4:00 p.m. – 9:00 p.m.
- Event duration: 1-hour minimum; 5-hour maximum
- Annual dispatch limit: Up to 60 hours
- Consecutive day dispatches: No constraints

Some parties spoke to positions on the duration that events should last. The DR Coalition supported 1-hour minimum dispatch and asserted that the "minimum dispatch duration should be one hour with a maximum up to the duration of the CAISO Warning."[45]

The CAISO advocated that the program should be available from 2:00 p.m. to 9:00 p.m. between the months of May and October.[46] CESA indicated its position that the program should be available from 5:00 p.m. to 9:00 p.m. and be available for four-hour continuous energy capacity.[47]

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[43] Exhibit PGE-1 at 3-1, Exhibit CAISO-1 at 8, Exhibit SCE-1 at 7, and Exhibit CLECA-1 at 6.

[44] Exhibit CAISO-1 at 11 and Exhibit TURN-1 at 18.

[45] Exhibit DRC-1 at 15.

[46] Exhibit CAISO-1 at 9.

[47] Exhibit CESA-1 at 7.

PG&E recommended that ELRP enrollment be uncapped.[48]

5.5 Eligible Customers

There is support in the record for two distinct groups of customers to be eligible for ELRP participation: (1) non-residential customers and aggregators not participating in DR programs, and (2) market-integrated proxy DR (PDR) resources.

- Group A: Select non-residential customers and aggregators not participating in DR programs
  - A.1. Non-Residential, Non-DR Customers
  - A.2. Base Interruptible Program (BIP) Aggregators
  - A.3. Rule 21 Exporting distributed energy resources (DER)
  - A.4. Virtual Power Plant (VPP)
- Group B: Market-integrated PDR resources
  - B.1. Third-party DR Providers Resources
  - B.2. IOU Capacity Bidding Program (CBP) Resources

More specific information about the detailed attributes of the groups of eligible customers and minimum size/peak reduction thresholds are outlined in Attachment 1 of this decision.

The inclusion of all eligible customers groups, including A.1 and A.2, is based on party input in the prepared testimony. For instance, PG&E and SCE supported including IOU distribution non-residential customers.[49] PG&E asserted that there should be a minimum 1 kilowatt (kW) of load reduction threshold for participation.[50] SCE indicated that customers' accounts should

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[48] Exhibit PGE-1 at 3-7.

[49] Exhibit PGE-1 at 3-3 and Exhibit SCE-1 at 7.

[50] Exhibit PGE-1 at 3-7.

have a peak demand of at least 200 kW to be eligible to participate.[51] SDG&E indicated that there should be a minimum load shed requirement of 100 kW. Several parties supported allowing dual participation with BIP.[52]

CESA provided significant insight in its prepared testimony that led to the inclusion of groups A.3 and A.4. CESA indicated support for allowing net exports by behind the meter solar plus storage, vehicle-to-grid (V2G) resources, and other distributed energy resources that can meet a base performance requirement.[53] CESA also indicated that double compensation for exports is a non-issue because exports are not modeled in the California Energy Commission forecast and because the provision of reliability services in accordance with the ELRP are outside the RA framework; safety and reliability concerns associated with exports can be addressed in the interconnection process.[54]

Cal Advocates opposed CESA's position on exports by behind the meter solar plus storage, asserting that it is duplicative of other existing programs like the Self-Generation Incentive Program.

Inclusion of customer group B was based on testimony from numerous parties, including CLECA, DR Coalition, Joint DR Parties, and CESA. The large electric IOUs diverged from these parties in their view regarding inclusion of Group B due to complications they identified around tracking and billing.

Parties disagreed about the use of prohibited resources during ELRP events. Numerous parties were supportive of their use under limited conditions, for example only as a last resort and within certain parameters, while being

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[51] Exhibit SCE-1 at 7.

[52] Exhibit PGE-1 at 3-5, Exhibit SDGE-1 at 4, Exhibit SCE-1 at 7, Exhibit CESA-1 at 7.

[53] Exhibit CESA-1 at 7.

[54] Exhibit CESA-1 at 22-23.

mindful of local air quality permitting requirements. These parties included Calpine, PG&E, SCE, SDG&E, 350 Bay Area, California Efficiency and Demand Management Council, Center for Energy Efficiency and Renewable Technologies, CESA, CLECA, Joint DR Parties, Green Power Institute, NRG, Shell, and Vote Solar -Large Scale Solar Association – Solar Energy Industries Association. Parties that expressed more significant skepticism or opposition included Cal Advocates, California Environmental Justice Alliance - Sierra Club– Union of Concerned Scientists, Middle River Power, and Sunrun.

5.6 Event Triggers

ELRP will utilize a day ahead (DA) event trigger.

The ELRP DA trigger for both Group A and Group B resources is tied to a DA Alert, per the Alert, Warning, Emergency (AWE) process defined by the CAISO Operating Procedure 4420, declaration by CAISO. An ELRP event cannot be triggered by an IOU for a localized transmission or distribution emergency.

Following an Alert declaration by the CAISO, the IOUs will exercise discretion to activate the DA trigger for Group A participants, either selectively staggered over time or all DA participants at the same time. The start time and duration specified by the IOU will define the ELRP event window for the Group A participants called by the IOU.

There was significant party support for having the program event triggers controlled by CAISO.[55] PG&E[56] and DR Coalition[57] support having an ELRP event called during declared CAISO Warning or Emergency stage with a 30-

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[55] Exhibit PGE-1 at 3-2, Exhibit SDGE-1 at 7, Exhibit SCE-1 at 8, and Exhibit DRC-1 at 14, and Exhibit PIO-1 at 12.

[56] Exhibit PGE-1 at 3-1.

[57] Exhibit DRC-1 at 12.

minute notice. Including a day ahead trigger, as supported by SCE,[58] is intended to address IOU concerns that customers will not have enough time to produce meaningful load reductions in the real time market. The CAISO expressed concern that triggering too early could distort the market. While we understand CAISO's concern, the practical need for participants to have time to respond in time to provide the benefit overrides the market distortion concern.

5.7 Compensation

The full guidance regarding compensation is outlined in Attachment 1 of this decision. Some of the highlights of the compensation mechanism and party input are outlined in this section.

Only incremental load reduction (ILR) is eligible for compensation under ELRP. ILR is defined as the load reduction achieved during an ELRP event incremental to the non-event applicable baseline and any other existing commitment.

Any load reduction technology may be used during an ELRP event to achieve ILR. Prohibited resources may be used during an ELRP event to achieve ILR, including during the overlapping period with an independently triggered event in a dual-enrolled DR program, but only for achieving load reduction incremental to any other existing commitment (*e.g.*, under a dual-enrolled DR program).

General ELRP compensation parameters for all customers include the following:

- After-the-fact pay-for-performance will be made at a prefixed energy-only ELRP Compensation Rate applied to ILR.

[58] Exhibit SCE-1 at 8.

- There are no capacity-like payments or enrollment incentive.
- There are no penalties for non- or under-performance.

The ELRP Compensation Rate is set at $1 per kilowatt hour (kWh) (or $1000 per megawatt hour (MWh)). The ELRP Compensation Rate will be set at the same level for the following sub-groups: Group A customers, Group B PDRs, and BIP customers delivering ILR during an ELRP event.

There was strong support in the record for compensation to occur after the fact based only on the amount of load reduction achieved, with no capacity payments.[59] CLECA supports ELRP compensation for any ILR beyond BIP.[60]

Ultimately, the adopted compensation rates were developed to ensure that the compensation was substantial enough to drive participation without over--compensating participants. Party-proposed energy-only compensation rates included:

- PG&E and SCE: $.75/kWh[61]
- CESA: $750/MWh[62]
- TURN: DA Default Load Aggregation Point Locational Marginal Price[63]
- California Efficiency and Demand Management Council (CEDMC): BIP-$6/kWh; ELRP only - $36/kW-yr reservation payment + $0.95/kWh.

[59] Exhibit PGE-1 at 3-1, Exhibit CLECA-1 at 6, and Exhibit TURN-1 at 18.

[60] Exhibit CLECA-1 at 6.

[61] Exhibit PGE-1 at 3-7 and Exhibit SCE-1 at 9.

[62] Exhibit CESA-1 at 7.

[63] Exhibit TURN-1 at 18.

PG&E and SCE supported a performance cap of 200 percent of the nominated amount per participant[64]; SCE supported minimum performance of 50 percent.[65] Several parties supported ELRP being voluntary with no penalties for nonperformance.[66] SCE supported the ability to call events on a day-ahead and day-of basis.[67]

The ELRP baseline will be constructed by all IOUs according to the method described by SCE in its testimony[68] with some modifications, as described in Attachment 1.

5.8 ELRP Test Events

The large electric IOUs shall conduct one test event with two-hour duration per year for Group A participants. ELRP Group A participants, except for those relying exclusively on prohibited resources, are required to participate in the test events. Use of prohibited resources during a test event is not permitted and will not be compensated. Incremental load reduction delivered during an ELRP test event is eligible for ELRP compensation. The IOUs are directed to collaborate with the CAISO and the California Energy Commission in the testing process.

By precluding prohibited resources from participating in and receiving compensation for test events and ordering the IOUs to collect data on other testing and nameplate capacity to determine the resource amount, we further ensure that our addition of ELRP to exempted demand response program events will not undermine the policy goals we established in D.16-09-056 while

[64] Exhibit PGE-1 at 3-7 and Exhibit SCE-1 at 9.

[65] Exhibit SCE-1 at 9.

[66] Exhibit PGE-1 at 3-7, Exhibit TURN-1 at 19, and Exhibit SCE-1 at 7.

[67] Exhibit SCE-1 at 7.

[68] Exhibit SCE-1 at 9.

exempting certain resources from the prohibited resource requirements during demand response events.

5.9 ELRP Program Approval

Within 30 days of the effective date of this Decision, PG&E, SCE and SDG&E shall jointly file a Tier 1 AL incorporating the ELRP terms and conditions for Group A. For incorporating the ELRP terms and conditions for Group B, IOUs shall jointly file a Tier 1 AL within 60 days of this Decision. Limited deviations to accommodate IOU-specific implementations due to IT and billing systems are permitted. The filings shall include details necessary to implement the ELRP guidelines set forth above and address various aspects of ELRP pilot design and processes, including enrollment, the process to update enrollment related program parameters, ELRP event notification and customer acknowledgment, ILR measurement, and settlement.

5.10 Cost Recovery

PG&E, SCE, and SDG&E are authorized to establish one-way balancing accounts regarding the development, implementation, and operation of the program, along with incentives paid under the program. These balancing accounts may also be used to track other costs that are specifically authorized to be incurred in this decision, such as for CPP and DR program changes. The balancing accounts shall be effective as of the date of this decision. These three electric IOUs shall file Tier 1 Advice Letters within 5 days of the issuance of this decision establishing the new one-way balancing accounts.

This ELRP budget reflects projected costs for IOU program administration, including IT, evaluation, measurement, and verification costs, in addition to costs for compensating eligible customers who have contributed load reductions in response to an ELRP event. Customer compensation costs for each IOU assume a compensation rate of $1/kilowatt-hour for up to the 60-hour annual limit; however, if no ELRP events are called, customer compensation costs are assumed to be zero.

These balancing accounts shall have the following annual caps:

- PG&E $3.9 million for administration and $28.6 million for customer compensation,
- SCE $2.9 million for administration and $33.8 million for customer compensation, and
- SDG&E $1.6 million for administration and $14.8 million for customer compensation.

6. Modifications to Existing IOU DR Programs

Attachment 1 outlines various modifications to existing DR programs that the large electric IOUs shall institute going forward. We considered the totality of the record, and the following modifications to existing DR programs are adopted.

6.1 Cost-effectiveness

In the December 18, 2020 ALJ Ruling, parties were directed to respond to the following question:

> IOU DR programs are required to demonstrate cost effectiveness using the methods described in the DR 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.

