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# ATTACHMENT 1

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### 1. Flex Alert

A Statewide Flex Alert Paid Media campaign shall continue to be funded by the ratepayers of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), together, the investor-owned utilities (IOUs). The following is the guidance on the continued implementation of this program.

SCE shall revise the existing contract with the Statewide Marketing, Education and Outreach (ME&O) vendor DDB San Francisco (ME&O vendor) to increase the year two budget to \$22 million. The year one budget was \$12 million, but an additional \$10 million was allocated by the California State Legislature through the General Fund in Fiscal Year 2021-22<sup>1</sup> and implemented through a separate contract in 2021. 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 allocation is provided 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 coordinate with Energy Division staff to receive direction on the scope of the amended contract and budget during the implementation and administration of the contract. The contract shall terminate on December 31, 2023, unless the contract is extended in a future demand response proceeding as discussed below.

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<sup>1</sup> The language in the state budget states "Pursuant to CPUC Decision 21-03-056, the Commission or its delegee may award or designate follow-on funding in the amount of \$10,000,000 to the Flex Alert program contemplated in the decision. When used for contracts, awards provided using this authority are exempt from Public Contract Code, Government Code, Department of General Services, and any other normally applicable requirements for awarding, advertising, or amending contracts."

The Flex Alert campaign shall include marketing messaging and materials for the IOU Residential Emergency Load Reduction Program (ELRP) modifications adopted in this decision. PG&E, SCE, and SDG&E (together, the IOUs) shall fund the paid-media Flex Alert campaign for 2022 and 2023 with funds collected from all benefitting customers (i.e., bundled IOU, community choice aggregator (CCA), and Direct Access customers) using Public Purpose Program (PPP) balancing accounts. Each IOU will collect its share of the authorized Flex Alert campaign PPP funds from all benefitting customers in its service territory.

This decision authorizes a budget of \$22 million per year, for 2022 and 2023, to support the Statewide Flex Alert Paid Media campaign. The decision also authorizes IOUs up to 3% of the annual Flex Alert budget to cover IOU administration costs. If the Commission and stakeholders have an interest in considering an extension of paid Flex Alert marketing after December 31, 2023, then the IOUs shall request, as needed, continuation of funding for the Statewide Flex Alert Paid Media Campaign to support the ELRP in the IOU Demand Response Portfolio Applications that are expected to be filed by the IOUs at the CPUC in May 2022.

Consistent with D.21-03-056, SCE, PG&E, and SDG&E shall collect the authorized funds for the statewide paid-media Flex Alert campaign from all customers in their service territories (i.e., bundled customers and customers of CCAs and customers of Direct Access) 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.

The Flex Alert modifications in this decision supersede those previously adopted in D.21-03-056.

## **2. Modifications to IOU Demand Response Programs**

### **Cost-Effectiveness**

As directed in D.21-03-056, the use of our traditional cost-effectiveness tools is waived for all demand response proposals adopted in this decision for years 2022 and 2023, under certain conditions. Regarding changes to existing demand response programs adopted in this decision, the IOUs have proposed to use their existing demand response 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.

### **Cost Recovery**

As directed in D.21-03-056, PG&E, SCE, and SDG&E shall continue to utilize unspent funds from their existing demand response 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 demand response 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 Demand Response Programs Balancing Account and Base Revenue Requirement Balancing Account for this purpose.

### **Modifications to Demand Response Programs of All IOUs**

#### **Procurement of Demand Response Resources from Third-Party Demand Response Providers**

The IOUs shall procure Resource Adequacy capacity from eligible third-party demand response providers (DRPs) for 2022 and 2023 deliveries through bilateral contracts. The procured demand response capacity shall count toward the overall megawatt (MW) targets established for each 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 would not be applied to any LSEs' Maximum Cumulative Capacity bucket cap calculation.

The third-party demand response resources shall be integrated into the CAISO markets as economic demand response (under a Proxy Demand Resource product) and must abide by all

resource adequacy 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 demand response resources procured by the IOUs per above order. The procurements 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. The IOUs shall submit bilateral contracts to the Commission through Tier 1 Advice Letters which is consistent with the process ordered in this decision for other procurement.

#### **Auto Demand Response Customized Incentives**

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

#### **Capacity Bidding Program**

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

#### **Prohibited Resources Using Renewables**

Resolution E-4906 is modified to include in its definition of allowable renewable fuels the Renewable Portfolio Standard-eligible fuels certified by the California Energy Commission (CEC). Behind-the-meter generators utilizing CEC-certified Renewable Portfolio Standard-eligible fuels are exempt from the prohibited resources policy in D.16-09-056 and permitted for use in Demand Response programs. The IOUs are directed to update their tariffs and contracts to incorporate the updated prohibited resources policy effective March 1, 2022.

