STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

FILED
10/29/21
03:24 PM

October 29, 2021

Agenda ID #20018
Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 20-11-003:

This is the proposed decision of Administrative Law Judge Sarah R. Thomas. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's December 2, 2021 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Pursuant to Rule 14.6(c)(10), comments on the proposed decision must be filed within 12 days of its mailing and reply comments must be filed within 18 days of its mailing. Comments are due on November 10, 2021 and reply comments are due on November 16, 2021.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ ANNE E. SIMON
Anne E. Simon
Chief Administrative Law Judge

AES:lil

Attachment

Decision **PROPOSED DECISION OF ALJ THOMAS** (Mailed 10/29/2021)

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

PHASE 2 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 2022 AND 2023

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PHASE 2 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 2022 AND 2023

Summary

This decision adopts several supply- and demand-side requirements to ensure there is adequate electric power in the event of extreme weather during times of greatest need in summers 2022 and 2023. Power outages in August 2020 triggered the opening of this proceeding, and while improvements have been made to increase supply and lower demand for electricity, concerns remain.

On July 30, 2021, Governor Newsom issued an Emergency Proclamation urging all state energy agencies to ensure there is adequate electricity to meet the needs of Californians in 2022. The Commission has conducted an analysis of the need for new resources and found that a range of 2,000 to 3,000 megawatts of new supply- and demand-side resources should help address grid reliability concerns in the most extreme circumstances in 2022 and 2023.

This decision adopts the following supply- and demand-side measures to help provide contingency resources to support the grid in an extreme weather event. Each of these measures will help fill the need for additional resources in 2022 and 2023.

- We adopt the following demand-side changes:
  - We expand on the Emergency Load Reduction Program (ELRP) adopted in Phase 1 of this proceeding;
  - We make modifications to the ELRP aimed to increase participation and provide clarity in guidance. Among these modifications, the compensation rate of ELRP is expanded to $2 per kilowatt hour;
  - We add an ELRP program that allows residential customers to receive compensation for reductions in energy use during system emergencies, with special

outreach to low-income customers and customers in Disadvantaged Communities[1];

    - We expand on electric vehicle potential by allowing aggregation of vehicle to grid managed charging and discharge to support the grid at net peak;
    - We broaden the Flex Alert media campaign to focus on the new Residential ELRP program and continue existing activities into 2022 and 2023;
    - We make changes to existing Demand Response programs, both on a statewide basis and to individual programs that pertain to each major electric Investor-Owned Utility;
    - We approve a large smart thermostat incentive program designed to reduce air conditioning a few degrees during emergencies, with special protection for low-income customers that qualify for our Energy Savings Assistance Program; and
    - We add pilots to test the effectiveness of dynamic rates that change rapidly in response to grid emergencies.
- We adopt the following supply-side measures, among others, intended to enhance the availability of electric generation to serve load in summer 2022 and 2023:
    - We allow energy storage projects that are not fully deliverable as long as they provide peak and net peak grid reliability benefits in summer 2022 or 2023;
    - We expand use of a centralized procurement entity as a means of procuring reliability resources located in local areas; and

[1] Pursuant to Section 39711 of the Health and Safety Code, Disadvantaged Communities are defined as (1) Areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation and (2) Areas with concentrations of people that are of low income, high unemployment, low levels of homeownership, high rent burden, sensitive populations, or low levels of educational attainment. *See also* Health and Safety Code Section 116426.

- o We encourage accelerated on-line dates for procurement already ordered.

Two attachments are adopted. Attachment 1 provides an overview of the modifications the Commission is making to the demand side programs, with the exception of the ELRP. Attachment 2 outlines the modifications being made to the ELRP.

This proceeding is closed.

1. Background

In August 2020, California experienced a series of rolling blackouts caused by inadequate energy supply, an extreme heat wave, and market factors. This Commission (CPUC), California Independent System Operator (CAISO) and the California Energy Commission (CEC) issued a Root Cause Analysis of the reasons for the outages, and concluded that additional supply and demand measures were required to avoid a repeat of the 2020 experience in summer 2021.

In the months that followed, this Commission, the CEC and the CAISO took swift and aggressive action to improve near-term system reliability in time for Summer 2021. Among other things, we ordered procurement of new supply and demand side resources for summers 2021 and 2022; the CEC approved efficiency improvements at existing power plants to increase their generation capacity; and the CAISO implemented market changes to better reflect supply and demand during stressed hours. Despite record-breaking heat in California this past summer, which led to tight grid conditions on multiple occasions, we avoided rolling outages like the ones experienced in August 2020.

However, as we have all experienced firsthand, the acceleration of climate change continues to create extreme and unpredictable heat events, droughts, and wildfires across the West—all of which are more frequent and more intense and lead to added stress on our electric grid, especially during critical hours of the day. In 2021, an unprecedented series of heat waves gripped the entire West Coast of the United States, with parts of the States of Oregon and Washington experiencing their first significant heat waves in history. Over the past several summers, California's heat waves have started earlier in the year and lasted longer than in the past.

Meanwhile, the problem of catastrophic wildfire also affected much of the western United States, threatening distribution and transmission lines responsible for ensuring electric reliability in California. A third crisis – extended drought and significantly diminished reservoir water supply – placed significant limits on the amount of hydroelectric generation available up and down the West Coast. Coupled with these other changes, the increase in use of solar energy in California requires adaptation to ensure adequate electric supply remains after the sun sets each day to an even greater extent than previous modeling has suggested.

This perfect storm of reliability challenges requires urgent action now. The Commission must help ensure Californians have adequate energy supply and flexibility in energy demand to ensure energy reliability in summer 2022 and 2023. Our key concern is to ensure the availability of adequate supply, and reduction in electric demand, during the time of day when solar energy ramps down but while electric demand remains high – the so-called net peak demand period. This period generally covers the hours of 4:00 p.m. to 9:00 p.m., as described in Decision (D.) 21-03-056.

The Commission opened this rulemaking on November 19, 2020. During the proceeding's first phase, the Commission issued two decisions, D.21-02-028[2]

[2] *Reh. denied,* D.21-05-036.

and D.21-03-056,[3] focused on ensuring the State has adequate electric supply for 2021. The Commission ordered procurement of additional energy resources like storage, and created innovative Demand Response (DR) programs to help curb energy use during the critical hours of the day when the sun is setting but energy use remains high. The Commission is actively engaged in implementation of the Phase 1 decisions.[4]

This is Phase 2 of the proceeding, focused on increasing electric supply and reducing demand for 2022 and 2023. On July 30, 2021, Governor Newsom signed an Emergency Proclamation to "free up energy supply to meet demand during extreme heat events and wildfires that are becoming more intense and to expedite deployment of clean energy resources this year and next year."[5]

Among the directives included in the Governor's July 30, 2021 Emergency Proclamation was the following:

> All energy agencies shall act immediately to achieve energy stability during this emergency, and the California Public Utilities Commission is requested to do the same. In particular, the California Energy Commission is directed, and the California Public Utilities Commission and the California Independent System Operator are requested, to work with the State's load serving entities on accelerating plans for the construction, procurement, and rapid deployment of new clean energy and storage projects to mitigate the risk of

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[3] *Modified,* D.21-06-027.

[4] For more information on implementation of activities related to summer reliability, *see* Summer Reliability (ca.gov).

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

> capacity shortages and increase the availability of carbon-free energy at all times of day.

The Emergency Proclamation also stated:

> The California Public Utilities Commission is requested to exercise its powers to expedite Commission actions, to the maximum extent necessary to meet the purposes and directives of this proclamation, including by expanding and expediting approval of demand response programs and storage and clean energy projects, to ensure that California has a safe and reliable electricity supply through October 31, 2021, to reduce strain on the energy infrastructure, and to ensure increased clean energy capacity by October 31, 2022.

On September 8, 2021, the CEC adopted a "Summer 2022 Stack Analysis" for summer 2022 to estimate the potential gap between supply and demand in 2022 under average and extreme weather conditions similar to those in summer 2020, and projected a potential need for contingency resources during summer 2022. This Commission has conducted an analysis with updated information of the potential shortfall at net peak in summers 2022 and 2023 under the most extreme conditions, and finds an additional need for supply- and demand-side resources of between 2,000 and 3,000 megawatts (MW).

On August 2, 2021, the assigned Administrative Law Judge (ALJ) sent a ruling to the parties setting forth a proposed scope and schedule for Phase 2. After taking comment from the parties due on August 6, 2021, the Assigned Commissioner issued a scoping memo providing the scope and schedule of Phase 2, finding that "An expedited process is essential to ensure there is adequate supply and demand management to achieve electrical system reliability in 2022 and 2023."

The scope of Phase 2 was set forth as follows:

- Increase peak and net peak supply resources in 2022 and 2023:
  - Expedited generation and energy storage procurement, including utility-owned generation and third-party generation, and expedited contracting and other processes;
  - Updates to Resource Adequacy (RA) requirements;
  - CAISO's Capacity Procurement Mechanism authority;
  - Analysis of need/net-short – particularly at net peak – and resources available to meet this need, in light of recent trends in weather and resource availability;
  - Integrated Resource Planning (IRP) procurement - mechanisms to accelerate online dates;
  - Planning Reserve Margin (PRM) adjustment for 2022 and/or 2023;
  - Interconnection; and
  - Other opportunities to increase supply.
- Reduce peak and net peak demand in 2022 and 2023:
  - Flex Alert;
  - Critical Peak Pricing;
  - ELRP;
  - Modifications to existing supply-side DR programs (including Investor-Owned Utility (IOU) supply-side DR programs, DR Auction Mechanism (DRAM), and other third-party DR);
  - New DR programs or pilots including but not limited to the California Environmental Justice Alliance (CEJA) Just Flex Rewards, Pacific Gas and Electric Company (PG&E) Power Saver Rewards Pilot briefed during Phase 1, and capacity bidding program with dispatch in real-time market;
  - Electric vehicle participation in DR or load management;

  - o Measures to minimize loss of DR enrollment;
  - o Rate structures, including pilot rates introduced for a limited period or limited to certain customer classes or subsets of such classes; and
  - o Other opportunities to reduce demand or net demand including virtual power plants, distributed energy resource export, distributed generation.
- Memorandum or Balancing Accounts to cover the cost of programs in 2022 and 2023.

The Phase 2 scoping memo also made clear that other Commission proceedings were already focused on increasing supply and/or reducing demand for reliability purposes, and instructed parties to participate in those cited proceedings if they wished to influence outcomes. The proceedings cited were the Energy Efficiency Rulemaking (R.) 13-11-005, Microgrids, R.19-09-009, and the Self-Generation Incentive Program, R.11-12-005[6]; the scoping memo directed parties wishing to influence outcomes in the listed proceedings to participate in those proceedings. We also served the scoping memo on the Commission's IRP and RA service lists.

After the scoping memo was issued on August 10, 2021, the Assigned ALJ furnished the parties a template to use to formulate their proposals for 2022-23 in a ruling dated August 11, 2021. In addition to inviting new proposals, the ruling allowed parties who had made proposals in Phase 1 that the Commission did not adopt to re-propose those options. The ruling also acknowledged that two parties, CEJA and PG&E, had made proposals after adoption of the Phase 1 decisions in July 2021, as authorized by an assigned ALJ ruling on June 14, 2021, and invited those parties to indicate whether they still supported their proposals.

[6] The reference should have been to the latest Self-Generation Incentive Program proceeding, R.20-05-012.

Parties were directed to include their proposals in opening testimony due September 1, 2021.

Energy Division staff also issued its own summer 2022-23 reliability concepts for party consideration, furnished to the parties by ALJ ruling dated August 16, 2021 (Staff Concept Paper). The Staff Concept Paper discussed a large number of supply- and demand-side options, aimed at sparking dialogue and shaping party proposals.

Parties served opening testimony on September 1, 2021, and reply testimony on September 10, 2021. Forty-seven parties served opening testimony and 26 served reply testimony.[7] This decision admits all testimony into the record.[8]

The parties filed opening briefs on September 20, 2021, and reply briefs on September 27, 2021. The ALJ also issued a ruling on September 30, 2021 proposing to take official notice of the CEC's Summer Stack Analysis described above, and inviting comment. A handful of parties submitted comment on the stack analysis on October 7, 2021.

2. Issues Before the Commission

This decision adopts the following requirements designed 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 2022 or 2023. In the order listed below, we address the following issues:

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[7] A list of the parties that served opening and/or reply testimony, with the acronyms used in this decision to refer to them, appears in Attachment 3 to this decision.

[8] Citations to a party's Phase 2 opening and reply testimony appear in this decision as "[Name of party] Opening (or Reply) Testimony at [page number]," and opening and reply briefs appear as "[Name of party] Opening (or Reply) Brief at [page number]."

1. *Need*: The need for additional contingency resources to serve California's electricity customers in the event of extreme heat in summers 2022 and 2023;
2. *Demand:* New and modified demand-side programs, including DR program changes, ELRP changes and a new Residential ELRP pilot, a smart thermostat program and two dynamic rate pilots, along with extension of the Flex Alert paid media campaign to 2022 and 2023; and
3. *Supply*: New supply-side resources and policies to meet the need for electricity at net peak in summer 2022 and 2023.

Attachments 1 and 2 to this decision contain details of the programs we order in this decision, including program parameters, eligibility, process and implementation, rates, marketing and outreach, and cost allocation and recovery. Attachment 2 describes ELRP changes and Attachment 1 contains all other program requirements.

3. Need for Additional Resources

This section addresses the need for additional resources in the summers of 2022 and 2023 to help maintain reliability in the most extreme weather events, and includes a discussion of the PRM.

In summary, we find that if an extreme weather event were to occur, there is a need for contingency resources in the summers of 2022-2023 in the range of 2,000 MW to 3,000 MW. We are not changing the PRM applicable to IRP or RA obligations, which is being addressed in those proceedings, but instead we continue the approach adopted in D.21-03-056 of authorizing the three large IOUs to procure additional resources to meet an "effective PRM."

The 2,000-3,000 MW range provides for the procurement of contingency resources to meet an effective PRM of between 20% and 22.5% to ensure reliable electric supply during extreme circumstances. Additional resources that meet this higher effective PRM will provide additional reliability in the event of a need for contingencies above the existing PRM during extreme events.

3.1. Background on Procurement Need for 2022-2023

As discussed in D.21-02-028, the summer 2020 rolling outages spotlighted reliability deficiencies in California's electricity system. The Joint Agency Root Cause Analysis and party comments in this proceeding have pointed to a number of causes for the outages, as well as an array of solutions.

Since those events, the Commission has ordered additional procurement in multiple venues. We ordered additional procurement for 2021 and 2022 in Phase 1 of this proceeding, and additional procurement for 2023-2026 in the IRP decision on Mid-Term Reliability, D.21-06-035. Nonetheless, current planning and procurement resource levels may not be sufficient through 2023 under extreme conditions.

3.2. Party Comments on Procurement Need

Many parties supported continuing with the current approach to procure additional capacity needed in 2022 and in some cases 2023, or more broadly supported additional procurement.[9] Other parties opposed additional procurement for 2022 and/or 2023 without further analysis of need.[10] In addition, a number of parties supported a higher PRM,[11] while others opposed it

[9] *See, e.g.,* CAISO Opening Testimony at 1-11; PG&E Opening Testimony at 9-6 - 9-8; Cal Advocates Opening Testimony at 1-3; SCE Reply Testimony at 18-19; SDG&E Opening Testimony, DeTuri and Maiga at 3-11, SDG&E Reply Testimony, DeTuri and Maiga at 2-3; MRP Reply Testimony at 3-4; LS Power Opening Testimony at 5-6.

[10] *See* TURN Reply Testimony at 3-4; UCS Opening Testimony at 2-7; PCF Opening Testimony at 9-14.

[11] CAISO Opening Testimony at 9-13; Cal Advocates Opening Testimony at 1-1 – 1-6; MRP Reply Testimony at 3-4; Calpine Reply Testimony at 6-7; LS Power Opening Testimony at 2; Wartsila Reply Testimony at 3-4; Saavi Energia Opening Testimony at 4.

absent a more complete loss of load study and consideration in the RA and IRP proceedings.[12]

With regard to the CEC 2022 Summer Stack Analysis, a small number of parties commented, and all of them pointed out limitations of the analysis.[13] SCE recommended changes to certain assumptions including the hydroelectric drought de-rate, import and retirement assumptions and base demand.[14] We apply SCE's general approach to examining the CEC 2022 Summer Reliability Stack Analysis below.

3.3. Determination of Procurement Need

Considering party comments, the CEC 2022 Summer Reliability Stack Analysis, recent CPUC decisions in the IRP and RA proceedings, the occurrence of reliability problems in 2020 during extreme weather events, CAISO's calling of Flex Alerts multiple times in the summer of 2021, and the Governor's July 2021 Emergency Proclamation, we determine that we must act now to ensure contingency reliability resources are available for the summers of 2022 and 2023.

Numerous extreme conditions and supply risks may be mitigated by continuation and expansion of contingency procurement in 2022 and 2023. The conditions include heightened risks associated with climate change, extreme heatwaves, dry hydro conditions, potential West-wide capacity shortages, supply chain issues with procurement underway, and project contract failures, among a host of other planning uncertainties.

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[12] *See, e.g.,* UCS Opening Testimony at 3-6; PCF Opening Testimony at 6.

[13] *See, e.g.,* UCS Opening Testimony at 3; CalCCA Opening Testimony at Appendix A; SDG&E Opening Testimony, DeTuri and Maiga at 8-9; SCE Opening Testimony at 81.

[14] SCE Opening Testimony at A-1-4.

Accordingly, this decision continues its order for the large electric IOUs to pursue incremental demand- and supply-side resources for 2022 and extends the order to 2023. In continuing with this approach, the Commission is exercising its policy prerogative to pursue a variety of strategies to increase supply and reduce demand to maintain reliability of the grid during extreme weather events.

As noted in D.21-02-028, this incremental procurement is intended to serve CAISO load, and we again encourage CAISO to ensure that these resources do not support exports even if they are not designated as RA resources.[15]

The subsequent sections address the approach we adopt for determining the exact amount of contingency procurement and the approach for realizing the procurement.

3.3.1. Adopted Procurement Need Direction

After consideration of the record of this proceeding, we determine that the appropriate approach for realizing the procurement to meet the need identified in this decision is to continue with the effective PRM approach adopted in Phase 1. The procurement from Phase 1 was targeted to an effective PRM of at least 17.5% for 2021 and 2022, with a requirement that all resources procured to meet the effective PRM be available during net peak.

In this decision we extend the effective PRM approach to 2023 and increase the effective PRM target from 17.5% to a range of 20% to 22.5%.

3.3.2. Background on Emergency Reliability Procurement Target

In D.21-03-056, the Commission adopted an effective PRM of 17.5% for the IOUs, stating:

> Given that a portion of the resources that make up [Load Serving Entities' (LSEs')] 15% PRM are solar resources whose

[15] D.21-02-028 at 9.

> 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 [Net Qualifying Capacity (NQC)] of solar in September, which has been the Integrated Energy Policy Report forecast peak load month in recent years.[16]

3.3.3. Adopted Emergency Reliability Procurement Target

With regard to the amount of additional reliability resources that should be procured, we continue our current approach with some modification. We agree with CAISO, SCE, PG&E, SDG&E, Cal Advocates and other parties that recommend continuing the current approach to procurement of additional resources. The weather experienced throughout the summer of 2020 and 2021 was extreme, and we must plan in anticipation of more frequent extreme weather events resulting from climate change.

There must be sufficient resources in place to meet demand during the net peak hour. For this reason, we require all incremental resources procured as a result of this proceeding to be available during net peak. That is, because a resource such as solar is unavailable at net peak because the sun has set, it does not contribute to the need at net peak. Ultimately, changes to the Commission's overall resource planning framework may be necessary, but considerations of more permanent changes to the Commission's RA program requirements and longer-term planning standards should be made in the RA and IRP proceedings, respectively.

[16] D.21-03-056 at 43.

In recognition of the continued tight grid conditions experienced this summer, CAISO's testimony reflecting a significant shortfall in LSE supply plan resources at net peak,[17] and the need for additional contingency resources identified in the CEC Summer 2022 Stack Analysis, we establish a revised targeted procurement range of 2,000 MW to 3,000 MW for summers 2022 and 2023. This range is inclusive of, not additive to, the targeted procurement of 1,000 MW of contingency resources adopted in D.21-02-028 and D.21-03-056. As we explain below, the result is an effective PRM of 20% to 22.5% during system peak, and 15% to 17.5% at net peak.

While the Commission has reached this conclusion based on the factors detailed above, we include expanded discussion of the CAISO's net peak need analysis and the CEC 2022 Summer Stack Analysis in subsequent sections, as both analyses of potential need for contingency resources are complex in nature.

We choose to set a target range rather than a point target because we recognize there is current and near-term uncertainty both in demand variation and resource availability. The load impacts of the new and voluntary programs we adopt, and continue, in this decision cannot be predicted with certainty.

We expect a large quantity of new resources to come online in 2022, and subsequent years, as a result of the current IRP procurement authorizations. Given the magnitude of the procurement ordered, the timelines in which these resources are required to be on-line, and a number of procurement challenges discussed in this decision, there is risk that the over 40 LSEs responsible for this procurement will not bring all of the ordered resources on-line by the deadlines ordered in the IRP proceeding. Indeed, a recently released Energy Division

[17] CAISO Opening Testimony at 1-11.

report on the status of the August 2021 tranche of resources ordered in the D.19-11-016 procurement order indicates that a number of projects expected by August 2021 were delayed. [18]

In addition, much of this IRP procurement will be performed by LSEs that are relatively new, have never procured new resources in the quantities they have been ordered to procure, or both. We are concerned that adding the procurement of contingency resources to these existing challenges would only serve to further increase these challenges.

We therefore allocate procurement responsibility for the additional contingency resources ordered in this decision to the three large IOUs, using the same allocation ratios used for the summer 2021 incremental procurement. These ratios are based approximately on the Transmission Access Charge (TAC) area CAISO load shares for each utility's service territory.[19] The resulting target procurement amounts are 900 MW-1,350 MW each for PG&E and Southern California Edison Company (SCE) service territories and 200 MW-300 MW for San Diego Gas & Electric Company (SDG&E) service territory. The additional resources to meet the 2,000 MW to 3,000 MW range must be available at peak and net peak. Further, we prioritize here the procurement of resources that are RA eligible and that will be visible to the CAISO in supply plans and participate in CAISO markets to the extent feasible.

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[18] Energy Division Staff Report, "Procurement in Compliance with D.19-11-016 per February 1, 2021 Filings, 8/23/2021", available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/ed_staff_review_of_feb2021_data_in_compliance_with_d1911016.pdf, on the IRP Procurement Track (ca.gov) Website.

[19] *See* CEDU 2020 Managed Forecast – LSE and BA Tables Mid Demand – Mid AAEE Case – Corrected March 2021, Form 1.5b, https://efiling.energy.ca.gov/GetDocument.aspx?tn=237319&DocumentContentId=70504.

The CEC's peak demand forecast for the CAISO TAC area for the 2022 summer months is approximately 45,000 MW, so each 1,000 MW is equivalent to approximately a 2.5% increase in the PRM for CPUC jurisdictional entities.[20] Thus, added to the 15% PRM requirement in the RA program that applies to all LSEs, the adopted range of additional contingency procurement results in an effective PRM of 20% to 22.5%. Importantly, these effective PRMs only apply to the CPUC jurisdictional LSEs' portion of CAISO load. To the extent that non-jurisdictional entities do not also procure to similar targets, the overall CAISO effective PRM would be lower than these estimates.

While the IRP decisions have ordered an additional 2,825 MW of new resources to come online for the summer of 2023 (825 MW by August 1, 2023 in D.19-11-016 and 2,000 MW more by August 1, 2023 in D.21-06-035), the uncertainties we describe above will persist into 2023. Consequently, we apply the adopted target procurement range of 2,000 MW-3,000 MW for 2023 as well.

Procurement of contingency resources for summer 2021 approached but did not fully reach the 1,000 MW target adopted in D.21-03-056 in all summer months. For instance, the IOUs collectively reached approximately 800 MW for August, whereas they surpassed the target in September with approximately 1,150 MW.[21] Looking ahead to the summers of 2022 and 2023, there is the real potential for delays associated with procurement already underway in compliance with the recent IRP decisions (D.21-06-035 and D.19-11-016), and

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[20] As observed in D.21-02-028, 2.5% x 45,000 is approximately 1,100 MW, but since CPUC jurisdictional entities represent 90% of the CAISO TAC area, their share of the PRM is 90% of this value, or approximately 1,000 MW.

[21] 2021 Excess Resource Reports. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

practical timing constraints on the ability to bring new resources online between now and 2022 and 2023. For example, there are interconnection queue limitations, supply chain issues being faced as a result of the COVID-19 pandemic, high global demand for battery storage, and challenges with skilled labor availability for engineering and construction of new energy resources, all of which will impact LSEs' ability to bring resources on-line in the coming two summers.

Based on these realities, we expect it could be extremely difficult to actually identify and procure sufficient demand- and supply-side resources to reach 2,000 MW of on-line and available contingency resources for summer 2022, let alone the 3,000 MW target. While we acknowledge the very real obstacles to procuring this amount of resources on such short timelines, it is important to identify the level of contingency resources that may be needed to ensure reliability in the most extreme weather events. The range of 2,000–3,000 MW is that level.

Given this difficulty, we understand the possibility that the IOUs may not achieve the targeted procurement by summer 2022 or 2023. It may not be possible to reduce the risk to zero during an extreme weather event given the short timeline we face. Nonetheless, we have created a pathway for significant additional demand- and supply-side contingency resources that we can count on going into the summer and that can be deployed in an organized and responsible fashion if needed.

Progress toward meeting the targeted procurement should be reasonably understood by mid to late spring 2022. At that time, in the event that sufficient progress has not been made, the State can determine whether there is a need for additional action to further reduce the risk of outages resulting from an extreme weather event as contemplated in the CEC 2022 Summer Stack Analysis.

While this expedited contingency procurement will certainly be challenging, there are several reasons to be guardedly optimistic that the IOUs can make significant progress toward meeting the targeted procurement by next summer. For instance, the resources procured for summer 2021 reliability in response to the previous decisions in this proceeding that are still in place for 2022 and 2023 can help meet these targets. In addition, we are authorizing this procurement with a longer lead time than the 2021 contingency procurement, so there is a greater amount of lead time for 2022 and 2023 procurement to meet emergency summer reliability needs. We have also identified a broader array of resources that can be procured to achieve these targets, which could increase the amount of resources that can successfully be brought on-line by 2022 and 2023 compared to 2021.

In the event that emergency procurement efforts are so successful that they result in excess procurement, the resources could be used as backfill in the event some LSEs fail to meet their IRP procurement requirements. They could also allow for downward adjustments in future procurement orders, or help support faster retirement of aging generation not accounted for in previous IRP orders.

The following sections include expanded discussion of the CAISO's net peak need analysis and the CEC 2022 Summer Stack Analysis, as both these analyses of potential need for contingency resources are complex in nature.

3.3.4. CAISO Net Peak Analysis

CAISO recommends the Commission establish a net peak RA requirement and increase the PRM from 15% to 17.5%.[22] The Utility Reform Network (TURN) supports CAISO's recommendation of a net peak RA requirement and the methodology CAISO proposes.[23] CAISO's net peak RA proposal would set an RA requirement at 8:00 p.m. and assume zero solar production at this hour, leaving the eligible RA capacity value of solar at zero, and making solar ineligible to meet any part of the net peak RA requirement.

This approach does not take into account that other resources also produce differently at net peak. For instance, the nameplate capacities of natural gas plants are de-rated to reflect their output during gross peak when temperatures are typically at their highest levels and output is most impacted, and wind speeds typically begin picking up in the evening hours compared to the gross peak. Under a net peak RA requirement, if established, some technologies might have higher eligible RA capacity value while solar might be zero. De-rating a solar resource's ability to serve a new net peak PRM standard without reviewing how other resources serve load at net peak may be an over-simplification of a complex planning problem.

If one nonetheless considers the CAISO analysis, certain results emerge. In its testimony, CAISO provides a table that estimates the 2021 resource shortfalls that would result from a net peak RA program with the current 15% PRM, which ranges from a 972 MW shortfall in May to a maximum shortfall of 1,951 MW in August 2021.[24]

[22] CAISO Opening Testimony at 2-11 and 12-14.

[23] TURN Reply Testimony at 4-6.

[24] CAISO Opening Testimony at 8.

The CAISO's analysis uses a net peak forecast for 2021 that is approximately 1,100 MW lower than the August 2022 net peak forecast used in the CEC's Stack Analysis. Further, several hundred megawatts of resources shown on the August 2021 supply plans were procured as a result of this proceeding. Since these resources were above the LSEs' collective 15% PRM obligation, they would be redundant with the additional procurement target we set in this decision.