The large electric IOUs raised several considerations in response to this question, notably that the DR Cost-Effectiveness Protocols, the tool by which cost-effectiveness of DR programs are measured, has not been updated to reflect recent avoided cost information that the Commission adopted in 2020.[69] Hence, they asserted, the protocols were not ready for use in this proceeding. Additionally, the utilities state that in past DR proceedings, DR pilot programs, such as the ELRP, were typically not subject to cost-effectiveness review.[70] The IOUs state that programmatic changes to existing DR programs are evaluated for cost-effectiveness over a period of five years (the length of funding for the utilities' DR portfolio).[71] Since the program changes proposed in this proceeding are for a shorter time period, proper cost-effectiveness analysis is not feasible. Lastly, the IOUs state that given the accelerated timeline of the proceeding, it was not feasible to produce cost-effectiveness testimony for their DR proposals.[72] The DR Coalition stated cost-effectiveness considerations are a lower priority and would limit the Commission's flexibility to adopt changes that could drive greater DR participation.[73] CLECA stated that because the impacts on ratepayers could be significant, cost-effectiveness analysis should be done.[74]

We find the arguments by the IOUs and the DR Coalition to be persuasive. We agree that the existing DR cost-effectiveness protocols do not reflect recent avoided cost information that was adopted and that DR pilots are usually not subject to cost-effectiveness review. The ELRP as adopted in this decision is a pilot program; hence, we waive the use of our traditional cost-effectiveness tools for all DR proposals that are adopted in this decision for years 2021 and 2022,

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[69] Exhibit PGE-1 at 4-19.

[70] Exhibit PGE-1 at 4-19.

[71] Exhibit PGE-1 at 4-19.

[72] Exhibit PGE-1 at 4-19.

[73] Exhibit DRC-1 at 37.

[74] Exhibit CLECA-1 at 19.

under certain conditions. Regarding changes to existing DR programs adopted in this decision, the IOUs have proposed to use their existing DR budgets to fund many of those changes, which will help mitigate potential impacts to ratepayers. Any changes that require new incremental funding must be tracked in the memorandum accounts authorized in this decision, and requests for cost recovery will undergo reasonableness review.

6.2. Modifications to Existing DR Programs of All IOUs

All IOUs shall update their program tariffs to allow year-round enrollment in their BIP for the duration of the ELRP pilot. SCE shall do the same for its agricultural pumping interruptible (AP-I) programs for the duration of the ELRP pilot. A customer who enrolls by April 30 in any given calendar year must be enrolled for at least 6 months before exiting the program. A customer who enrolls after April 30 in any given calendar year must remain enrolled for at least 12 months before exiting the program. Existing unenrollment windows (i.e., during November for SCE and PG&E, and during November and April for SDG&E) are unchanged. As SCE notes, moving "from the current April lottery process to year-round enrollment [in the BIP and AP-I programs] enables maximum participation of the interested participants to apply and enroll prior to the hottest summer months when DR is needed most. SCE recommends no changes to the current unenrollment window in November, but requests that D.18-11-029, Ordering Paragraph (OP) 5 be deleted and allow year-round enrollment onto the programs.[75] Further, as DR Coalition notes, the Commission should allow "enrollment and unenrollment on a rolling basis: BIP and AP-I

[75] Exhibit SCE-1 at 12.

enrollment should be allowed on a rolling basis rather than once per year."[76] For the duration of the ELRP pilot, the timing requirements set forth in D.18-11-029, OP 5 are suspended and year-around enrollment in the BIP and AP-I programs is allowed.

The DR reliability cap established in D.10-06-034 is temporarily raised to 3% for the duration of the ELRP pilot for all IOUs. SCE,[77] NRG,[78] and DR Coalition[79] propose eliminating the cap, whereas the CAISO and TURN oppose even a temporary expansion. A 3% cap is adopted as a reasonable middle ground.

We clarify that there is no restriction on the IOUs from utilizing the funding for the DR Marketing, Education and Outreach program to actively market BIP. While there is room for new customer enrollments due to the temporary increase to the DR reliability cap, the rationale articulated in D.12-04-045 is inapplicable. We note this clarification in response to the testimony of PG&E.[80]

Finally, the CAISO indicates it is contemplating potential baseline adjustment increase(s) during stressed grid conditions. The IOUs are directed, and third-party DR providers are invited, to work collaboratively with the CAISO to explore baseline options during stressed system conditions. As a result of this exploration, to the extent the CAISO introduces new baseline options for energy market settlement, the IOUs are permitted to utilize the new

[76] Exhibit DRC-1 at 22.

[77] Exhibit SCE-1 at 14.

[78] Exhibit NRG-1 at 3.

[79] Exhibit DRC-1 at 20.

[80] Exhibit PGE-1 at 4-21.

baseline options in their respective CBPs, and DR providers are permitted to utilize the new baseline options for the Demand Response Auction Mechanism.

6.3. Modifications to SCE's Existing DR Programs, Pilots, and Related Support Programs

6.3.1. Base Interruptible Program

SCE is authorized to increase the BIP incentive by 20% for 2021 and 2022.

We adopt this proposal from SCE[81] after considering the testimony of parties like TURN and CLECA.

TURN notes in its reply testimony that it retains its "concern about how to parse the incentive payments for a partial year given that PG&E's are the same each month and SCE's are not… [TURN] believe[s] it [is] problematic to allow customers to get high incentive payments in the summer months without being responsible for participation during the winter months."[82]

CLECA notes in its reply testimony that is supports "the proposals of SCE to increase BIP incentives by 20% and PG&E to increase BIP incentives by $1.50 kW." CLECA indicates it strongly opposes TURN's suggestion that the current incentives for BIP are too high. CLECA notes that BIP participants face major business challenges in running their businesses and serving their customers when they reduce load, especially when the program is called as often as it was in 2020.

Considering the weight of the evidence, we adopt SCE's proposal to increase the BIP incentive by 20% for 2021 and 2022.

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[81] Exhibit SCE-1 at 13.

[82] Exhibit TURN-2 at 5-6.

6.3.2. Smart Energy Program (SEP) (*i.e.*, SCE's Bring Your Own Device Program)

SCE is authorized to update the SEP tariff to modify the medical baseline exclusion and align it with the existing medical baseline exclusion language in the SDP tariff, and to optimize new acquisition opportunities to increase customer enrollment in SEP (*e.g.,* IDSM, point-of-sale enrollment, etc.). We adopt this after considering SCE's testimony.[83]

SCE is authorized an incremental $3.33 million in funding through 2022 for modifying the medical baseline provision and acquisition opportunities.[84]

SCE's proposal to eliminate the restriction preventing participation by customers of CCAs and ESPs by converting SEP from generation to distribution funding by 2022 is approved, and SCE is authorized $2.87 million additional funding for labor, non-labor vendor support, participant incentives and ME&O to implement the proposal.[85] We note that 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.

6.3.3. Summer Discount Programs (SDP) (*i.e.*, SCE's A/C Cycling Program)

After considering the record, we adopt the following modifications to SCE's SDP.

SCE's proposal to market and pay a sign-up bonus of $50 to increase SDP enrollment, along with an incremental funding request for $1.5 million for each year in 2021 and 2022, is approved.[86] SCE's proposal for the purchase and

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[83] Exhibit SCE-1 at 16-17.

[84] Exhibit SCE-1 at 19, Table II-3.

[85] Exhibit SCE-1 at 17-19.

[86] Exhibit SCE-1 at 20.

installation of up to 60,000 new load control devices for new SDP enrollments, along with an incremental funding request for $3.64 million in 2022, is approved.[87] SCE's proposal 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 is approved.[88] Additionally, SCE shall revise the SDP tariffs to remove the minimum dispatch requirement, while preserving the maximums of 20 economic hours and 180 emergency hours annually.[89]

6.3.4. Capacity Bidding Program

SCE's proposal to add residential accounts to CBP instead of conducting a one-year residential CBP pilot, and to add a 5-in-10 baseline (with 40% day-of adjustment) for residential accounts, requiring no incremental funding, is approved.[90]

As noted in SCE's proposal, SCE also 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 in AL 4182-E.[91] SCE estimates expanding the CBP to residential accounts and aggregators could add more CBP capacity, particularly during the net peak load hours.[92] No incremental funding is needed for this proposal, but SCE requires Commission approval before SCE can start on implementation; as such, SCE's request for Commission approval for this proposal is adopted in this proceeding. SCE

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87 Exhibit SCE-1 at 20.

88 Exhibit SCE-1 at 21.

89 Exhibit SCE-1 at 21-22.

90 Exhibit SCE-1 at 22-23.

91 Exhibit SCE-1 at 22.

92 Exhibit SCE-1 at 22.

should submit a supplement to its advice letter to make any revisions necessary to reflect this decision.

The DR Coalition and TURN support higher CBP incentives for CBP participation in SCE's service area because the program is typically called frequently during the summer months. SCE's proposal to increase CBP Day-Ahead and Day-Of capacity incentive rates ($/kW-year) by 20 percent for 2021 and 2022 is approved.

CESA supports SCE's proposed VPP Phase II pilot proposal to further demonstrate the potential of VPPs in supporting emergency reliability. SCE's proposal to create Phase II of its VPP pilot to acquire additional vendors and customers, test dispatchable technologies, including hybrid battery energy storage, and various dispatch strategies, including grid reliability events, is approved.

6.3.5. DR Systems and Technology

SCE is authorized cost recovery for $106,000 to make the following upgrades to its DR systems and technology infrastructure:[93]

- Extend the legacy Alhambra Control Platform for one additional year;
- Enhance the DR Event Website and DR Mobile App; and
- Create a test rack to confirm when a DR event has taken place.

[93] Exhibit SCE-1 at 28-29.

6.4. Modifications to PG&E's Existing DR Programs, Pilots, and Related Support Programs

6.4.1. Base Interruptible Program

PG&E shall increase its BIP incentive rate by $1.50/kW for 2021 and 2022 as follows:

Potential Load Reduction	Current Incentive Rate	Revised Incentive Rate
1kW to 500kW	$8.00/kW	$9.50/kW
501 kW to 1,000kW	$8.50/kW	$10.00/kW
1,001kW and greater	$9.00/kW	$10.50/kW

CLECA's testimony, as discussed in the section regarding SCE's BIP modifications, supports this modification.

6.4.2. Capacity Bidding Program

PG&E shall modify the CBP tariff to increase the maximum number of events allowed per month from five to six, with the clarification that the foregoing takes precedence over the maximum number of 30 hours per operating month.[94]

PG&E's proposal to extend the CBP operating days to seven days per week by adding a weekend option, along with a 25 percent capacity incentive adder for the weekend participation for 2021 and 2022, but no change in program hours is approved for 2021 and 2022.

PG&E's proposal to increase the CBP capacity incentive level for the month of October from the current $2.27/kW to $6.80/kW for the Day-Ahead participation option for 2021 and 2022 is approved.

[94] Exhibit PGE-1 at 4-5.

6.5. Modifications to SDG&E's Existing DR Programs, Pilots, and Related Support Programs

6.5.1. Base Interruptible Program

As proposed by SDG&E, the current 100 kW minimum requirement for participation in BIP is waived, and all non-residential customers of SDG&E are eligible to enroll and participate in BIP.[95] Additionally SDG&E is authorized to update the measuring hours for customers' monthly average peak demand to align the measuring hours for customers with availability assessment hours on which BIP's performance is measured.[96] Further, SDG&E is authorized to change the time period used to calculate the BIP capacity incentive from 1:00 p.m. to 6:00 p.m. window to 4:00 p.m. to 9:00 p.m. window.[97] As SDG&E's testimony noted, these proposals are pending before the Commission in Advice Letters 3615 and 3522.[98] SDG&E should submit supplements to make necessary revisions to each advice letter to reflect this decision.

SBUA recommends a 5:00 p.m. to 10:00 p.m. peak period.[99] This supports SDG&E's testimony summary of its loss-of-load expectation analysis based on its 2021 portfolio, which indicates the "highest likelihood of a loss of load event occurring between 5:00 pm to 10:00 pm."[100]

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[95] Exhibit SDGE-3 at 11.

[96] Exhibit SDGE-3 at 11.

[97] Exhibit SDGE-3 at 21.

[98] Exhibit SDGE-3 at 11, 21.

[99] Exhibit SBUA-2 at 12-14.

[100] Exhibit SDGE-2 at 7.