#### **Modifications to PG&E's Demand Response Programs, Pilots, and Related Support Programs**

1. 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’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 SEASONAL INCENTIVE FOR BIP

Line No.	Potential Load Reduction	Current Incentive (Year-Round)	Proposed Incentive (May – October)
1	1 kW to 500 kW	\$9.50/kW	\$10.50/kW
2	501 kW to 1,000 kW	\$10.00/kW	\$11.00/kW
3	1,001 kW and greater	\$10.50/kW	\$11.50/kW

2. For the Base Interruptible Program 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 for 2023 costs.
3. 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).
4. 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.
5. PG&E’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.

**Modifications to SCE’s Demand Response Programs, Pilots, and Related Support Programs**

6. 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.

7. SCE's proposal to reinstate the pre-cooling strategy where applicable in its Smart Energy Program (SEP) is approved.
8. 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.
9. To address CAISO tariff changes stemming from CAISO's Summer Reliability enhancements for reliability demand response resources (RDRR), SCE's proposal to modify effective immediately its Reliability Program Event Parameters, so that 1) the Base Interruptible Program (BIP) and Agricultural Program-Interruptible (AP-I) parameters match, and 2) the parameters for the SDP and SEP match is approved. modifications to SDG&E's Demand Response Programs, Pilots, and Related Support Programs

### **Modifications to SDG&E's Demand Response Programs, Pilots, and Related Support Programs**

10. SDG&E is authorized to continue in 2022 its Capacity Bidding Program residential pilot approved in D.21-03-056.
11. 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. \$1.6 million is authorized for this program for 2023, as well as a \$51,000 incremental marketing budget.

### **3. Dynamic Rate Pilots**

#### **A. Valley Clean Energy & PG&E Pilot for Agricultural Pumping**

PG&E is directed to collaborate with Valley Clean Energy (VCE) in administering and evaluating a dynamic transactive pilot rate for agricultural pumping loads in VCE's territory with the attributes described in this section. The design and execution of this pilot is intended to be modeled on the concepts and technologies implemented in the CEC EPIC-funded pilots involving dynamic rates: EPC-15-054 and EPC-16-045. This pilot shall be administered under PG&E's DR *Emerging Technologies* program authorized in D.17-12-003 with incremental funding described below.

The section addresses the following critical pilot proposal design elements:

- Program Parameters
- Pilot Duration
- Rate Design
- Billing
- Pilot Evaluation
- Pilot Funds
- Advice Letters

#### **Program Parameters**

VCE will enroll agricultural pumping load service points from their customer base with aggregated peak load exceeding 5 MW. VCE may engage service providers for pump automation and energy management services to equip the pumps with the capability to automatically optimize the pump operation in response to a dynamic rate to achieve bill savings.

#### **Pilot Duration**

The pilot is authorized for three years (2022-2024), starting no later than May 1, 2022, and may be extended and/or expanded after the initial period pending approval by the CPUC.

Proposal for expansion and/or extension of the pilot, or conversion of the pilot to an optional rate may be considered in a future General Rate Case or other relevant future proceedings.

## **Rate Design**

The pilot rate design will incorporate the ideas in the 6-step Distributed Energy Resource (DER) & Demand Flexibility roadmap described by Energy Division Staff at the May 25, 2021, workshop on Advance DER and Demand Flexibility Management.<sup>2</sup>

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.

VCE and/or PG&E may engage a service provider with a suitable IT platform to automate the creation of dynamic hourly prices for the generation and delivery components and present the composite dynamic hourly prices via an internet-based pathway to be accessed by customers and the automated pumps.

## **Billing**

To avoid the need to integrate the pilot rate tariff with PG&E's billing systems, VCE will use a "shadow bill" approach to provide participants compensation for any load shift by the customer's equipment in response to the pilot rate. Participants will continue to pay their current VCE bill under the otherwise applicable tariff and will also receive a shadow bill, which they will not pay. The shadow bill will illustrate a customer's potential savings under the dynamic pilot rate. Participants will receive payments from VCE for their pilot rate savings on either a monthly or annual basis.

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'

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<sup>2</sup> <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>



shadow bills. PG&E is directed to set up a 2-way balancing account to track expenses related to the delivery component of the customer bill savings during the pilot.

### **PG&E Circuit Utilization Data**

PG&E is directed to utilize both historical and real-time, or as frequent as possible, hourly circuit load data from the distribution circuits that service participating customers to calibrate and calculate the distribution capacity cost recovery price function. The circuit load data shall be integrated as data inputs into the pilot's IT platform to generate the delivery component of the dynamic prices.

### **Pilot Evaluation**

PG&E is directed to 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 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.
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.

The evaluations of this pilot should be included in any future PG&E evaluations of the potential of agricultural load responsiveness to dynamic pricing.

### **Pilot Funds**

PG&E is authorized a budget of up to \$3.25 million for the administration and execution of the 3-year pilot to be used in the manner specified in the table below.