In addition, because the CAISO's analysis uses resources included on August 2021 supply plans, its analysis excludes 2021 IRP resources ordered in D.19-11-016 that were not online by August 2021 and the 850 MW of 2022 IRP resources ordered online by August 2022 in D.19-11-016. The increase in the net peak forecast (1,100 MW) largely nets out with the additional 2021 and 2022 IRP resources, so applying CAISO's net peak approach to August 2022 results in a shortfall of approximately 2,200 MW. Adjusting for the 90% of CAISO load represented by CPUC jurisdictional LSEs, achieving a 15% PRM at net peak would require procurement of an additional 2,000 MW by CPUC jurisdictional entities in 2022.

It is unclear whether CAISO's proposed 17.5% PRM would be applied at net peak or if the CAISO is proposing a 17.5% gross peak requirement and a 15% net peak requirement. If the CAISO intended to combine these recommendations, then to meet a 17.5% net peak requirement, an additional 2.5% of resources would be required on top of the 2,000 MW estimated above. As noted previously in this and past decisions, a 2.5% adjustment to the PRM represents approximately 1,000 MW for CPUC jurisdictional entities' share of CAISO load, so achieving a 17.5% PRM at net peak would require 1,000 MW of resources in addition to the 2,000 MW of procurement needed to meet the 15% PRM at net peak.

After adjusting for August 2022 demand forecast and supply differences compared with August 2021, CAISO's proposed net peak RA requirement results in a need for 2,000 MW of additional resources available at net peak to achieve a 15% PRM and 3,000 MW to achieve a 17.5% PRM.

We understand that it may be the CAISO's preference that all of the resources procured to meet its targeted net peak PRM would be RA eligible resources which are visible to them on supply plans, and in an ideal world we would prefer this to be the case as well. However, given the timelines for procurement and the size of the need for contingency resources, we believe it could be extremely challenging for these levels of new RA-eligible resources to be brought online by next summer, in addition to the significant amount of procurement already underway. Consequently, this decision authorizes the procurement of a wide variety of resources, some of which will be RA resources that will be visible to the CAISO on supply plans, while others will not. We prioritize here the procurement of resources that are RA eligible and that will be visible to the CAISO in supply plans and participate in CAISO markets to the extent feasible.

3.3.5. CEC 2022 Summer Stack Analysis[25]

Following the grid stresses experienced in June and July 2021, the CEC developed an hourly stack analysis for summer 2022 to provide near-term situational awareness in the event of West-wide extreme weather and prolonged

[25] On September 30th, the ALJs issued a ruling taking official notice of the CEC 2022 Summer Stack Analysis and requesting party comments. The comments in response generally supported the approach taken here, in which the Commission broadens the analysis and applies its own policy expertise to assess the need for additional resources.

drought (CEC 2022 Summer Stack Analysis).[26] The CEC analysis provides a snapshot of an extreme weather event coupled with conservative assumptions on availability of hydroelectric and imported resources and the potential need for contingencies in summer 2022. The CEC analysis can be used as a point of reference in determining resources needed to maintain grid reliability in the most extreme summer weather events. However, as noted in the Appendix to the CEC's adopted Summer 2021 Midterm Reliability Analysis,[27] the Summer Stack Analysis is:

> . . . primarily intended to provide a snapshot of a potential worst-case scenario to inform the level of contingencies that the state should plan for. As such, the extreme scenario is developed to capture extreme demand and supply conditions that might represent a very low likelihood. While portions of an identified shortfall using the Hourly Stack Analysis in an extreme weather scenario might be deemed necessary to be addressed by additional procurement, *the intention of an Hourly Stack Analysis is not to determine whether traditional procurement is needed.* (Emphasis added.)

The CEC 2022 Summer Stack Analysis observes that resources equivalent to a 22.5% PRM may be needed to prevent rotating outages during a "worst case scenario" that assumes a high level of resource outages, persistent drought conditions, and limited or no access to additional economic imports all occur simultaneously. The CEC then considers the resulting need for contingency resources (or "net short" in shorthand) if these extremes occur at the peak and net peak hours of each summer month. Under this scenario, the analysis projects

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[26] 411194667.PDF (ca.gov) or CEC, "2022 Summer Stack Analysis," September 2021, CEC-200-2021-006, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M411/K194/411194667.PDF.

[27] CEC, "Midterm Reliability Analysis," September 2021, CED-200-2021-009, at A-1. https://www.energy.ca.gov/sites/default/files/2021-09/CEC-200-2021-009.pdf.

potential need for contingency resources during a few hours that could range from 200 MW to 4,350 MW.

As stressed by the CEC in its Midterm Reliability Analysis, this risk stacking approach is a different approach to need determination from traditional electricity resource planning and RA approaches and is not intended to determine the level of traditional resources needed. Resource planners forecast the probability of a loss of load event based on historic variations in weather, electricity demand, and resource performance. Traditionally, California resource planning uses a "probabilistic" approach – that is, it considers various scenarios, rather than a single worst-case scenario. The CEC analysis takes a "deterministic" approach that assumes all worst-case scenarios occur simultaneously. Acknowledging these differences, we do find it helpful to compare the resulting net short with the procurement range adopted in this decision.

In examining an extreme scenario, the CEC uses conservative assumptions for available supply and expected demand. For example, the analysis assumes a 40% reduction in the DR resources that will be available in the future based on DR performance described in the Final Root Cause Analysis of the Mid-August 2020 Extreme Heat Wave, which results in an assumed maximum of 1,000 MW in 2022.[28] The analysis also assumes that the Redondo Beach once-through-cooling generating station (834 MW) will retire in 2021 and thus not be available to serve load in 2022. In addition, the analysis uses an average of several recent years of RA imports as a proxy for the estimated MW value available from 2022 RA imports. Finally, to account for increasingly common extreme weather events

[28] Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf (caiso.com).

and higher levels of unanticipated outages of RA resources than historically assumed, the CEC analysis builds in a PRM of 22.5% through both the peak and net peak periods.

The CEC noted the assumptions used in its analysis were based on the best data available to it at the time and recognized the need to update these assumptions as new information becomes available.[29] This decision discusses new information with regard to some of the assumptions used in the analysis. With regard to expected DR resources, energy use on future extreme weather days may be far higher than CAISO assumed in estimating the DR load drop of these customers during the 2020 events.[30] We addressed this issue in D.21-03-056 in Phase 1 of this proceeding, noting that

> 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 baseline options in their respective [Capacity Bidding Programs (CBPs)], and DR providers are permitted to utilize the new baseline options for the [DRAM]. D.21-03-056 at 31-32.

[29] 411194667.PDF (ca.gov) or CEC, "2022 Summer Stack Analysis," September 2021, CEC-200-2021-006, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M411/K194/411194667.PDF.

[30] The public versions of the Load Impact Protocol filings associated with the DR that was under contract with CPUC-jurisdictional entities during the summer 2020 heat waves are available on the Commission's website for R.13-09-011.

The Commission's Load Impact Protocol process[31] estimates the load impact of DR programs for the upcoming year. There is necessarily a lag in this analysis because DR providers (DRPs) estimate performance for the year ahead. Thus, for example, filings in 2021 include projected estimates of resources that will be available in 2022, based on analysis of DR resources' performance in 2020.

The Load Impact Protocol analysis suggests that when baselines are adjusted for the extreme weather events, DR in aggregate performed much closer to estimated levels during the August and September 2020 heat waves. It makes downward adjustments to 2022 DR values to reflect the performance of some categories of DR resources. Consequently, the Load Impact Protocol-adjusted values for 2022 DR resources represent a reasonable estimate of expected performance of DR resources procured by CPUC-jurisdictional entities, excluding credits for avoided PRM procurement and avoided line losses.

Current summer 2022 DR authorizations for CPUC jurisdictional LSEs, IOU DR, DRAM contract estimates and third-party DRPs based on the Load Impact Protocol analysis of 2020 DR performance are approximately 1,650 MW.[32] If one adds to this number the CEC's estimate of 2022 DR procurement by LSEs that are not under CPUC jurisdiction, the total DR value for 2022 is approximately 1,700 MW. This is 700 MW more than the 1,000 MW value included in CEC's analysis; making this adjustment to reflect Load Impact Protocol-based expected DR values for 2022 would reduce the CEC's net short estimate by approximately 700 MW.

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[31] For a general overview of the process, *see* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/introduction-to-load-impact-protocols-lips.pdf.

[32] 2022 DR Values are posted to this Commission's RA compliance website - Resource Adequacy Compliance Materials (ca.gov).

With regard to the assumption of Redondo Beach generating station availability in 2022, on October 19th, the California Water Resources Control Board voted to extend the Redondo Beach generating station permit through 2023,[33] which is information the CEC did not have when developing its analysis. This additional resource reduces the net short estimate by an additional 834 MW.

The CEC assumes imports based on average of several years of RA imports as a proxy for 2022 RA imports. However, this approach does not fully reflect changes in the Commission's RA import policy that took effect this year. The 2021 levels of RA imports therefore represent a more accurate proxy for 2022 RA imports than an average of several years. The 2021 RA imports for July, August, and September 2021 were 5,800 MW, 6,000 MW, and 6,700 MW, respectively. Using these values rather than the multi-year averages results in a reduction in the net short estimate by approximately 500 MW for July and September and an increase in the net short by approximately 500 MW for August.

Finally, the CEC 2022 Summer Stack Analysis indicates that it includes the expedited procurement resources that were previously directed in this proceeding in its estimate of new resources coming online by next summer, and these megawatts would be redundant with the resources we authorize in this proceeding. Thus, 1,000 MW of resources need to be added to the CEC's net short estimates to avoid double-counting.

Applying all of the foregoing adjustments to the CEC 2022 Summer Stack Analysis of net short during the most extreme weather events results in a September 2022 need for additional contingency resources at net peak of approximately 3,320 MW (4,350 MW minus 700 MW of additional DR, 830 MW

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[33] For information regarding the California Water Resources Control Board's decision, *see* https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/policy.html.

for the Redondo Beach Generating Station, and 500 MW additional September RA imports, plus 1,000 MW of expedited procurement resources included in the CEC's analysis). Adjusting this result, which is a CAISO-wide analysis, to reflect the 90% of CAISO load represented by CPUC jurisdictional entities, the resulting net short estimate is approximately 3,000 MW (90% of 3,320 MW).

We turn to a determination of how to meet our estimate of a needed 2,000 to 3,000 MW in an extreme weather event. We first discuss demand-side programs, and then discuss supply-side programs and processes.

4. Demand Side Changes

4.1. Modifications to ELRP

4.1.1. Background of the ELRP

The Commission adopted the initial program parameters for ELRP in the second decision in this proceeding, D.21-03-056. That decision explained the purpose of ELRP is to allow the large electric IOUs and the CAISO to have access to additional load reduction opportunity during times of high grid stress and inadequate market resources. The goal of developing ELRP was to provide additional tools for the avoidance of rotating outages while also minimizing costs to ratepayers.

The initial program parameters for ELRP included a duration of five years and participation of both customers not participating in market-integrated (also referred to as supply-side) DR programs and participating in CAISO market-integrated Proxy Demand Resources (PDRs). The Commission then adopted D.21-06-027 that modified the parameters of ELRP that were initially set in D.21-03-056 regarding the availability of a day-of trigger for Group A participants.

To achieve greater value from ELRP, this decision makes further refinements to the parameters of the ELRP, as adopted in Attachment 2 of this decision. Attachment 2 contains the guidance that the Commission has previously adopted regarding the parameters of the ELRP. This previous guidance is modified in Attachment 2, in red-line form, to clarify the updated guidance on ELRP that this decision adopts. At a high level, the modifications outlined in Attachment 2 to ELRP expand the existing group of eligible customers and add further eligibility for non-residential aggregators, Vehicle-Grid Integration (VGI) aggregators, and residential customers.

4.1.2. Modifications to the ELRP Framework

Several non-substantive modifications have been made to the ELRP guidance to improve readability and clarity of interpretation.

Additionally, in accordance with the Commission's grant of the large IOUs' motion for extension of time to file their DR applications, the review of the ELRP has been moved to continue to coincide with those applications in 2022.

4.1.3. Group A.1 Non-Residential Participant Eligibility

The eligibility requirement that Group A.1 participants in ELRP not take current service on a critical peak pricing or real-time pricing equivalent tariff is removed. We adopt this position with consideration of testimony from SCE and CALSSA.[34]

Additionally, the minimum size threshold parameter for Group A.1 participants in ELRP is modified in SCE's territory from 200 kilowatts (kW) of peak demand to 100 kW of peak demand and for SDG&E's territory the requirement for customers to drop 100 kW is modified to 50 kW. SCE and SDG&E both indicate they believe they have the capability to allow smaller

[34] CALSSA Reply Testimony at 8; Joint DR Parties Reply Testimony at 11; SCE Opening Testimony at 36-37.

enrollment sizes. This should allow for more medium-sized businesses to participate in ELRP, which otherwise may not have been possible with the previously, higher minimum size thresholds.[35]

4.1.4. Group A.2 Non-Residential Aggregators Eligibility

The A.2 group is expanded to included non-Base Interruptible Program (non-BIP) aggregators of non-residential, non-BIP customers. Non-BIP aggregators with aggregated customer resources meeting the following criteria are eligible to participate in ELRP:[36]

- The aggregated resource is not simultaneously enrolled in a supply-side DR program offered by an IOU, third-party DRP, or Community Choice Aggregator (CCA), and
- Customers participating in the aggregation meet the eligibility criteria under A.1 (except the Minimum Size Threshold requirement does not apply), and
- The aggregated resource capacity meets or exceeds the Minimum Aggregation Size Threshold.

If a non-BIP aggregator of non-residential customers chooses not to participate, its customers may independently participate in ELRP under A.1, subject to the applicable criteria and requirements.

The IOUs are authorized to dispatch the aggregated resources offered by the non-BIP aggregators for at least the Minimum Aggregation Dispatch Hours. In addition to the Group A triggers defined below, the IOUs may exercise discretion to dispatch the non-BIP aggregation in response to other forecasted or anticipated grid stress conditions, such as high locational marginal prices in the

[35] CESA Reply Testimony at 19; Joint DR Parties Opening Testimony at 26; SCE Opening Testimony at 37; SDG&E Opening Testimony, Mantz and McConnell at 17.

[36] AEE Opening Testimony at 4.

CAISO markets, extreme heat waves, etc., to achieve the Minimum Dispatch Hours. The IOUs may negotiate agreements with the non-BIP aggregators to clarify other requirements as needed, including potential administration fees, to implement the Minimum Dispatch Hours and related ELRP compensation.

The Minimum Aggregation Size Threshold is set at 500 kW. The Minimum Aggregation Dispatch Hours is set at 10 hours per season.

This modification is made to provide more certainty to aggregators regarding potential compensation for the participation of customers in Group A.2.

4.1.5. Group A.3 Rule 21 Exporting DER Eligibility

This decision clarifies that residential Net Energy Metering (NEM) customers meeting the eligibility standards outlined for Group A.3 participants are eligible to participate in ELRP. NEM customers have been eligible to participate as Group A.3 participants from the inception of the ELRP, and this modification clarifies the ways to participate.

We clarify that sub-group A.3 involves direct participation by a single customer with Rule 21 Exporting Distributed Energy Resources. Later in this decision, we discuss the addition of a new ELRP sub-group A.5 that involves participation by an aggregator with a VGI aggregation of one or more customers' sites.

4.1.6. Group A.4 Virtual Power Plant (VPP) Aggregator Eligibility

Regarding VPP aggregation eligibility, modifications are made to Group A.4 participation guidance.

We authorize stand-alone storage to participate.[37] This type of load shift can help grid reliability, and ELRP incentives for Incremental Load Reduction should compensate these stand-alone batteries for the service they provide to the grid.

We further provide guidance for minimum number of compensated dispatch hours. We make this modification with consideration of testimony from the Joint DR parties. Joint DR Parties indicate they "support establishing an ELRP reservation payment or minimum dispatch guarantee to customers with [Behind The Meter] storage resources and eligible back-up generation."[38] The minimum VPP dispatch hours is set at 20 hours per season.

The IOUs may negotiate agreements with the VPP aggregators to clarify other requirements as needed, including potential administration fees, to implement the Minimum Dispatch Hours and related ELRP compensation

4.1.7. Group A.5 Electric Vehicle (EV) and Vehicle-Grid Integration (VGI) Aggregator Eligibility

We adopt a proposal from the Staff Concept Paper that expands ELRP eligibility to include additional uses of EVs and VGI for emergency reliability purposes. The new EV/VGI aggregator option will be labeled ELRP Group A.5.

The new ELRP group builds on ELRP Group A.3 as adopted in Phase 1. New ELRP Group A.5 is open to aggregations consisting of any combination of EVs and charging stations. Such aggregations may include groups of customers with EVs capable of managed one-way charging (V1G) and bi-directional charging and discharging (V2G). Both bundled and unbundled residential

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[37] Joint DR Parties Opening Testimony at 24.

[38] Joint DR Parties Opening Testimony at 24.

customers and/or non-residential bundled or unbundled customers that meet the criteria listed below are eligible to participate via the aggregations in ELRP Group A.5.

4.1.7.1. Background on ELRP EV/VGI

The Legislature[39] and the Commission[40] have affirmed that EVs can provide benefits to the grid by "altering the time, charging level, or location at which grid-connected [EVs] charge or discharge." The ELRP pilot adopted in D.21-03-056 included Group A.3, which allows EVs at a single host site to support the grid at net peak through V2G export.

The Staff Concept Paper in this proceeding asked for party input on an additional option to allow aggregation of EVs capable of managed charging and discharging (including V1G managed charging or V2G discharge) to support the grid at net peak and increase the effectiveness of the ELRP:

> **1(d). Electric Vehicle/Vehicle to Grid Integration (EV/VGI) Aggregation Pilot:**
>
> Currently the ELRP pilot has at least one provision (Group A option A.3) to allow electric vehicles to support the grid at net peak through vehicle to grid export. Energy Division Staff believes there may be additional potential for VGI aggregation integration (V1G managed charging and/or V2G discharge) to support the grid at net peak and to increase the effectiveness of the ELRP. Aggregating and dispatching EV resources through the ELRP represents an opportunity to enable and demonstrate the technical capabilities and customer engagement strategies necessary to harness and deploy this nascent resource. These efforts could serve to establish a

[39] Senate Bill (SB) 676, Stats. 2019, Ch. 484 ("This bill would require the PUC, by December 31, 2020, in an existing proceeding, to establish strategies and quantifiable metrics to maximize the use of feasible and cost-effective electric vehicle grid integration by January 1, 2030.").

[40] D.20-12-029 at Section 4, "Revising the Definition of Electric Vehicle Grid Integration."

foundation for further deployment of VGI resources, which is a priority for the CPUC and EV stakeholders given the enormous potential of these resources. The pilot may require revisions to interconnection rules to enable streamlined and affordable access to the grid for EVs and EV Supply Equipment (EVSE) with bi-directional capabilities. Staff proposes:

i. Allow aggregators to utilize networks of V1G or bi-directionally capable charging stations (EVSEs) to be eligible to participate in ELRP, providing the aggregation can contribute [Incremental [L]oad [R]eduction . . . exceeding the Minimum VGI Aggregation Size Threshold of 25 kW within an IOU service territory.

ii. The IOU shall dispatch the VGI aggregators for at least 30 hours per season including ELRP events and compensate the aggregators for the [Incremental Load Reduction] delivered during the dispatched hours.

iii. In case the EVSE is located on different meter (stand-alone EVSE) from the related host site meter (for example, Multi-Unit Dwellings), the aggregator is permitted to virtually aggregate the stand-alone EVSE meter(s) with the host site load on the different meter to partially bypass the V2G export restriction on the stand-alone EVSE meter(s). The virtual load aggregation of all stand-alone EVSEs and the related host site must not be negative at any time, even when the host site is participating in an event called by another DR program. V2G discharge is prohibited outside of the IOU dispatched hours.

iv. The [Incremental Load Reduction] settlement shall be based on the measurements at the EVSE meter, or EVSE sub-meter if the EVSE is taking service through the host site meter.[41]

[41] Staff Concept Paper at 5.

4.1.7.2. Party Comments on ELRP EV/VGI Aggregation

As detailed below, there was broad support for the Staff Concept Paper proposal to increase EV/VGI options in ELRP from parties (AEE, CESA, Joint DR, Joint Parties, VGIC, PG&E, SDG&E, ev.energy), with some limited dissent (CALSSA and SCE).[42]

PG&E generally supports the staff concept, while SCE asserts the proposal would not result in any meaningful contributions to 2022 system reliability based on SCE's current record. SCE states it has no two-way charging stations, and that it is aware of two existing two-way charging stations that have resulted in only one request for SCE's interconnection queue. CESA responds to SCE's assertion that there is limited potential for two-way charging by noting this commercial pathway has not yet been fully implemented.[43]

Other issues raised by parties include ev.energy's and VGIC's request to define "aggregators" broadly to include DR third-party providers and any managed charging company or vendor capable of controlling EV charging, including those that contract bilaterally with IOUs or CCAs. These parties also ask the Commission not to require aggregators to integrate directly with the CAISO.

CALSSA states the Commission should have the same rules for EVs/EVSE and stationary battery storage, since the technology is fundamentally the same. VGIC responds that EVs are similar but need special attention because they are

[42] *See generally* AEE Opening Testimony at 5; CALSSA Opening Testimony at 3; CESA Opening Testimony at 52, Reply Testimony at 22; Joint DR Parties Opening Testimony at 26; Joint Parties Opening Testimony at 13; VGIC Opening Testimony at 3; PG&E Opening Testimony at 7-3; SCE Opening Testimony at 68; SDG&E Opening Testimony, Mantz and McConnell at 22; ev.energy Opening Testimony at 7; and Enchanted Rock Reply Testimony at 6.

[43] CESA Opening Testimony at 23.

not currently eligible for the subsidies allowed for storage in the Commission's NEM and Self Generation Incentive Programs.

VGIC estimates an approximately 270 MW contribution to the grid by year 2 of the pilot based on VGIC's assumed 5% participation rates and VGIC's assumed potential for each EV to reduce load from V1G by 5 kW during an ELRP event. MCE comments that its own managed charging pilot had reductions of 1.4 kW of load per driver (V1G). VGIC estimates that V2G participation could provide an additional 23 MW. (MCE does not estimate load reduction potential for V2G.)

CESA, the Joint DR Parties and VGIC support the staff proposal that IOUs dispatch VGI aggregations for at least 30 hours per season. VGIC notes that establishing a minimum number of dispatch hours per season provides certainty to aggregators on the level of compensation. The Joint DR parties assert a capacity or reservation payment or minimum number of dispatch hours are important signals to encourage participation.

SDG&E and PG&E have concerns about a 30-hour guarantee. SDG&E opines that 30 hours is not reasonable, noting that had the ELRP pilot existed in 2019, SDG&E would likely have had zero ELRP events because no critical peak pricing events were called that year. PG&E states that mandating IOUs to force dispatch for at least 30 hours without an emergency does not seem to align with how and why ELRP was developed. CESA and VGIC respond that the IOUs could identify and define either lower trigger points (*e.g.*, CAISO Flex Alerts instead of the CAISO Alert, Warning, Emergency signal) or other applications for which these aggregated resources could be useful.[44]

On the staff proposal of a 25 kW minimum threshold for aggregators, VGIC asks for a lower 15 kW threshold to maximize participation from EVs, while PG&E asserts the 25 kW threshold is a realistic target.[45]

4.1.7.3. Adopted Direction for ELRP Group A.5, EV/VGI Aggregation

We adopt the staff proposal for EV/VGI aggregations including both one-way managed charging and bi-directional EV charging and discharging. We acknowledge that the impact of including VGI aggregation under Group A.5 is uncertain, but we see the pilot as an opportunity to deploy and scale this resource, which will be critical in the coming years to ensure EVs can enhance reliability.

Technology capable of bi-directional EV charging is relatively new to the market and public uptake and awareness are low. Understanding this resource will be critical in the coming years to ensure EVs can enhance reliability and provide flexibility to the grid. A pilot program could help highlight the technology's potential, while contributing some support to the grid at net peak.

ELRP Group A.5 is open to VGI aggregators of any combination of EVs and charging stations operating in V1G or V2G configurations. Aggregators may deploy the service with residential or non-residential bundled or unbundled customers.

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[44] Comments on the 30-hour minimum appear in CESA Opening Testimony at 52, Reply Testimony at 23; Joint DR Parties Opening Testimony at 26; VGIC Opening Testimony at 10, Reply Testimony at 5l; PG&E Opening Testimony at 7-4; and SDG&E Opening Testimony, Mantz and McConnell at 22.

[45] VGIC Opening Testimony at 16; PG&E Opening Testimony at 7-4.

All participants must meet the following criteria:

- The VGI aggregation or any customer site within the aggregation is not simultaneously enrolled in a market-integrated, supply-side DR program offered by an IOU, third-party DRP, or CCA;
- A customer site within the VGI aggregation is not currently taking service on a critical peak pricing or real time pricing-equivalent tariff;
- All sites within the VGI aggregation are located within the distribution service area of a single IOU; and
- The VGI aggregation can contribute Incremental Load Reduction, as defined in Attachment 2, equal to or greater than the Minimum VGI Aggregation Size Threshold for a minimum of one hour.

NEM customers with EVs meeting the above requirements are eligible to participate in the VGI aggregation. Attachment 2 spells out additional technical details of the program, including the use of sub-metering, Rule 21 interconnection requirements, and IOU rights and responsibilities.

Staff proposed that the IOUs dispatch the VGI aggregators for at least 30 hours per season including ELRP events and compensate the aggregators for load reduction delivered during the dispatched hours. We adopt minimum VGI dispatch hours of 30 hours per season as an incentive for customers to participate in the program since they would otherwise have no assurance of receiving compensation.

While there may not be 30 "emergency" hours in a season, the IOUs may dispatch the VGI aggregation during other times of system need. In addition, the dispatch process will help educate customers, aggregators, IOUs, and the Commission on the technology and systems needed to dispatch these resources.

IOUs have discretion to meet the 30-hour minimum by dispatching aggregators in response to forecasted or anticipated grid stress conditions, such as high locational marginal prices in the CAISO markets and extreme heat waves. The IOUs may negotiate agreements with the VGI aggregators to clarify other requirements needed, including potential administration fees, to implement the dispatch hours and compensation.

The staff concept proposal was for an aggregation size threshold set at a 25 kW minimum discharge level. We adopt the staff concept proposal for a minimum VGI aggregation size of 25 kW. This minimum level will encourage aggregators to increase the pool of participants and reduce administrative costs for IOUs.

To determine compensation for Incremental Load Reduction, an EVSE meter, or EVSE sub-meter if the EVSE is taking service through the host site meter, may be used. The EVSE sub-meter must meet applicable standards established by the Commission if and when adopted.[46]

We also provide flexible options to allow EVs to safely discharge for purposes of ELRP participation as noted further in Attachment 2.

4.1.8. ELRP Group B Market-Integrated Resources Eligibility

We clarify that at the time of enrollment, or at designated times during the ELRP pilot, Group B participating DRP will list the PDRs that will participate in ELRP and nominate an estimated target load reduction quantity (August) to be achieved during an ELRP event by each participating PDR resource. Participation during an ELRP event is entirely voluntary, and no financial

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[46] PG&E, SCE and SDG&E filed a Final Plug-In Electric Vehicle Submetering Protocol in R.18-12-006 pursuant to an August 19, 2020 *Ruling Resetting Procedural Schedule to Continue the Development of a Plug-in Electric Vehicle Submetering Protocol*.

penalties will result from not meeting or exceeding the nominated target load reduction quantity during the event.[47]

4.1.9. Backup Generation Dispatch Sequence

We clarify that if Group B is triggered in the day ahead market, backup generators associated with customers participating in Group B and not exempted under the Prohibited Resources policy and located in Disadvantaged Communities shall not be dispatched.

Further, we clarify that if Group A is triggered in the day ahead market, backup generators associated with customers participating in Group A and not exempted under the Prohibited Resources policy and located in Disadvantaged Communities shall not be dispatched. These backup generators may be dispatched six hours prior to the start of the ELRP event and may be used in compliance with Rule 21 and other applicable regulations and permits. That is conditioned on whether in the day-of following a day ahead trigger, the IOUs through Joint ELRP Operations Board consultations determine that backup generators support may be needed based on anticipated grid stress conditions.[48]

If Group A or B is triggered in the day-of market, backup generators associated with the customers participating in the respective ELRP Groups and not exempted under the Prohibited Resources policy and located in Disadvantaged Communities may be dispatched at the same time as other resources and may be used in compliance with Rule 21 and other applicable regulations and permits.[49]

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[47] SCE Opening Testimony at 38.

[48] Sierra Club Opening Testimony at 11-21, TRN Reply Testimony at 9.

[49] Sierra Club Opening Testimony at 20.

4.1.10. Group B Day of Trigger

We clarify that the ELRP day of trigger for Group B resources is activated when a Warning or Emergency, per the Alert, Warning, Emergency process, is declared by the CAISO. The start time and duration specified in the CAISO's declaration defines the Group B ELRP event window.