6.5.2. Capacity Bidding Program

As proposed by SDG&E, SDG&E shall modify its CBP tariff to increase the maximum number of events allowed per month from six events to nine events, with the additional three events reserved for CAISO or SDG&E emergencies.[101] As requested by SDG&E, any non-performance penalties associated with the three additional monthly CBP events will be waived.

As proposed by SDG&E, SDG&E shall modify its CBP tariff to:

- Adjust notification time to be 5:00 PM for the CBP Day-Ahead product.
- Update the CBP Day-Of product notification time to 40 minutes to allow the program to be bid into the CAISO Day-Of market.[102]

As proposed by SDG&E, SDG&E shall launch the CBP Residential Pilot in 2021.[103]

6.5.3. Air Conditioning Saver

As proposed by SDG&E, SDG&E shall modify the air conditioning (AC) Saver tariff to allow participation by residential net energy metering (NEM) customers.[104]

As proposed by SDG&E, SDG&E shall modify the AC Saver tariff to increase the maximum number of events allowed in a year from 20 events to 25 events, with the additional 5 events reserved for CAISO or SDG&E emergencies.[105]

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[101] Exhibit SDGE-3 at 12.

[102] Exhibit SDGE-3 at 12.

[103] Exhibit SDGE-3 at 12.

[104] Exhibit SDGE-3 at 13.

[105] Exhibit SDGE-3 at 13.

SDG&E is additionally authorized to a) pursue emergency agreements with device manufacturers who already have devices participating in the AC Saver program to signal existing installed thermostats that are not in an existing DR program to secure additional load reduction, and b) offer a reasonable incentive, consistent with the guidelines described by SDG&E, to these manufacturers for increasing the number of participating thermostats.[106]

6.6. Cost Recovery

PG&E, SCE, and SDG&E shall utilize unspent funds from their existing DR budgets adopted in D.17-12-003, to the extent existing funds are available.

To the extent that any tariff amendments are necessary to effectuate the DR program changes ordered in this decision, those changes should be documented in a Tier 1 Advice Letter to be filed by PG&E, SCE, and SDG&E, as well as the process for transferring balances within the IOU's the Demand Response Programs Balancing Account and Base Revenue Requirement Balancing Account for this purpose.

7. Expedited IRP Procurement

The December 18, 2020 ALJ ruling sought feedback on offering an incentive mechanism to expedite the Summer 2021 procurement ordered in D.19-11-016. Of the 3,300 megawatts (MW) net qualifying capacity (NQC) ordered in D.19-11-016, 50 percent is required to be online by August 1, 2021. Party testimony in response to the December 18, 2020 ruling, including that of CESA, CLECA, PG&E, Cal Advocates, SDG&E, and TURN, was generally opposed to this proposal. TURN noted that the current timeframe is too short, and SDG&E indicated that timelines may be more driven by the developer than

[106] Exhibit SDGE-3 at 14.

LSE. CLECA, PG&E, and TURN expressed concern that expedited procurement would likely lead to higher costs. In consideration of this testimony, we agree that at this moment offering an incentive to expedite procurement ordered under D.19-11-016 and due to come online August 1, 2021, would not be prudent. The Commission reserves the right to consider an incentive structure to expedite procurement under D.19-11-016 and due to come online August 1, 2022 or August 1, 2023, but is not putting forward direction to do so at this time.

8. Modifications to the Planning Reserve Margin

8.1. Party Positions

In testimony, parties expressed support and opposition for a wide range of alternatives related to the PRM.

CAISO recommends an increase in the PRM in light of the weather experienced throughout the summer of 2020 and in anticipation of more frequent extreme weather events resulting from climate change.

Some parties took a more neutral position, like PG&E, who did not immediately support a modification to the PRM, but suggested a robust study to determine the appropriate solution. However, PG&E did also offer additional insight into options the Commission could pursue in alternative to a strict increase to the PRM in accordance with current RA policy. PG&E indicated support for three options to allocate procurement responsibility: (1) allocate the additional procurement need among all Commission-jurisdictional LSEs, (2) allocate the additional procurement need to the IOUs to procure on behalf of customers within their service territories, or (3) allow the CAISO to utilize capacity procurement mechanism to procure backstop capacity.[107]

[107] Exhibit PGE-1 at 6-3 and 6-4.

PG&E also suggested that the Commission require all Commission-jurisdictional LSEs to submit preliminary, non-binding RA plans for the summer of 2021 by a specified date and suggested a date no later than March 17, 2021.

CalCCA took a somewhat similarly nuanced approach. It indicated the additional time it takes to set the appropriate PRM levels for the RA program is too substantial, considering the need to translate the dual peak and post-peak requirements to individual LSEs, if it intends to implement its changes in time to address Summer 2021 reliability. CalCCA indicated the Commission can achieve the same reliability benefits via an IOU-procurement approach that does not modify the PRM requirements for individual LSEs.[108] CalCCA recommended that the authorized supply and demand-side solutions should not, cumulatively, exceed 1,073 MW.[109]

TURN took a stronger position of opposition to a modification to the PRM. It asserted that the Commission should not increase the PRM at this time, as advocated by CAISO, because the SCE Loss of Load Expectation study shows that the system will be adequately reliable in 2021.[110]

8.2. Discussion

We agree with SCE, CAISO, and other parties who recommend an increase in resources in light of the weather experienced throughout the summer of 2020 and in anticipation of more frequent extreme weather events resulting from climate change. Consistent with the scope of this proceeding, we also agree that there is a need to ensure that there are sufficient resources in place to meet

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[108] Exhibit CCCA-1 at 22.

[109] Exhibit CCCA-1 at 3.

[110] Exhibit TURN-1 at 2.

demand during the net peak hour, which is why all the incremental resources procured through this proceeding are required to be available during net peak.

Ultimately, changes to resource planning metrics and RA requirements should be made in the IRP and RA proceedings, respectively, and this work is already scoped into those proceedings. In this decision, we adopt an interim approach that effectively increases the PRM beginning summer 2021 to 17.5%. This change is limited to 2021 and 2022, and subject to modification in the RA proceeding.

In its testimony, CAISO recommends adopting a 17.5% PRM, to account for increased levels of forced outages currently being experienced by California's fleet, and it recommends applying this reserve margin "when solar is at or near zero."[111]

There are a host of challenges associated with implementing CAISO's recommendation as proposed, including but not limited to:

- Changing system RA requirements mid-year and developing a penalty and waiver process to reflect this sudden change, given that there is currently no penalty waiver process for system RA requirements;
- Revising RA program rules that were designed to require LSEs to meet their share of peak demand, not demand "…when solar is at or near zero;"
- Coordinating individual LSE procurement to meet this new requirement with the procurement we have directed IOUs to perform on behalf of all LSEs in their service territories; and
- Addressing the fact that some of the resources we are directing IOUs to procure in this decision will be triggered during emergencies and will therefore not be RA resources

[111] Exhibit CAISO-2 at 2.

> with must offer obligations that would count towards the increased PRM requirement.

Given the tightness of the market at this time, coupled with the fact that we are directing the large electric IOUs to perform almost all of the expedited procurement being authorized in this proceeding versus putting the requirement on all LSEs, the most practical and expeditious method to implement an effective 17.5% PRM that supports the goal of meeting net peak demand is to continue to require all LSEs, including the IOUs, to meet their 15% system RA PRM requirement and direct the large electric IOUs to target a minimum of 2.5% of incremental resources that are available at net peak through the efforts authorized in this proceeding. For 2021, this results in a minimum target of 450 MW for PG&E, 450 MW for SCE, and 100 MW for SDG&E, based on 2.5% of the average CPUC jurisdictional share of CAISO peak load during peak summer months per the California Energy Commission's 2019 Integrated Energy Policy Report forecast for the year 2021. These minimum MW targets will also apply to 2022 unless superseded by a future Commission decision.

All of the resources being procured through this proceeding, including emergency-triggered resources that do not count towards RA like the ELRP, should be included in meeting these incremental procurement targets.

Given that a portion of the resources that make up LSEs' 15% PRM are solar resources whose generation is declining rapidly at net peak, these procurement targets represent a floor, and the IOUs are encouraged to exceed their respective targets by as much as an additional 50%, which would result in approximately 1,500 MW of incremental procurement and an effective PRM of 19%. The additional 1,500 MW of resources is selected as an upper end target because it represents the NQC of solar in September, which has been the Integrated Energy Policy Report forecast peak load month in recent years.

We recognize that by design, the amount of customer participation and resulting MW for some new DR programs and changes to existing DR programs adopted in this decision cannot be known in advance. On the other hand, some resources that participate in some programs may be redundant with MW that already count towards RA (*e.g.*, PDR that is an RA resource but is only partially scheduled in the CAISO market and sheds load after ELRP is triggered in excess of the scheduled quantity). For these reasons, IOUs are to consider their respective upper end targets as "soft caps" for all resources authorized for procurement in this proceeding, but as "hard caps" for incremental supply side generation and in-front-of-meter storage resources. In other words, the total procurement under this proceeding, including RA and non-RA DR resources, could exceed the upper end targets, but generation and in-front-of-meter resources alone may not exceed 150% of each IOU's target.

IOUs shall target their incremental procurement in this range during the months of most concern, including May through October but most importantly should endeavor to meet and exceed their respective minimum MW targets in July, August, and September. The net costs associated with this procurement shall be passed through to all benefiting customers consistent with the existing cost allocation mechanism. We clarify that because this procurement is additional to LSEs' RA requirements, there will not be RA capacity benefits to allocate to all LSEs, as is usually the case with resources procured through the cost allocation mechanism. In this instance, the benefits provided to all LSEs is increased electric reliability without requiring all LSEs to procure their share of these incremental resources under this expedited timeframe or be subject to RA program penalties for not doing so.

We recognize that some contracts may not be tailored to the months of most concern and may require year-round obligations, so we make clear here that while IOUs should strive to layer resources to meet the most critical months, the net costs associated with this incremental procurement shall be shared by all customers in each IOU's service territory, since all customers share the additional reliability benefits.

In its testimony, CAISO points out that the higher PRM must be adopted as a new RA requirement in order to trigger its Capacity Procurement Mechanism. Again, under this interim approach all LSEs must meet their existing 15% PRM RA requirements, and the resources being procured by IOUs on their behalf do not contribute to these requirements. To the extent LSEs fail to meet their RA requirements, CAISO can backstop for them up to 15% PRM, which, coupled with the IOU 2.5% procurement target, will achieve, at a minimum, an effective PRM of 17.5%.

We recognize that under the scenario in which all LSEs meet their 15% PRM requirements but one or more IOUs fail to meet their additional 2.5% target, the effective 17.5% PRM approach we adopt here would not allow CAISO to trigger its Capacity Procurement Mechanism. However, we also note that these targets will remain in effect for IOUs through the timeframe in which CAISO would trigger its CPM – as described in CAISO's testimony the trigger would be a deficient month-ahead RA showing by one or more LSE. It is unclear to us that the CAISO would have a substantively better ability to procure resources in the market within that timeframe than the IOUs, who will also have the advantage of not needing to wait until the month ahead showings reflect deficiencies.. Moreover, as noted above, should LSEs collectively not meet their 15% PRM RA requirements in the month-ahead space, CAISO can still trigger CPM procurement to backstop those deficiencies.

These incremental PRM procurement targets will remain in effect for each IOU in 2021 and 2022, unless superseded by a future Commission decision.

For situational awareness, after hydroelectric resource conditions are better understood and to better prepare for any additional measures to meet summer peak load in the event of another extreme weather event, all LSEs are required to provide Energy Division non-binding month-ahead RA filings for July, August and September no later than April 15, 2021, reflecting their most recent RA positions, including any excess RA procurement (but excluding IOU procurement authorized in this proceeding).

9. Additional Capacity Procurement

PG&E, SCE, and SDG&E are directed to continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve this effective 17.5% PRM for the months of concern.

Consistent with the guidance provided in D.21-02-28 – and consistent with the resources that have been contracted for by IOUs in response to that decision – procured resources must be available to serve load at peak and net peak, and the IOUs should give preference to storage contracts (from new solicitations, bilateral negotiations, or offering counterparties an opportunity to refresh prior IRP procurement bids), upgrades resulting in increased efficiency of existing generation resources, and contract terms that are shorter in duration.

All procurement contracts should be submitted to Energy Division via a Tier 1 AL on a continuing basis, except for contracts for incremental gas generation of five years or more and incremental imports. Contracts of five years or more for incremental generation at existing gas power plants should be submitted to Energy Division via a Tier 3 AL. Contracts for fossil-fuel development at new sites or for redevelopment or full repowering at existing or mothballed electric generation sites will not be considered. Tier 1 ALs are not required, but may be submitted, for incremental imports, provided the IOUs remain within the "hard cap" procurement limits for supply--side generation and storage resources discussed above.

We understand that IOUs will be procuring to meet both their individual 15% PRM RA requirements and the additional procurement directed in this proceeding. To facilitate compliance, we clarify that IOU procurement, including RA resources procured under D.21-02-028, should first be used to meet bundled service RA requirements.

We also recognize that a combination of RA eligible and non-eligible resources will be used to meet the effective 17.5% PRM. All RA eligible resources supporting the effective PRM should be shown as RA and reflected in supply plans to ensure that these resources are subject to RA obligations and incentive mechanisms, do not receive CPM double-payments, and are ineligible for export. Of these resources, only costs associated with RA resources in excess of an IOU's own 15% PRM should be charged to all benefiting customers in the IOU's service territory via the CAM.

To the extent feasible, IOUs should acquire and pair imports contracted to meet the effective 17.5% PRM with maximum import capability and include these costs in their CAM procurement costs. If existing IOU-owned maximum import capacity is paired with imports to construct an RA product, the IOU should calculate and include the average price it received for sales of its excess maximum import capability or, if not available or representative of market value, another reasonable market benchmark.

After accounting for resources procured under D.21-02-028 and additional resources procured under the authority of this decision – including an estimate of ERLP resources since actual ELRP MW will not be known until after the fact – if an IOU has not met its minimum procurement target for the months of June through October (since the monthly RA plans for May are already filed), and it has excess RA capacity beyond its own RA requirements after making reasonable attempts to sell this excess capacity to other LSEs to meet their 15% PRM requirements, it may use these resources to meet the minimum MW procurement target at the imputed cost of the 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark.

Given that over 500 MW of resources have already been procured in response to the procurement orders in D.21-02-028, and making even conservative assumptions of additional ELRP procurement, we would expect that there would be minimal need to include these resources to meet the IOUs' respective minimum targets. However, for the months of July through September, the IOUs may use any excess, unsold RA resources in their portfolios to supplement the resources they have procured under the authority of this expedited procurement proceeding – including estimates of ERLP resources – up to their respective soft caps (675 MW for PG&E and SCE, and 150 MW for SDG&E). This approach encourages higher levels of RA to be visible and available to CAISO for the three months of historically highest grid stress, consistent with CAISO's recommendation that higher procurement levels than their proposed 17.5% PRM be achieved.

The benefit of making these resources visible to CAISO as RA resources is that they will be subject to RA requirements and incentive/penalty mechanisms, will not be deemed eligible for export, nor be identified as eligible for a CPM payment in the event that CAISO's CPM is triggered. This approach also avoids the unintended outcome of IOUs buying excess RA resources from one another's RA solicitations to the extent each need to do so to meet their targeted additional 17.5% PRM procurement, potentially at premiums well in excess of the 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark.

The IOUs shall provide the monthly amounts of the excess resources they used to meet their additional procurement targets, as well as the calculus used to determine these amounts (i.e., net of other resources contracted under this proceeding's authority, including their estimated ELRP resources), to Energy Division, and Energy Division is directed to post this information on its website.

To the extent that any additional adjustments to balancing accounts are needed to provide for CAM cost recovery of the procurement authorized in this decision, the IOUs may file Tier 2 advice letters with the effective date of the tariff modification to be the effective date of this decision.

10. Expanded Electric Vehicle Participation

The December 18, 2020 ALJ ruling also sought feedback on whether the CPUC should revise electric vehicle (EV) programs and/or incentives to leverage EV load flexibility in order to respond to a reliability event in Summer 2021. PG&E and SCE expressed doubt that short-term measures could be developed in time to expand EV participation by summer 2021, and instead suggested that the CPUC encourage EVs to participate in existing DR programs.[112] On the other

[112] Exhibit PGE-1 at 4-21 and Exhibit SCE-1 at 43.

hand, CalCCA and CESA expressed support for providing incentives or payments for EVs that can export to the grid. CESA commented that some EVs can export to the grid and recommended specific incentives for resources that would include EVs that export.[113] CalCCA[114] endorsed vehicle grid integration (VGI) Working Group recommendation 2.12, which in part, proposes self-generation incentive program (SGIP) (or SGIP-type) incentives for EVs that export to the grid.[115] CESA commented that EVs with bi-directional charging capabilities offer a potential grid reliability resource.[116] CESA recommends providing capacity and energy payments from 2021 through 2025 for behind-the-meter resources including exports.

Considering testimony from CalCCA and CESA, as well as from other parties who generally supported allowing behind the meter distributed energy resources with exporting capabilities to provide emergency reliability services[117], this decision provides an opportunity for EV customers that meet certain size and Rule 21 export permitting criteria to participate in ELRP (customer group

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[113] Exhibit CESA-1 at 29 wherein it recommends providing capacity and energy payments from 2021 through 2025 for behind-the-meter resources including exports and provides recommendations on how to leverage EVs through DR programs.

[114] Exhibit CCCA-1 at 33.

[115] CalCCA quoted the June 30, 2020 VGI Working Group Final Report (Exhibit CCCA-1 at 38) summary of recommendation 2.12 (without listing the recommendation number): "Allow V1G and V2G to qualify for SGIP to level the playing field with incentives for other DERs, but V1G would get less incentive compared to V2G based on permanent load shift logic." The VGI Working Group Final Report contains a link to the VGI Policy Recommendations Database. Recommendation 2.12 in the Database, column titled "CPUC Energy Division Comments and Party Responses," states in part "We recommend saying "SGIP (or SGIP-type) incentives for V2G and V1G" in order to broaden this category." Available at https://airtable.com/shr9JBvC2bAofuJpj.

[116] Exhibit CESA-1 at 29.

[117] Exhibit CLECA-1 at 6 and Exhibit DRC-1 at 14

A.3). We note that 1) this action is consistent with D.20-12-029 ("Decision Concerning Implementation of Senate Bill 676 and Vehicle-Grid Integration Strategies"); and that 2) D.20-09-035 ("Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup") establishes a standard Rule 21 process for DC-coupled interconnection of EVs that export and provides direction on developing a standard Rule 21 AC-coupled interconnection option.

This decision also establishes a VPP option under ELRP (customer group A.4) for resource aggregations that participate in NEM and meet other specified criteria. According to the VGI Working Group final report, EVs that export cannot participate in NEM and thus would not be eligible under this ELRP customer group. Accordingly, we believe it is reasonable to explore the issue of how EV aggregations with export capability could be leveraged as DR to provide grid services, and an upcoming workshop ordered by D.20-12-029 may provide an opportunity for that discussion.[118]

11. SCE and PG&E Motions Regarding Memorandum Accounts

On January 11, 2021, SCE filed a motion in this proceeding seeking an order to approve a memorandum account to track costs incurred pursuant to this rulemaking. Similarly, on January 12, 2021, PG&E filed a motion in this proceeding seeking an order approving a memorandum account to track costs incurred pursuant to this rulemaking.

[118] Decision 20-12-029 ordered the IOUs to host a workshop in Q1 2021 to "ensure that large electrical corporations and potential VGI market actors understand program requirements and the potential for VGI to provide DR services." This workshop will provide a venue for IOUs and stakeholders to discuss opportunities for EVs to provide reliability-focused DR programs in the near to medium term.

SCE indicated in its motion that it will need to take preliminary actions prior to the Commission's issuance of a final decision, including the procurement of services, development and testing of system modifications, creation and distribution of marketing material, and outreach for DR program enrollment. SCE noted in its motion "the requested Memorandum Account would track costs that are incremental, substantial, and not speculative, thus satisfying the standard for approving such accounts that the Commission has discussed in prior decisions."[119] Further, SCE indicates that the effective date of the memorandum account should be the date of the filing of the January 11, 2021 motion. The January 11, 2021 motion of SCE is granted. SCE is authorized to establish the requested memorandum account and to utilize that account to track incremental costs incurred to begin working on SCE's demand response proposals in Rulemaking 20-11-003, as well as incremental costs for other activities authorized in this decision that are not specifically authorized for recovery. The effective date of the memorandum account hereby authorized shall be January 11, 2021, the filing date of the Motion. Amounts recorded in the memorandum account may be included in a future application for recovery in rates. SCE shall submit a Tier 1 Advice Letter to the Commission's Energy Division to modify any tariff provisions necessary for the establishment of this memorandum account.

PG&E's January 12, 2021 motion sought similar relief to the request of SCE in SCE's January 11, 2021 motion. In PG&E's motion, it outlines that its opening testimony included four major areas of proposals to either augment existing programs or stand-up new programs, in anticipation of summer 2021. PG&E

[119] January 11, 2021 motion of SCE at 2.

indicated it "may need to incur costs for one or more of these program areas prior to a final decision in this proceeding, in order to support implementation for the summer 2021 season."[120] PG&E thus indicated that it filed the motion for authorization to use the proposed memorandum account with an effective date of January 12, 2021, the filing date of the motion. The January 12, 2021 motion of PG&E is granted. PG&E is authorized to establish the requested memorandum account and to utilize that account to track incremental costs incurred to begin working on proposals in Rulemaking 20-11-003, as well as incremental costs for other activities authorized in this decision that are not specifically authorized for recovery. The effective date of the memorandum account hereby authorized shall be January 12, 2021, the filing date of the Motion. Amounts recorded in the memorandum account may be included in a future application for recovery in rates. PG&E shall submit a Tier 1 Advice Letter to the Commission's Energy Division to modify any tariff provisions necessary for the establishment of this memorandum account.

Consistent with these two authorizations, SDG&E is authorized to track incremental costs incurred to begin working on proposals in R.20-11-003 in its existing Advanced Metering and Demand Response Memorandum Account. SDG&E may seek recovery of those costs by application, and if approved, seek recovery of the costs via its Rewards and Penalties Balancing Account. SDG&E shall submit a Tier 1 Advice Letter to the Commission's Energy Division to modify any tariff provisions necessary to permit it to record such costs in the Advanced Metering and Demand Response Memorandum Account for future

[120] January 12, 2021 motion of PG&E at 2.

recovery of authorized amounts through the Rewards and Penalties Balancing Account.

12. Additional Issues to Consider in this Proceeding

Based on comments to the Proposed Decision, we have determined that it is prudent to leave this proceeding open to potentially evaluate and consider the adoption of party proposals, or elements of the party proposals, in an additional phase of this proceeding. Proposals like those that the California Environmental Justice Alliance included in its testimony that was admitted to the record and the PG&E proposed Residential Rewards program could provide significant load reduction during peak and net peak periods beginning in 2022. In a second phase to this proceeding, we may consider proposals like these and others that have been posed in the evidentiary record of this proceeding.

13. Administrative and Procedural Matters

On February 5, 2021, Cal Advocates moved to file under seal a portion of the evidentiary record, specifically its exhibit titled as "Opening Testimony 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, Confidential Version."

Consistent with the requirements of D.06-06-066, D.17-09-023, and General Order (GO) 66-D, Cal Advocates filed and served a motion that included a declaration setting forth which data is proposed for confidential treatment and why. With good cause being shown, this exhibit is admitted under seal for the duration of three years and is marked as exhibit CA-1C. During this time frame, the specified information should not be publicly disclosed except on further Commission order or ALJ ruling. If any party believes that it is necessary for this information to remain under seal for longer than three years, the party should file a motion showing good cause for extending this order by no later than 30 days before the expiration of this order.

The Commission affirms the rulings issued in this proceeding, and any motions that were not ruled on are denied as moot.

14. Reduction of Comment Period and Comments on the Proposed Decision

Pursuant to Rule 14.6(a)(1) and 14.6(a)(8) of the Commission's Rules of Practice and Procedure, and Public Utilities Code Section 311(g)(2), the Commission is shortening the 30-day comment period for the Proposed Decision on the basis of an unforeseen emergency situation. Opening comments are due on March 15, 2021, and reply comments are due on March 19, 2021.