Adding a day of trigger for Group B will add additional load curtailment potential on days when the CAISO's Alert, Warning, Emergency declaration is made for the same day. It would also create more parity between the two ELRP groups.

4.1.11. ELRP Compensation Rate

The ELRP Compensation Rate for both Group A and B is set at $2 per kilowatt-hour (kWh) or $2,000 per megawatt-hour (MWh).[50] We remove the requirement that ELRP compensation for an event to be bounded for Group A participants between 50 and 200 percent of pre-nominated load shed or exported energy quantity.[51]

Parties noted that the California State Emergency Program (CSEP), the emergency demand reduction program initiated by Governor Newsom's July 30, 2021 Emergency Proclamation, set a compensation level of $2/kWh. The Joint Parties indicated that this compensation level should be extended to the ELRP for all participants.[52]

PG&E took a more cautious approach to considering the appropriate compensation level for ELRP, indicating that it is not clear that doubling the

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[50] CESA Opening Testimony at 51, Joint DR Parties Opening Testimony at 26, SCE Opening Testimony at 37-38.

[51] CESA Opening Testimony at 51, Joint DR Parties Opening Testimony at 26.

[52] Joint DR Parties Opening Testimony at 7.

compensation level is justified at this time. SCE was more supportive of aligning the ELRP compensation level with the CSEP. SDG&E did not object to increasing the ELRP compensation to $2/kWh, although it did caution that this could create the expectation for other DR programs to be aligned with this significantly higher compensation than existing programs.

Additionally, some parties advocated that the Commission adopt a significantly higher compensation rate in the ELRP, as high as $6/kWh in some circumstances.

Ultimately, in setting the compensation level for ELRP we recognize the emergency nature of the ELRP and accept that a higher compensation for this emergency program could avert unexpected outages during time of extreme weather. A compensation level of $2/kWh is appropriate because this program is triggered during times of the grid being the most stressed.

Regarding Group A.4 VPP compensation, the adopted baseline methodology may be used in conjunction with a meter or a sub-meter associated with a storage device that directly measures the energy flows into/out of the storage device to determine the Incremental Load Reduction for the ELRP settlement.[53]

4.1.12. Advice Letters

We clarify the requests for modification to the ELRP framework that can be requested by the IOUs through Tier 2 Advice Letter. We extend the subjects that may be addressed in Tier 2 Advice Letters to include issues of dual participation between ELRP and other DR programs and issues of minimum dispatch hours. We clarify that a request to allow a particular dual participation

[53] Joint DR Parties Opening Testimony at 9.

option should be accompanied with an explanation and methodology to demonstrate how the Incremental Load Reduction during overlapping event could be attributed uniquely to ELRP participation and avoid double compensation.

4.1.13. Balancing Accounts and Cost Recovery

PG&E, SCE and SDG&E shall continue to use the one-way balancing accounts authorized in D.21-03-056 regarding the development, implementation, and operation of the ELRP pilot program, along with incentives paid under the program.

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.

Program Administration Budgets

These balancing accounts shall have the following annual caps for program administration across all ELRP sub-groups, *except* ELRP sub-group A.6 (Residential customers):

- PG&E $7.3 million,
- SCE $5.7 million, and
- SDG&E $3.0 million.

Additionally, these balancing accounts shall have the following caps for Residential ELRP (sub-group A.6) program administration and marketing, education, and outreach:

- PG&E:
    - 2022: $9.4 million for administration and $2.5 million for marketing, education, and outreach.

   - 2023: $8.7 million for administration and $2.0 million for marketing, education, and outreach.
- SCE:
   - 2022: $10.0 million for administration and $2.5 million for marketing, education, and outreach.
   - 2023: $9.0 million for administration and $1.6 million for marketing, education, and outreach.
- SDG&E:
   - 2022: $3.0 million for administration and $0.75 million for marketing, education, and outreach.
   - 2023: $2.7 million for administration and $0.5 million for marketing, education, and outreach.

Incentive Budgets

Additionally, these balancing accounts shall have the following annual caps for Incremental Load Reduction compensation across all ELRP sub-groups, *including* the ELRP sub-group A.6 (Residential customers):

- PG&E $94.0 million,
- SCE $76.6 million, and
- SDG&E $30.8 million.

4.2. Residential ELRP

This decision adds a new Residential ELRP pilot as ELRP Group A.6 designed to extend to residential customers the opportunity to be compensated for their contribution to system reliability and load reduction during times of grid stress. The program will require IOUs to automatically enroll California Alternative Rates for Energy (CARE) customers and certain other groups of customers, and allow all other eligible residential customers to opt in to the program if they are not already enrolled in another supply side DR program or other programs detailed here. We order specific marketing and outreach for CARE customers and residents of Disadvantaged Communities.

4.2.1. Background of Residential ELRP

CEJA and PG&E each proposed a type of Residential ELRP in Phase 1, and the Staff Concept Paper contained a proposal as well. The staff proposal was as follows:

> **Expand Eligibility to Include Residential Customers:**
>
> Currently, most residential customers do not participate in [DR] programs that compensate them for load reductions, but the CAISO often depends on load reduction from residential customers through the Flex Alert program, which is a voluntary program that calls on social action to reduce demand but does not compensate individual customers. This raises questions of both equity and effectiveness given that the CPUC has developed numerous programs, including ELRP, that compensates non- residential customers for load reduction, but comparatively few programs for residential customers. Additionally, the voluntary Flex Alert program may have diminishing impacts over time as customer fatigue sets in. To address these possible concerns, Energy Division staff offers a proposal concept for consideration that all residential customers be considered eligible to participate in ELRP by default (except customers participating in existing supply-side DR programs). To implement this policy, the following proposal concept details are offered for CPUC consideration:
>
> i. All residential customers would be automatically enrolled in ELRP (except customers currently enrolled in supply-side DR programs). There would be no required sign-up or acknowledgment process.
>
> ii. The triggering requirements for these residential customers would be the CAISO calling a Flex Alert or Grid Alert in the day-ahead.
>
> iii. The Flex Alert marketing would be modified to promote ELRP event and to utilize all available channels to reach and notify customers about the imminent event and the

opportunity to reduce consumption and receive payment or bill credit.

iv. The payments for load reduction would be based on meter-verified incremental load reduction . . . relative to a "simple" baseline to be established by the IOUs.

v. Program would be administered through the IOUs.

vi. IOUs and third-party DRP would still be permitted to target

vii. Residential ELRP customers to enroll them into their respective supply-side DR program, in which case the customer is removed from ELRP.[54]

4.2.2. Party Comments on Residential ELRP

CEJA and PG&E offered their own proposals, and parties commented on those proposals in Phase 1.[55] The scoping memo for Phase 2 made clear that those proposals would be part of the record for consideration of Residential ELRP.[56]

CEJA proposed a two-year, $20 million "Just Flex Rewards" program pilot to target low income and Disadvantaged Community households, allowing them to lower their energy consumption during ELRP events and be compensated for their participation. The proposal included automatic enrollment of all residential customers in Disadvantaged Communities and low-income customers. The

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[54] Staff Concept Paper at 8-9.

[55] The following commenters submitted Opening Testimony on January 11, 2021 on a residential option during Phase 1: CEJA, PG&E, Small Utilities, CAISO, CalCCA, CARE, CBEA, CEERT, CESA, CLECA, DR Coalition, ecobee, GPI, Joint DR Parties, NRG, PCF, Peterson Power, Pioneer, Polaris, Public Advocates, SBUA, SCE, SDG&E, SEIA, Sierra Club, TeMix, TURN, UCAN, and VCE. Further, CEJA, PG&E, AReM, CAISO, CalCCA, Calpine, CARE, CEERT, CESA, CGNP, CLECA, DR Coalition, GPI, Joint DR Parties, PCF, Peterson Power, SBUA, SCE, SDG&E, Sierra Club, TEMIX, TURN, and UCAN submitted Reply Testimony on during Phase 1 on January 19, 2021.

[56] August 10, 2021 Scoping Memo at 5.

proposal prohibited dual enrollment in third-party and IOU DR programs. IOUs would alert customers of triggering events using the existing text messaging platforms they use for alerting customers to Public Safety Power Shutoff (PSPS) events.

Messaging would include information on actions to save energy, such as not running major appliances, turning up the temperature on air conditioning units, and turning off non-essential lights. The messaging would include requests to respond by a certain time indicating whether the household intends to participate and would allow customers to opt out of participation in the future. The community-based organizations that have been working with utilities related to PSPS events and the IOUs would consult with the joint CEC/CPUC Disadvantaged Communities Advisory Group about their materials describing the program to ensure that the materials are accessible and transparent to low-income customers and customers in Disadvantaged Communities. The IOUs would follow the guidance in the Commission's decision in R.18-10-007, ensuring that the materials are available in prevalent languages, and utilize the outreach findings that have been shown to be most effective in outreach surveys.

PG&E proposed its Power Savers Reward Program (PSRP), an out-of-market resource available through a variety of dispatch triggers. All residential customers, bundled and unbundled, with and without smart technologies in their homes, would be eligible to participate in the PSRP unless they are already enrolled in a DR program or on a critical peak pricing program. CAISO Alert, Warning, Emergency alerts and Flex Alert would trigger the programs. There would be special outreach and marketing to low-income customers and customers in Disadvantaged Communities.

PG&E proposed Options A, B and C. Under PG&E's proposed Option A, the approximately 1.6 million PG&E customers who receive Home Energy Reports and are not participating in Option B or any other DR or critical peak pricing program would receive alerts in advance of peak and near peak days to decrease energy use the next day. Pilot participants would receive educational energy communications, event day tips, and performance reports from PG&E. PG&E would implement a targeted marketing campaign to recruit customers who are low-income, CARE- or Family Electric Rate Assistance- (FERA) eligible, and in Disadvantaged Communities. This targeted population would receive a $10 annual end-of-season incentive for their participation. The incentives for low-income, CARE/FERA and Disadvantaged Community residential customers would equate to over $3 million per pilot year at $10 per customer based on a population of 696,000 customers.

PG&E's Option B would require that participants have qualifying technology such as a smart thermostat or the associated end-use appliance (*e.g.*, a central air conditioner, EV or heat pump water heater). PG&E would dispatch smart technologies during DR events and the devices would curtail energy use according to agreed-upon levels. The program would include pre-event cooling that would temporarily increase energy use to ensure the home is prepared for lower energy consumption during event hours. The pilot would initially focus on smart thermostats as their highest penetration rates will provide faster load reducing benefits. PG&E would test and assess flat incentive amounts versus pay-for-performance or end-of season incentives for cost-effectiveness and customer satisfaction.

PG&E's Option C for TOU customers would dispatch smart technologies according to a customer's TOU rate schedule. It is otherwise similar to Option B, but with a focus on ensuring the home is prepared for lower energy consumption during TOU hours. This option would be available to customers who have enrolled in Option B, are on a TOU rate, and have technology capable of automated response.

In Phase 2, parties provided comment on the CEJA, PG&E and Staff Concept Paper proposals that focused on the following areas. Comments in support of Residential ELRP included the observation that it restores some equity between Residential and non-Residential sectors in ELRP. They supported Residential customer compensation for voluntary load reductions, and observed that the program could provide an avenue for low-income customers and customers in Disadvantaged Communities to save on energy costs by being compensated for load reductions.[57] Others focused on the potential for Residential ELRP to increase awareness of energy usage and the need for load reduction for millions of customers.

CEJA supported an opt out program that would include all Residential customers, but also recommended special focus on informing low-income customers and customers in Disadvantaged Communities of the program.[58] Parties favoring an opt out option liked that it would ensure all residential customers were enrolled by default. Other commenters suggested an opt in

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[57] CEJA Opening Testimony at 7; OhmConnect Opening Testimony at 8; Joint Parties Reply Testimony at 4, and SDG&E July 21, 2021 Reply to Supplemental Testimony at 2-5. *See also* PG&E July 7, 2021 Supplemental Testimony at 4 and 11, proposing a flat $10 incentive exclusively for Disadvantaged Community and low-income customers. PG&E's subsequent proposal supports incentives for all customers enrolled in the program; PG&E Opening Testimony at 3-2.

[58] CEJA Opening Testimony at 1-9; *see also* CEJA July 7, 2021 Supplemental Testimony.

approach on the ground it would create more buy-in to the program and help lead to intentional load reductions by customers.[59]

In Phase 2, each IOU also proposed its own program that would be extended to a subset of its residential customers, with PG&E proposing to enroll between 1.6 million and 3 million customers, SCE 1.8 million and SDG&E 0.5 million. SCE and SDG&E recommended a gradual rollout to ensure customers were not simply enrolled in a program without being aware of it, cautioning about free ridership.[60] PG&E did not oppose an opt out program for all residential customers.[61] Oracle and SDG&E also raised free ridership concerns, noting that customers could be compensated for actions that they would have taken without compensation.[62] However, Oracle highlighted a Baltimore Gas and Electric program similar to Residential ELRP, which has been able to overcome many free ridership concerns through maximizing the awareness of the program and providing effective behavioral messaging.[63]

SCE proposed a Whole Home Savings Pilot that would auto-enroll high energy-usage customers who have opted in to receive transactional emails from SCE.[64] SCE proposes leveraging customer data to provide personalized tools to reduce energy usage and deploying a variety of marketing methods to educate customers and maximize participation.[65] SCE recommended $2/kWh incentives

[59] SCE Opening Testimony at 67; SDG&E Opening Testimony, Mantz and McConnell at 18-21; *see* Oracle Opening Testimony at 10.

[60] SCE Opening Testimony at 67.

[61] PG&E Opening Testimony at 2-9.

[62] Oracle Opening Testimony at 10; SDG&E Opening Testimony, Mantz and McConnell at 20-21.

[63] Oracle Opening Testimony at 11.

[64] SCE Opening Testimony at 7-14.

[65] *Id.* at 11.

and the use of Flex Alerts or CAISO Grid Alerts as triggers.[66] SCE also proposed limiting dispatches to one event per day and 2 events per week, with static 2-hour events. SCE requested that customers be allowed to dually enroll in other residential DR programs.[67] Finally, SCE proposed a baseline method "Meter Before/Meter After" that measures the energy usage before and during the DR event.[68]

SDG&E did not develop its own proposal for a version of Residential ELRP. It described its existing "Peak Day" behavioral DR pilot program that provides tailored energy-saving suggestions and Home Energy Reports to approximately 525,000 customers that were previously auto-enrolled.[69] Events in DR occur between 4:00 – 9:00 p.m. during the summer. SDG&E is running its pilot using Oracle's platform, with a program similar to the program Oracle proposes. SDG&E is testing whether it can achieve peak reduction without the use of monetary incentives.[70]

Oracle supports a behavioral DR program where customers are asked to take specific actions to reduce energy use during the DR event, based on the individual customer's energy consumption. Soon after the DR event, customers would receive their performance results compared to their neighbors. The messaging would include tips and tools to reduce energy usage as well as

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[66] *Id.* at 9-10.

[67] *Id.* at 8-9.

[68] *Id.* at 10.

[69] SDG&E Opening Testimony, Mantz and McConnell at 18-21.

[70] *Id.*

additional offerings, such as programmable thermostats to motivate customers to adopt automated technology and achieve deeper peak reductions.[71]

PG&E's program also includes individualized messaging to encourage reduction, thank you emails with performance reports, and additional tips and tools. PG&E believes its incentive proposal will motivate customers to take action on event days because they would be competing to earn points and receive compensation with electronic gift cards.[72]

Third-party DRPs expressed concern that an opt out option for Residential ELRP could dampen demand for their DR programs, and recommended either an opt in approach or a way for customers interested in enrolling in DR to easily disenroll from ELRP.[73] OhmConnect suggested that the IOUs be required to conduct an open enrollment period for third-party DR programs to serve as a conduit for customer enrollment in supply-side DR programs.[74] MCE opposed auto-enrolling CCA customers in ELRP on the ground it would cause customer confusion.[75]

Other comments focused on the high cost per kW of the program, the administrative and IT costs and challenge of implementing such a large program in time for 2022, limited flexibility of the resource since it is only available to be

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[71] Oracle Opening Testimony at 3.

[72] PG&E Opening Testimony at 2-6 – 2-7.

[73] Joint DR Parties Opening Testimony at 26; *see also* Joint Parties Opening Testimony at 9-10, Reply Testimony at 2 (additional third-party DR issues).

[74] OhmConnect Opening Testimony at 4-5; *see also* Joint Parties Reply Testimony at 5; TURN Opening Brief at 9-10.

[75] MCE Opening Testimony at 3-1 – 3-4.

dispatched on a day-ahead basis, and unknown cost impact because of the newness of the concept.[76]

Several parties supported special attention to residential customers in Disadvantaged Communities, low-income customers and customers eligible for CARE/ESA. They asserted such customers would be motivated by the potential for bill savings due to their high energy burden.[77] CEJA also outlined a detailed proposal for outreach to these customers, requesting that customers be informed of the timeframe ELRP will be called, measures that can be taken to achieve reductions, and estimated bill credits if all measures are taken.[78]

Several parties expressed concern about the trigger for Residential ELRP of the CAISO-initiated Flex Alert, which taken together could suggest that the conditions under which Flex Alert is initiated could be re-examined and updated. Joint Parties do not support using Flex Alerts as a "hard" trigger because the conditions under which it is called are subjective.[79] CLECA does not support Residential ELRP, in part because Flex Alerts are not always reflective of actual capacity shortages.[80] Multiple parties expressed concern with customer fatigue due to the frequency of Flex Alerts.[81] SCE supports limiting the Residential ELRP events to two hours and a maximum of 2 events per week because of its view that frequent Flex Alerts degrade customer confidence in the

[76] SCE Opening Testimony at 66-67, and CLECA Opening Testimony at 3 and 8-9.

[77] OhmConnect Opening Testimony at 8; Joint Parties Reply Testimony at 4; *see also* CEJA Opening Testimony at 8 (supporting ELRP with modifications).

[78] CEJA Opening Testimony at 7-8.

[79] Joint Parties Opening Testimony at 11-12.

[80] CLECA Opening Testimony at 8.

[81] CEJA Opening Testimony at 6; OhmConnect Opening Testimony at 6; PG&E Opening Testimony at 2-6; and SCE Opening Testimony at 65.

California electric grid, which could therefore impact the State's ability to achieve electrification and meet environmental goals.[82]

4.2.3. Adopted Residential ELRP Direction

This Commission has undertaken recent efforts to address affordability and promote equity in utility rates.[83] Expanding ELRP to residential customers will provide CARE customers and customers in Disadvantaged Communities an additional pathway to reduce their utility bills. Compensating customers who reduce their energy usage when called upon by the CAISO through the Flex Alert program will promote equity because many residential customers are already participating in the Flex Alert program and are not receiving compensation. We also expect to achieve greater load impact by providing monetary incentives, which is consistent with the stated goals of this proceeding.[84] Further, we see the value in creating a new program for residential

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[82] SCE Opening Testimony at 65.

[83] These affordability initiatives include:

- July 2020 - D.20-07-032, adopting metrics for assessing the relative affordability of public utility service;
- February 2021 - En Banc (all Commissioner meeting) to discuss staff white paper on affordability, strategies for cost control, and alternatives for funding climate change initiatives;
- April 2021 – Commission-issued affordability report that assesses the affordability of public utility service in California; and
- September 2021 – Scoping memo issued in affordability proceeding, R.18-07-006, opening a new phase in the proceeding to explore strategies to mitigate future energy rate increases.

[84] PG&E Opening Testimony at 2-7, stating that offering incentives could increase performance compared to its 2015-16 pilot using the Oracle platform that did not include incentives and only achieved a 0.04 to 0.07 kW load impact per customer; and OhmConnect Reply Testimony at 3, listing financial incentives as a critical component of achieving consumption reductions.

customers that will help them become more aware of their energy usage[85] and potentially gain confidence in the electric grid.

We adopt a four-year Residential ELRP pilot in which bundled and unbundled residential customers of an IOU are eligible to enroll in ELRP by opting-in to participate.[86] As discussed below, the IOUs shall automatically enroll (that is, apply an opt out approach to) certain groups of residential customers.

Customers may not simultaneously be enrolled in another supply side DR program offered by an IOU, third-party DR provider or CCA. Customers likewise may not be taking service on a critical peak pricing, SmartRate or similar dynamic rate tariff.[87] Finally, a CCA may elect not to participate in the Residential ELRP pilot adopted here, in which case its customers would be ineligible to enroll.

We are not prepared to adopt a Residential ELRP that would automatically enroll all residential customers, and choose instead to allow most residential customers to opt in to such a program. We are somewhat concerned with the cost of compensating of customers for load reductions they might have had without such a program – the potential for free ridership. We are more concerned about the risk of low participation rates due to lack of customer buy-in as a result of automatic enrollment. For this reason, we support the IOUs' targeted approaches of automatically enrolling customer segments that may already be engaged or would be easier to engage because they have chosen to

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[85] *See* OhmConnect July 21, 2021 Reply Testimony at 2-3, using the term "energy engaged."

[86] The Residential ELRP pilot is identified as Group A.6 in Attachment 2 which accompanies this decision and contains all program requirements.

[87] A dynamic rate is both a rate program and an event-based DR program.

receive transactional emails (SCE),[88] or already receive Home Energy Reports (PG&E and SDG&E).[89] We also support IOU efforts to create behavioral programs that provide game-like motivation to customers such as a variety of attractive marketing and education methods, personalized actions customers can take to save energy during events based on consumption data analysis, prompt follow up with performance results, point systems and alternative forms of payment like electronic gift cards.

We are also concerned with the cost of administering this program. The utility will need to track each enrolled customer, send messaging, provide customer service, and calculate event performance. Further, utilities need time to build a large-scale program. A pilot that does not automatically enroll all residential customers will allow the Commission to observe enrollment levels, customer complaints, load reduction and other outcomes before committing the entire population of residential customers to a program.

We are persuaded that disenrollment should be easy for customers. Customers participating in Residential ELRP may at any time enroll in a supply-side DR program offered by the IOU, registered third-party DRP or CCA and shall be promptly unenrolled by the IOU from ELRP without the need for any action on the part of the customer. Customers can also opt out of the program through a simple process. Similarly, eligible customers should be able to opt in to an IOU's Residential ELRP pilot easily. We decline to order an open enrollment period for DR programs as OhmConnect requests, given the limited time to summer 2022.

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[88] SCE's Whole Home Savings Pilot; SCE Opening Testimony at 7-14.

[89] PG&E's PG&E proposed a Power Saver Rewards Pilot; PG&E Opening Testimony at 2-9; and SDG&E Peak Day program; SDG&E Opening Testimony, Mantz and McConnell at 20-21.

The following IOU programs that auto-enroll sets of select customers are approved, as modified herein, as each IOU's Residential ELRP pilot for the duration of the pilot:

- PG&E's Power Savers Rewards Program, Option A, with auto-enrollment of customers who receive PG&E's Home Energy Reports. PG&E's Options B and C are not approved.
- SCE's proposed Whole Home Savings Pilot, with auto-enrollment of "high usage customers who have opted in to receive transactional emails." Dual participation is not permitted at this time.
- SDG&E's "Peak Day" Behavioral DR program, with auto-enrollment of "existing Home Energy Report . . . customers."

In addition to the IOU-specific auto-enrolled set of select customers specified above, the IOUs shall auto-enroll residential customers in the CARE program. These customers may opt in to receive alerts of the program being triggered, and elect for those alerts to come by email, phone call, text message, bill insert or mailer. These customers may also opt out of ELRP.

In their marketing, education, outreach, and event notification efforts focused on the foregoing auto-enrolled customers and customers in Disadvantaged Communities, the IOUs shall incorporate elements of CEJA's Just Flex Rewards proposal including both in-language accessibility, and specific outreach for CARE and Disadvantaged Community customers, as described in Attachment 2 to this decision.

IOUs shall use a CAISO-issued Flex Alert declaration as the trigger for dispatching Residential ELRP customers, in addition to the Group A triggers described below. To provide more predictability for stakeholders regarding the conditions and parameters under which CAISO will issue a Flex Alert notice, this

Commission's Energy Division staff will work with CAISO to develop an objective set of criteria that triggers Flex Alerts. We request that any changes be made in time for the 2022 ELRP season.

The IOUs shall establish a process for a CCA to inform the IOU of its election to exclude its customers from ELRP. The CCA must make its election by January 31 of a new ELRP pilot year.

The IOUs shall collaborate to establish common program parameters, including a minimum dispatch window (which must be at least 2 hours), the start time of the dispatch, marketing strategies that limit customer confusion by ensuring that individualized messaging from the IOUs is consistent with the messaging from the statewide Flex Alert campaign, and statewide unified branding. Each large IOU shall file a Tier 2 Advice Letter within 30 days of issuance of this decision to establish the parameters and proposed cost of its ELRP Residential pilot program. In the Flex Alert paid media campaign portion of this decision, below, we also address marketing for Residential ELRP for 2022 and 2023.

The baseline against which load reductions will be calculated and compensation paid, will be similar to that used in SCE's residential CBP authorized in D.21-03-056: a 5-in-10 baseline with 40% day-of adjustment.[90]

We decline to adapt SCE's Meter Before/Meter After proposal because it could exclude customers who actually participated in an ELRP event such as customers who pre-cool their homes or use other strategies that should be encouraged. One example is a customer who turns off all her lights and air

[90] A 5-in-10 baseline is the average load during the same hours as the DR event, of the five days with the highest usage, selected from the past 10 business days. The day-of adjustment is a ratio of (a) the average load of the first three out of the four hours prior to the event to (b) the average load of the same hours from the historical days selected for the baseline.

conditioning at 2:00 p.m. to go to shopping in her community in preparation for an event scheduled for 4:00 - 6:00 p.m. SCE's proposal would not reward this customer because energy usage would be measured only during the hour before the event and during the event.

PG&E, SCE and SDG&E may continue to use the one-way balancing accounts authorized in D.21-03-056 to record costs of the Residential ELRP program, including costs of development, implementation, and operation of the program along with incentives paid under the program. These balancing accounts shall have the following annual caps for the Residential ELRP, with additional allowances for the increased scope of customers that will be auto-enrolled compared to IOU proposals. The approved administrative and Marketing Education and Outreach (ME&O) caps are shown below:

Residential ELRP A.6 Budgets by Category*						
(in $Millions)	**PG&E**		**SCE**		**SG&E**	
	2022	2023	2022	2023	2022	2023
*Administrative – Systems & IT, Notifications, Labor, Measurement & Evaluation***						
Requested Admin Budget	*$ 9.4*	*$ 8.7*	*$ 17.4*	*$ 11.1*	*NA*	*NA*
Approved Admin Budget	**$ 9.4**	**$ 8.7**	**$ 10.0**	**$ 9.0**	**$ 3.0**	**$ 2.7**
Marketing, Education & Outreach (ME&O)						
Requested ME&O Budget	*$ 0.5*	*$ 0.5*	*$ 5.4*	*$ 1.6*	*NA*	*NA*
Approved ME&O Budget	**$ 2.5**	**$ 2.0**	**$ 2.5**	**$ 1.6**	**$ 0.75**	**$ 0.5**
Annual Totals	$11.9	$10.7	$12.5	$10.6	$3.75	$3.2
Totals Per IOU	$22.6		$23.1		$6.95	

**Not including incentives, which are included in the combined incentive budget for all ELRP groups.*
*** Not including Rule 24/32 third-party systems & IT costs.*

4.3. Modifications to IOU DR Response Programs

4.3.1. Cost Effectiveness

As directed in D.21-03-056, the use of our traditional cost-effectiveness tools is waived for all DR proposals adopted in this decision for years 2022 and 2023, 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 D.21-03-056, and requests for cost recovery will undergo reasonableness review.

4.3.2. Cost Recovery

As directed in D.21-03-056, PG&E, SCE and SDG&E shall continue to 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, as well as the process for transferring balances within the IOU's DR Programs Balancing Account and Base Revenue Requirement Balancing Account for this purpose.

4.4. Modifications to DR Programs that Apply to All IOUs

4.4.1. Procurement of DR Resources from Third-Party DR Providers

The IOUs shall procure RA capacity from eligible third-party DRPs for 2022 and 2023 deliveries through bilateral contracts.[91] We agree that given the time constraints set in this proceeding, bilateral contracts would allow the IOUs

[91] Joint Parties Opening Testimony at 18 and TURN Reply Testimony at 19.

to tailor the contracts to their specific needs. The procured DR capacity shall count toward the overall MW targets established for each IOU in this decision. Because these procured resources are incremental to IOUs' and all LSEs' 15% PRM, these resources would not be applied to any LSEs' Maximum Cumulative Capacity (MCC) bucket cap calculation.

The third-party DR resources procured by the IOUs shall be integrated into the CAISO markets as economic DR (under a Proxy Demand Resource product) and must abide by all RA and CAISO rules. For the purposes of this emergency related procurement only, the DRPs are not required to have completed the Load Impact Protocol process for the DR resources procured by the IOUs. The procurement shall be informed by the DRPs' past performance.