Commission action is required in this situation more quickly than permitted under the public review and comment period for proposed decisions. A delay in a Commission Decision on this matter beyond March 2021 would put reliability at risk in the forthcoming summer of 2021. As we learned from SCE at the prehearing conference, a Commission decision that is finalized in April 2021 would not allow for enough time to have successful DR programs adopted in time to enhance reliability in the summer of 2021.

Commission action under a reduced comment period is therefore necessary to avoid events that could severely impair or threaten to severely impair public health or safety, and because the instant reliability challenges and procurement timelines constitute unusual matters that cannot be disposed of by normal procedures if the duties of the Commission are to be fulfilled.

Independent Energy Producers, Center for Energy Efficiency and Renewable Technology, TURN, Californians for Renewable Energy, DR Coalition, Vehicle-Grid Integration Council, Joint DR Parties, Protect Our

Communities Foundation, Utility Consumers' Action Network, SDG&E, Sierra Club/California Environmental Justice Alliance/Union of Concerned Scientists, Cal Advocates, California Independent System Operator, California Energy Storage Alliance, California Community Choice Association, PG&E, California Large Energy Consumers Association, The Regents of the University of California/Direct Access Customer Coalition/Alliance for Retail Energy Markets, SCE, LS Power, Google, City and County of San Francisco, and Polaris Energy Services filed comments on March 15, 2021.

Ecobee, Department of Market Monitoring of the California Independent System Operator Corporation, California Independent System Operator Corporation, California Environmental Justice Alliance/Sierra Club/Union of Concerned Scientists, TURN, Independent Energy Producers Association, Cal Advocates, PG&E, Utility Consumers' Action Network, SDG&E, California Energy Storage Alliance, Direct Access Customer Coalition/The Regents of the University of California/Alliance for Retail Energy Markets. Center for Energy Efficiency and Renewable Technologies. Joint DR Parties, California Community Choice Association, SCE, Small Business Utilities Advocates, Protect Our Communities Foundation, PowerSecure, Peterson Power Systems, and California Large Energy Consumers Association filed reply comments on March 19, 2021.

We reviewed and considered all opening and reply comments.

14.2. Modifications to the Proposed Decision in Response to Comments

The Commission considered the opening and reply comments, and the following revisions based on comments to the proposed decision have been made.

The proceeding will remain open to consider additional party proposals for summer 2022.

In response to comments from SCE, we modify the proposed decision to clarify that all three large electric IOUs must fund the Flex Alert campaign using Public Purpose Program balancing accounts. Additionally, in response to comments by PG&E, we place a 3% budget cap on Flex Alert program admin costs.

In regard to CPP, in response to comments from PG&E, we authorize PG&E to spend and recover up to $2 million to implement the new CPP event hours of 4:00 pm to 9:00 pm. In response to comments from SCE, we extend the deadline for SCE to include weekends and holidays as potential call days for its CPP program to June 1, 2022. In response to comments from PG&E, we increase the amount PG&E is authorized for new customer education focused on improving CPP performance to $635,000 (from $500,00). In response to comments from SCE, we increase the amount SCE is authorized for new customer education focused on improving CPP performance to $1,000,000 ($500,000 annually for 2021 and 2022). In response to comments from California Community Choice Association, we modify the IOU-CCA workshop scope to include alternative approaches for CCAs to promote load shedding, including how the CCAs should coordinate with IOUs on programs and remove the scoped issue of feasibility and challenges to IOUs integrating CPP program credits and charges into their billing systems through billing system determinants.

Regarding ELRP, we make the following modifications to the proposed decision in response to comments. In response to comments from SCE, we remove the day-of trigger option, keeping only the day-ahead trigger. In response to comments from California Large Energy Consumers Association and DR Coalition, we allow for compensation for ELRP test events at rate of $1/kWh (for one 2-hour test per season for Group A only). However, in response to comments by California Environmental Justice Alliance/Union of Concerned Scientists/Sierra Club, we do not permit or allow compensation for prohibited resources during ELRP test events. In response to comments from the DR Coalition, we increase the Day-Of adjustment for the ELRP baseline from 80% to 100%. In response to comments from the Joint DR Parties, for Group B we eliminate invoicing threshold of $10,000 and allow invoicing 2x per season. In response to reply comments from the CAISO Department of Market Monitoring, and to mitigate the unintended consequences of ELRP on CAISO market operations, we adjust the settlement method so that the ELRP compensation for the ILR delivered by a Group B resource during an ELRP event is reduced by CAISO market clearing price, either the day-ahead or real-time clearing price—whichever is higher. In response to comments from PG&E, SCE, and SDG&E, we clarify the process by which IOUs may submit Advice Letters to modify or defer implementation of various aspects of ELRP design. In response to comments from PG&E, we clarify that the ELRP budget caps are annual. In response to comments by California Environmental Justice Alliance/Union of Concerned Scientists/Sierra Club and Cal Advocates regarding the eligibility of prohibited resources in ELRP, and the prohibition on the participation of such resources in Commission decision D.16-09-056, we first that note that D.16-09-056 exempts an enumerated set of programs from the prohibited resource restrictions. The proposed decision is revised to clarify that the new ELRP is included as an exempted program, that is not subject to the demand response prohibited resource requirements and restrictions. We find it is reasonable to exempt the ELRP program from the prohibition because ELRP is an out of market emergency program designed to avoid rotating outages during extreme grid stress conditions. To be clear, this decision does not impact the bar on prohibited resource participation in BIP and only exempts incremental load reductions provided under the ELRP. Further, we note that the scoping ruling in this proceeding expressly identified the use of back-up generation participation in an emergency load reduction program as issue 2(c)(v) within the scope of this proceeding. The scoping ruling was served on the parties to Rulemaking 13-00-001 from which D.16-09-056 issued, placing parties to that proceeding on notice that the Commission could include ELRP within the demand response programs exempted by Ordering Paragraph 3 of D.16-09-056. Finally, the December 18, 2020 ALJ ruling and attached staff proposal further expressly directed parties to address whether customers should be permitted to use prohibited resources during an ELRP event in their testimony and reply testimony. We find that parties received proper and adequate notice and opportunity to be heard on this issue for the Commission to find that ELRP as a demand response program should be exempted from prohibited resource restrictions. In response to comments of the California Environmental Justice Alliance/Union of Concerned Scientists/Sierra Club, we identify ELRP design aspects that are subject to revision in years 2023-2025 in the DR application proceeding expected to commence in November 2021: minimizing use of diesel backup generators where there are safe, cost-effective, and feasible alternatives; consideration of local air pollution impacts on disadvantaged communities; and other modifications to make the program more effective and consistent with the state's decarbonization goals. To this end, PG&E, SCE, and SDG&E should collect data on backup generator participation in ELRP, such as location, type of fuel used, and the capacity of the generator, in years 2021 and 2022.

In response to comments, we made the following modifications to the demand response direction in the proposed decision. In response to comments from PG&E, we change each IOU's Base Interruptible Program (BIP) enrollment requirement to ensure that regardless of when a customer enrolls throughout the year, they must remain enrolled for at least one full summer. Existing unenrollment windows are unchanged. In response to comments from CAISO, we direct the IOUs (and invite third-party DR providers) to collaborate with CAISO to explore potential baseline adjustment increases during stressed grid conditions; permit IOUs to utilize the new baseline options in their respective CBP; and permit DR providers to utilize the new baseline options for capacity invoicing under the Demand Response Auction Mechanism.

In response to comments from DR Coalition and TURN, we increase SCE's CBP incentive rates by 20% for 2021 and 2022. In response to comments of CESA and SCE, we approve SCE's proposal to create Phase II of its Virtual Power Plant (VPP) pilot. In response to comments from PG&E, DR Coalition, and TURN, we approve PG&E's proposal to extend CBP to seven days per week, along with a 25% capacity incentive adder for weekend participation for 2021 and 2022 and approve PG&E's proposal to increase the CBP capacity incentive level for October from the current $2.27/kW to $6.80/kW for the Day-Ahead option in 2021 and 2022. In response to comments from SDG&E, we waive any non-performance penalties for the three additional monthly CBP events authorized for SDG&E.

In response to comments, we made the following modifications to the planning reserve margin and capacity procurement direction in the proposed decision. In response to comments from SCE and SDG&E, we clarify that the PRM increase in place for only 2021 and 2022, and is subject to modification in the RA proceeding. In response to comments from the Alliance for Retail Energy Markets, we clarify that there will not be RA capacity benefits to allocate to all LSEs associated with this procurement (as is usually the case with resources procured through CAM).

In response to comments from TURN, Cal Advocates, and California Environmental Justice Alliance/Union of Concerned Scientists/Sierra Club, authorization by Application for fossil-fuel contracts for redevelopment or full repowering at existing or mothballed electric generation sites has been removed.

In response to comments from SCE, we clarify that IOU procurement, including RA resources procured under D.21-02-028, may first be used to meet bundled service needs. In response to comments from the CAISO, we require IOUs to include all RA eligible resources supporting the effective 17.5% PRM in their month-ahead RA showings. IOUs should pair any new imports with maximum import capacity (MIC) and include these MIC and contract costs in their CAM procurement costs. In response to comments from CAISO, SCE, and California Community Choice Association, we authorize the IOUs to meet their minimum MW procurement targets using resources in their existing portfolios and charging the Power Charge Indifference Adjustment RA System Market Price Benchmark for these resources if they have long RA positions and have made reasonable attempts to sell the excess capacity to other LSEs. This is allowed only to the extent that the IOU determines it will <u>not</u> meet its minimum procurement target for June, and October after accounting for (estimating) any additional DR and ERLP resources resulting from this decision. For July, August, and September, it is allowed up to each IOU's respective soft cap, though again, after accounting for any additional DR and ERLP resources.

Regarding balancing and memorandum accounts, we make the following modifications in response to comments. In response to comments from PG&E, we clarify that IOUs should use one-way balancing accounts to track incremental costs <u>that are specifically authorized for recovery</u> by the decision and that those costs may be recovered in the IOUs' annual balancing account true-up advice letters. Additionally, in response to comments from PG&E, we clarify that IOUs should use memorandum accounts to track incremental costs for activities authorized in this decision <u>that are not specifically authorized for recovery</u> and that those costs may be included in a future application for recovery in rates.

15. Assignment of Proceeding

Marybel Batjer is the assigned Commissioner and Brian Stevens is the assigned ALJ in this proceeding.

Findings of Fact

1. In August 2020, a majority of the western United States encountered a prolonged extreme heat event.

2. As a result of the prolonged heat event, the CAISO initiated rotating outages in its balancing authority area to prevent wide-spread service interruptions.

3. On October 6, 2020, the CPUC, California Energy Commission, and CAISO published a Preliminary Root Cause Analysis report that examined the cause of the August 2020 rotating outages.

4. The Preliminary Root Cause Analysis identified several actions that will address the contributing factors that caused the August 2020 rotating outages. The actions identified in the Preliminary Root Cause Analysis include expediting

the regulatory and procurement processes to develop additional resources that can be online by summer 2021.

5. There is a need for incremental physical resources and modified demand response measures to address grid needs during the system peak and net peak demand periods for summer 2021 and 2022 and to prevent similar service interruptions to the August 2020 rotating outages.

6. Time is of the essence, and the Commission needs to expeditiously signal support of contracts for expansion of existing resources that can help maintain reliability in summer 2022 by delivering during peak and net peak demand periods.

7. Decision 21-02-028 identified a robust procurement process for capacity that is online in 2021 that may be replicated for capacity procurement that may be online for 2022 need or to meet the modified PRM developed in this decision.

8. Flex Alert is a statewide media campaign that educates consumers regarding the positive impacts of conservation, helps them understand grid conditions and informs consumers when conservation is needed because electricity supplies are short. Long-term support and funding of the program can establish and sustain a trusted brand and consumer tool that is essential to overall grid reliability.

9. Contracting with existing marketing, education, and outreach vendors for the implementation of the 2021 and 2022 iterations of the Flex Alert program allows the program to be available for the summers of 2021 and 2022. In the longer run, an open solicitation may identify a vendor that is able to provide greater value.

10. The Commission's Energy Division can provide oversight on the implementation of a Flex Alert program.

11. Directing one electric IOU to manage the Statewide contract for Flex Alert reduces the complexity of the administration of the program, and SCE is capable of executing this function. $12 million per year is an appropriate level of funding for the Statewide contract for Flex Alert, and 3% of that budget is an appropriate cap for IOU administration costs.

12. It is appropriate for all customers in the service territories of the large electric investor-owned utilities to fund the Flex Alert paid media campaign program authorized in this decision.

13. CPP is a retail rate mechanism whereby a utility or LSE charges a higher price for consumption of electricity during peak hours on selected days, referred to as critical peak days or event days. Currently PG&E, SCE, and SDG&E all have active CPP programs, although the design elements for each individual large electric IOU differ.

14. Aligning the timing of CPP events with the times the grid is most stressed will allow for CPP to be available at the critical times when most needed to avert potential rotating outages.

15. Utilizing funds to educate impacted customers about the CPP program will allow for the CPP to be more effective when called because customers are more aware of the impact of CPP and how to take appropriate action in reducing consumption at the critical times.

16. CCAs and ESPs generally are not providing CPP programs for their customers, citing a number of perceived barriers to implementation.

17. An ELRP will allow the large electric IOUs and CAISO to access reasonably certain controlled load reduction during times of high grid stress and emergencies involving inadequate market resources, with the goal of avoiding rotating outages while minimizing cost to ratepayers.

18. The appropriate duration for the first iteration of ELRP is as a pilot program that will run for the years 2021-2025, with years 2023-2025 subject to review and revision in the DR application proceeding expected to be initiated November 2021.

19. ELRP load reduction capacity could be excluded from the RA/California Energy Commission peak forecast framework with no CAISO market obligations.

20. There are numerous parameters outlined in Attachment 1 of this decision that will allow the ELRP to be effectively administered.

21. The following customers could be eligible to participate in the ELRP A) Non-Residential, Non-DR Customer: BIP Aggregators, Rule 21 Exporting DERs, and VPP and B) Market-integrated PDR resources: Third-party DR Providers and IOU CBP PDR Resources.

22. It is reasonable to allow prohibited resources to participate in ELRP and to add ELRP to the list of programs exempted from the demand response prohibited resource requirements and restrictions because ELRP is an out of market emergency program designed to avoid rotating outages during extreme grid stress conditions.

23. The issuance of an OIR; a ruling incorporating the Staff Proposal, which included questions regarding the Staff Proposal; and the opportunity for comment on the OIR and Staff Proposal together constitute the proper notice and comment methodology required to create a record in this proceeding for this decision to include ELRP on the list of demand response programs that are exempt from the bar on the use of prohibited resources.

24. The appropriate trigger for ELRP is day-ahead.

25. Triggering an ELRP by an IOU for a localized transmission or distribution emergency is an inappropriate use of the program.

26. In the future, when the CAISO completes the transition from the current AWE process to the North American Electric Reliability Corporation Energy Emergency Alert standards, then the AWE declarations may be replaced by the equivalent CAISO issued day-ahead EEA level notices in accordance with AWE Levels table in Attachment 1.

27. The appropriate ELRP Compensation Rate is set at $1 / kilowatt-hour (kWh) (or $1000 / megawatt-hour (MWh)).

28. The baseline and settlement parameters outlined in Attachment 1 are the appropriate baseline and settlement determinants for the ELRP program in terms of determining the load reduction of the program participants.

29. It is appropriate for the IOUs to conduct test events for ELRP participants in Group A as outlined in Attachment 1.

30. Within 30 days of the effective date of this Decision, PG&E, SCE and SDG&E could jointly file a Tier 1 AL incorporating the ELRP terms and conditions for Group A. Limited deviations to accommodate IOU-specific implementations due to IT and billing systems could be permitted. The filing could include details necessary to implement the ELRP guidelines set forth in Attachment 1 and address various aspects of ELRP pilot design, including enrollment, event notification and customer acknowledgment, ILR measurement, and settlement.

31. Within 60 days of this Decision, the IOUs could jointly file a Tier 1 AL incorporating the ELRP terms and conditions for Group B. Limited deviations to accommodate IOU specific implementations due to IT and billing systems could be permitted. The filing could include the details necessary to implement the

ELRP guidelines set forth in Attachment 1 and address various aspects of ELRP pilot design and processes, including enrollment, the process to update enrollment related program parameters, ELRP event notification, ILR measurement, and settlement and invoicing.

32. An IOU's Tier 1 AL filing to defer implementation of certain ELRP design elements, where permitted, could include an explanation for why the delay is necessary or reasonable.

33. As experienced in ELRP is gained, the IOUs could seek to modify various aspects of ELRP design by jointly filing a Tier 2 AL before or by December 31 of each program year to manage program enrollment, improve program efficiency, increase potential load reduction available to ELRP, avoid unintended interactions between ELRP Group B participation and CAISO market operations, and improve program value and reduce program cost. The change request could be limited to technical aspects of the program design related to program participation criteria (including various minimum threshold parameters), program trigger(s), Group A baselines and settlement, and Group B baselines, settlement, and invoicing guidelines. Changes to sub-group A.1 Minimum Size Threshold parameter could be sought via an IOU-specific Tier 2 AL.

34. PG&E, SCE, and SDG&E could be authorized to establish one-way balancing accounts to track costs that are specifically authorized to be incurred in this decision, including regarding the development, implementation, and operation of ELRP, along with incentives paid under the program. The balancing accounts could be effective as of the date of this decision. These three electric IOUs could file Tier 1 ALs within 5 days of the issuance of this decision establishing the new one-way balancing accounts. Amounts recorded in the balancing account that are specifically authorized to be incurred in this decision

could be recoverable in the annual balancing account true-up ALs. The record supports these balancing accounts to have the following annual caps for ELRP, with the proviso that any excess costs above the IOUs' annual caps for administration may be tracked in their respective memorandum accounts also authorized in this decision:

- PG&E $3.9 Million for administration and $28.6 million for customer compensation,
- SCE $2.9 Million for administration and $33.8 million for customer compensation, and
- SDG&E $1.6 Million for administration and $14.8 million for customer compensation.

35. Waiving the use of our traditional cost-effectiveness tools for all demand response proposals that are adopted in this decision for years 2021 and 2022 will allow for increased participation.

36. Year-round enrollment in BIP and SCE's AP-I will allow for greater participation in these DR programs, resulting in decreased peak and net peak load during times when these programs are triggered. A good way to manage this is to ensure that the participants who enroll in the program by April 30 in any given calendar year remain for at least 6 months before being able to exit, and that participants who enroll after April 30 remain at least 12 months before exiting the program. Given the existing unenrollment windows (i.e., during November for SCE and PG&E, and during November and April for SDG&E), this guarantees that new enrollees must participate in one full summer before exiting.

37. Increasing the DR reliability cap to 3% allows for greater participation in the reliability DR programs, resulting in decreased peak and net peak load during times when the program is triggered.

38. Removing restrictions on utilizing the funding for the Demand Response Marketing, Education and Outreach program to actively market BIPs while there is room for new customer enrollment allows for greater participation in BIP, resulting in decreased peak and net peak load during times when the program is triggered.

39. The CAISO indicates it is contemplating potential baseline adjustment increase(s) during stressed grid conditions. PG&E, SCE, and SDG&E could be directed, and third-party DR providers could be invited, to work collaboratively with the CAISO to explore baseline options during stressed system conditions. To the extent the CAISO introduces new baseline options for energy market settlement, the IOUs could be permitted to utilize the new baseline options in their respective CBPs, and DR providers could be permitted to utilize the new baseline options for the Demand Response Auction Mechanism.

40. If SCE increases the BIP incentive 20% there will be greater participation in this DR program, resulting in decreased peak and net peak load during times when the program is triggered.

41. If SCE updates the SEP tariff to modify the medical baseline exclusion, with an authorized incremental budget of $3.3 million, and aligns it with the existing medical baseline exclusion language in the SDP tariff, and optimizes new acquisition opportunities to increase customer enrollment in SEP (*e.g.*, integrated demand-side management, point-of-sale enrollment, etc.), there will be increased participation resulting in decreased peak and net peak load during times when the program is triggered.

42. If SCE's proposal to eliminate the restriction preventing participation by customers of CCAs and ESPs by converting SEP from generation to distribution funding by 2022 is approved, and SCE is authorized $2.87 million additional

funding for labor, non-labor vendor support, participant incentives and ME&O to implement the proposal, there will be greater participation in the program, resulting in decreased peak and net peak load during times when the program is triggered.

43. Approving SCE's proposal to market and pay a sign-up bonus of $50 to increase SDP enrollment, along with an incremental funding request for $1.5 million for each year 2021 and 2022 will result in greater participation in the program, resulting in decreased peak and net peak load during times when the program is triggered.

44. Approving SCE's proposal for the purchase and installation of up to 60,000 new load control devices for new SDP enrollments, along with incremental funding of $3.64 million in 2022 will result in greater participation in the program, resulting in decreased peak and net peak load during times when the program is triggered.

45. Approving SCE's proposal to increase SDP residential incentives by 25 percent from current levels and use the SDP contingency incentives authorized will result in greater participation in the program, resulting in decreased peak and net peak load during times when the program is triggered.

46. If SCE revises its SDP tariffs to remove the minimum dispatch requirement, while preserving the maximums of 20 economic hours and 180 emergency hours annually, the result will be greater participation in the program, resulting in decreased peak and net peak load during times when the program is triggered.

47. Approving SCE's proposal to add residential accounts to CBP instead of conducting a one-year residential CBP pilot and add a 5-in-10 baseline (with 40% day-of adjustment) for residential accounts, requiring no incremental

funding, will result in greater participation in the program, resulting in decreased peak and net peak load during times when the program is triggered.

48. Approving SCE's proposal to increase CBP Day-Ahead and Day-Of capacity incentive rates ($/kW-year) by 20 percent for 2021 and 2022 could add more capacity to the program.

49. Approving SCE's proposal to create Phase II of its VPP pilot to acquire additional vendors and customers, test dispatchable technologies, including hybrid battery energy storage, and various dispatch strategies, including grid reliability events, could provide additional capacity to grid by the third quarter of 2021.

50. SCE can modify its DR systems and technology infrastructure, at the cost of $106,000, that will allow for more efficient programs that could reduce load at peak and net peak times including extending the legacy Alhambra Control Platform for one additional year, enhancing the DR Event Website and DR Mobile App, and creating a test rack to confirm when a DR event has taken place.

51. Increasing PG&E's BIP incentive rate by $1.50/kW for 2021 and 2022 will result in increased participation that will lead to decreased peak and net peak load during times when this program is triggered.

52. Approving a modified PG&E CBP tariff to increase the maximum number of events allowed per month from five to six, with the clarification that the foregoing takes precedence over the maximum number of 30 hours per operating month, will result in increased participation that will lead to decreased peak and net peak load during times when this program is triggered.

53. Approving PG&E's proposal to extend the CBP operating days to seven days per week by adding a weekend option, along with a 25 percent capacity

incentive adder for the weekend participation for 2021 and 2022, could contribute to grid reliability during all days of the CBP DR season.

54. Approving PG&E's proposal to increase the CBP capacity incentive level for the month of October from the current $2.27/kW to $6.80/kW for the Day-Ahead participation option for 2021 and 2022 would garner additional participation in October.

55. Approval of SDG&E's proposal for the current 100 kW minimum requirement for participation in BIP to be waived, and all non-residential customers of SDG&E being eligible to enroll and participate in BIP will result in increased participation and lead to decreased peak and net peak load during times when this program is triggered.

56. Updating the measuring hours for SDG&E customers' "monthly average peak demand" to align the measuring hours for customers with "availability assessment hours" on which BIP's performance is measured will result in more effective participation and lead to decreased peak and net peak load during times when this program is triggered.

57. Changing the time period SDG&E uses to calculate the BIP capacity incentive from 1:00 p.m. to 6:00 p.m. window to 4:00 p.m. to 9:00 p.m. window will lead to decreased peak and net peak load during times when this program is triggered and result in increased participation.