The IOUs shall include performance requirements in their purchase agreements with the DRPs. To standardize payment/penalty requirements in these contracts, the IOUs shall adopt the capacity payment and penalty structure from PG&E's Capacity Bidding Program.

4.4.2. Auto DR Customized Incentives

The IOUs are authorized to pay upfront 100% of the eligible incentives for a custom Auto DR project on the condition that the customer's enrollment commitment to participate in an economically bid market integrated DR program is extended from three years to five years. This modification is effective for 2022 and 2023 only. [92]

SCE proposed reversing the policy set in D.12-04-045 in order to increase program enrollment and cited a 2020 joint IOU study performed by Energy Solutions that found the 60/40 incentive split is a major barrier to participation

[92] SCE Opening Testimony at 40-43.

as it does not align with customer business models and adds uncertainty to customers' financial planning.[93]

Polaris supports eliminating the 60/40 incentive split. Polaris does not support extending the participation requirement from three to five years, indicating it is beyond most commercial planning and DR cycles, which means programs could change twice before the commitment ends. Further, it notes that irrigation automation represents about half of the program megawatts in recent years. Polaris notes that farmers are struggling and may be forced to fallow land while still being required to pay the incentive back or face a claw back of the incentive payment.[94]

TURN supports eliminating the 60/40 incentive payment split for custom Auto DR incentives and the extension of the enrollment requirement from three years to five years. TURN indicates this will help expedite the movement toward automated DR.[95]

The Joint Parties support eliminating the 60/40 incentive split for custom Auto DR incentives and the extension of the enrollment requirement to five years calling the latter "a reasonable step toward balancing out any incremental risk that the Commission may perceive as a result of the transition back to an up-front incentive structure."[96]

4.4.3. Capacity Bidding Program

We clarify that the alternative baseline adjustment option allowed by CAISO and already authorized for use in IOU Capacity Bidding Programs in

[93] SCE Opening Testimony at 40-43.

[94] Polaris Reply testimony at 6.

[95] TURN Reply testimony at 16.

[96] Joint Parties Reply testimony at 14.

D.21-03-056 can be used for calculating capacity performance in their respective Capacity Bidding Programs.

The Joint Parties propose the Commission explicitly authorize use of the CAISO's new baseline options for CBP and DRAM capacity settlement.[97] The Joint Parties indicate that D.21-03-056 was unclear whether the intent of the Commission was that the CAISO's alternative baseline be applicable to energy market settlement only or capacity settlement also. The Joint Parties want the Commission to specify that the CAISO's alternative baselines are applicable to the calculation of CBP capacity incentive payment and DRAM contract payments – and that the Commission requests the CAISO extend its alternative day-of adjustment factor for the May-October 2022 and 2023 term.

TURN agrees with the Joint Parties that the Commission should explicitly authorize use of the CAISO's new baseline options for CBP capacity incentive payments and DRAM contract payments saying it's "reasonable and sensible and should be adopted."[98]

The Joint DR Parties agree with the adoption for all Capacity Bidding Programs this alternative baseline adjustment.[99]

4.4.4. Prohibited Resources Using Renewables

Resolution E-4906 is modified to include in its definition of allowable renewable fuels the Renewables Portfolio Standard-eligible fuels certified by the CEC.[100] Behind-the-meter generators utilizing CEC-certified Renewables Portfolio Standard-eligible fuels are exempt from the prohibited resources policy

[97] Joint Parties Opening Testimony at 30.

[98] TURN Reply Testimony at 22.

[99] Joint DR Parties Reply Testimony at 5.

[100] Joint Parties Opening Testimony at 30 and Joint DR Parties Reply Testimony at 13.

in D.16-09-056 and permitted for use in DR programs. The IOUs are directed to update their tariffs and contracts to incorporate the updated prohibited resources policy effective March 1, 2022.

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

PG&E's proposal to implement a price bid cap of $650/MWh for its Capacity Bidding Elect and Elect+ programs for the years 2022 and 2023 is approved. PG&E notes that "during the August 2020 heatwave a number of CBP Aggregators elected to bid their resources at, or close to, the CAISO's maximum bid price of $1,000/MWh, which resulted in about 45 percent of CBP resources not being dispatched. Had a bid cap of $650/MWh been in place, all nominated CBP resources would have been dispatched at least once during the August 2020 heatwave." [101]

PG&E's proposal to increase the current Base Interruptible Program (BIP) compensation level by $1/kW for the months of May through October for the years 2022 and 2023 is approved. PG&E notes that "[t]he reason[s] for the proposed increase is driven by a desire to encourage enrollment, recognize greater opportunity costs during the peak season (May-October), and to help 'minimize loss of DR enrollment.'"[102] This $1/kW seasonal increase is unique to 2022 and 2023 as justified by the Governor's July 30, 2021 Emergency Proclamation, and is not intended to continue beyond 2023.

Both the Joint DR Parties and the Joint Parties supported the increased incentive for BIP, although they proposed an even higher increase in compensation. We were not compelled to go beyond the proposal of PG&E.

[101] PG&E Opening Testimony at 4-1.

[102] PG&E Opening Testimony at 4-2.

PG&E's proposal to create and manage a new out-of-market residential smart thermostat control pilot program is approved for 2022 and 2023. PG&E is authorized to spend an incremental $12.4 million in incentives, administration, and marketing in 2022 and 2023 for this pilot as well as existing identified funding. For the program to continue beyond 2023, this program must be market integrated (as supply-side DR).[103]

PG&E is authorized to replace one-way thermostat control technology with newer two-way devices in 2022 and 2023 in its SmartAC program. PG&E is authorized an incremental $3.4 million in funding in 2022 and 2023 for administration, marketing, and retention incentives for this device exchange.[104] The Joint Parties support exchanging one-way technology, and a one-time $25 retention payment [included in PG&E's proposal and budget].[105]

PG&E's request for $1.2 million in incremental funds for Information Technology system enhancements to support third-party DR is approved, and PG&E may use the one-way balancing account authorized in D.21-03-056 to track these expenses.[106] We support this request for funding authorization to assist PG&E in improving the scalability and performance of its systems that support third-party DR customers, which should support leveling the playing field between third-party and IOU DR.

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[103] PG&E Opening Testimony at 4-6 to 4-10.

[104] PG&E Opening Testimony at 4-4 to 4-6 and 4-10.

[105] Joint Parties Reply Testimony at 11.

[106] PG&E Opening Testimony, p. 5-3 to 5-9.

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

Non-residential customers enrolled in SCE's Summer Discount Program (SDP) are permitted to dual participate in ELRP under the customer subgroup "A.1. Non-Residential, Non-DR Customers," and are not subject to the Minimum Size Threshold of subgroup A.1.[107] We agree that this modification will increase enrollment and decrease attrition.

SCE's proposal to reinstate the pre-cooling strategy where applicable in its Smart Energy Program (SEP) is approved. TURN supports this proposal.[108] SCE notes that "[p]re-cooling of homes can also help slow the deterioration of load impacts by extending the amount of time it takes the home to warm to its event setpoint. Pre-cooling can also reduce participant opt-outs through increased participant comfort."[109]

SCE's proposal to increase the ME&O budget for its SEP by $1.27 million in 2022, and $980,000 in 2023, to reach a broader audience through targeted marketing channels and leveraging marketing automation technology to improve ME&O effectiveness is approved.[110]

To address CAISO tariff changes stemming from CAISO's Summer Reliability enhancements for reliability DR resources (RDRR), SCE's proposal to modify effective immediately its Reliability Program Event Parameters, so that

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[107] SCE Opening p. 17-20.

[108] TURN Reply Testimony at 24.

[109] SCE Opening Testimony at 23 referencing the 2020 Smart Energy Program Load Impact Evaluation at 30.

[110] SCE Opening Testimony at 22-24.

1) the BIP and Agricultural Program-Interruptible (AP-I) parameters match, and 2) the parameters for the SDP and SEP match is approved.[111]

CLECA agrees with SCE that the CAISO RDRR market enhancements are sub-optimal.[112]

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

SDG&E is authorized to continue in 2022 its CBP residential pilot approved in D.21-03-056.[113]

SDG&E is authorized to create an enhanced Capacity Bidding Program-Commercial Elect option with three bid price tiers and increased capacity incentives as proposed by SDG&E. SDG&E is authorized to use existing funding for 2022, and is authorized $1.6 million for 2023, as well as a $51,000 incremental marketing budget.[114]

Joint DR parties say they "applaud San Diego gas and Electric Company's proposal to add an Elect option to SDG&E's CBP program." They note that SDG&E's proposal is less flexible than PG&E's option, but that it is "still a significant enhancement to SDG&E's CBP program."[115]

4.8. Flex Alert Paid Media Campaign

This decision requires continuation of the Flex Alert paid media campaign ordered in D.21-03-056 for the summers of 2022 and 2023, with two changes. First, the budget for 2022 and 2023 shall be $22 million, which represents the same budget as approved for 2021 ($12 million), plus $10 million in additional

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[111] SCE Opening Testimony at 49.

[112] CLECA Reply Testimony at 5-7.

[113] SDG&E Opening Testimony, Mantz and McConnell at 13.

[114] SDG&E Opening Testimony, Mantz and McConnell at 13-15.

[115] Joint DR Parties Reply Testimony at 4.

ratepayer funding that matches a $10 million appropriation for the program from the State General Fund approved in the 2021 Budget Trailer Bill, Assembly Bill 128.[116] Second, the Flex Alert campaign shall include marketing of the new Residential ELRP pilot adopted in this decision.

4.8.1. Background of the Flex Alert Proposal

The Staff Concept Paper proposed that if the Commission extended the ELRP pilot to residential customers, the Flex Alert campaign should be modified to "promote ELRP event[s] and to utilize all available channels to reach and notify customers about the imminent event[s] and the opportunity to reduce consumption and receive payment or bill credit."

The Phase 1 decision and record are useful to understand the Flex Alert program ordered for 2021 and 2022. A December 18, 2020 ruling in Phase 1 attached a staff proposal for the campaign with the following characteristics:

> Electric IOU participation in a paid media Flex Alert campaign using ratepayer funds for the purpose of mitigating the need for rotating outages;
>
> Contract management through a contract between one electric IOU and a marketing agency;
>
> Solicitations for marketing vendors in the early spring of 2021 and launch of the program for the summer of 2021; and
>
> A contract for the summers of 2021 and 2022.

Decision 21-03-056 directed the implementation of a statewide Flex Alert program available for the summers of 2021 and 2022. It required SCE to contract with vendor DDB San Francisco for a two-year period and conduct a

[116] Stats. 2021, Ch. 21, Sec. 2.00, subd. 8660-001-0001, item 2 ("The Public Utilities Commission or its delegee may award or designate funding in the amount of $10,000,000 from the General Fund in support of the Flex Alert program to achieve the purposes contemplated in Decision 12-03-056 [sic; should be Decision 21-03-056].").

performance assessment during year two (2022). The decision directed SCE, PG&E and SDG&E to fund the campaign with funds collected from all benefitting customers (*i.e.*, bundled IOU, CCA and Direct Access customers) using Public Purpose Program balancing accounts. The decision authorized a budget of $12 million per year, for two years, to support the campaign, allowing up to 3% of the annual Flex Alert budget to cover IOU administration costs.

4.8.2. Party Positions on the Flex Alert Proposal

Comments on Flex Alert were few since the program has already been ordered for 2021 and 2022. SCE proposed its own program,[117] and the California Efficiency + Demand Management Council (CEDMC) and CEJA recommended that the Flex Alert marketing include CEJA's Just Flex Rewards program, which mirrors the Residential ELRP this decision orders.[118]

4.8.3. Adopted Flex Alert Direction

We adopt a continuation of the Statewide Flex Alert paid media campaign funded by the ratepayers of PG&E, SCE and SDG&E for 2022-2023, with a budget of $22 million in each year. The IOUs shall expand the campaign to include the Residential ELRP campaign as described below and in Attachment 1. (Additional Residential ELRP details appear in Attachment 2.)

The 2021 fiscal year (year one) budget was $12 million in ratepayer funds, and an additional $10 in General Fund dollars for fiscal year 2021-22, which was implemented through a separate contract executed in 2021. A $22 million budget for 2022 and 2023 is reasonable due to the conditions described in this order,

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[117] SCE Opening Testimony at 11.

[118] CEDMC Reply Testimony at 5-8; CEJA Opening Testimony at 7.

which justify keeping marketing levels steady, especially with the added marketing we order for the new Residential ELRP pilot.

SCE shall revise the existing contract with the Statewide Marketing, Education and Outreach vendor DDB San Francisco (ME&O vendor) to increase the 2022 fiscal year (year two) budget to $22 million each year, as it is now in the amount of $12 million. SCE shall also revise the existing contract with the ME&O vendor to extend the paid Flex Alert Media campaign through December 31, 2023 at the same budget of $22 million per year. If for some reason additional funds become available for fiscal year 2022 or 2023, SCE shall amend the program to incorporate that additional funding.

SCE shall execute a contract with the ME&O vendor within 60 days of the effective date of this decision to allow for adequate program implementation for the 2022 summer months. SCE shall seek and follow direction from the Commission's Energy Division staff on the scope of and budget for the amended contract, and during the implementation and administration of the contract. The contract shall terminate on December 31, 2023, unless the Commission orders the contract extended.

The Flex Alert campaign shall include marketing messaging and materials for the new Residential ELRP pilot adopted in this decision. PG&E, SCE and SDG&E shall fund the campaign for 2022 and 2023 with funds collected from all benefitting customers in their service territories (*i.e.*, customers of the bundled IOUs, CCAs, Electric Service Providers and Direct Access providers) using Public Purpose Program balancing accounts. The budget is allocated based on each IOU's portion of the CPUC jurisdictional share of CAISO peak load: 45% for SCE, 45% for PG&E, and 10% for SDG&E.

We authorize IOUs up to 3% of the annual Flex Alert paid media campaign budget to cover IOU administration costs. If needed, the IOUs may request continuation of the funding and contract for the campaign beyond December 31, 2023, to support ELRP in the IOU DR application proceeding we anticipate opening in May 2022.

In all other respects, the Flex Alert campaign shall continue in its current form into 2022, including use of Community Based Organizations to assist with marketing in Disadvantaged Communities.

4.9. Smart Thermostats

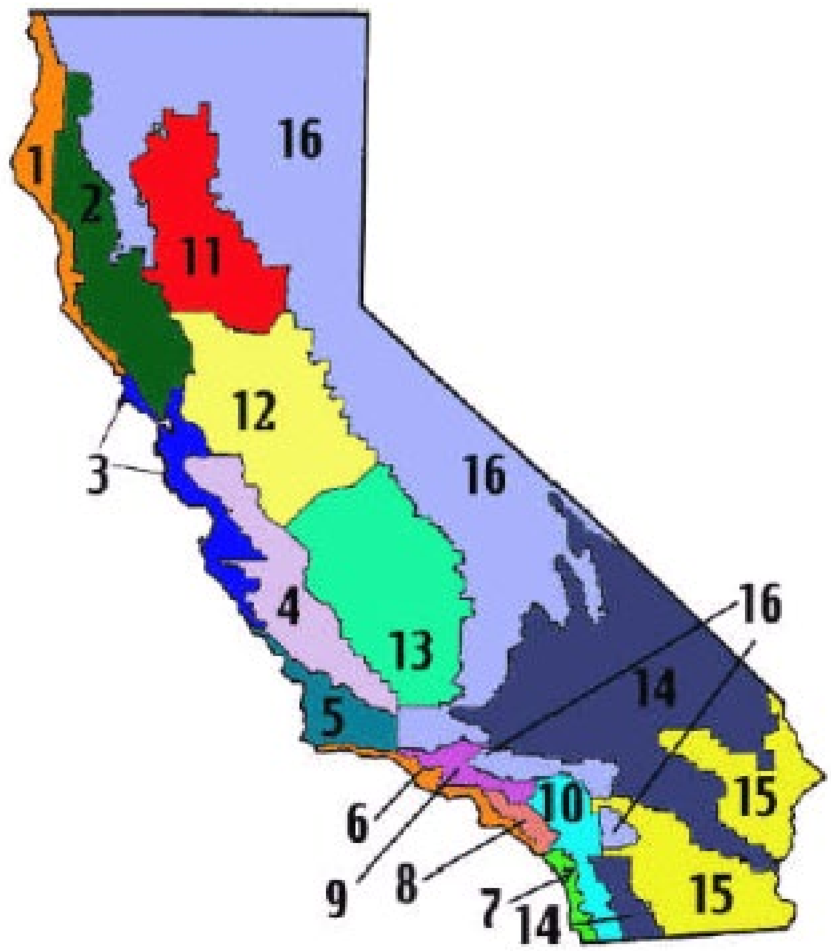
This decision authorizes a budget of up to $22.5 million in technology incentives ($75 per thermostat) to develop a limited, two-year Residential Smart Communicating Thermostat program for 2022-2023 to incentivize the installation of up to 300,000 smart communicating thermostats (smart thermostats or smart thermostat) in hot climate zones, specifically, climate zones 9, 10, 11, 12, 13, 14 and 15. As described below, the climate zone limitations do not apply to smart thermostats installed under the ESA program. To ensure the smart thermostats actually control air conditioning load in times of emergency, the program will require customers, except those qualified for ESA, to pre-enroll in a CAISO market integrated supply-side DR program. This program will be run statewide, and the IOUs may request up to an additional 10% of the technology incentive budget for administrative costs. Fifty percent of the technology incentive budget, or up to $11.25 million, will be available to DRPs to provide rebates through third-party DR programs. DRPs should have competitively equal access to the rebates as the IOUs.[119]

[119] *See* Joint Parties Opening Testimony at 20-25.

4.9.1. Background on Smart Thermostats

Air conditioning load increases substantially in the summer months, and especially in hot climate zones. Climate zones 9, 10, 11, 12, 13, 14 and 15 appear on the following map in Figure 1, and generally represent the California Central Valley, inland portions of the Bay Area and inland regions in Southern California. When reliability emergencies occur, control of air conditioner use in those areas – within the boundaries of customer health and safety – could help reduce demand. Smart thermostats, when combined with a market-integrated, supply-side DR program, will automatically turn down air conditioning (*i.e.*, increase the temperature by a few degrees) during reliability events and thus reduce electric load.

Figure 1. Climate Zone Map



In its Staff Concept Paper, Energy Division proposed a program like the one adopted here, reasoning that focusing on hot climate zones would deliver the highest potential energy savings for smart thermostat measures.[120] Staff also observed that smart thermostat programs have the potential to provide significant demand savings when paired with existing [DR] programs. By focusing smart thermostat installations to climate zones that have demonstrated the highest energy savings and pairing them with a DR program, a higher amount of savings and reliability is expected.

[120] Staff Concept Paper, Section 8.

For income-qualified customers eligible to participate in the Commission's ESA program, staff noted that smart thermostat subsidies are already available for those customers in all climate zones. There, the Staff Concept Paper proposed retaining such subsidies, and also making participation in a supply-side DR program voluntary, but encouraged:

1. Continue to allow smart thermostats in all climate zones with potential voluntary participation in the supply-side DR program. [The Energy Savings Assistance Program] makes smart thermostats available to all eligible customers across all climate zones for PG&E, [SCE and SDG&E] service territory. Due to the program design, it is recommended that this be allowed to continue.
2. For hotter climate zones that currently allow central Air Conditioning . . . measures (and potentially paired with insulation measures) as well as smart thermostats, include voluntary participation in the supply-side DR program.[121]

4.9.2. Party Comments on Smart Thermostats

Many parties addressed smart thermostat programs, proposing their own programs and responding to the staff proposal. Some opposed limiting the programs to hot climate zones, preferring a program that would be available to customers in all climate zones[122] while Google supported the limitations.[123] Recurve urged focusing smart thermostat efforts on the 4:00 p.m. – 9:00 p.m. window where reliability concerns most often appear, but otherwise not limiting eligible climate zones.[124] SCE proposed raising the smart thermostat incentive payment to $125 (or the full amount of the device, whichever is less), to help

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[121] Staff Concept Paper at 16.

[122] SDG&E Opening Testimony, Mantz and McConnell at 27-28, Joint Parties Opening Testimony at 18.

[123] Google Opening Testimony at 6.

[124] SCE Opening Testimony at 27.

ensure customers will actually buy the thermostats.[125] The Joint Parties supported a program that ensures third-party DRPs can participate.[126]

As for ESA-eligible customers, PG&E supported the staff concept to allow smart thermostat incentives in all climate zones given that the Commission has already authorized such payments in its ESA decisions. CEJA requested a thermostat incentive payment of $200 with bill rebates for load reduction, while Grid Alternatives proposed a program roll-out to 70,000 customers.

A requirement of enrollment in a DR program was supported by Google Nest, with an option to opt out of the DR program and forego the smart thermostat rebate.[127] PG&E opposed mandatory DR program enrollment, alluding to a new program it plans to roll out.[128]

4.9.3. Adopted Smart Thermostat Direction

We adopt a smart thermostat program designed to achieve load reduction in hot climate zones. The program will subsidize the smart thermostat devices, and require that a customer (except an ESA-eligible customer) pre-enroll in a CAISO market integrated DR program that is administered by either an IOU or third-party DR provider. We authorize up to $22.5 million in technology incentives to be available over a two-year period, from 2022 to 2023. The program rebate amount for non-ESA participants of $75, not to exceed the full cost of the equipment, shall be uniform across all program implementers. The program will be available for non-ESA customers in climate zones 9, 10, 11, 12,

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[125] Recurve Opening Testimony at 16.

[126] SCE Opening Testimony at 27.

[127] Joint Parties Opening Testimony at 20-25.

[128] Google Nest Opening Testimony at 8, Appendix B.6.

13, 14 and 15. The IOUs shall jointly file a Tier 2 Advice Letter with details of the program as further described below.

We are not persuaded that an emergency smart thermostat program in cooler coastal zones will deliver meaningful energy savings. Indeed, many smart thermostat incentives have been distributed to customers in cooler climate zones, with minimal load reduction.[129] However, the Commission has already adopted smart thermostat incentives for CARE/ESA-eligible customers without a DR requirement and we continue that authorization here, as described below.

Fifty percent of the technology incentive budget, or up to $11.25 million, will be available to third-party DRPs to provide rebates through the third-party supply-side DR programs. The third-party DRPs should have competitively equal access to the rebates as the IOUs. IOUs may request up to an additional 10% of the technology incentive budget for administrative costs. Each IOU must justify the amount of administrative budget that will be required to administer the program in the joint Tier 2 Advice Letter filing this decision requires.

The technology incentive amount will be up to $75 per smart thermostat, or the full cost of the smart thermostat, whichever is less. This incentive amount is similar to that authorized in previous Commission programs,[130] reflecting our belief that subsidizing up to the entire smart thermostat cost will increase program participation. Prior to incentive payment, the IOUs must certify installation of an eligible thermostat and enrollment in an eligible IOU or third-party supply-side DR program.

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[129] Impact Evaluation of smart thermostats Residential Sector - Program Year 2018, CPUC, https://pda.energydataweb.com/api/view/2339/CPUC%20Group%20A%20Report%20Smart%20Thermostat%20PY%202018_PDA.pdf.

[130] *See, e.g.*, D.17-12-003 at 82.

Within 15 days of issuance of this decision the IOUs shall meet and confer with third-party DRPs to discuss the process to distribute rebate awards, and to certify smart thermostat installation and DR program enrollment. Within 45 days of issuance of this decision, the IOUs shall jointly file a Tier 2 Advice Letter that reflects a consensus across third-party DRPs and IOUs on the foregoing issues. The joint Advice Letter shall include the following items:

- Program design and budget;
- Amount of administrative budget each IOU will need to administer the program;
- A discussion of any balancing or memorandum account authorization sought to track program expenditures;
- Goal for number of customers reached, by when, and estimated MW demand savings;
- Identification of qualifying thermostats eligible for the $75 incentive;
- A process to ensure customers of both IOUs and third-party DRP programs are eligible for smart thermostat incentives;
- A description of the DR programs a customer must enroll in to be eligible for the thermostat incentive, and how that enrollment will occur before the customer receives a rebate; and
- The process for identifying customers who qualify for the Energy Savings Assistance program.

Income-eligible customers who are participating in the ESA program will continue to be eligible to receive no-cost, direct install smart thermostats through ESA for all climate zones. This eligibility is consistent with current policy detailed in the Statewide ESA Program Policy and Procedures Manual, as described in D.16-11-022 and reaffirmed in D.21-06-015. We carve out this group so that IOUs and third-party DRPs do not offer a $75 rebate to ESA-eligible customers who are eligible to have the whole cost of the smart thermostat subsidized, along with a package of other measures. Hence, if IOUs or third-party DRPs participate in the smart thermostat program adopted here, they must ensure the customer they are engaging is not otherwise eligible for ESA.

Thus, the IOUs and third-party DRPs participating in the smart thermostat program adopted here will be required to verify customer eligibility for ESA, and if eligible, refer the customer to the IOUs' ESA programs. The IOUs and their ESA contractors, during their in-person assessment and installation, shall promote but not require enrollment in a DR program.

The Staff Concept Paper raised one point regarding Energy Efficiency and DR benefits of smart thermostats. In its testimony, PG&E responded to the Staff Concept Paper by proposing a change to a smart thermostat Energy Efficiency-DR integration program the Commission adopted in D.18-05-041.[131] PG&E requested leave for IOUs to propose changes to that program through an Advice Letter. The relevant program involves installation of smart thermostats and other distributed energy resource technology measures through the Commission's Energy Efficiency program, and captures DR benefits beyond energy savings. Decision 18-05-021 directed the IOUs to use $1 million for the residential sector and $20 million for the commercial sector from their "Integrated Demand-Side Management" program budgets to integrate delivery of Energy Efficiency and DR capabilities to customers. The guidance in D.18-05-041 also states that:

> The IOU [Energy Efficiency] PAs [Program Administrators] shall solicit, and other PAs should consider soliciting, third parties to design and implement programs to test various

[131] D.18-05-041 at 36-38.

> strategies and technologies for integrating [DR] capability with existing energy efficiency activities.[132]

PG&E refers to an Integrated Demand-Side Management Program Guidance document that PG&E did not attach to its testimony.[133] This document requests clarification on whether IOUs may conduct the foregoing integration activity themselves, without recourse to a third-party administrator. In reviewing D.18-05-041, however, it is clear that it allows IOUs to conduct the foregoing Energy Efficiency-DR integration activity without a third-party entity designing or implementing the program. IOUs must use the remaining budget and follow all other requirements outlined for limited integration programs described in D.18-05-041. The IOUs shall file a Tier 2 Advice Letter within 45 days of issuance of this decision that should specify:

- Remaining budget from the originally authorized budget in D.18-05-041;
- How the remaining budget should be allocated among the IOUs to run their integration Energy Efficiency-DR programs; and
- Program implementation plans and design including information on how they comply with requirements outlined in D.18-05-041.

4.10. Dynamic Rate Pilots

We adopt two pilots that test how dynamic rates can cause customers to shift energy usage to off peak times, which can enhance system reliability in times of emergency. The first pilot, proposed by Valley Clean Energy (VCE), focuses on shifting agricultural water pumping to off peak times for reliability purposes through the use of dynamic rates and incentives. The second pilot,

[132] *Id*. at 36.

[133] PG&E Opening Testimony at 7-9 & n.8.

supported by SCE, uses TeMix's technology to facilitate the use of dynamic rates as an incentive to shift load for customers using electric vehicles, behind the meter energy storage, and similar flexible technologies.

4.10.1. Background on Dynamic Rate Pilots

Dynamic rates are time varying rates structured to provide incentives to customers to engage in energy consumption when demand is low, through rate differences. Time-varying rates include time of use rates and dynamic rates like critical peak pricing and real time pricing.[134] Time of use rates are set by time of day and are static throughout the season. Dynamic rates, on the other hand, can vary from day to day and hour to hour. For example, a real time pricing dynamic rate may pass the wholesale price of electricity directly to the retail customer as a portion of the commodity energy cost. Compared to other time-varying rates, a dynamic rate sends customers a much more granular and variable price signal about when to shift load.

Dynamic rates based on real time pricing may do the following under certain circumstances:

- Reduce grid infrastructure costs and greenhouse gas emissions.
- Improve reliability and integration of renewables.
- Facilitate greater integration and fair compensation of distributed energy resources.

Several jurisdictions currently offer real time pricing rates, including ComEd and Ameren in Illinois (for approximately 30,000 residential customers), Georgia Power (for approximately 2,000 non-residential customers), and Spain

[134] *See* D.12-12-004 (uses "time of day" instead of "time of use.").

where a dynamic rate based on real time pricing is the default rate for approximately 10 million residential customers.

In California, real time pricing rates have occasionally been offered on a pilot or optional basis. For example, D.21-07-010 for SDG&E's GRC Phase 2 directed SDG&E to offer a pilot real time pricing rate that passes the wholesale price of electricity to retail customers as a portion of the commodity energy cost.[135] In addition, SDG&E's "Power Your Drive" rate for EV charging stations is a real time pricing rate with hourly commodity prices based on hourly CAISO day ahead energy market prices and hourly critical peak pricing-style pricing adders during hours of high system and circuit utilization to recover the cost of fixed generation and delivery (distribution) capacity in lieu of monthly demand charges.

The CEC's Electric Program Investment Charge (EPIC) grant number EPC-15-054 funded a transactive energy pilot in SCE's territory where the real time pricing rate included multiple dynamic rate components. The commodity rates were linked to the CAISO energy market price; dynamic capacity (generation and delivery) prices based on system/circuit utilization prices recovered the cost of fixed generation and delivery (distribution) capacity in lieu of monthly demand charges.

4.10.2. VCE Agricultural Pumping Dynamic Rate Pilot Proposal

VCE is a CCA in PG&E's territory and proposed to test the use of dynamic rates to provide incentives for large agricultural customers to pump water when it is least costly to do so. PG&E shall work with VCE under PG&E's DR Emerging Technologies program authorized in D.17-12-003 in administering and

[135] *See* D.21-07-010 at 47.

evaluating a dynamic transactive pilot rate for agricultural pumping loads in VCE's territory.

4.10.2.1. Background on VCE Agricultural Pumping Dynamic Rate Pilot Proposal

The Staff Concept Paper included VCE's proposal, which it also made in Phase 1 of this proceeding.

> **4. Agricultural Demand Flexibility Pilot**
>
> In Phase 1 of this proceeding, Valley Clean Energy (VCE), noting that it has annual irrigation pumping usage of ~100,000 MWh/year (15% of total service area load), submitted in its opening testimony a proposal for an Agricultural Demand Flexibility Pilot, supported by Sonoma Clean Power Authority, to be made available to customers on irrigation pumping tariffs. Staff offers as a proposal concept that a modified version of VCE's proposal be considered by the CPUC to tap into the load reduction/shift potential available in the pumping sector. VCE and other parties are encouraged to submit a more fleshed out proposal that includes the following elements:
>
> Incentivize automation of the pumping loads to receive an experimental rate that incorporates generation and delivery costs in hourly prices, with conventional monthly demand charges replaced by hourly, dynamic capacity charges. Design the experimental rate incorporating the ideas in the 6-step Distributed Energy Resource (DER) & Demand Flexibility roadmap described by ED Staff at the May 25, 2021, workshop on Advance DER and Demand Flexibility Management, specifically Steps 2 through 6. (Citation omitted.)
>
> Include a provision to hold PG&E harmless for any difference in cost recovery between the experimental rate's charges and the otherwise applicable tariff.

> Present the experimental rate to customers in a similar manner as the Step 1 of the above referenced 6-step roadmap.[136]

VCE responded with a proposal in its Opening Testimony. It explained that more than 85% of its service territory is designated for agricultural use, and that the agricultural sector represents approximately 18% of VCE's total annual load and 16% of its peak demand. VCE proposed a pilot for customers on irrigation pumping tariffs that will give the customers dynamic price signals using an experimental rate. Customers who successfully respond to the price signals and shift load out of expensive hours—typically the ramp hours—will enjoy bill savings.

VCE proposes to enroll agricultural customers with aggregated peak load exceeding 5 MW in the pilot.[137] It seeks a three-year pilot program, running in 2022, 2023 and 2024. The pilot incorporates concepts from the DER & Demand Flexibility roadmap described in the Staff Concept Paper.[138] VCE plans to partner with TeMix and Polaris on the technology, which has already been tested through the CEC's ratepayer funded EPIC program.[139]

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[136] Staff Concept Paper at 12.

[137] VCE Opening Testimony at 6.

[138] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops/advanced-der-and-demand-flexibility-management-workshop.

[139] CEC grants EPC-15-054 and EPC-16-054, respectively.

4.10.2.2. Party Comments on VCE Agricultural Pumping Dynamic Rate Pilot Proposal

Polaris, Joint DR Parties, TeMix and the California Farm Bureau Federation supported the pilot.[140] PG&E objected to the pilot, asserting the dynamic rate may not cover all fixed costs.[141] CLECA raised similar concerns for commercial customers.[142]

4.10.2.3. Adopted VCE Agricultural Pumping Dynamic Rate Pilot Direction

We approve VCE's pilot and direct PG&E to work with VCE on implementation. The proposal is for a limited pilot project focused on the agricultural sector which has flexibility in when it pumps water. Agriculture pumping has the capability to supply significant demand flexibility at low cost, since peak demand is 100% shiftable. The pilot has the potential to unlock up to 5 MW in the near term. The pilot has a simple, low-cost, program design with clear benefits matched to meet customer needs, and low administrative costs. Based on Polaris' submission, the estimated annual cost of the bill savings for customers on the pilot rate (without overhead costs) is $0.239/kWh for up to 800 MWh/year of load shift from peak to off peak periods.[143]

The pilot will provide valuable data about the potential of dynamic rates for load shift. The results from the program may help inform other load flexibility pilots and be used to scale dynamic rates to other customers. A dynamic hourly tariff provided day-ahead, with week-ahead projections, can be

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[140] Polaris Reply Testimony at 2; Joint DR Parties Opening Testimony at 27, Reply Testimony at 11-12; TeMix Opening Brief at 3-4; Farm Bureau Reply Brief at 3.

[141] PG&E Reply Testimony at 8-1 to 8-8.

[142] CLECA Opening Testimony at 7-8.

[143] Polaris Reply Brief at 4.

easily integrated with pump automation controllers. Automation will increase the responsiveness of the loads.

Non-generation and non-delivery costs (*e.g.*, transmission rates and non-bypassable charges) will be recovered through existing rate structures. The recommended "shadow bill" approach ensures that customers pay their default bills under the existing applicable tariffs. The pilot scale is limited to 5 MW of peak load, and therefore, the potential for any cost shift is contained.[144]

A volumetric rate for generation and delivery capacity cost recovery has been piloted in SCE territory through the CEC/EPIC funded Retail Automated Transactive Energy System (RATES) pilot project (EPC-15-054). The dynamic tariff in the RATES pilot was scaled to recover all authorized generation and distribution revenues. Therefore, if pumping loads do not respond to dynamic prices and shift their usage, there is very limited potential for any under or over collection of revenues. If loads do respond to the dynamic prices, then the pilot will have achieved the intended purpose of shifting load to enhance system reliability. The VCE pilot provides an opportunity to assess the potential of a dynamic retail rate approach to incentivizing load shift.

The week ahead rate projections in the pilot will provide signals to agricultural customers on how to schedule pumping. Pumping is a significant portion of VCE's load, and therefore could deliver significant savings at peak. The pilot therefore provides an opportunity to examine a sector with significant load impact, and the results may be used to inform future rate design.

[144] Polaris' Reply Brief at 4 extrapolates from its prior Transactive Energy Pilot that saving/incentives for the estimated load shift would be $192,720/year.

We adopt a "shadow bill" approach to address PG&E's and CLECA's objections about the revenue neutrality of the VCE pilot rate.[145] Customers will pay their PG&E bill based on existing tariffs, but the shadow bill will show the customer savings under the pilot dynamic rate, and VCE will pay customers for the difference between the shadow bill and the existing tariff. PG&E's concerns over the need for billing systems upgrades and costs associated with those upgrades[146] are met by Joint DR parties' proposal[147] for this "shadow" billing solution.[148]

As for PG&E's assertion that it is not appropriate to use AutoDR or Public Purpose Program funds for enrolling/integrating loads into the pilot program,[149] we authorize new funding as specified in Attachment 1.

PG&E's objection that existing DR programs have not encouraged participation in the agricultural sector[150] supports trying a different approach as proposed in the VCE pilot. The pilot encourages action by providing prices and tools for agricultural customers to schedule usage ahead of time. Existing CEC/EPIC funded projects (EPC-16-045) have demonstrated success in incentivizing agricultural pumping load shift in response to dynamic prices provided ahead of time.[151]

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[145] *See* VCE Opening Testimony at 7-9; Polaris Opening Brief at 6; Joint DR Parties Reply Testimony at 12.

[146] PG&E Reply Testimony at 8-2.

[147] Joint DR Parties Reply Testimony at 12.

[148] TeMix Opening Brief at 10 points to SCE Advice Letter 3837-E for an example solution.

[149] PG&E Reply Testimony at 8-3.

[150] PG&E Reply Testimony at 8-4.

[151] Polaris Opening Testimony at 9.

PG&E's concern about the utilization of system/circuit load estimates for calculating the dynamic capacity recovery components of the pilot rate lacks merit, as there are existing Commission-approved retail rates, such as the SDG&E Power Your Drive Rate, where capacity costs are recovered through hourly pricing adders that are applied based on projections of high-usage system/circuit hours.

As described in Attachment 1 to this decision, the pilot will last for three years (2022-2024), and shall start no later than May 1, 2022. PG&E shall submit a midterm evaluation of the program no later than December 31, 2023, and a final evaluation no later than March 1, 2025, as described below. VCE and/or PG&E may engage a service provider with a suitable IT platform to automate dynamic hourly prices and make them accessible to customers and automated agricultural water pumps.

For the generation components of the service by VCE, (1) energy costs will be based on the CAISO wholesale market prices, and (2) generation capacity and flexible capacity costs will be recovered on an hourly basis using the scarcity pricing concept: more fixed costs are recovered when system utilization is higher relative to the system capacity limit.

For the delivery component of the service by PG&E, (1) line losses will be recovered through volumetric rates, which could be time dependent, and (2) distribution capacity costs will also be recovered on an hourly basis using the scarcity pricing concept in lieu of monthly or annual demand charges.

The capacity cost recovery functions (hourly price vs. system utilization) for all components (generation capacity, flexible capacity, and distribution capacity) will be calibrated to fully recover annual VCE generation costs and PG&E delivery costs. Other costs, including billing, metering, access, public purpose, and transmission costs may either be recovered through the existing rate structures or through a monthly subscription charge.

PG&E will provide funds to or reimburse VCE, if necessary, for crediting any savings realized by the customers with respect to the delivery component of the pilot rate in the customers' shadow bills. PG&E shall set up a two-way balancing account to track expenses related to the delivery component of the customer bill savings during the pilot.

PG&E shall conduct a mid-term and final evaluation of this pilot. The mid-term evaluation report shall be released no later than December 31, 2023, and a final evaluation shall be released no later than March 1, 2025. The evaluations should include the following elements:

1. The response of agricultural loads to prices, including the response to non-binding week ahead price projections. This should evaluate the efficacy of the pilot tariff in shifting agricultural loads enrolled in the program from peak to off-peak periods and should be compared to other VCE agricultural loads;
2. In the case that VCE incorporates binding forecast projections, the evaluation should also include an assessment of this element;
3. The monthly bill impacts of the pilot dynamic rate in comparison to a customer's otherwise applicable tariff;
4. An evaluation of the recovery of generation and RA costs for customers on the pilot tariff. This evaluation should assess the impact of any under collection of generation and RA revenues against the impact of the shifted participant loads on marginal generation and RA costs; and
5. An evaluation of the recovery of delivery costs for customers on the pilot tariff. This evaluation should assess the impact of any under-collection of delivery revenues against the impact of the shifted participant loads on marginal delivery costs.

PG&E is authorized a budget of up to $3.25 million for the administration and execution of the three-year pilot to be used in the manner specified in the table below.

Cost category	Budget
Integration and automation[152] of pumping loads with the pilot price signal	$1,000,000[153]
Vendor fees, Systems and Technology	$1,500,000[154]
Program Administration, including Billing and Evaluation	$750,000

VCE (in coordination with PG&E) shall submit a Tier 1 Advice Letter no later than 60 days after issuance this decision that includes the following elements: (1) pilot scope, (2) pilot partners, (3) shadow bill implementation, (4) pilot dates, (5) pilot tariff design, and (6) details of how circuit and system data will be used to calibrate and calculate tariff price curves.

PG&E (in coordination with VCE) is directed to submit a Tier 1 Advice Letter no later than 60 days after issuance of this decision that includes, the following elements: (1) details of how circuit utilization data from the distribution circuits that serve VCE customers will be used to calibrate and calculate the delivery component of the dynamic prices, (2) details of how the circuit utilization data will be integrated with the pilot IT platform, and (3) the administration and evaluation budgets for this pilot.

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[152] For pump integration and automation, customers could be funded up to $200 per kW of shiftable load as a one-time payment with a minimum three-year participation requirement, or for the duration of the pilot if it is extended up to a maximum of five years.

[153] *See* VCE Opening Testimony at 12 (proposing use of AutoDR funds for integration/automation of pumping loads.

[154] *See* TeMix Opening Testimony at 3-4.

4.10.3. SCE Dynamic Rate Pilot Proposal for All Customers and End Uses

We grant SCE authorization to use TeMix's RATES platform for a three-year (2022-2024) dynamic pricing pilot in SCE's territory, and grant SCE its requested $2.5 million for the pilot. The pilot is intended to assist in assessing the costs and benefits of real-time rates, including required infrastructure, manufacturer interest and customer impacts. SCE shall administer the pilot under its DR Emerging Markets and Technologies program authorized in D.17-12-003.

4.10.3.1. Background of SCE Dynamic Rate Pilot

SCE and TeMix propose a three-year dynamic rate pilot that uses a rate calculation platform developed by TeMix.[155] The pilot builds on the work done under a CEC-EPIC funded RATES pilot.[156] SCE seeks funding of $2.5 million for the pilot, which would run in 2022, 2023 and 2024. TeMix explains that its platform follows the "UNIDE" roadmap that Commission staff presented at the workshop cited in the staff concept proposal for this proceeding. TeMix explains that its UNIDE platform enables calculation of dynamic rates for flexible distributed energy resources such as electric vehicles and energy storage.[157]

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[155] TeMix Opening Testimony at 1-2; SCE Reply Testimony at 8-10.

[156] CEC grant EPC-15-054; available at https://www.energy.ca.gov/publications/2020/complete-and-low-cost-retail-automated-transactive-energy-system-rates.

[157] TeMix Opening Testimony at 2.

4.10.3.2. Party Comments on the SCE Dynamic Rate Pilot

The Joint DR Parties support the pilot as a means of providing expedited access to dynamic pricing and customer billing of such rates.[158] They recommend making dynamic rates available to smart enabling technologies such as EV charging, behind the meter energy storage, and other controllable loads.[159] Polaris also supports use of the TeMix portal for dynamic rate pilots in other IOU territories.[160]

Stating that it is interested in exploring new pricing tariffs and enabling software that can facilitate local grid reliability and wholesale market optimization, SCE supports use of the TeMix platform on a pilot basis, for "further demonstrations that can accelerate solutions for system reliability for 2022 and 2023."[161] SCE states the pilot "can provide a forum to explore options for both transactive price models and real time pricing with other parties and stakeholders, and demonstrate how new forms of distributed energy resources can act as both customer assets and grid interactive resources."[162]

There was no opposition to the pilot.

4.10.3.3. Adopted SCE Dynamic Rate Direction

We grant SCE authorization to conduct the pilot for the purpose of studying how price responsive pilot projects can enhance system reliability in 2022 and 2023.

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[158] Joint DR Parties Reply Testimony at 12, 24-26.

[159] Joint DR Parties Opening Testimony at 27.

[160] Polaris Reply Testimony at 2-3.

[161] SCE Reply Testimony at 8-9.

[162] *Id*. at 8.

As further set forth in Attachment 1, the pilot is open to SCE residential, commercial, and industrial customers, and SCE may prioritize customers with smart enabling price-responsive end-uses such as electric vehicle charging, behind-the-meter batteries, and controllable loads. The pilot is authorized for three years (2022-2024), starting no later than May 1, 2022.

To reduce the time required to integrate the pilot rate tariff with SCE's billing systems, SCE may use a "shadow bill" approach to provide participants compensation for any load shift by the customer's equipment in response to the pilot prices. In such an approach, participants will continue to pay their current SCE bill under the otherwise applicable tariff and will also receive a shadow pilot bill, which they will not pay, that illustrates a customer's potential savings under the pilot rate. Participants will receive payments from SCE for their pilot rate savings on either a monthly or annual basis.

SCE shall conduct a mid-term and final evaluation of the pilot to assess the costs and benefits of real-time rates, including required infrastructure, manufacturer interest, and customer impacts. The mid-term report shall be released no later than December 31, 2023, and a final evaluation shall be released no later than March 1, 2025.

SCE shall submit a Tier 1 Advice Letter no later than 60 days after issuance of this decision that includes, but is not limited to, the following elements: (1) pilot scope, (2) pilot partners, (3) shadow bill implementation, (4) pilot dates, and (5) pilot tariff design.

5. Supply Side Resources

5.1. Summary of Procurement Ordered in this Decision

The purpose of this section is to summarize the characteristics and contracting requirements for procurement of the supply-side resources adopted in prior decisions and modified slightly as described in the subsections above. This decision applies the following requirements to the additional procurement ordered through this decision:

- Resources must available during both the peak and net peak demand periods.
- Resources may not yet have full capacity deliverability status but must be capable of providing energy/grid reliability benefits during the peak and net peak periods.
- Commercial Online Dates (COD) (or contracts that are otherwise operationally consistent with the guidance in this decision) by June 1, 2022, is preferred but resources COD or operational by August 1, 2023, will be considered.
- Potential resources may include utility-owned storage, with Commission consideration of such projects through a Tier 2 Advice Letter.
- Resource types that may be considered for procurement include:
    - Incremental capacity from existing power plants through efficiency upgrades, revised power purchase agreements/tolling arrangements.
    - Contracting for generation that is at-risk of retirement.
    - Incremental energy storage, including utility-owned storage.
    - Acceleration of CODs from a resource that is otherwise required to meet an LSE's IRP target, e.g. acceleration to June 1, for a resource that would otherwise be online by August 1.
    - Firm forward imported energy, as well as import contracts that ensure delivery during tight system conditions (*e.g.*, alerts, warnings, and emergencies or at contractually pre-specified prices) but the latter category can only be procured by IOUs and applied to the incremental reliability procurement targets adopted in this decision.

- RA-only contracts or contracts that include dispatch rights may be proposed.
- Contracts of five years or more for efficiency improvements resulting in incremental generation at existing gas power plants require a Tier 3 Advice Letter.
- Incremental storage and preferred local resources procured by the Central Procurement Entity.

We also address some of the proposals made by parties or in the Staff Concept Paper. We allow the Central Procurement Entity to procure local capacity and allow bilateral contracting. We reject staff concept proposals to 1) increase or add penalties for delay or other failure of such procurement, 2) impose a non-bypassable charge (NBC) for emergency procurement ordered in this proceeding; and 3) change least cost dispatch (LCD) rules for hydroelectric generation.

In the following sections, we provide details on each of the foregoing supply-side requirements.

5.2. Additional Capacity Procurement and Use of Excess Resources to Meet Targets

PG&E, SCE and SDG&E shall continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve the range of additional procurement authorized in this decision for the months of concern. These efforts should take the form of solicitations, ongoing bilateral negotiations, IOUs offering counterparties an opportunity to refresh prior IRP procurement bids, accelerated procurement of resources procured by LSEs to meet their IRP obligations for summer months prior to their required online dates, upgrades resulting in increased efficiency of existing generation resources, and imports. Consistent with resources ordered in Phase 1 in

D.21-02-028 and D.21-03-056, the resources ordered here shall be available to serve load at peak and net peak.

Unless otherwise stated in this decision, IOUs shall submit all procurement contracts to the Commission via Tier 1 Advice Letters on a rolling basis. One exception is for contracts for incremental gas generation of five years or more and incremental imports. IOUs shall submit contracts of five years or more for efficiency improvements that result in incremental generation at existing gas power plants to the Commission in Tier 3 Advice Letters. Contracts for fossil-fuel development at new sites or for redevelopment or repowering at existing electric generation sites are not allowed and will not be considered. Tier 1 Advice Letters are not required, but may be submitted, for incremental imports. As noted previously, a combination of RA eligible and non-eligible resources will be used to meet the contingency procurement target range. All RA eligible resources supporting the effective PRM should be included in supply plans and IOUs' month ahead RA showings 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. 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 shall pair imports contracted with maximum import capacity 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 shall calculate and include the average price it received for sales of its excess maximum import capability (MIC) or, if not available or representative of market value, another reasonable market benchmark.

If an IOU has not met its minimum contingency procurement target for the months of June and October with RA eligible resources that can be reflected on supply plans, it may use excess resources in its existing portfolios to meet the minimum contingency procurement target (900 MW for PG&E and SCE, and 200 MW for SDG&E), provided it has made reasonable attempts to sell this excess capacity to other LSEs. In these instances, the excess resources may be accounted for at the imputed cost of 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark.

For the months of July, August, and September, excess resources from an IOU's existing portfolios may be used to meet or supplement these procurement targets up to the upper end of its contingency procurement target (1,350 MW for PG&E and SCE, and 300 MW for SDG&E), provided it has made reasonable attempts to sell this excess capacity to other. Again, these excess resources may be accounted for at the imputed cost of 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark. This approach ensures that the greatest amount of additional resources are procured during the three months of highest grid stress historically.

The benefit of showing these excess resources from IOUs' existing portfolios of 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 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 applied to the CAM, as well as the calculus used to determine these amounts to Energy Division, and Energy Division will post this information on its website.

Finally, 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 may file Tier 2 Advice Letters with the effective date of the tariff modification to be the effective date of this decision.

5.3. Utility Owned and Third-Party Energy Storage

An Assigned Commissioner Ruling issued in this case on September 17, 2021, explained to all parties that this proceeding's Phase 1 decisions granted IOUs authority to procure for utility owned storage (UOS) to meet 2022 summer reliability needs. We address 2023 UOS in this decision.

5.3.1. Party Comments on Utility Owned and Third-Party Energy Storage

SDG&E requests that the Commission issue a second ruling as soon as possible applying the direction set forth in the ACR to utility-owned energy storage projects that can be online by summer of 2023. SDG&E also cites to several UOS projects that amount to over 200 MW that could be online late 2022 or early 2023.[163]

CESA agrees that the UOS projects identified by SDG&E represent promising potential for new incremental capacity to be added in support of near-term emergency reliability needs. CESA requests that the Commission require

[163] SDG&E Opening Testimony, DeTuri and Maiga at 3-11, McKay *passim*.

IOUs to procure third-party energy storage solutions in addition to UOS as long as it can be online to meet summer 2023 needs.[164] SDG&E agrees that the Commission should not prefer utility ownership of energy storage resources over third-party ownership, citing Governor Newsom's Emergency Proclamation's acknowledgement that potential reliability solutions include development of new resources by both IOUs and third parties through expedited processes.[165]

SCE notes that the ACR, D.21-02-028 and D.21-03-056 provide authority for SCE's UOS proposal. Under SCE's proposal, the UOS resources would first interconnect to non-CAISO controlled facilities and operate as a distribution asset. During this time, SCE would recover costs from all customers in its service territory through its distribution charge. Once the storage facilities are able to obtain interconnection to the CAISO's transmission system and CAISO's wholesale market, SCE will allocate the costs and benefits of the resource through the Cost Allocation Mechanism. SCE requests that the Commission confirm this allocation approach in a Phase 2 decision.[166]

SCE also requests that the Commission confirm its understanding that the IOUs' authorization to pursue UOS for summer 2022 applies to UOS resources that may be operated by the IOUs as non-CAISO controlled grid assets, "fully

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[164] CESA Opening Brief at 6-8. *See also* IEP Opening Testimony at 7 ("[t]here are no inherent advantages to utility ownership that should lead the Commission to prefer utility ownership of storage assets over independent ownership. Although constructing independently-owned equipment within a substation footprint may raise security and access concerns, the Commission should broaden consideration to other sites that share similar attributes with substations regarding site control, ease of interconnection, and deliverability.").

[165] SDG&E Reply Testimony, DeTuri and Maiga at 4-5.

[166] SCE Opening Testimony at 58-59.

within the jurisdiction of the Commission, that would not participate in the wholesale energy market or qualify for RA credit by summer 2022."[167]

SCE asks the Commission to allow UOS procurement in addition to IOU third-party procurement to meet summer 2022 procurement targets. Specifically, SCE recommends that the Commission set UOS targets and third-party targets based on the IOU's upper end targets in D.21-03-056. SCE also asks the Commission to find here that IOUs and LSEs may count any UOS projects toward their IRP mid-term reliability procurement requirements in D.21-06-035 based on their cost responsibility for such projects.[168]

PG&E recommends that the Commission continue the use of a Tier 2 AL process for utility-owned resources, with broad cost recovery through the existing Cost Allocation Mechanism. PG&E also requests that the Commission indicate that utility-owned resources approved in this proceeding do not require a corresponding or subsequent application to be submitted to meet the procurement orders from D.21-06-035, the IRP decision that ordered 11,500 MW of new resources.[169]

5.3.2. Adopted UOS and Third-Party Storage Direction

We agree with SDG&E and CESA that energy storage that can be brought online by summer 2022 or 2023 to meet the procurement targets, identified above, may be both UOS and third-party resources. These storage resources need not be fully deliverable in 2022 or 2023, as long as they provide peak and net peak grid reliability benefits in summer 2022 or 2023. We encourage siting

[167] SCE Opening Brief at 49.

[168] *Id*. at 50.

[169] PG&E Opening Brief at 40.

these resources in locations where they will also provide benefits to local reliability and Disadvantaged Communities.

We also confirm that SCE's proposed cost allocation for its UOS procurement would be an acceptable alternative to the CAM authority granted in D.21-02-028 when operating the resources as non-CAISO controlled grid assets prior to deliverability to CAISO markets Collecting the costs of this procurement through distribution rates until the resource is fully deliverable to CAISO markets is consistent with principles of CAM treatment. Distribution rates flow to all customers in an IOU's service territory, similar to CAM costs (which flow thorough a delivery charge to all benefiting customers). Additionally, resource costs should be tied to benefits and since distribution customers will receive the benefits of these resources, costs should follow this same allocation. Consistent with the principles of the CAM authority we granted in D.21-02-028, once the resource is connected to the transmission system and deliverable to CAISO markets, the costs shall no longer be collected through distribution rates, and instead the net capacity costs and benefits will be accounted for through the CAM mechanism.

Given the urgency to get new resources online, we also agree with PG&E that the Tier 2 Advice Letter process and Cost Allocation Mechanism for utility owned storage should continue for 2022 and 2023. We clarify that the IRP requirement established in D.21-06-035 obligating the IOUs to submit an application for utility-owned resources procured to meet IRP requirements is not required for this procurement. Such a requirement would lead to delays in contract execution.

5.4. Central Procurement Entity

This decision allows SCE and PG&E to negotiate bilateral contracts for the emergency procurement ordered in this decision in their capacities as Central Procurement Entities (CPE).

5.4.1. Background on CPE

In D.20-06-002 in the RA proceeding, the Commission adopted a centralized framework for the procurement of local RA in the PG&E and SCE distribution service areas, beginning with the 2023 RA compliance year. The decision identified PG&E and SCE as the CPEs for their respective distribution service areas, established an all-source solicitation process to procure existing and new resources, and required a Tier 3 Advice Letter process for contacts that exceeded five years in duration.

5.4.2. Party Comments on CPE

PG&E proposes in this proceeding that it be allowed bilateral contracting authority in its capacity as the CPE in addition to using the all-source solicitation process from D.20-06-002. PG&E asks to be allowed to bilaterally contract with counterparties that can both (1) provide incremental local RA resources in the CAISO-designated local areas of the procuring CPE's distribution service area and (2) meet the near-term emergency-based procurement requirements for the summers of 2022 and 2023 ordered in this decision.[170]

PG&E asks the Commission to allow the CPE to file a Tier 1 Advice Letter, consistent with D.21-02-028 and D.21-03-056, for expedited approval of bilateral contracts. PG&E requests that the costs of any incremental local RA resources be

[170] PG&E Opening Brief at 37-38.

allocated similarly to other Cost Allocation Mechanism resources procured by the CPE for local area reliability.[171]

Calpine supports PG&E's proposal, but notes that gas generation is cleaner than many of the alternatives that are being considered for emergency procurement. Calpine proposes that any procedure adopted for PG&E's proposal should apply to all resource types and not just preferred resources.[172] CESA argues that it is unclear why PG&E needs to utilize its CPE function rather than its bundled procurement requirements to secure resources.[173]

5.4.3. Adopted CPE Direction

In its capacity as the CPE for local procurement, an IOU is best suited for the procurement of local resources through all-source solicitations to arrive at the least cost best fit set of options. However, given the near-term reliability needs to procure additional resources, the CPE is better suited to sign bilateral contracts for local procurement rather than an IOU's bundled procurement arm. This is because the CPE has been designated to meet local area requirements on behalf of all customers in the IOUs service area.[174] For the purposes of the procurement authorized in this decision CPEs may make use of bilateral negotiations as well as all-source solicitations to procure local area resources. PG&E 's proposal to limit this procurement to storage and preferred resources will help to ensure that the CPE framework objectives are upheld, and we adopt it.

[171] *Id*. at 38.

[172] Calpine Opening Brief at 7.

[173] CESA Reply Testimony at 10.