58. SDG&E's proposal to modify its CBP tariff to increase the maximum number of events allowed per month from six events to nine events, with the additional three events reserved for CAISO or SDG&E emergencies, will result in increased participation and lead to decreased peak and net peak load during times when this program is triggered. Waiving any non-performance penalties

associated with the three additional monthly CBP events would encourage participation in those CBP events.

59. SDG&E's proposal to modify its CBP tariff to (1) adjust notification time to be 5:00 PM for the CBP Day-Ahead product and (2) update the CBP Day-Of product notification time to 40 minutes to allow the program to be bid into the CAISO Day-Of market will result in more effective participation and lead to decreased peak and net peak load during times when this program is triggered.

60. SDG&E's launch of the CBP Residential Pilot in 2021 results in more opportunity for customers to participate in DR programs and thus will lead to decreased peak and net peak load during times when this program is triggered.

61. SDG&E's proposal to modify the AC Saver tariff to allow participation by residential NEM customers will result in increased participation and lead to decreased peak and net peak load during times when this program is triggered.

62. SDG&E's proposal to modify the AC Saver tariff to increase the maximum number of events allowed in a year from 20 events to 25 events, with the additional 5 events reserved for CAISO or SDG&E emergencies will result in increased participation and lead to decreased peak and net peak load during times when this program is triggered.

63. SDG&E's proposal to a) pursue emergency agreements with device manufacturers who already have devices participating in the AC Saver program to signal existing installed thermostats that are not in an existing DR program to secure additional load reduction, and b) offer a reasonable incentive, consistent with the guidelines described by SDG&E, to these manufacturers for increasing the number of participating thermostats, will result in increased participation and lead to decreased peak and net peak load during times when this program is triggered.

64. There is a need for an increase in supply side resources in light of the weather experienced throughout the summer of 2020 and in anticipation of more frequent extreme weather events resulting from climate change.

65. There is a need to ensure that there are sufficient supply side resources in place to meet demand during the net peak hour, and thus all the incremental resources procured through this proceeding are required to be available during net peak.

66. Adopting an interim approach to increasing supply side resources that effectively increases the PRM to 17.5% from summer 2021 through 2022, subject to modification in the RA proceeding, will support procurement of incremental supply side resources.

67. Given the tightness of the market at this time, coupled with the fact that we are directing PG&E, SCE, and SDG&E to perform almost all of the expedited procurement being authorized in this proceeding versus spreading the requirement to all LSEs, the most practical and expeditious method to implement a 17.5% PRM that supports the goal of meeting net peak demand is to continue to require all LSEs to meet their 15% system RA PRM requirement and direct PG&E, SCE, and SDG&E to target a minimum of 2.5% of incremental resources that are available at net peak through the efforts authorized in this proceeding. For 2021, 2.5% of the average CPUC jurisdictional share of CAISO peak load for the peak summer months per the California Energy Commission's 2019 Integrated Energy Policy Report forecast for the year 2021 results in a minimum incremental procurement target of 450 MW for PG&E, 450 MW for SCE, and 100 MW for SDG&E.

68. All resources procured through this proceeding, including emergency-triggered resources that do not count towards RA like ELRP, are

incremental and it is reasonable to include them in meeting incremental procurement targets.

69. Given some unknowns about DR resource availability, considering PG&E, SCE, and SDG&E respective upper end targets as "soft caps" for all resources authorized for procurement in this proceeding, but as "hard caps" for incremental supply side generation and in-front-of-meter storage resources, the total procurement under this proceeding, including RA and non-RA DR resources, could exceed the upper end targets.

70. It is not reasonable for generation and in-front-of-meter resources alone to exceed 150% of each PG&E's, SCE's, and SDG&E's incremental procurement target.

71. It is most critical that PG&E, SCE, and SDG&E target incremental procurement during the months of most concern, including May through October, and especially endeavor to meet and exceed their respective minimum MW targets in July, August, and September.

72. To fairly distribute the cost and reliability benefits of this procurement, it is reasonable to pass the net costs associated with this procurement through to all benefiting customers consistent with the existing cost allocation mechanism.

73. Because this procurement is additional to LSEs' RA requirements, there will not be RA capacity benefits to allocate to all LSEs, as is usually the case with resources procured through the cost allocation mechanism. In this instance, the benefits provided to all LSEs is increased electric reliability without requiring all LSEs to procure their share of these incremental resources under this expedited timeframe or be subject to RA program penalties for not doing so.

74. After hydroelectric resource conditions are better understood and to better prepare for any additional measures to meet summer peak load in the event of

another extreme weather event, it is reasonable for all LSEs to provide Energy Division non-binding month-ahead RA filings for July, August and September no later than April 15, 2021, reflecting their most recent RA positions, including any excess RA procurement (but excluding IOU procurement authorized in this proceeding).

75. PG&E, SCE, and SDG&E could be directed to continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve this effective 17.5% PRM for the months of concern. Consistent with the guidance provided in D.21-02-028, the IOUs could give preference to storage contracts (from new solicitations, bilateral negotiations, or offering counterparties an opportunity to refresh prior IRP procurement bids), upgrades resulting in increased efficiency of existing generation resources, and contract terms that are shorter in duration. All procurement contracts could be submitted to Energy Division via a Tier 1 AL on a continuing basis, except for contracts for incremental gas generation of five years or more and incremental imports. Contracts of five years or more for incremental generation at existing gas power plants could be submitted to Energy Division via a Tier 3 AL. Contracts for fossil-fuel development at new sites or for redevelopment or full repowering at existing or mothballed electric generation sites will not be considered. Tier 1 ALs are not required, but could be submitted, for incremental imports, provided the IOUs remain within the "hard cap" procurement limits for supply-side generation and storage resources discussed above.

76. IOU procurement, including RA resources procured under D.21-02-028, could first be used to meet bundled service RA requirements, because IOUs will

be procuring to meet both their individual 15% PRM RA requirements and the additional procurement directed in this proceeding.

77. Because a combination of RA eligible and non-eligible resources may be used to meet the effective 17.5% PRM, all RA eligible resources supporting the effective PRM could be included in IOUs' month ahead RA showings and included on supply plans to ensure that these resources are subject to RA obligations and incentive mechanisms, do not receive CPM double-payments, and are visible to the CAISO as RA resources not eligible for export. Of these resources, only costs associated with RA resources in excess of an IOU's own 15% PRM could be charged to all benefiting customers in the IOU's service territory via the CAM.

78. IOUs may acquire and pair imports contracted to meet the effective 17.5% PRM with maximum import capability and include these costs in their CAM procurement costs. If existing IOU-owned maximum import capacity is paired with imports to construct an RA product, the IOU could calculate and include the average price it received for sales of its excess maximum import capability or, if not available or representative of market value, another reasonable benchmark.

79. After accounting for resources procured under D.21-02-028 and additional resources procured under the authority of this decision, if an IOU has not met its minimum procurement target for the months of June through October, and it has excess RA capacity beyond its own RA requirements after making reasonable attempts to sell this excess capacity to other LSEs to meet their 15% PRM requirements, it could show these resources to meet the minimum MW procurement target at the imputed cost of the 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark.

80. For the months of July through September, the IOUs could use any excess, unsold RA resources in their portfolios to supplement the resources they have procured under the authority of this expedited procurement proceeding – including estimates of ERLP resources – up to their respective soft caps (675 MW for PG&E and SCE, and 150 MW for SDG&E). This approach could encourage higher levels of RA to be shown and available for the three months of historically highest grid stress.

81. A benefit of showing these resources is that they will be subject to RA requirements and incentive/penalty mechanisms, and they will be visible to CAISO as RA resources that are not available for export or a CPM payment. This approach also avoids the unintended outcome of IOUs buying excess RA resources from one another's RA solicitations to the extent each need to do so to meet their targeted additional 17.5% PRM procurement, potentially at premiums well in excess of the 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark.

82. The IOUs could provide the monthly amounts of the excess resources they applied to the CAM and included on their monthly RA plans, as well as the calculus used to determine these amounts to Energy Division, and Energy Division could post this information on its website.

83. To the extent that any additional adjustments to balancing accounts are needed to provide for CAM cost recovery of the procurement authorized in the decision, the IOUs could file Tier 2 ALs with the effective date of the tariff modification to be the effective date of this decision.

84. SDG&E could be authorized to track incremental costs incurred to begin working on proposals in R.20-11-003 in its existing Advanced Metering and Demand Response Memorandum Account. SDG&E could seek recovery of those

costs by application, and if approved, seek recovery of the costs via its Rewards and Penalties Balancing Account. SDG&E could submit a Tier 1 AL to the Commission's Energy Division to modify any tariff provisions necessary to permit it to record such costs in the Advanced Metering and Demand Response Memorandum Account for future recovery of authorized amounts through the Rewards and Penalties Balancing Account.

Conclusions of Law

1. A Statewide Flex Alert paid media campaign program administered by SCE should be designed and authorized, as outlined in Section 1 of Attachment 1, to encourage ratepayers to voluntarily reduce demand during moments of a stressed grid in California.

2. PG&E, SCE and SDG&E should fund the paid-media Flex Alert campaign with funds collected from all benefitting customers (*i.e.*, bundled IOU, CCA, and Direct Access customers) using Public Purpose Program balancing accounts, with a cap of $12 million annually, with up to 3% of that budget authorized to cover IOU administration costs.

3. Modifications to the CPP programs of PG&E, SCE, and SDG&E should be instituted, as outlined in Section 2 of Attachment 1, to ensure that the program is more effective and aligned with the times of need.

4. PG&E should be authorized to recover $2,000,000 for the purpose of implementing 4:00 PM to 9:00 PM Critical Peak Pricing event hours in time for Summer 2022. PG&E should address the surcharge and credit changes related to potential event hours in the 4:00 PM to 9:00 PM event window in a Tier 2 AL.

5. PG&E should be authorized to recover $635,000 and SCE should be authorized to recover $1,000,000 ($500,000 annually for 2021 and 2022) for the

purpose of Critical Peak Pricing customer education with a focus on improving the performance of the program.

6. An ELRP program administered by PG&E, SCE, and SDG&E should be developed, as outlined in Section 3 of Attachment 1, as a tool that can provide emergency load reduction and serve as an insurance policy against the need for future rotating outages.

7. Adequate notice and opportunity to be heard was provided by the OIR and Staff Proposal, which discuss allowing prohibited resources to participate in ELRP.

8. Within 30 days of the effective date of this Decision, PG&E, SCE and SDG&E should jointly file a Tier 1 AL incorporating the ELRP terms and conditions. Limited deviations to accommodate IOU-specific implementations due to IT and billing systems should be permitted. The filing should include details necessary to implement the ELRP guidelines set forth above and in Section 3 of Attachment 1 and address various aspects of ELRP pilot design, including enrollment, event notification and customer acknowledgment, ILR measurement, and settlement.

9. PG&E, SCE, and SDG&E should be authorized to establish one-way balancing accounts to track costs that are specifically authorized to be incurred in this decision, including regarding the development, implementation, and operation of ELRP, along with incentives paid under the program. The balancing accounts should be effective as of the date of this decision. These three electric IOUs should file Tier 1 Advice Letters within 5 days of the issuance of this decision establishing the new one-way balancing accounts. Amounts recorded in the balancing account that are specifically authorized to be incurred in this decision should be recoverable in the annual balancing account true-up

ALs. These balancing accounts should have the following caps for ELRP, with the proviso that any excess costs above the IOUs' annual caps for administration may be tracked in their respective memorandum accounts also authorized in this decision:

- PG&E $3.9 million for administration and $28.6 million for customer compensation,
- SCE $2.9 million for administration and $33.8 million for customer compensation, and
- SDG&E $1.6 million for administration and $14.8 million for customer compensation.

10. Modifications to the existing DR programs of PG&E, SCE, and SDG&E should be instituted, as outlined in Section 4 of Attachment 1, to make the programs more effective and more aligned with grid need.

11. PG&E, SCE, and SDG&E should work collaboratively with the CAISO to explore baseline options during stressed system conditions. Third-party DR providers are invited to collaborate. As a result of this exploration, to the extent the CAISO introduces new baseline options for energy market settlement, the IOUs are permitted to utilize the new baseline options in their respective CBPs, and DR providers are permitted to utilize the new baseline options for the Demand Response Auction Mechanism.