[174] D.20-06-002 at Ordering Paragraph 2. The decision also clarified that RA import contracts must be paired with an import allocation right. *Id.* at Ordering Paragraph 5.

The CPE shall submit bilateral contracts executed pursuant to this authority as directed in the Phase 1 decision, D.21-02-028 and as summarized below.

5.5. Imports

We relax certain RA rules with regard to imports for IOUs only in order to help address summer reliability and potentially provide a wider pool of import products to procure for the summer months.

5.5.1. Background on Imports

In D.20-06-028, the Commission revised its rules for imports to count toward RA requirements. The Commission clarified its RA import rules to ensure that RA imports did not represent "speculative supply" that might not be available during stressed system conditions.

The new rules count non-resource-specific imports toward RA requirements, provided that:

(a) The contract is an energy contract with no economic curtailment provisions;

(b) The energy must self-schedule (or in the alternative, bid in at a level between negative $150/MWh and $0/MWh) into the CAISO day-ahead and real-time markets at least during the Availability Assessment Hours throughout the RA compliance month, consistent with the MCC buckets; and

(c) The energy must be delivered to the load-serving entity in accordance with the governing contract, consistent with the MCC buckets.

5.5.2. Party Comments on Imports

CalCCA recommends two modifications to existing import RA requirements that would apply for imports procured to meet the summer 2022 and 2023 emergency procurement requirements adopted in this proceeding.[175] It recommends that we not apply the requirement to bid zero dollars or below for year 2022 and 2023 to these resources. It further asks the Commission to allow LSEs to meet emergency reliability procurement targets by contracting with imports after the RA showings deadline, up to the available unused MIC.

CalCCA's proposal would authorize LSEs to procure additional imports after RA showings, up to the amount of available MIC that was not used for monthly RA showings. CalCCA argues "that doing so would obviate the need for LSEs to procure additional MIC or take MIC from their own portfolio and then determine the value of that MIC, while still ensuring the imports procured are deliverable. By procuring imports after the month-ahead showing process, the amount of MIC not used for RA showings will be known, indicating a high probability that a firm energy import at that location would flow to the CAISO load."[176]

WPTF believes that imports procured for reliability purposes should be subject to RA import rules.[177] SCE proposes the Commission work with the CAISO to determine a process to upload monthly imports purchased after T-30,[178] on RA supply plans. The T-30 date is the CAISO's deadline to allow resources, procured by LSEs, to be designated as RA supply for California load. This action would allow these resources to be treated as RA for CAISO market mechanism purposes. SCE is already procuring non-RA imports after the T-30 window to help enhance system reliability under its existing D.21-03-056

[175] CalCCA Opening Testimony at 16.

[176] *Id*. at 17.

[177] WPTF Opening Testimony at 5.

[178] T-30 means thirty days prior to the first day of the compliance month.

authority. SCE suggests that monthly import products can be available in the market closer to the flow date, but after the RA compliance filing deadline. TURN supports SCE's proposal.[179]

5.5.3. Adopted Imports Direction

The August 2020 rotating outages and subsequent periods of stressed grid conditions in 2020 and 2021 involved high electricity demand and resource deficiencies that were not limited to the CAISO balancing authority area but were widespread across neighboring balancing authorities. These are the exact conditions in which unspecified imports become "speculative" and are at most risk of not performing. Importantly, the Day Ahead prices during the hours of concern for many of these periods did not reach the $1,000 price cap at which these unspecified imports regularly bid into the market, so few if any of these products would have been committed to deliver in the Day Ahead market, and under current CAISO market rules imports have no obligation to bid into the real time markets.

Consequently, had the new import rules not been in place this summer and had LSEs met their RA requirements with unspecified imports in place of other more reliable RA resources – especially resources that must offer into the real time markets in addition to the Day Ahead market – the stressed grid conditions we experienced this summer would have been significantly more challenging.

In light of these concerns, relaxing the RA import rules could have the unintended consequence of adversely impacting reliability rather than improving it. Therefore, we do not adopt here CalCCA's proposal to relax

[179] TURN Reply Testimony at 7.

import rules for all LSEs to meet their RA obligations. However, we do see merit in providing the IOUs maximum flexibility in procuring to achieve the targeted range of additional reliability resources authorized in this decision.

Consequently, we adopt CalCCA's recommendation that the import rules be relaxed, allowing import contracts that do not meet import requirements because they are executed after the month-ahead showing process in order to meet the effective PRM. This approach is justified because these contracts are structured to ensure delivery during tight conditions. We allow the IOUs to execute import contracts for the effective PRM that do not meet the RA import requirements but are structured to ensure delivery during tight system conditions (*e.g.*, CAISO Alerts, Warnings, and Emergencies or at contractually pre-specified prices).

We also see merit in SCE's proposal to allow late procured imports procured by IOUs to meet the effective PRM adopted here to be treated as RA under the CAISO's market mechanisms. Such action would enhance reliability by allowing these late procured imports to be treated as RA supply. Therefore, we direct Energy Division staff and the IOUs to work with CAISO to allow these resources to be shown as RA on supply plans.

5.6. Accelerate Procurement Already Ordered

Another staff concept put forward was to accelerate procurement already ordered in the Commission's IRP proceeding. We believe it may make sense to allow LSEs or project developers to bid into the IOUs' solicitations or contract bilaterally for accelerated procurement of 2022 resources. Accelerating 2024 IRP procurement into 2023 might be possible, but is already in scope for the IRP proceeding and should be considered there.

5.6.1. Background on Accelerated Procurement

Various decisions in the IRP proceeding have recently ordered additional procurement. The IRP Mid-Term Reliability decision, D.21-06-035, ordered an unprecedented 11,500 MW in new capacity for the 2023-2026 period, after D.19-11-016 in the same proceeding had ordered procurement of an initial 3,300 MW.

The Staff Concept Paper in this proceeding asked for party comment on whether accelerating some of the procurement ordered in both of these decisions might provide reliability at net peak for summer 2022 and 2023:

> All LSEs were ordered to procure new resources beginning in June 2023 in IRP decision D.21-06-035, the IRP's Mid-Term Reliability (MTR) Procurement Decision. To the extent that these 2023 resources could be brought online by summer 2022, the CPUC could provide an incentive to LSEs for early compliance with D.21-06-035.

Another staff concept was to give LSEs incentives to bring their IRP resources online early to ensure they are available for 2023.

5.6.2. Party Comments on Accelerated Procurement

The majority of parties providing testimony on whether to accelerate existing IRP obligations assert there is little ability for LSEs to accelerate procurement from 2023 into 2022 at this point in time. They assert they cannot move procurement due in August 2023 a full year earlier due to project development timelines. The testimony also noted that supply chains are especially tight at the moment, due to the impact of the COVID pandemic, making acceleration even less likely.

5.6.3. Adopted Accelerated Procurement Direction

We strongly encourage all LSEs – whether CPUC jurisdictional or not -- to take all steps possible to accelerate procurement to support increased grid reliability, but we decline to develop a new incentive regime for LSEs or generators to bring IRP procurement on earlier than expected. We agree with party comments that this could introduce gaming issues, which we wish to avoid. We also do not believe an entirely new incentive mechanism is necessary, since to the extent that IRP-ordered resources can be accelerated, generators and/or LSEs can and are encouraged to offer these resources into RFOs or bilaterally negotiate with the IOUs for incremental capacity that can be brought online in 2022 or 2023 in advance of the IRP required August deadlines. This effectively results in the same outcome, but allows for a market test of the price for accelerating these resources, since IOUs can compare offers of accelerating these projects with other resources being offered to meet their incremental procurement targets, rather than setting an arbitrary incentive amount and creating a new, likely complicated, reimbursement mechanism.

5.7. Introduce Penalties for Delays to D.19-11-016 Procurement

We do not introduce penalties for delays to the IOU and LSE procurement ordered in D.19-11-016. However, the Commission will closely monitor all ordered procurement and online dates to ensure deadlines are met.

5.7.1. Background of D.19-11-016 Penalty Issue

The staff concept paper proposed instituting penalties related to procurement ordered in D.19-11-016, where no current penalties exist.[180] That decision, issued in the Commission's IRP proceeding, ordered system-level RA capacity of 3,300 MW by all LSEs serving load within the CAISO balancing authority area.

The staff concept paper made the following suggestion:

> [The] CPUC could apply penalties to [LSEs] for not bringing ordered procurement resources online in accordance with [IRP] decision D.19-11-016. D.19-11-016 required Tranche 1 resources by August 1, 2021 and Tranche 2 resources by August 1, 2022, and Tranche 3 resources by August 1, 2023. There are no penalties imposed on LSEs for failure to meet online dates with new resources per D.19-11-016; however, as detailed in D.20-12-044, the CPUC intends to consider whether to order backstop procurement and allocate the cost of that backstop procurement to one or more LSEs.
>
> The CPUC could consider putting all LSEs on notice that it intends to impose fixed penalties (for instance, potentially $50,000 per incident) or capacity-based (potentially $10/kW by Month for each month delay) for any LSE that fails to achieve commercial online dates consistent with the order. The CPUC may consider a grace period of up to six months from the expected online dates. Although collectively, LSEs contracted for sufficient Tranche 1 resources, some Tranche 1 projects were delayed for a variety of reasons. Penalties (with or without a grace period) may ensure that the delayed Tranche 1 resources materialize prior to June 2022. Penalties (with or without a grace period) may ensure that Tranche 2

[180] A later decision in the IRP proceeding ordered an additional 11,500 MW of procurement to meet the CEC's Mid-Term Reliability predictions of need over the period 2023-2026. That decision imposes penalties related to delays or failures in procurement of the 11,500 MW ordered.

> and 3 resources materialize with minimum delays in 2022 and 2023. Any procurement delayed Penalties would be incremental to any penalties associated with [RA] deficiencies, and LSEs would not be exempt from penalties even if they were otherwise fully resourced for [RA].

5.7.2. Party Positions on D.19-11-016 Penalties

Most parties commenting on whether to impose penalties for delays or failures in D.19-11-016 procurement oppose the proposal.[181] They assert penalties will not spur speedy procurement at this time, since close to 100% of D.19-11-016 contracts have already been executed. They state LSEs are adequately incentivized to bring delayed procurement online via the backstop procurement mechanism.[182]

Cal Advocates supports penalties targeted to getting delayed summer 2021 procurement online by June 1, 2022.[183]

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181 Comments opposing penalties appear in the CALCCA Opening Testimony at 8; Calpine Opening Testimony at 2; IEP Opening Testimony at 3; CESA Opening Testimony at 11; LS Power Opening Testimony at 7; SEIA Opening Testimony at 12; SCE Opening Testimony at 76; SDG&E Opening Testimony, DeTuri and Maiga at 6; PG&E Opening Testimony at 9-1; WPTF Opening Testimony at 2; and CASMU Opening Testimony at 6.

182 SCE Opening Testimony at 77 ("SCE recommends the Commission maintain the process in D.20-12-044 for LSEs to submit biennial compliance filings and apply the trigger mechanism for IOUs to backstop an LSE that fails to meet milestone requirement.").

As described in D.20-12-044 at 4:

> The backstop procurement mechanism contemplated by D.19-11-016 assumed that backstop procurement would be needed when LSEs that planned to self-provide their required capacity were unable to do so for a variety of reasons. D.19-11-016 determined that if this happens, the Commission may order the relevant investor-owned utility (IOU) to conduct procurement on behalf of the LSE that has failed to procure its allocated share of capacity and/or on behalf of its customers.

183 Cal Advocates Opening Testimony at 21.

5.7.3. Discussion of D.19-11-016 Penalties

We decline to impose penalties related to D.19-11-016. Given that contracts for that procurement are already executed, penalties will not hasten contracting. However, Commission staff will be very involved in ensuring that all remaining procurement of the 3,300 MW ordered in D.19-11-016 is on a path to timely online status, and will intervene if delays become apparent. Energy Division will be in ongoing contact with all affected LSEs to ensure procurement and online dates are on track for summer 2022.

5.8. Increase RA Penalties

We also decline to increase penalties already adopted for failures in RA procurement.

5.8.1. Background on RA Penalties

Decision 21-06-029 adopted a tiered RA penalty structure to be implemented in 2022. RA penalties will double or triple for LSEs with recurring deficiencies. However, since the structure has not yet been implemented, all LSEs will likely be in Tier 1 for much of 2022.

The Staff Concept Paper asked parties to comment on whether the Commission should increase penalties related to RA in order to ensure all obligations are in place on time. Staff's proposal was as follows:

> Pursuant to D.20-06-031, the RA penalty structure is currently $8.88 kW/month for LSEs who fail to meet summer system RA obligations in the month ahead. The CPUC could consider doubling the penalties for LSEs who may be short in August 2022 and September 2022.

5.8.2. Party Comments on RA Penalties

Most parties opposed additional penalties for failures in procurement.[184] Many parties considered it premature to revise the RA penalty structure at this time given that the tiered structure was recently adopted and will not be implemented until 2022.[185] Some parties supported consideration of increased penalties for the summer of 2022 given that there would be a delay between implementation of the tiered penalty structure and accrual of sufficient points by deficient LSEs to move them into higher penalty tiers.[186]

5.8.3. Discussion of RA Penalties

We agree with parties that the impacts of the recent changes to the RA penalty structure should be assessed before additional changes are made. We thus decline to increase the penalties for deficiencies in meeting RA obligations beyond those already adopted.

5.9. Once Through Cooling (OTC) Units

We eliminate the Tier 3 Advice Letter filing requirement for approval of IOU contracts with OTC units.

5.9.1. Background on OTC Units

The IOUs are currently authorized to contract with OTC units, including in anticipation of extension of their compliance deadlines. Existing Commission

[184] CalCCA Reply Testimony at 9; PG&E Opening Testimony at 9-2; Cal Advocates Opening Testimony at 3-2; SCE Opening Testimony at 78; WPTF Opening Testimony at 4; SEIA Opening Testimony at 11-15; MRP Opening Testimony at 20; CESA Opening Testimony at 14; LS Power Opening Testimony at 3.

[185] CalCCA Opening Testimony at 9-10; PG&E Opening Testimony at 9-3 – 9-4; Cal Advocates Opening Testimony at 3-2 – 3-3; SCE Opening Testimony at 78; WPTF Opening Testimony at 4; CESA Opening Testimony at 14; MRP Opening Testimony at 20; TURN Reply Testimony at 8; LS Power Opening Testimony at 7.

[186] Calpine Opening Testimony at 3.

decisions require that the IOU seek approval of the OTC contracts via a Tier 3 Advice Letter.[187]

5.9.2. Party Comments on OTC Units

SCE asks that the Commission eliminate the Tier 3 Advice Letter requirement for OTC units needed for emergency reliability adopted in D.21-02-028. SCE states the time needed to obtain Tier 3 Advice Letter approval impedes timely contracting. SCE argues that the requirement places the IOUs at a competitive disadvantage against non-IOU buyers that do not require Commission approval. SCE requests that the Commission authorize the IOUs to contract with OTC units through 2023 under their Bundled Procurement Plan authority without the requirement to file a Tier 3 Advice Letter."[188]

5.9.3. Adopted OTC Direction

Given that no other LSE has to file for approval of contracts with OTCs, we approve of SCE's request. This result will put the IOUs on a level playing field with the non-IOUs, and help the IOUs to meet their RA obligations. Ultimately, the extension of the OTC units is predicated on the expiration date of their Water Board permit, not the contracting process (nor the regulatory approval process of any contracts) that these units hold with counterparties.

5.10. Cost Allocation Mechanism

5.10.1. Background on Cost Allocation Mechanism

D.21-02-028 and D.21-03-056 allowed the IOUs to procure resources for all customers in their service territory for emergency reliability purposes and recover costs for those resources through a Cost Allocation Mechanism.[189] The

[187] D.19-11-016 at 48.

[188] SCE Opening Brief at 56.

[189] D.21-02-028 at 12.

Staff Concept Paper asked whether this authority should be broadened for 2022 and 2023.

5.10.2. Party Comments on Cost Allocation Mechanism

CalCCA argues that if the Commission adopts a procurement mechanism in which the IOUs procure on behalf of all benefitting customers, the Commission should clarify the method for allocating costs and benefits. Specifically, CalCCA suggests that if an IOU contract under D.21-03-056 extends beyond 2022, the costs and benefits should either be allocated solely to bundled service customers, not through the CAM, or that all customers should be allocated both the costs and the benefits.

SCE notes that neither IOUs nor other LSEs receive RA benefits for D.21-03-056 "effective" PRM procurement, and for that reason opposes CalCCA's proposal.

SCE agrees with CalCCA that it would be helpful for the Commission to clarify the treatment of RA benefits after the period of the emergency ends. SCE supports allocation of any RA benefits associated with D.21-03-056 procurement to all benefitting customers for the remaining term of the contracts (or utility-owned resource) after the emergency period.

5.10.3. Adopted Cost Allocation Mechanism Direction

We do not change the Cost Allocation Mechanism authority granted in D.21-02-028 and D.21-03-056, and extend that decision's allowance to summer 2023 procurement ordered in this decision. If an IOU needs to use the procurement to meet its bundled service RA requirements, then the costs are not recovered through CAM, but rather from bundled service customers. In D.21-03-056, the Commission recognized 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.

Emergency reliability procurement benefits all customers, whether bundled IOU customers or customers of other LSEs. The Cost Allocation Mechanism appropriately places cost requirement responsibility with all customers for emergency procurement ordered in D.21-03-056. Therefore, we make no change to that decision's CAM authority, except that we extend this authority to emergency procurement authorized in this decision.

After the emergency procurement period, during which IOUs procure incremental reliability resources on behalf of all customers, ends, the RA benefits of any resources whose contracts extend beyond the emergency procurement period shall be allocated consistent with their approved Cost Allocation Mechanism.

5.11. NBC for Emergency-Based Procurement

We decline to adopt the staff concept proposal for a NBC for emergency-procurement ordered in this decision.

5.11.1. Background on NBC

The staff concept proposal on an NBC for emergency reliability procurement was detailed, as follows:

> **Emergency Procurement and Cost Recovery via a Non-Bypassable Charge**
>
> The CPUC could establish a new non-bypassable charge (NBC) for cost recovery of costs associated with emergency procurement that adds additional reserve margin and does not already fit into an existing cost recovery mechanism.

> Although there is an existing Cost Allocation Mechanism (CAM) charge frequently used for IOU cost recovery associated with eligible capacity costs, the CAM charge does not usually allow for cost recovery for emergency procurement that adds to reserve margins or for resources that do not provide firm [RA].

The staff went on to list "emergency" procurement options, and we adopt some of those in other portions of this decision, but we reject the idea of an NBC itself. Instead, the procurement options we adopt will be subject to the CAM process described in this decision.

5.11.2. Party Comments on NBC

SDG&E supported an NBC. PG&E and SCE opposed it on the ground the existing CAM charge authorized in Phase 1 of this proceeding is adequate for cost recovery.[190]

5.11.3. Discussion of NBC

We are not convinced there is a need for a new NBC given that the Commission has already authorized use of a CAM mechanism to allocate procurement costs to all LSEs in Phase 1 of this proceeding and in this decision. The main benefit of an NBC would be that non-IOU procurement could be eligible. However, this would be complicated since standards are unclear for contract approval and reasonableness review of non-IOU contracts.

5.12. Change LCD for Hydroelectric Generation

We reject staff's proposed LCD for hydroelectric generation change on the ground that it is not necessary for reliability.

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[190] SDG&E Opening Testimony, DeTuri and Maiga at 4; SCE Opening Testimony at 79-80; PG&E Opening Testimony at 9-4 – 9-5.

5.12.1. Background of LCD for Hydroelectric Generation

The Staff Concept Paper for hydroelectric resources suggested that IOUs be permitted to hold hydroelectric generation in reserve for the most grid-stressed conditions:

> **Bundled Procurement Rules Modifications**
>
> Under existing bundled procurement rules, the IOUs are required to schedule and bid their hydro resources to achieve least cost procurement. The CPUC could adjust these rules to allow IOUs to preserve hydro generation for maximum availability during strained grid conditions, instead of using hydro at all times when it appears to be economically efficient. This policy change would effectively allow IOUs to plan for hydro resources to count for a higher RA value in August and September, during hours when it is most critically needed.

5.12.2. Party Comments on LCD for Hydroelectric Generation

Most parties argued that additional flexibility to bid hydroelectric generation into the market were not warranted.[191] PG&E and SCE both oppose the staff proposal to allow use of hydroelectric generation where reliability concerns are greatest.[192] PG&E states it already manages hydroelectric generation to maximize its availability during reliability events:

> Modifications would not result in additional capacity being available for critical peak events nor additional RA value available in August and September as suggested.
>
> PG&E optimizes the dispatch of its hydroelectric fleet on a forecast basis to maximize customer benefit, which includes the ability to generate during critical reliability events.

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[191] PG&E Opening Testimony at 9-5; SCE Opening Testimony at 80; MRP Opening Testimony at 26; TURN Reply Testimony at 8.

[192] PG&E Opening Testimony 9-5 – 9-6, SCE Opening Testimony at 80.

> Throughout the year and for each of PG&E's watersheds, water plans are updated weekly, using the latest forecasts of water supply and energy demand as well as safety, physical, operational, and license constraints.

SCE also asserts adjustment to the hydro generation rules is unnecessary:

> Least cost dispatch principles . . . ensure[] that resources are awarded when they are needed the most (*i.e.*, when market prices are highest, or system conditions are strained). Thus, there is no need to adjust bundled procurement rules.

When considering the trade-off between generating in earlier months of the year versus August and September, PG&E's processes already incorporate maximizing generation for the later summer period. While PG&E uses price forwards to indicate when energy is most needed, there is a correlation between prices and high need periods. Additionally, PG&E's operators consider summer reliability needs and August and September RA needs when making dispatch decisions throughout the year. PG&E does not believe that changing the regulatory framework for hydroelectric bidding decisions will result in any incremental benefits given that actual dispatch decisions generally would not change.

Regardless of the RA value (measured in terms of a net qualifying capacity), PG&E makes its dispatchable hydroelectric capacity available during critical reliability events. PG&E does not believe that the capacity that would be available next year during similar critical events would be any less than this year, and it could be greater, if the drought diminishes. Additionally, PG&E does not believe this capacity would be any greater if the LCD rules were changed as proposed in the Concept Paper. Accordingly, PG&E does not believe modifications to the current LCD practices are warranted for its hydroelectric resources and opposes this proposal from the Concept Paper.

5.12.3. Adopted LCD Direction

We find that there is no need to change the LCD rules for hydroelectric generation.

6. Process for Commission Review of Allowed Procurement

The process for Commission review of additional, incremental procurement ordered in this decision is similar to the process we adopted in D.21-02-028 and D.21-03-056. The large electric IOUs shall submit contracts that conform with this decision for consideration as Advice Letters. As noted in various places, most contracts are appropriate for Tier 1 Advice Letters; utilities shall submit contracts for utility-owned storage as Tier 2 Advice Letters. Contracts of five years or more for incremental generation at existing gas power plants shall be submitted to the Commission via a Tier 3 Advice Letter. Along with the contracts, the Advice Letter submittals shall include the following additional summarized information to assist with evaluation. As stated above, Tier 1 Advice Letters are not required but may be submitted for incremental imports. A summary of the resources being selected and a brief discussion of the procurement and selection method and criteria;

- Operational information of the resources contracted and a demonstration that the resource will be available during the peak and net peak demand hours in summer 2022 and/or summer 2023;
- Pricing and net market value analysis along with a summary of the key contract terms;
- A completed analysis by the independent evaluator;
- To the extent comparable data exists, a demonstration of cost competitiveness, recognizing that premiums for

expedited procurement must be considered in any such demonstration;

- A demonstration that the resource is incremental (except for contracts with resources falling of contract and at risk of retirement); and
- A demonstration that the resource has a path to deliver its online date in summer 2022 or 2023.

To assist the Commission with evaluation, pursuant to Section 7.3.1 of General Order 96-B, Tier 1 Advice Letters that are submitted to the Commission that result from this decision are effective no sooner than five days after submission. Solely for purposes of supply-side procurement ordered in this decision, we shorten the protest period for those Tier 1 Advice Letters to 10 calendar days after submission. Additionally, the large electric IOUs are authorized to file Tier 2 Advice Letters for utility-owned storage with a COD by summer 2022 or 2023. These IOUs may also file Tier 2 Advice Letters making any tariff changes needed to adjust balancing accounts to implement this decision.

Consistent with D.21-03-056, 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 2022 and 2023. The filings are due no later than April 15, 2022 (for 2022) and April 15, 2023 (for 2023) reflecting the LSE's most recent RA positions, including any excess RA procurement (but excluding the IOUs' "effective PRM" procurement authorized in this proceeding).

7. Conclusion

The Commission must act now to ensure there are adequate resources available to provide reliable electricity to Californians in summers of 2022 and

2023 in the occurrence of extreme weather events. With the combination of supply- and demand- side resources ordered here, the Commission attempts to help better position the State to meet Californians' electricity need at net peak – after the sun goes down each day and solar energy stops producing – in summer 2022 and 2023 during extreme weather events. If additional changes are needed as summer 2022 approaches, the Commission will take further steps as necessary to help maintain reliability.

8. Comments on Proposed Decision

The proposed decision of ALJ Thomas in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. The comment period was shortened pursuant to Commission Rule of Practice and Procedure 14.6(c)(10) on the ground of public necessity, such that opening comments were due on November 10, 2021 and reply comments were due on November 16, 2021. Opening comments were filed on _________ by_______ and reply comments were filed on ___________by___________.

9. Assignment of Proceeding

Marybel Batjer is the assigned Commissioner and Sarah R. Thomas and Brian Stevens are the assigned ALJs in this proceeding.

Findings of Fact

1. On July 30, 2021, Governor Newsom issued an Emergency Proclamation calling on the Commission, among other State agencies, to require additional electric resources be available in summer 2022 on an expedited basis due to extreme heat events, prolonged drought, decreased hydroelectric generation, catastrophic wildfires and climate change.

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

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

4. 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.

5. The 2020 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.

6. There is a need for incremental physical resources and modified DR measures to address grid needs during the system peak and net peak demand periods for summer 2022 and 2023 and to prevent similar service interruptions to the August 2020 rotating outages.

7. 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 and 2023 by delivering during peak and net peak demand periods.

8. There is a need for new supply- and demand-side resources to serve as continency resources at net peak in summer 2022 and 2023.

9. The Commission has data and policy expertise that allow it to assess the need for additional contingency resources at net peak in summer 2022 and 2023.

10. If an extreme weather event were to occur, there is a need for contingency resources in the summers of 2022-2023 in the range of 2,000 MW to 3,000 MW.

11. The 2,000-3,000 MW range provides for the procurement of contingency resources to meet an effective PRM of between 20% and 22.5% to ensure reliable electric supply during extreme circumstances. Additional resources that meet this higher effective PRM will provide additional reliability in the event of a need for contingencies above the existing PRM during extreme events.

12. Since the summer 2020 rolling outages and Joint Agency Root Cause Analysis, the Commission has ordered additional procurement in multiple venues.

13. Current planning and procurement resource levels may not be sufficient through 2023 under extreme conditions.

14. Numerous extreme conditions and supply risks may be mitigated by continuation and expansion of contingency procurement in 2022 and 2023. The conditions include heightened risks associated with climate change, extreme heatwaves, dry hydro conditions, potential West-wide capacity shortages, supply chain issues with procurement underway, and project contract failures, among a host of other planning uncertainties.

15. In D.21-03-056, the Commission adopted an effective PRM of 17.5% for the IOUs.

16. The weather experienced throughout the summer of 2020 and 2021 was extreme, and we must plan in anticipation of more frequent extreme weather events resulting from climate change.

17. Because a resource such as solar is unavailable at net peak because the sun has set, it does not contribute to the need at net peak.

18. CAISO's testimony reflects a significant shortfall in LSE supply plan resources at net peak.

19. The load impacts of the new and voluntary programs we adopt, and continue, in this decision cannot be predicted with certainty.

20. A large quantity of new resources will come online in 2022 and subsequent years as a result of recent IRP procurement decisions.

21. There is risk that the over 40 LSEs responsible for new IRP procurement will not bring all of the ordered resources on-line by the deadlines ordered in the IRP proceeding.

22. A recently released Energy Division report on the status of the August 2021 tranche of resources ordered in the D.19-11-016 procurement order indicates that a number of projects expected by August 2021 were delayed.

23. Much new IRP procurement will be performed by LSEs that are relatively new, have never procured new resources in the quantities they have been ordered to procure, or both.

24. Adding the procurement of contingency resources to these existing challenges would only serve to further increase these challenges.

25. Applying the TAC area CAISO load shares for each utility's service territory to the contingency procurement set forth in this decision results in target procurement amounts of 900 MW-1,350 MW each for PG&E and SCE service territories and 200 MW-300 MW for SDG&E service territory.

26. The CEC's peak demand forecast for the CAISO TAC area for the 2022 summer months is approximately 45,000 MW, so each 1,000 MW is equivalent to approximately a 2.5% increase in the PRM for CPUC jurisdictional entities.

27. Added to the 15% PRM requirement in the RA program that applies to all LSEs, the adopted range of additional contingency procurement results in an effective PRM of 20% to 22.5%.

28. Uncertainty regarding whether there is adequate supply in an extreme weather event will persist into 2023.

29. Procurement of contingency resources for summer 2021 resources approached but did not fully reach the 1,000 MW target adopted in D.21-03-056 in all summer months.

30. The IOUs collectively reached approximately 800 MW of D.21-03-056 ordered resources for August 2021, and surpassed the target in September 2021 with approximately 1,150 MW.

31. There is potential for delays associated with procurement already underway in compliance with the recent IRP decisions (D.21-06-035 and D.19-11-016) due to interconnection queue limitations, supply chain issues being faced as a result of the COVID-19 pandemic, high global demand for battery storage, and challenges with skilled labor availability for engineering and construction of new energy resources.

32. It may be difficult to identify and procure sufficient demand and supply-side resources to reach 2,000 MW of on-line and available contingency resources for summer 2022, let alone the 3,000 MW target.

33. It may not be possible to reduce the reliability risk in summers 2022 and 2023 to zero during an extreme weather event.

34. The procurement ordered here has a longer lead time than the 2021 contingency procurement ordered in Phase 1.

35. De-rating a solar resource's ability to serve a new net peak PRM standard without reviewing how other resources serve load at net peak may be an over-simplification of a complex planning problem.

36. The nameplate capacities of natural gas plants are de-rated to reflect their output during gross peak when temperatures are typically at their highest levels

and output is most impacted, and wind speeds typically begin picking up in the evening hours compared to the gross peak.

37. The CAISO's analysis uses a net peak forecast for 2021 that is approximately 1,100 MW lower than the August 2022 net peak forecast used in the CEC's stack analysis.

38. The CAISO's analysis in its testimony uses resources included on August 2021 supply plans, and excludes 2021 IRP resources ordered in D.19-11-016 that were not online by August 2021 and the 850 MW of 2022 IRP resources ordered online by August 2022 in D.19-11-016.

39. A 2.5% adjustment to the PRM represents approximately 1,000 MW for CPUC jurisdictional entities' share of CAISO load, so achieving a 17.5% PRM at net peak would require 1,000 MW of resources in addition to the 2,000 MW of procurement needed to meet the 15% PRM at net peak.

40. After adjusting for August 2022 demand forecast and supply differences compared with August 2021, CAISO's proposed net peak RA requirement results in a need for 2,000 MW of additional resources available at net peak to achieve a 15% PRM and 3,000 MW to achieve a 17.5% PRM.

41. On September 8, 2021, the CEC adopted its 2022 Summer Stack Analysis. The CEC analysis provides a snapshot of an extreme weather event coupled with conservative assumptions on availability of hydroelectric and imported resources and the potential need for contingencies in summer 2022.

42. A risk stacking approach is a different approach to need determination from traditional electricity resource planning. Resource planners forecast the probability of a loss of load event based on historic variations in weather, electricity demand, and resource performance.

43. Traditionally, California resource planning uses a "probabilistic" approach – that is, it considers various scenarios, rather than a single worst-case scenario. The CEC analysis takes a "deterministic" approach that assumes all worst-case scenarios occur simultaneously.

44. The CEC analysis assumes a 40% reduction in the DR resources that will be available in the future based on DR performance described in the Final Root Cause Analysis of the Mid-August 2020 Extreme Heat Wave, which results in an assumed maximum of 1,000 MW in 2022.

45. The CEC analysis assumes that the Redondo Beach once-through-cooling generating station (834 MW) will retire in 2021.

46. On October 19, 2021, the California Water Resources Control Board approved extension of the Redondo Beach generating station, which delivers 834, for two years.

47. The Commission's Load Impact Protocol process estimates the load impact of DR programs for the upcoming year. There is a lag in this analysis because DRPs estimate performance for the year ahead. Filings in 2021 include projected estimates of resources that will be available in 2022, based on analysis of DR resources' performance in 2020.

48. Using the Commission's Load Impact Protocol analysis, DR in aggregate performed closer to estimated levels during the August and September 2020 heat waves than a 40% discount assumed in other analyses.

49. Current summer 2022 DR authorizations for CPUC jurisdictional LSEs, IOU DR, DRAM contract estimates and third-party DRPs based on the Load Impact Protocol analysis of 2020 DR performance are approximately 1,650 MW.

50. If one adds to 1,650 MW the CEC's estimate of 2022 DR procurement by LSEs not under CPUC jurisdiction, the total DR value for 2022 is approximately 1,700 MW, or 700 MW more than the 1,000 MW value included in CEC's analysis.

51. The 2021 RA imports for July, August, and September 2021 were 5,800 MW, 6,000 MW, and 6,700 MW, respectively. Using these values rather than the multi-year averages results a reduction in the CEC net short estimate by approximately 500 MW for July and September and an increase in the net short by approximately 500 MW for August.

52. Phase 1 of this proceeding ordered 1,000 MW of resources.

53. The Commission should set a target range of new procurement rather than a point target because there is current and near-term uncertainty both in demand variation and resource availability.

54. Phase 1 of this proceeding adopted the ELRP as a pilot, and further refinements in this phase of the proceeding may allow for greater participation and benefit from the implementation of the program.

55. Updated guidance regarding the dispatch of prohibited backup generation in the ELRP may allow for reduced emissions while still allowing for the reliability benefit of allowing the generators to participate.

56. Both customer Groups A and B could have a day-of trigger for a more agile implementation of the ELRP.

57. $2.00/kWh is an appropriate compensation level for ELRP.

58. EVs can provide benefits to the grid by altering the time, charging level, or location at which grid connected EVs charge or discharge.

59. Technology capable of bi-directional EV charging is relatively new to the market and public uptake and awareness are low.

60. A minimum VGI dispatch hours of 30 hours per season in the EV/VGI pilot adopted here could provide an incentive for customers to participate in the program.

61. An EV/VGI pilot will help educate customers, aggregators, IOUs, and the Commission on the technology and systems needed to dispatch these resources.

62. A minimum VGI aggregation size of 25 kW may encourage aggregators to increase the pool of participants and reduce administrative costs for IOUs.

63. There are modifications to the DR programs of PG&E, SCE and SDG&E, as well as statewide modifications, that could result in greater participation in those programs and reduced load at the net-peak hours during stressed grid conditions, thus lowering the likelihood of an extreme weather-related blackout.

64. Adopting a pilot Residential ELRP may allow customers, IOUs, other stakeholders and the Commission to test and refine the program.

65. Compensating Residential ELRP customers to reduce their energy usage during CAISO Flex Alerts will promote equity and help achieve a greater load impact than without incentives. Robust marketing, education, and outreach along with behavioral DR tools that are attractive to customers such as personalized messaging, prompt performance results, or point systems may lead to higher participation rates.

66. The Commission has undertaken recent efforts to address affordability and promote equity in utility rates.

67. Many residential customers already participate in the Flex Alert program and do not receive compensation.

68. A Residential ELRP pilot that does not automatically enroll all residential customers will allow the Commission to observe enrollment levels, customer

complaints, load reduction and other outcomes before committing the entire population of residential customers to a program.

69. Climate zones 9, 10, 11, 12, 13, 14 and 15 are hot climate zones.

70. Air conditioning load increases substantially in the summer months, and especially in hot climate zones.

71. Smart thermostats, when combined with a market-integrated, supply-side DR program, can automatically turn down air conditioning (*i.e.*, increase the temperature by a few degrees) during reliability events and thus reduce electric load.

72. For income-qualified customers eligible to participate in the Commission's ESA program, smart thermostat subsidies are already available for those customers in all climate zones.

73. The Commission has already adopted smart thermostat incentives for CARE/ESA-eligible customers without a DR requirement.

74. Low-income customers in the ESA program are eligible for a fully subsidized smart thermostat.

75. The existing smart thermostat Energy Efficiency-DR integration program the Commission adopted in D.18-05-041 involves installation of smart thermostats and other distributed energy resource technology measures through the Commission's Energy Efficiency program, and captures DR benefits beyond energy savings.

76. Dynamic rates are time varying rates structured to provide incentives to customers to engage in energy consumption when demand is low, through rate differences.

77. In California, real time pricing rates have occasionally been offered on a pilot or optional basis.

78. Agriculture pumping has the capability to supply demand flexibility at low cost.

79. A dynamic rate pilot may provide data about the potential of dynamic rates for load shift.

80. Week ahead rate projections provide signals to agricultural customers on how to schedule pumping.

81. A shadow bill in the dynamic rate pilots adopted in this decision will allow customers to receive full payment for energy used during the pilots.

82. Collecting the costs of the UOS procurement ordered in this decision through distribution rates until the resource is fully deliverable to CAISO markets is consistent with principles of CAM treatment.

83. Distribution rates flow to all customers in an IOU's service territory, similar to CAM costs (which flow thorough a delivery charge to all benefiting customers).

84. A requirement for IOUs to submit an application for the UOS resources allowed in this decision may lead to delays in contract execution.

85. In its capacity as the CPE for local procurement, an IOU is best suited for the procurement of local resources through all-source solicitations to arrive at the least cost best fit set of options.

86. Given the near-term reliability needs to procure additional resources, the CPE is better suited to sign bilateral contracts for local procurement rather than an IOU's bundled procurement arm.

87. The August 2020 rotating outages and subsequent periods of stressed grid conditions in 2020 and 2021 involved high electricity demand that was not limited to the CAISO balancing authority area but was widespread across neighboring balancing authorities.

88. If reliability concerns extend outside California, the availability of imports into California can be speculative.

89. Day Ahead prices during the hours of concern in August 2020 did not reach the $1,000 price cap at which these unspecified imports regularly bid into the market.

90. Under current CAISO market rules imports have no obligation to bid into the real time markets.

91. Allowing generators and/or LSEs to offer the supply-side resources covered in this decision into RFOs or bilaterally negotiate with the IOUs for incremental capacity that can be brought online in 2022 or 2023 in advance of the IRP required August deadlines may allow for a market test of the price for accelerating these resources, since IOUs can compare offers of accelerating these projects with other resources being offered to meet their incremental procurement targets.

92. Contracts for procurement ordered in D.19-11-016 are already executed.

93. Penalties adopted in D.21-06-029 will not be implemented until 2022.

94. Emergency reliability procurement benefits all customers, whether bundled IOU customers or customers of other LSEs.

95. Phase 1 of this proceeding adopted the ELRP as a pilot, and further refinements in this phase of the proceeding may allow for greater participation and benefit from the implementation of the program.

96. Updated guidance regarding the dispatch of prohibited backup generation in the ELRP may allow for reduced emissions while still allowing for the reliability benefit of allowing the generators to participate.

97. There are different eligibility parameters for customer participation in ELRP, and those parameters are outlined as Group A and B customers with subsections within those groupings.

98. It is in the public interest for Group A.1 ELRP participant customers to be eligible to take service on a critical peak pricing or real-time pricing tariff while also participating in the ELRP.

99. An appropriate minimum size threshold parameter for Group A.1 Participants is 200 kW of peak demand in SCE's territory 100 kW of peak demand in SDG&E's territory.

100. There will be greater participation in the ELRP if Group A.2 eligibility is expanded to include non-BIP aggregators of non-residential, non-BIP customers that meet the criteria outlined in this decision.

101. An appropriate minimum aggregation size threshold for Group A.2 participants is 500 kW with the minimum dispatch hours set at 10 hours per season.

102. ELRP enrollment may be greater if stand-alone storage is eligible to participate as a Group A.4 eligible customer.

103. For Group B market-integrated resources, it is in the best interest of the administration of the ELRP for participating DRPs to list the PDR that will participate in ELRP and nominate an estimated target load reduction quantity to be achieved during an ELRP event by each participating PDR resource.

104. Clarifying that if Group B is triggered in the day ahead market, backup generators associated with customers participating in Group B and not exempted under the Prohibited Resources policy and located in Disadvantaged Communities shall not be dispatched would reduce potential negative externalities from the dispatch of backup generators in the ELRP.

105. Clarifying that if Group A is triggered in the day ahead market, backup generators associated with customers participating in Group A and not exempted under the Prohibited Resources policy and located in Disadvantaged Communities shall not be dispatched would reduce potential negative externalities from the dispatch of backup generators in the ELRP.

106. Clarifying that if Group A or B is triggered in the day-of market, backup generators associated with the customers participating in the respective Groups may not be exempted under the Prohibited Resources policy and located in Disadvantaged Communities and may be dispatched at the same time as other resources and may be used in compliance with Rule 21 and other applicable regulations.

107. Both customer groups A and B could have a day-of trigger for a more agile implementation of the ELRP.

108. The requirement that ELRP compensation for an event be bounded for Group A participants between 50 and 200 percent of pre-nominated load shed or exported energy quantity is not necessary or beneficial for an effective implementation of ELRP.

109. The California State Emergency Program (CSEP), the emergency demand reduction program initiated by Governor's Newsom's July 30, 2021 emergency proclamation set a compensation level of $2/kWh.

110. Appropriate balancing account annual caps for program administration across all ELRP sub-groups, except ELRP sub-group A.6 (Residential customers) are PG&E $7.3 million, SCE $5.7 million, and SDG&E $3.0 million.

111. Appropriate balancing account annual caps for Incremental Load Reduction compensation across all ELRP sub-groups, including the ELRP

sub-group A.6 (Residential customers) are PG&E $94.0 million, SCE $76.6 million, and SDG&E $30.8 million.

112. There are modifications to the DR programs of PG&E, SCE and SDG&E, as well as statewide modifications, that could result in greater participation in those programs and reduced load at the net-peak hours during stressed grid conditions, thus lowering the likelihood of an extreme weather-related blackout.

113. Tariff amendments that the IOUs need to implement to effectuate the direction in this decision relative to DR programs could be requested from the Commission in a tier 1 Advice Letter.

114. Additional capacity at net peak may be achieved by the IOUs procuring RA capacity from DRPs for 2022 and 2023 deliveries through bilateral contracts. This RA capacity could count towards any additional need that is assigned in this proceeding and any agreements could contain performance agreements to ensure delivery.

115. The IOUs could be authorized to pay upfront 100% of the eligible incentives for a custom Auto DR project on the condition that the customer's enrollment commitment to participate in an economically bid market integrated DR program is extended from three years to five years. This modification could be effective for 2022 and 2023 only.

116. The alternative baseline adjustment option allowed by CAISO and already authorized for use in IOU Capacity Bidding Programs in D.21-03-056 could be used for calculating capacity performance in their respective Capacity Bidding Programs.

117. Resolution E-4906 could be modified to include in its definition of allowable renewable fuels the Renewables Portfolio Standard-eligible fuels certified by the CEC.

118. PG&E's proposal to implement a price bid cap of $650/MWh for its Capacity Bidding Elect and Elect+ programs for the years 2022 and 2023 could incent greater enrollment in the program.

119. PG&E's proposal to increase the current BIP compensation level by $1/kW for the months of May through October for the years 2022 and 2023 could incent greater enrollment in the program.

120. PG&E's proposal to create and manage a new out-of-market residential smart thermostat control pilot program is approved for 2022 and 2023 could incent greater participation in demand reduction during times of need.

121. PG&E could replace one-way thermostat control technology with newer two-way devices in 2022 and 2023 in its SmartAC program to incent greater participation in demand reduction during times of need.

122. PG&E's request for $1.2 million in incremental funds for Information Technology system enhancements could support third-party DR, and PG&E could use the one-way balancing account authorized in D.21-03-056 to track these expenses.

123. Non-residential customers enrolled in SCE's SDP could be permitted to dual participate in ELRP under the customer subgroup "A.1. Non-Residential, Non-DR Customers," and not be subject to the Minimum Size Threshold of subgroup A.1 as an effort to increase enrollment and decrease attrition.

124. SCE's proposal to reinstate the pre-cooling strategy where applicable in its SEP could slow the deterioration of load impacts and reduce opt-outs.

125. SCE's proposal to increase the ME&O budget for its SEP by $1.27 million in 2022, and $980,000 in 2023, to reach a broader audience through targeted marketing channels and leveraging marketing automation technology to improve ME&O effectiveness could be approved.

126. To address CAISO tariff changes stemming from CAISO's Summer Reliability enhancements for RDRR, SCE's proposal to modify effective immediately its Reliability Program Event Parameters, so that 1) the BIP and AP-I parameters match, and 2) the parameters for the SDP and SEP match could be approved

127. SDG&E could continue in 2022 its CBP residential pilot approved in D.21-03-056 to ensure this relevant load reduction remains available.

128. SDG&E could create an enhanced Capacity Bidding Program-Commercial Elect option with three bid price tiers and increased capacity incentives as proposed by SDG&E. SDG&E could be authorized to use existing funding for 2022, and is authorized $1.6 million for 2023, as well as a $51,000 incremental marketing budget.

Conclusions of Law

1. The Commission should adopt and LSEs including PG&E, SCE and SDG&E should be bound by the requirements of Attachments 1 and 2 to this decision.

2. The Commission should require procurement of additional supply- and demand-side resources that are available at net peak in summer 2022 and 2023.

3. The Commission should adopt a target procurement range of 2,000 MW to 3,000 MW in contingency resources for 2022 and 2023.

4. The Commission should continue the approach adopted in D.21-03-056 of authorizing the three large IOUs to procure additional resources to meet an "effective PRM."

5. The Commission should continue to order the large electric IOUs to pursue incremental demand and supply side resources for 2022, and extend the order to 2023.

6. The Commission should allocate procurement responsibility for the additional contingency resources ordered in this decision to the three large IOUs, using the same allocation ratios used for summer 2021 incremental procurement in the Phase 1 decisions.

7. The Commission should authorize the procurement of a wide variety of resources, some of which will be RA resources that will be visible to the CAISO on supply plans, while others will not be.

8. The Commission should prioritize the procurement of resources that are RA eligible and that will be visible to the CAISO in supply plans and participate in CAISO markets to the extent feasible.

9. There should be sufficient resources in place to meet demand during the net peak hour.

10. The additional resources ordered in this decision to meet the 2,000 MW to 3,000 MW range should be available at peak and net peak.

11. The Commission should revise the ELRP pilots adopted in D.21-03-056 to ensure reliability at net peak in summer 2022 and 2023.

12. The Commission should adopt a Residential ELRP pilot.

13. In its Residential ELRP pilot, the Commission should adopt targeted outreach for CARE customers and customers in Disadvantaged Communities.

14. The Flex Alert paid media campaign budget should not be reduced from the 2021 budget for 2022 and 2023, and should include outreach related to Residential ELRP.

15. The Commission should revise DR programs with the program design features described in Attachment 2 to ensure reliability at net peak in summer 2022 and 2023.

16. For the EV/VGI pilot adopted here as part of ELRP, any EVSE meter or sub-meter used should meet applicable standards established by the Commission if and when adopted.

17. The Commission should allow procurement of UOS to ensure reliability at net peak in summer 2022 and 2023.

18. The Commission should allow market-based approaches to accelerate procurement already ordered in its IRP proceeding, including project cost, but the Commission and IOUs should have discretion to reject such approaches to prevent gaming or overpriced resources.

19. The Commission should adopt two dynamic rates pilots to test how dynamic rates can help ensure reliability at net peak in summer 2022 and 2023.

20. The Commission should expand use of smart thermostats paired with DR to control air conditioning use by adjusting the temperature setting a few degrees to ensure reliability at net peak in summer 2022 and 2023.

21. The Commission should allow customers eligible for ESA to receive smart thermostats at no cost to them, and should not require such customers to enroll in a DR program to receive such a subsidy. Such ESA-eligible customers may receive outreach about enrollment in DR programs.

22. IOUs may conduct the Energy Efficiency-DR integration activity adopted in D.18-05-041 without a third-party entity designing or implementing the program.

23. The Commission should not change the Cost Allocation Mechanism authority granted in D.21-02-028 and D.21-03-056, and should extend that decision's allowance to summer 2023 procurement ordered in this decision.

24. The Commission should adopt some of the proposals in the Staff Concept Paper to ensure reliability at net peak in summer 2022 and 2023.

25. The Commission should reject some of the proposals in the Staff Concept Paper that will not enhance reliability at net peak in summer 2022 and 2023.

26. Updated guidance regarding the dispatch of prohibited backup generation in the ELRP should be implemented to allow for reduced emissions while still allowing for the reliability benefit of allowing the generators to participate.

27. Group A.1 ELRP participant customers should be eligible to take service on a critical peak pricing or real-time pricing tariff while also participating in the ELRP.

28. An appropriate minimum size threshold parameter for Group A.1 Participants of 200 kW of peak demand in SCE's territory and 100 kW of peak demand in SDG&E's territory should be adopted.

29. ELRP Group A.2 eligibility should be expanded to include non-BIP aggregators of non-residential, non-BIP customers that meet the criteria outlined in this decision.

30. An appropriate minimum aggregation size threshold for Group A.2 participants of 500 kW with the minimum dispatch hours set at 10 hours per season should be adopted.

31. Stand-alone storage should be eligible to participate as a Group A.4 eligible customer in the ELRP.

32. For Group B market-integrated resources, DRPs should list the PDR that will participate in ELRP and nominate an estimated target load reduction quantity to be achieved during an ELRP event by each participating PDR resource.

33. To reduce potential negative externalities from the dispatch of backup generators in the ELRP, if Group B is triggered in the day ahead market, backup generators associated with customers participating in Group B and not exempted

under the Prohibited Resources policy and located in Disadvantaged Communities should not be dispatched.

34. To reduce potential negative externalities from the dispatch of backup generators in the ELRP, if Group A is triggered in the day ahead market, backup generators associated with customers participating in Group A and not exempted under the Prohibited Resources policy and located in Disadvantaged Communities should not be dispatched.

35. If Group A or B is triggered in the day-of market, backup generators associated with the customers participating in the respective Groups should not be exempted under the Prohibited Resources policy and located in Disadvantaged Communities should be dispatched at the same time as other resources and should be used in compliance with Rule 21 and other applicable regulations and permits.

36. Both customer groups A and B should have a day-of trigger for a more agile implementation of the ELRP.

37. $2.00/kWh should be the compensation level for ELRP.

38. The requirement that ELRP compensation for an event to be bounded for Group A participants between 50 and 200 percent of pre-nominated load shed or exported energy quantity should not be necessary for an effective implementation of ELRP.

39. Balancing account annual caps for program administration across all ELRP sub-groups, except ELRP sub-group A.6 (Residential customers), for PG&E of $7.3 million, SCE of $5.7 million, and SDG&E of $3.0 million should be adopted.

40. Balancing account annual caps for Incremental Load Reduction compensation across all ELRP sub-groups, including the ELRP sub-group A.6

(Residential customers), for PG&E of $94.0 million, SCE of $76.6 million, and SDG&E of $30.8 million should be adopted.

41. There are modifications to the DR programs of PG&E, SCE and SDG&E, as well as statewide modifications, that could result in greater participation in those programs and reduced load at the net-peak hours during stressed grid conditions, thus lowering the likelihood of an extreme weather-related blackout and should be adopted.

42. Tariff amendments that the IOUs need to implement to effectuate the direction in this decision relative to DR programs should be requested from the Commission in a Tier 1 Advice Letter.

43. Additional capacity at net peak should be achieved by the IOUs procuring RA capacity from DRPs for 2022 and 2023 deliveries through bilateral contracts. This resource capacity should count towards any additional need that is assigned in this proceeding and any agreements could contain performance agreements to ensure delivery.

44. The IOUs should be authorized to pay upfront 100% of the eligible incentives for a custom Auto DR project on the condition that the customer's enrollment commitment to participate in an economically bid market integrated DR program is extended from three years to five years. This modification should be effective for 2022 and 2023 only.

45. The alternative baseline adjustment option allowed by CAISO and already authorized for use in IOU Capacity Bidding Programs in D.21-03-056 should be used for calculating capacity performance in their respective Capacity Bidding Programs.

46. Resolution E-4906 should be modified to include in its definition of allowable renewable fuels the Renewables Portfolio Standard-eligible fuels certified by the CEC.

47. PG&E's proposal to implement a price bid cap of $650/MWh for its Capacity Bidding Elect and Elect+ programs for the years 2022 and 2023 should be approved to incent greater enrollment in the program.

48. PG&E's proposal to increase the current BIP compensation level by $1/kW for the months of May through October for the years 2022 and 2023 should be approved to incent greater enrollment in the program.

49. PG&E's proposal to create and manage a new out-of-market residential smart thermostat control pilot program should be approved for 2022 and 2023 to incent greater participation in demand reduction during times of need.

50. PG&E should be authorized to replace one-way thermostat control technology with newer two-way devices in 2022 and 2023 in its SmartAC program to incent greater participation in demand reduction during times of need.

51. PG&E's request for $1.2 million in incremental funds for Information Technology system enhancements should be approved to support third-party DR, and PG&E should use the one-way balancing account authorized in D.21-03-056 to track these expenses.

52. Non-residential customers enrolled in SCE's SDP should be permitted to dual participate in ELRP under the customer subgroup "A.1. Non-Residential, Non-DR Customers," and not be subject to the Minimum Size Threshold of subgroup A.1 as an effort to increase enrollment and decrease attrition.

53. SCE's proposal to reinstate the pre-cooling strategy where applicable in its SEP should be approved to slow the deterioration of load impacts and reduce opt-outs.

54. SCE's proposal to increase the ME&O budget for its SEP by $1.27 million in 2022, and $980,000 in 2023, to reach a broader audience through targeted marketing channels and leveraging marketing automation technology to improve ME&O effectiveness should be approved.

55. To address CAISO tariff changes stemming from CAISO's Summer Reliability enhancements for RDRR, SCE's proposal to modify effective immediately its Reliability Program Event Parameters, so that 1) the BIP and AP-I parameters match, and 2) the parameters for the SDP and SEP match should be approved.

56. SDG&E should be authorized to continue in 2022 its CBP residential pilot approved in D.21-03-056 to ensure this relevant load reduction remains available.

57. SDG&E should be authorized to create an enhanced Capacity Bidding Program-Commercial Elect option with three bid price tiers and increased capacity incentives as proposed by SDG&E. SDG&E should be authorized to use existing funding for 2022, and $1.6 million for 2023, as well as a $51,000 incremental marketing budget.

58. In D.20-06-002 in the RA proceeding, the Commission adopted a centralized framework for the procurement of local RA in the PG&E and SCE distribution service areas, beginning with the 2023 RA compliance year.

59. The Commission has designated the CPE to meet local area requirements on behalf of all customers in the IOUs service area.

60. In D.20-06-028, the Commission revised its rules for imports to count toward RA requirements. The Commission clarified its RA import rules to

ensure that RA imports did not represent "speculative supply" that might not be available during stressed system conditions.

61. The new RA rules from D.20-06-028 count non-resource-specific imports toward RA requirements, provided that: a) The contract is an energy contract with no economic curtailment provisions; b) The energy is self-scheduled (or in the alternative, is bid in at a level between negative $150/MWh and $0/MWh) into the CAISO day-ahead and real-time markets at least during the Availability Assessment Hours throughout the RA compliance month, consistent with the MCC buckets; and c) The energy is delivered to the load-serving entity in accordance with the governing contract, consistent with the MCC buckets.

O R D E R

IT IS ORDERED that:

1. Attachments 1 and 2 to this decision are adopted in their entirety, and Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) shall comply with the requirements set forth therein. To the extent Attachments 1 and 2 contain requirements in addition to those in this decision, SCE, PG&E and SDG&E shall comply with those additional requirements. To the extent this decision contains requirements in addition to those in Attachments 1 and 2 to this decision, SCE, PG&E and SDG&E shall comply with those additional requirements.

2. Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company shall pursue incremental demand- and supply-side resources for 2022 and 2023 to maintain reliability of the grid during extreme weather events.

3. In recognition of the continued tight grid conditions experienced this summer, the California Independent System Operator's testimony reflecting a

significant shortfall in Load Serving Entity supply plan resources at net peak, and the need for additional contingency resources identified in the California Energy Commission's Summer 2022 Stack Analysis, Southern California Edison Company(SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) shall use their best efforts to meet a revised targeted procurement range of 2,000 megawatts (MW) to 3,000 MW for summers 2022 and 2023, which includes and is not additive to the targeted procurement of 1,000 MW of contingency resources adopted in Decision (D.) 21-02-028 and D.21-03-056 and results in an "effective PRM" of 20%-22.5%. Based on the proportional load share in each utility's service territory, the revised targeted procurement range represents 900 – 1,350 MW of additional procurement for SCE and PG&E, and 200 – 300 MW for SDG&E.

4. A Statewide Flex Alert paid media campaign program administered by Southern California Edison Company shall be continued in 2022 and 2023, as outlined in Attachment 1, to encourage ratepayers to voluntarily reduce demand during moments of a stressed grid in California.

5. 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 $22 million annually in 2022 and 2023, and up to 3% of that budget is authorized to cover administration costs.