12. SCE should modify its DR systems and technology infrastructure, with authorized cost recovery of $106,000 that would allow for more efficient programs that could reduce load at peak and net peak times include extending the legacy Alhambra Control Platform for one additional year, enhancing the DR Event Website and DR Mobile App, and creating a test rack to confirm when a DR event has taken place.

13. Modifications to the PRM should be instituted, as outlined in Section 5 of Attachment 1, to provide a more appropriate reserve for electricity capacity supply side resources during the moments of the most stressed grid.

14. Continued authorizations for supply side procurement by PG&E, SCE, and SDG&E should be instituted, as outlined in Section 6 of Attachment 1, to ensure adequate capacity is procured and secured to meet the appropriate capacity need to avert the potential for rotating outages. The net costs associated with this procurement should be passed through to all benefiting customers consistent with the existing cost allocation mechanism. PG&E, SCE, and SDG&E should be directed to continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve this effective 17.5% PRM for the months of concern. All procurement contracts should be submitted to Energy Division via a Tier 1 advice on a continuing basis, except for contracts for incremental gas generation of five years or more and incremental imports. Contracts of five years or more for incremental generation at existing gas power plants should be submitted to Energy Division via a Tier 3 Advice Letter. Contracts for fossil-fuel development at new sites or for redevelopment or full repowering at existing or mothballed electric generation sites will not be considered. Tier 1 ALs are not required, but may be submitted, for incremental imports, provided the IOUs remain within the "hard cap" procurement limits for supply-side generation and storage resources discussed in Section 6 of Attachment 1.

15. PG&E, SCE, and SDG&E should utilize unspent funds from their existing DR budgets adopted in D.17-12-003, to the extent existing funds are available. To the extent that any tariff amendments are necessary to permit use of existing DR balancing accounts to effectuate the DR program changes ordered in this

decision, those changes should be documented in a Tier 1 AL, as well as the process for transferring balances within the IOU's the Demand Response Programs Balancing Account and Base Revenue Requirement Balancing Account for this purpose.

16. The January 11, 2021 motion of SCE should be granted. SCE should be authorized to establish the requested memorandum account and to utilize that account to track incremental costs incurred to begin working on SCE's DR proposals in R.20-11-003, as well as incremental costs for other activities authorized in this decision that are not specifically authorized for recovery. The effective date of the memorandum account hereby authorized should be January 11, 2021, the filing date of the Motion. Amounts recorded in the memorandum account may be included in a future application for recovery in rates. SCE should submit a Tier 1 AL to the Commission's Energy Division to modify any tariff provisions necessary for the establishment of this memorandum account.

17. The January 12, 2021 motion of PG&E should be granted. PG&E should be authorized to establish the requested memorandum account and to utilize that account to track incremental costs incurred to begin working on proposals in R.20-11-003, as well as incremental costs for other activities authorized in this decision that are not specifically authorized for recovery. The effective date of the memorandum account hereby authorized should be January 12, 2021, the filing date of the Motion. Amounts recorded in the memorandum account may be included in a future application for recovery in rates. PG&E should submit a Tier 1 Advice Letter to the Commission's Energy Division to modify any tariff provisions necessary for the establishment of this memorandum account.

18. SDG&E should be authorized to track incremental costs incurred to begin working on proposals in R.20-11-003 in its existing Advanced Metering and Demand Response Memorandum Account. SDG&E may seek recovery of those costs by application, and if approved, seek recovery of the costs via its Rewards and Penalties Balancing Account. SDG&E should submit a Tier 1 AL to the Commission's Energy Division to modify any tariff provisions necessary to permit it to record such costs in the Advanced Metering and Demand Response Memorandum Account for future recovery of authorized amounts through the Rewards and Penalties Balancing Account.

19. Exhibit CA-1C should be admitted under seal for the duration of three years. During this time frame, the specified information should not be publicly disclosed except on further Commission order or ALJ ruling. If any party believe that it is necessary for this information to remain under seal for longer than three years, the party should file a motion showing good cause for extending this order by no later than 30 days before the expiration of this order.

20. Rulemaking 20-11-003 should remain open to potentially address further issues scoped into this proceeding.

O R D E R

IT IS ORDERED that:

1. Attachment 1 to this decision is adopted in its entirety.

2. A Statewide Flex Alert paid media campaign program administered by Southern California Edison Company shall be designed and authorized, as outlined in Section 1 of Attachment 1, to encourage ratepayers to voluntarily reduce demand during moments of a stressed grid in California.

3. Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company shall fund the paid-media Flex Alert

campaign with funds collected from all benefitting customers (*i.e.*, bundled investor-owned utility, community choice aggregator, and Direct Access customers) using Public Purpose Program balancing accounts, with a cap of $12 million annually, and up to 3% of that budget is authorized to cover administration costs.

4. Modifications to the Critical Peak Pricing programs of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall be instituted, as outlined in Section 2 of Attachment 1, to ensure that the program is more effective and aligned with the times of need.

5. Pacific Gas and Electric Company is authorized to update its Peak Day Pricing and SmartRate surcharges and credits to maintain revenue neutrality by filing a Tier 2 Advice Letter with revised surcharges and credits for Summer 2022 using the most recently approved sales forecast.

6. Pacific Gas and Electric Company is authorized to recover $635,000 and Southern California Edison Company is authorized to recover $1,000,000 ($500,000 annually for 2021 and 2022) for the purpose of Critical Peak Pricing customer education with a focus on improving the performance of the program.

7. An Emergency Load Reduction Program (ELRP) administered by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall be developed, as outlined in Section 3 of Attachment 1, as a tool that can provide emergency load reduction and serve as an insurance policy against the need for future rotating outages, , and as an exempted program under Ordering Paragraph 3 of Decision 16-09-056, thereby not subject to the prohibited resource requirements and restrictions.

8. Within 30 days of the effective date of this Decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas &

Electric Company shall jointly file a Tier 1 Advice Letter incorporating the Emergency Load Reduction Program (ELRP) terms and conditions. Limited deviations to accommodate investor-owned utility specific implementations due to information technology and billing systems shall be permitted. The filing shall include details necessary to implement the ELRP guidelines set forth above and address various aspects of ELRP pilot design and processes, including enrollment, the process to update enrollment related program parameters, ELRP event notification and customer acknowledgment, incremental load reduction measurement, and settlement.

9. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall establish one-way balancing accounts covering costs that are specifically authorized to be incurred in this decision, including those regarding the development, implementation, and operation of the Emergency Load Reduction Program, along with incentives paid under the program. The balancing accounts shall be effective as of the date of this decision. Amounts recorded in the balancing accounts that are specifically authorized to be incurred in this decision shall be recoverable in the annual balancing account true-up advice letters. PG&E, SCE, and SDG&E shall file Tier 1 Advice Letters within 5 days of the issuance of this decision establishing the new one-way balancing accounts.

These balancing accounts shall have the following caps, with the proviso that any excess costs above Pacific Gas and Electric Company's (PG&E), Southern California Edison Company's (SCE), and San Diego Gas & Electric Company's (SDG&E) annual administration caps may be tracked in their respective memorandum accounts also authorized in this decision:

- PG&E $3.9 million for administration and $28.6 million for customer compensation,
- SCE $2.9 million for administration and $33.8 million for customer compensation, and
- SDG&E $1.6 million for administration and $14.8 million for customer compensation.

10. Modifications to the existing demand response programs of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall be instituted, as outlined in Section 4 of Attachment 1, to make the programs more effective and more aligned with grid need.

11. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall work collaboratively with the California Independent System Operator (CAISO) to explore baseline options during stressed system conditions. Third-party demand response (DR) providers are invited to collaborate. As a result of this exploration, to the extent the CAISO introduces new baseline options for energy market settlement, PG&E, SCE, and SDG&E are permitted to utilize the new baseline options in their respective Capacity Bidding Programs, and DR providers are permitted to utilize the new baseline options for the Demand Response Auction Mechanism.

12. Southern California Edison Company shall modify its demand response (DR) systems and technology infrastructure, with authorized cost recovery of $106,000 that would allow for more efficient programs that could reduce load at peak and net peak times, including extending the legacy Alhambra Control Platform for one additional year, enhancing the DR Event Website and DR Mobile App, and creating a test rack to confirm when a DR event has taken place.

13. Modifications to the planning reserve margin shall be instituted, as outlined in Section 5 of Attachment 1, to provide a more appropriate reserve for electricity capacity supply side resources during the moments of the most stressed grid.

14. Continued authorizations for supply side procurement by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall be instituted, as outlined in Section 6 of Attachment 1, to ensure adequate capacity is procured and secured to meet the appropriate capacity need to avert the potential for rotating outages. The net costs associated with this procurement shall be passed through to all benefiting customers consistent with the existing cost allocation mechanism. PG&E, SCE, and SDG&E are directed to continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve this effective 17.5% planning reserve margin for the months of concern. All procurement contracts shall be submitted to Energy Division via a Tier 1 Advice Letter on a continuing basis, except for contracts for incremental gas generation of five years or more and incremental imports. Contracts of five years or more for incremental generation at existing gas power plants shall be submitted to Energy Division via a Tier 3 Advice Letter. Contracts for fossil-fuel development at new sites or for redevelopment or full repowering at existing or mothballed electric generation sites will not be considered. Tier 1 Advice Letters are not required, but may be submitted, for incremental imports, provided the IOUs remain within the "hard cap" procurement limits for supply-side generation and storage resources discussed in Section 6 of Attachment 1.

15. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall utilize unspent funds from their

existing demand response (DR) budgets adopted in Decision 17-12-003, to the extent existing funds are available. To the extent that any tariff amendments are necessary to permit use of existing DR balancing accounts to effectuate the DR program changes ordered in this decision, those changes shall be documented in a Tier 1 Advice Letter, as well as the process for transferring balances within the investor owned utility's Demand Response Programs Balancing Account and Base Revenue Requirement Balancing Account for this purpose.

16. Exhibit CA-1C is admitted under seal for the duration of three years. During this time frame, the specified information shall not be publicly disclosed except on further Commission order or Administrative Law Judge ruling. If any party believes that it is necessary for this information to remain under seal for longer than three years, the party shall file a motion showing good cause for extending this order by no later than 30 days before the expiration of this order.

17. The January 11, 2021 motion of Southern California Edison Company (SCE) is granted. SCE is authorized to establish the requested memorandum account and to utilize that account to track incremental costs incurred to begin working on SCE's demand response proposals in Rulemaking 20-11-003, as well as incremental costs for other activities authorized in this decision that are not specifically authorized for recovery. The effective date of the memorandum account hereby authorized shall be January 11, 2021, the filing date of the Motion. Amounts recorded in the memorandum account may be included in a future application for recovery in rates. SCE shall submit a Tier 1 Advice Letter to the Commission's Energy Division to modify any tariff provisions necessary for the establishment of this memorandum account.

18. The January 12, 2021 motion of Pacific Gas and Electric Company (PG&E) is granted. PG&E is authorized to establish the requested memorandum account

and to utilize that account to track incremental costs incurred to begin working on proposals in Rulemaking 20-11-003, as well as incremental costs for other activities authorized in this decision that are not specifically authorized for recovery. The effective date of the memorandum account hereby authorized shall be January 12, 2021, the filing date of the Motion. Amounts recorded in the memorandum account may be included in a future application for recovery in rates. PG&E shall submit a Tier 1 Advice Letter to the Commission's Energy Division to modify any tariff provisions necessary for the establishment of this memorandum account.

19. San Diego Gas & Electric Company (SDG&E) is authorized to track incremental costs incurred to begin working on proposals in Rulemaking 20-11-003 in its existing Advanced Metering and Demand Response Memorandum Account. SDG&E may seek recovery of those costs by application, and if approved, seek recovery of the costs via its Rewards and Penalties Balancing Account. SDG&E shall submit a Tier 1 Advice Letter to the Commission's Energy Division to modify any tariff provisions necessary to permit it to record such costs in the Advanced Metering and Demand Response Memorandum Account for future recovery of authorized amounts through the Rewards and Penalties Balancing Account.

20. Rulemaking 20-11-003 remains open.

This order is effective today.

Dated March 25, 2021, at San Francisco, California.

MARYBEL BATJER
President
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
DARCIE HOUCK
Commissioners