6. Modifications to the Emergency Load Reduction Program administered by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall be made, as outlined in Attachment 2,

as a tool that can provide emergency load reduction and serve as an insurance policy against the need for future rotating outages.

7. Within 30 days (ELRP Group A), and 60 days (ELRP Group B), 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 Tier 1 Advice Letters incorporating the new Emergency Load Reduction Program (ELRP) terms and conditions for Group A and B, respectively, adopted in this decision and set forth in Attachment 2. 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, incremental load reduction measurement, and settlement.

8. 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 new 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 changes made in this decision, 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 five days of the issuance of this decision establishing the new one-way balancing accounts.

9. If Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company have existing balancing accounts for the Emergency Load Reduction Program, Demand Response Programs, or smart thermostat program adopted or modified in this decision, they shall use those balancing accounts to track costs of such programs, rather than establishing new one-way balancing accounts.

10. Modifications to the Demand Response (DR) programs of and procurement of new DR resources from third-party DR providers by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall be instituted, as outlined in Attachment 1, to make the DR resources more effective and more aligned with grid need.

11. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall work collaboratively with the California Independent System Operator (CAISO) and the California Public Utilities Commission's Energy Division to develop an objective set of criteria that triggers CAISO's Flex Alert program.

12. The net costs associated with the 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 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 achieve an effective 20% to 22.5% planning reserve margin for the months of concern. All procurement contracts shall be submitted to the Commission via a Tier 1 Advice Letter on a continuing basis, except for contracts for incremental imports, incremental utility owned resources, and incremental gas generation of five years or more. Tier 1 Advice Letters are not required, but

may be submitted, for incremental imports. Contracts for utility owned resources shall be submitted to the Commission via a Tier 2 Advice Letter. Contracts of five years or more for incremental generation at existing gas power plants shall be submitted to the Commission 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.

13. As directed in Decision (D.) 21-03-056, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall continue to utilize unspent funds from their existing Demand Response (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, as well as the process for transferring balances within the investor-owned utility's DR Programs Balancing Account and Base Revenue Requirement Balancing Account for this purpose.

14. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall procure Resource Adequacy capacity from eligible third-party Demand Response (DR) providers for 2022 and 2023 deliveries through bilateral contracts. The procured DR capacity shall count toward the overall megawatt targets established for each investor-owned utility (IOU) in this decision and must be available at peak and net peak. Because these procured resources are incremental to IOUs' and all load serving entities' (LSEs') 15% Planning Reserve Margin, these resources need not be applied to any LSEs' Maximum Cumulative Capacity bucket cap calculation. The IOUs shall submit bilateral contracts to the Commission through Tier 1 Advice Letters.

15. Resolution E-4906 is modified to include in its definition of allowable renewable fuels the Renewables Portfolio Standard-eligible fuels certified by the California Energy Commission (CEC). Behind-the-meter generators utilizing CEC-certified Renewables Portfolio Standard-eligible fuels are exempt from the prohibited resources policy in Decision 16-09-056 and permitted for use in Demand Response programs. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall update their tariffs and contracts to incorporate the updated prohibited resources policy effective March 1, 2022.

16. Pacific Gas and Electric Company's proposal to implement a price bid cap of $650/megawatt-hour for its Capacity Bidding Elect and Elect+ programs for the years 2022 and 2023 is approved.

17. Pacific Gas and Electric Company's (PG&E) proposal to increase the current Base Interruptible Program (BIP) compensation level by $1/kilowatt for the months of May through October for the years 2022 and 2023, is approved. For the BIP compensation level increase, PG&E is authorized to update its tariff to recoup the annual $1 million to $3 million in costs associated with this increase that it is unable to cover in 2022 through the budget of its current 2018-2022 funding cycle, as well as 2023 costs.

18. Pacific Gas and Electric Company's (PG&E) proposal to create and manage a new out-of-market residential smart thermostat control pilot program is approved for 2022 and 2023. PG&E is authorized to spend an incremental $12.4 million in incentives, administration, and marketing in 2022 and 2023 for this pilot as well as existing identified funding. For the program to continue beyond 2023, this program must be market integrated (as supply-side Demand Response).

19. Pacific Gas and Electric Company (PG&E) is authorized to replace one-way thermostat control technology with newer two-way devices in 2022 and 2023 in its SmartAC program. PG&E is authorized an incremental $3.4 million in funding in 2022 and 2023 for administration, marketing, and retention incentives for this device exchange.

20. Pacific Gas and Electric Company's proposal to make Information Technology system enhancements to bolster its "Share My Data" platform by improving scalability and performance is approved and cost recovery of $1.2 million in incremental funds is approved.

21. Southern California Edison's proposal to increase the Marketing Education and Outreach (ME&O) budget for its Smart Energy Program by $1.27 million in 2022, and $980,000 in 2023, to reach a broader audience through targeted marketing channels and leveraging marketing automation technology to improve ME&O effectiveness, is approved.

22. San Diego Gas & Electric Company (SDG&E) is authorized to create an enhanced Capacity Bidding Program-Commercial Elect option with three bid price tiers and increased capacity incentives. $1.6 million is authorized for this program for 2023, as well as a $51,000 incremental marketing budget.

23. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall continue to use the one-way balancing accounts authorized in Decision 21-03-056 regarding the development, implementation, and operation of the Emergency Load Reduction Program (ELRP), along with incentives paid under the program. These balancing accounts shall have the following annual caps for program administration across all ELRP sub-groups, except ELRP sub-group A.6 (Residential customers): PG&E $7.3 million, SCE $5.7 million, and SDG&E

$3.0 million. Additionally, these balancing accounts shall have the following caps for Residential ELRP (sub-group A.6) program administration and marketing, education, and outreach. PG&E: 2022: $9.4 million for administration and $2.5 million for marketing, education, and outreach; 2023: $8.7 million for administration and $2.0 million for marketing, education, and outreach. SCE: 2022: $10.0 million for administration and $2.5 million for marketing, education, and outreach; 2023: $9.0 million for administration and $1.6 million for marketing, education, and outreach. SDG&E: 2022: $3.0 million for administration and $0.75 million for marketing, education, and outreach; 2023: $2.7 million for administration and $0.5 million for marketing, education, and outreach. Additionally, these balancing accounts shall have the following annual caps for Incremental Load Reduction compensation across all ELRP sub-groups, including the ELRP sub-group A.6 (Residential customers): PG&E $94.0 million, SCE $76.6 million, and SDG&E $30.8 million.

24. The following Advice Letter filings related to the Emergency Load Reduction Program (ELRP) are either authorized or directed to be filed by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). Within 30 days of this Decision, PG&E, SCE and SDG&E shall jointly file a Tier 1 Advice Letter (AL) incorporating the modifications by this Decision to ELRP terms and conditions for Group A. Limited deviations to accommodate investor-owned utility (IOU) specific implementations due to information technology (IT) and billing systems are permitted. The filing shall include the 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 (ILR) measurement, and settlement. Within 60 days of this Decision, PG&E, SCE, and SDG&E shall jointly file a Tier 1 AL incorporating the modifications by this Decision ELRP terms and conditions for Group B. Limited deviations to accommodate IOU specific implementations due to IT and billing systems are permitted. The filing shall include the 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, ILR measurement, and settlement and invoicing. PG&E, SCE, and SDG&E may file Tier 1 ALs that request to defer implementation of certain ELRP design elements, where permitted, and shall include an explanation for why the delay is necessary or reasonable. As experience in ELRP is gained, the IOUs may seek to modify various aspects of ELRP design via an IOU-specific or joint IOU Tier 2 AL as appropriate before or by December 31 of each program year to manage program enrollment, improve program efficiency, increase potential load reduction available to ELRP, improve program value, and reduce program cost.

25. To participate in the Electric Vehicle and Vehicle-Grid Aggregation (VGI) aspects of the Emergency Load Reduction Program, aggregators shall meet the following criteria: a) The VGI aggregation or any customer site within the aggregation shall not be simultaneously enrolled in a market-integrated, supply-side Demand Response (DR) program offered by an Investor Owned Utility (IOU), third-party DR Provider, or Community Choice Aggregator; b) A customer site within the VGI aggregation shall not be taking service on a critical peak pricing or real time pricing-equivalent tariff; c) All sites within the VGI aggregation shall be located within the distribution service area of a single IOU;

and d) the VGI aggregation shall contribute Incremental Load Reduction, as defined in Attachment 2, equal to or greater than the Minimum VGI Aggregation Size Threshold for a minimum of one hour. Such aggregators shall comply with all additional requirements of Attachment 2 to this decision.

26. Participants in the Electric Vehicle and Vehicle-Grid Aggregation (VGI) aspects of the Emergency Load Reduction Program adopted in this decision shall receive minimum VGI dispatch hours of 30 hours per season. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) have discretion to meet the 30-hour minimum by dispatching aggregators in response to forecasted or anticipated grid stress conditions, such as high locational marginal prices in the California Independent System Operator markets and extreme heat waves. PG&E, SCE and SDG&E may negotiate agreements with the VGI aggregators to clarify other requirements needed, including potential administration fees, to implement the dispatch hours and compensation.

27. Participants in the Electric Vehicle and Vehicle-Grid Aggregation (VGI) aspects of the Emergency Load Reduction Program adopted in this decision shall have a minimum VGI aggregation size of 25 kilowatts.

28. Participants in the Electric Vehicle and Vehicle-Grid Aggregation (VGI) aspects of the Emergency Load Reduction Program who use Electric Vehicle Supply Equipment (EVSE) shall meet applicable standards established by the Commission for EVSE meters and sub-meters.

29. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall automatically enroll (that is, apply an opt out approach to) certain groups of residential customers in the Residential Emergency Load Reduction Program

(ELRP). PG&E, SCE and SDG&E shall auto-enroll residential customers in the California Alternate Rates for Energy program in the Residential ELRP. These customers may opt in to receive alerts of the program being triggered, and elect for those alerts to come by email, phone call, text message, bill insert or mailer. These customers may opt out of Residential ELRP at any time.

30. Customers of the Residential Emergency Load Reduction Program may not simultaneously be enrolled in another supply side Demand Response (DR) program offered by an Investor-Owned Utility, third-party DR provider or Community Choice Aggregator, or be taking service on a critical peak pricing, SmartRate or dynamic rate tariff.

31. A Community Choice Aggregator (CCA) may elect not to participate in the Residential Emergency Load Reduction Program (ELRP) pilot adopted in this decision, in which case its customers are ineligible to enroll. The CCA shall make its election by January 31 of each new Residential ELRP pilot year.

32. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall establish a process for a Community Choice Aggregator (CCA) to inform them of the CCA's election to exclude its customers from the Residential Emergency Load Reduction Program.

33. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall promptly unenroll customers participating in Residential Emergency Load Reduction Program that enroll in a supply-side Demand Response (DR) program offered by the Investor-Owned Utility, registered third-party DR provider or Community Choice Aggregator without the need for any action on the part of the customer.

34. To the extent customers are not automatically enrolled in the Residential Emergency Load Reduction Program (ELRP), Pacific Gas and Electric Company,

Southern California Edison Company, and San Diego Gas & Electric Company shall devise an easy process for eligible customers to be able to opt in to the Residential ELRP.

35. Pacific Gas and Electric Company's (PG&E) Power Savers Rewards Program, Option A, with auto-enrollment of customers who receive PG&E's Home Energy Reports, is approved. PG&E's Options B and C are not approved.

36. Southern California Edison Company's Whole Home Savings Pilot, with auto-enrollment of high usage customers who have opted in to receive transactional emails, is approved. Dual participation in another Demand Response program is not permitted.

37. San Diego Gas & Electric Company's "Peak Day" Behavioral Demand Response program, with auto-enrollment of existing Home Energy Report customers, is approved.

38. In their marketing, education, outreach, and event notification efforts focused on the auto-enrolled California Alternate Rates for Energy (CARE) customers and customers in Disadvantaged Communities, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall provide in-language accessibility and specific outreach for CARE and Disadvantaged Community customers, as described in Attachment 2 to this decision.

39. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall use a California Independent System Operator-issued Flex Alert declaration as the trigger for dispatching Residential Emergency Load Reduction Program (ELRP) customers. PG&E, SCE and SDG&E shall collaborate to establish common program parameters, including a minimum dispatch window (which must be at

least 2 hours), the start time of the dispatch, marketing strategies that limit customer confusion by ensuring that individualized messaging from PG&E, SCE and SDG&E is consistent with the messaging from the statewide Flex Alert campaign, and statewide unified branding. PG&E, SCE and SDG&E shall each file a Tier 2 Advice Letter within 30 days of issuance of this decision to establish the parameters and proposed cost of its ELRP Residential pilot program.

40. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall use the baseline for calculating load reductions in the Residential Emergency Load Reduction Program authorized in Decision 21-03-056: a 5-in-10 baseline with 40% day-of adjustment.

41. Customers in the smart thermostat program adopted in this decision (except Energy Savings Assistance program-eligible customers) shall pre-enroll in a California Independent System Operator market integrated Demand Response (DR) program that is administered by either an Investor-Owned Utility or third-party DR provider.

42. The smart thermostat program budget is authorized at up to $22.5 million in technology incentives to be available over a two-year period, from 2022 to 2023. The program rebate amount for non-Energy Savings Assistance program participants is $75, not to exceed the full cost of the smart thermostat equipment, and shall be uniform across all program implementers. Prior to incentive payment, the Investor-Owned Utility (IOU) serving the customer shall certify installation of an eligible thermostat and enrollment in an eligible IOU or third-party supply-side Demand Response program.

43. Fifty percent of the technology incentive budget of the smart thermostat program, or up to $11.25 million, shall be available to third-party Demand Response (DR) Providers (DRPs) to provide rebates through the third-party

supply-side DR programs. The third-party DRPs shall have competitively equal access to the rebates as the Investor-Owned Utilities (IOUs). IOUs may request up to an additional 10% of the technology incentive budget for administrative costs. Each IOU must justify the amount of administrative budget that will be required to administer the program in the joint Tier 2 Advice Letter filing this decision requires.

44. The smart thermostat program is available for non-Energy Savings Assistance program customers in climate zones 9, 10, 11, 12, 13, 14 and 15.

45. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall jointly file a Tier 2 Advice Letter with details of the smart thermostat program.

46. Within 15 days of issuance of this decision Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (collectively, IOUs) shall meet and confer with third-party Demand Response (DR) Providers (DRPs) to discuss the process to distribute rebate awards, and to certify smart thermostat installation and DR program enrollment. Within 45 days of issuance of this decision, the IOUs shall jointly file a Tier 2 Advice Letter that reflects a consensus across third-party DRPs and IOUs on the foregoing issues. The joint Advice Letter shall include the following items:

- Program design and budget;
- Amount of administrative budget each IOU will need to administer the program;
- A discussion of any balancing or memorandum account authorization sought to track program expenditures;
- Goal for number of customers reached, by when, and estimated megawatt demand savings;
- Identification of qualifying thermostats eligible for the $75 incentive;

- A process to ensure customers of both IOUs and third-party DRP programs are eligible for smart thermostat incentives;
- A description of the DR programs a customer must enroll in to be eligible for the thermostat incentive, and how that enrollment will occur before the customer receives a rebate; and
- The process for identifying customers who qualify for the Energy Savings Assistance program.

47. Income-eligible customers who are participating in the Energy Savings Assistance (ESA) program shall continue to be eligible to receive no-cost, direct install smart thermostats through ESA for all climate zones. Investor-Owned Utilities (IOUs) or third-party Demand Response (DR) Providers (DRPs) participating in the smart thermostat program adopted shall ensure the customer they are engaging is not otherwise eligible for ESA. IOUs and third-party DRPs participating in the smart thermostat program adopted here shall verify customer eligibility for ESA, and if eligible, refer the customer to the IOUs' ESA programs. The IOUs and their ESA contractors, during their in-person assessment and installation, shall promote but not require enrollment in a DR program.

48. In implementing the Integrated Demand-Side Management Program Guidance in this decision and Decision (D.) 18-05-041, the Investor Owned Utilities (IOUs) shall file a Tier 2 Advice Letter within 45 days of issuance of this decision that should specify: remaining budget from the originally authorized budget in D.18-05-041; how the remaining budget should be allocated among the IOUs to run their integrated Energy Efficiency-Demand Response programs; and program implementation plans and design, including information on how they comply with requirements outlined in D.18-05-041.

49. Valley Clean Energy's (VCE) dynamic rate pilot for agricultural water pumping is approved. Pacific Gas and Electric Company shall work with VCE on implementation. Non-generation and non-delivery costs (*e.g.,* transmission rates and non-bypassable charges) of the pilot shall be recovered through existing rate structures. The pilot scale shall be limited to 5 megawatts of peak load.

50. Customers participating in Valley Clean Energy's (VCE) dynamic rate pilot approved in this decision will receive a "shadow bill." Pacific Gas and Electric Company may bill participating customers based on existing tariffs, but the shadow bill will show the customer savings under the pilot dynamic rate, and VCE shall pay customers for the difference between the shadow bill and the existing tariff.

51. The Valley Clean Energy dynamic rate pilot approved in this decision is authorized for three years (2022-2024), and shall start no later than May 1, 2022.

52. In implementing the Valley Clean Energy (VCE) dynamic rate pilot approved in this decision, VCE and/or Pacific Gas and Electric Company (PG&E) may engage a service provider with a suitable Information Technology platform to automate dynamic hourly prices and make them accessible to customers and automated agricultural water pumps. For the generation components of the service by VCE, (1) energy costs shall be based on the California Independent System Operator wholesale market prices, and (2) generation capacity and flexible capacity costs shall be recovered on an hourly basis using the scarcity pricing concept: more fixed costs are recovered when system utilization is higher relative to the system capacity limit. For the delivery component of the service by PG&E, (1) line losses will be recovered through volumetric rates, which could be time dependent, and (2) distribution

capacity costs will also be recovered on an hourly basis using the scarcity pricing concept in lieu of monthly or annual demand charges.

53. Pacific Gas and Electric Company (PG&E) shall provide funds to or reimburse Valley Clean Energy (VCE), if necessary, for crediting any savings realized by the customers with respect to the delivery component of the VCE dynamic rate pilot in the customers' shadow bills. PG&E shall set up a two-way balancing account to track expenses related to the delivery component of the customer bill savings during the pilot.

54. Pacific Gas and Electric Company (PG&E) shall submit a midterm evaluation of the Valley Clean Energy (VCE) dynamic rate pilot program no later than December 31, 2023, and a final evaluation no later than March 1, 2025. The evaluations shall include the following elements:

- The response of agricultural loads to prices, including the response to non-binding week ahead price projections. This should evaluate the efficacy of the pilot tariff in shifting agricultural loads enrolled in the program from peak to off-peak periods and should be compared to other VCE agricultural loads;
- In the case that VCE incorporates binding forecast projections, the evaluation should also include an assessment of this element;
- The monthly bill impacts of the pilot dynamic rate in comparison to a customer's otherwise applicable tariff;
- An evaluation of the recovery of generation and resource adequacy costs for customers on the pilot tariff. This evaluation should assess the impact of any under collection of generation and resource adequacy revenues against the impact of the shifted participant loads on marginal generation and resource adequacy costs; and
- An evaluation of the recovery of delivery costs for customers on the pilot tariff. This evaluation should assess

> the impact of any under-collection of delivery revenues against the impact of the shifted participant loads on marginal delivery costs.

55. Southern California Edison Company (SCE) is authorized to conduct a dynamic rate pilot for the purpose of studying how price responsive pilot projects can enhance system reliability in 2022 and 2023. As further set forth in Attachment 1, the pilot is open to SCE residential, commercial, and industrial customers, and SCE may prioritize customers with smart enabling price-responsive end-uses such as electric vehicle charging, behind-the-meter batteries, and controllable loads.

56. Southern California Edison Company's dynamic rate pilot is authorized for three years (2022-2024), starting no later than May 1, 2022.

57. In its dynamic rate pilot authorized in this decision, Southern California Edison Company (SCE) may use a "shadow bill" approach to provide participants compensation for any load shift by the customer's equipment in response to the pilot prices. In such an approach, participants will continue to pay their current SCE bill under the otherwise applicable tariff and will also receive a shadow pilot bill, which they will not pay, that illustrates a customer's potential savings under the pilot rate. SCE shall make payments to participants in the program for their pilot rate savings on either a monthly or annual basis.

58. Southern California Edison shall conduct a mid-term and final evaluation of its dynamic rate pilot approved in this decision to assess the costs and benefits of real-time rates, including required infrastructure, manufacturer interest, and customer impacts. The mid-term report shall be released no later than December 31, 2023, and a final evaluation shall be released no later than March 1, 2025.

59. Southern California Edison Company shall submit a Tier 1 Advice Letter for its dynamic rate pilot no later than 60 days after issuance of this decision that includes, but is not limited to, the following elements: (1) pilot scope, (2) pilot partners, (3) shadow bill implementation, (4) pilot dates, and (5) pilot tariff design.

60. For supply side resources ordered to be procured in this decision, resources a) must be available during both the peak and net peak demand periods; b) are preferred to have Commercial Online Dates (COD) (or contracts that are otherwise operationally consistent with the guidance in this decision) by June 1, 2022, but resources COD or operational by August 1, 2023,will be considered; c) need not yet have full capacity deliverability status but must be capable of providing energy/grid reliability benefits during the peak and net peak periods; and d) may include utility-owned storage, with Commission consideration of such projects through a Tier 2 Advice Letter.

61. Supply side resource types that may be considered for the procurement adopted in this decision are:

- Acceleration of Commercial Online Dates from a resource that is otherwise required to meet a Load Serving Entity's IRP target, *e.g.* acceleration to June 1, for a resource that would otherwise be online by August 1.
- Incremental energy storage, including utility-owned storage.
- Firm forward imported energy, as well as import contracts that ensure delivery during tight system conditions (*e.g.*, alerts, warnings, and emergencies or at contractually pre-specified prices) but the latter category can only be procured by Investor-Owned Utilities and applied to the incremental reliability procurement targets adopted in this decision.
- Contracting for generation that is at-risk of retirement.

- o Incremental capacity from existing power plants through efficiency upgrades, revised power purchase agreements/tolling arrangements.

62. For the supply side procurement ordered in this decision, Resource Adequacy-only contracts or contracts that include dispatch rights may be proposed.

63. A Tier 3 Advice Letter shall be filed for contracts of five years or more for efficiency improvements resulting in incremental generation at existing gas power plants.

64. For the supply side procurement ordered in this decision, counterparties may include in their bids or contract proposals a price element that accelerates Commercial Online Dates

65. For the supply side procurement ordered in this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve the range of additional procurement authorized in this decision for the months of concern. These efforts should take the form of solicitations, ongoing bilateral negotiations, Investor-Owned Utilities offering counterparties an opportunity to refresh prior Integrated Resource Plan (IRP) procurement bids, accelerated procurement of resources procured by Load Serving Entities to meet their IRP obligations for summer months prior to their required online dates, upgrades resulting in increased efficiency of existing generation resources, and imports.

66. All Resource Adequacy (RA)-eligible resources supporting the effective Planning Reserve Margin (PRM) adopted in this decision shall be included in supply plans and Investor-Owned Utilities' (IOU) month ahead RA showings to ensure that these resources are subject to RA obligations and incentive

mechanisms, do not receive Capacity Procurement Mechanism double payments, and are visible to the California Independent System Operator as RA resources not eligible for export. 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 Cost Allocation Mechanism.

67. To the extent feasible, Investor-Owned Utilities (IOU) shall pair imports contracted with maximum import capacity and include these costs in their Cost Allocation Mechanism procurement costs. If existing IOU-owned maximum import capacity is paired with imports to construct a Resource Adequacy product, the IOU shall 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.

68. If an Investor-Owned Utility has not met its minimum contingency procurement target for the months of June and October with Resource Adequacy (RA)-eligible resources that can be reflected on supply plans, it may use excess resources in its existing portfolios to meet the minimum contingency procurement target (900 megawatts (MW) for Pacific Gas and Electric Company and Southern California Edison Company, and 200 MW for San Diego Gas & Electric Company), provided it has made reasonable attempts to sell this excess capacity to other Load Serving Entities. In these instances, the excess resources may be accounted for at the imputed cost of 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark.

69. For the months of July, August, and September, excess resources from an Investor-Owned Utility's existing portfolios may be used to meet or supplement procurement targets in this decision up to the upper end of its contingency procurement target (1,350 megawatts (MW) for Pacific Gas and Electric

Company and Southern California Edison, and 300 MW for San Diego Gas & Electric), provided it has made reasonable attempts to sell this excess capacity to other. These excess resources may be accounted for at the imputed cost of 2021 Power Charge Indifference Adjustment Resource Adequacy System Market Price Benchmark.

70. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall provide the monthly amounts of the excess resources they applied to the Cost Allocation Mechanism, as well as the calculus used to determine these amounts to Commission's Energy Division, and Energy Division will post this information on the Commission's website.

71. To the extent that any additional adjustments to balancing accounts are needed to provide for Cost Allocation Mechanism cost recovery of the procurement authorized in the decision, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company may file Tier 2 Advice Letters with the effective date of the tariff modification to be the effective date of this decision.

72. Energy storage that can be brought online by summer 2022 or 2023 to meet the procurement targets, identified above, may be both utility-owned storage and third-party resources. These storage resources need not be fully deliverable in 2022 or 2023, as long as they provide peak and net peak grid reliability benefits in summer 2022 or 2023. We encourage siting these resources in locations where they will also provide benefits to local reliability and Disadvantaged Communities.

73. Southern California Edison Company's cost allocation for its utility owned storage procurement as a distribution system asset rather than a generation asset resource is approved as an acceptable alternative to the Cost Allocation

Mechanism (CAM) authority granted in Decision 21-02-028 when operating the resources as non-California Independent System Operator (CAISO)-controlled grid assets prior to deliverability to CAISO markets while CAISO deliverability studies are performed since the rate impact is the same (distribution assets and CAM resources are charged to all customers) and it accomplishes the same grid benefit.

74. Consistent with the principles of the Cost Allocation Mechanism (CAM) authority this Commission granted in Decision 21-02-028, once a resource authorized in this decision is connected to the transmission system and deliverable to California Independent System Operator markets, Investor-Owned Utilities shall no longer collect costs for the resources through distribution rates, and instead shall account for the net capacity costs and benefits through the CAM mechanism.

75. The Tier 2 Advice Letter process and Cost Allocation Mechanism for utility owned storage adopted in Decision (D.) 21-02-028 is authorized for continue for 2022 and 2023. The Integrated Resource Plan (IRP) requirement established in D.21-06-035 obligating the Investor-Owned Utilities to submit an application for utility-owned resources procured to meet IRP requirements is not required for the procurement authorized in this decision.

76. Southern California Edison Company and Pacific Gas and Electric Company may negotiate bilateral contracts for the emergency procurement ordered in this decision in local reliability areas in their capacities as Central Procurement Entities (CPE). For purposes of the procurement authorized in this decision, CPEs may also use all-source solicitations to procure local area resources. Such resources shall be limited to energy storage and preferred resources.

77. Certain Resource Adequacy (RA) rules with regard to imports for Investor-Owned Utilities are relaxed with regard to imports used to meet the authorized procurement in this decision. Import contracts that do not meet import requirements because they are executed after the month-ahead showing process may be executed to meet the effective Planning Reserve Margin (PRM) adopted in this decision. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company may execute import contracts for the effective PRM that do not meet the RA import requirements but are structured to ensure delivery during tight system conditions (*e.g.*, California Independent System Operator Alerts, Warnings, and Emergencies or at contractually pre-specified prices).

78. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall work with the Commission's Energy Division to show late procured imports to meet the effective Planning Reserve Margin adopted here as Resource Adequacy resources under the California Independent System Operator's market mechanisms on supply plans.

79. All Load Serving Entities and project developers may bid into the Investor-Owned Utilities' solicitations or contract bilaterally for accelerated procurement of 2022 resources. We decline to adopt an incentive regime for such accelerated procurement.

80. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company are relieved from the obligation in Decision 19-11-016 of filing Tier 3 Advice Letters for approval of their contracts with Once Through Cooling (OTC) units if the units are needed for emergency reliability authorized in this proceeding. These Investor-Owned Utilities may

contract with OTC units through 2023 under their Bundled Procurement Plan authority without the requirement to file a Tier 3 Advice Letter.

81. The Cost Allocation Mechanism (CAM) authority granted in Decision (D.) 21-02-028 and D.21-03-056 is extended to the summer 2023 procurement ordered in this decision. If an Investor-Owned Utility (IOU) uses such procurement to meet its bundled service Resource Adequacy (RA) requirements, it shall not recover the costs of the resource through CAM, but rather from bundled service customers. After the emergency procurement period, during which an IOU procures incremental reliability resources on behalf of all customers, ends, the IOU shall allocate RA benefits of any resources whose contracts extend beyond the emergency procurement period consistent with their approved CAM authority.

82. All testimony served in Phase 2 of this proceeding is admitted into evidence in this proceeding.

83. Rulemaking 20-11-003 closed.

This order is effective today.

Dated ____________________________, at San Francisco, California.