<b>Expense Type</b>	<b>Amount (\$)</b>
<b>Integration and automation* of pumping loads with the pilot price signal</b>	\$1,000,000
<b>Vendor fees, Systems &amp; Technology</b>	\$1,500,000
<b>Program Administration, including Billing, and Evaluation</b>	\$750,000

\*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.

### **Advice Letters**

VCE (in coordination PG&E) will submit a Tier 1 Advice Letter no later than 60 days after 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, (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 this decision that includes, but in not limited to, 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.

## **B. SCE Pilot for All Customers and End Uses**

SCE is authorized to conduct a demonstration pilot of the TeMix proposed “Pilot UNIDE Program” to “conduct comprehensive studies that fully assess the costs and benefits of real-time rates, including required infrastructure, manufacturer interest, and customer impacts.” A budget of \$2.5 million for “administration, systems, metering, etc.” is approved to support this demonstration pilot for three years (2022 to 2024). The pilot shall be administered under SCE’s *DR Emerging Markets and Technologies* program authorized in D.17-12-003.

The section addresses the following critical pilot proposal design elements:

- Program Parameters
- Pilot Duration
- Billing
- Pilot Evaluation
- Advice Letters

### **Program Parameters**

SCE is encouraged to enroll residential, commercial, and industrial customer with smart enabling price-responsive end-uses such as electric vehicle charging, behind-the-meter batteries, and controllable loads.

### **Pilot Duration**

The pilot is authorized for three years (2022-2024), starting no later than May 1, 2022, and may be extended and/or expanded after the initial period pending approval by the CPUC.

Proposal for expansion and/or extension of the pilot, or conversion of the pilot to an optional rate may be considered in a future General Rate Case or other relevant future proceedings.

### **Billing**

To reduce the time required to integrate the pilot rate tariff with SCE's billing systems, SCE is encouraged to 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. The shadow bill 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.

### **Pilot Evaluation**

SCE is directed to conduct a mid-term and final evaluation of this 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.

### **Advice Letters**

SCE will submit a Tier 1 Advice Letter no later than 61 days after 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.

#### **4. Smart Thermostats and Integrated Demand-Side Management (IDSM) Program Development**

##### **Targeted Summer Reliability Smart Thermostat Program**

This decision authorizes a budget of up to \$22.5 million in technology incentives (\$75 per measure) to develop a limited, two-year Residential Smart Communicating Thermostat (SCT) program for 2022-23 to incentivize the installation of up to 300,000 SCT in hot climate zones (Climate Zones 9, 10, 11, 12, 13, 14, and 15). 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 third-party DRPs to provide rebates through third-party demand response programs. Third-party DRPs should have competitively equal access to the rebates as the IOUs.

This program will require customer pre-enrollment in a market integrated supply-side Demand Response program.

The technology incentive amount will be up to \$75, limited to the full cost of the SCT. Prior to incentive payment, the IOUs must verify installation of an eligible thermostat and enrollment in an eligible IOU or third-party program. Each IOU must justify the amount of administrative budget that will be required to administer the program.

Within 15 days of the effective date of this Decision, the IOUs shall meet and confer with the third-party DRPs to discuss the process for rebate awards, and installation and enrollment verification. Within 45 days of the effective date of this Decision, the IOUs shall jointly file a Tier 2 advice letter that reflects a consensus across third-party DRPs and IOUs on these issues. This advice letter will include the following:

- Program design and budget;
- Amount of admin budget each IOU will need to administer the budget;
- Specify if balancing or memorandum accounts will need to be established to track program expenditures;
- Goal for number of customers reached, by when, and estimated MW demand savings;
- Identification of qualifying SCT for incentive;
- Process for providing an incentive to both utility and third-party customers;
- Which Demand Response programs a customer can enroll in to be eligible for the product incentive, and how that enrollment occurs before the customer is rebated;
- Process for identifying customers that qualify for the Energy Savings Assistance (ESA) program.

### **Smart Thermostat program for Income-Qualified Customers**

ESA eligible customers will continue to be eligible to receive no-cost, direct install smart thermostats through ESA for all climate zones. This is consistent with current policy detailed in the Statewide ESA Program Policy and Procedures Manual per D.16-11-022 and reaffirmed in D.21-06-015. The IOUs and third-party DRPs participating in the Targeted Summer Reliability SCT Program 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 will not require, enrollment in a market-integrated supply-side demand response program.

### **Administration of Existing IDSM Program Budget**

Limited Integration EE-DR program guidance, as stated in D.18-05-041, is updated to allow IOUs to implement limited integration EE-DR programs, using remaining budget previously authorized through D.18-05-041, without a third-party entity designing or implementing the program. The IOUs shall jointly file a Tier 2 advice letter within 90 days specifying program implementation details including:

- Remaining budget to be used authorized through D.18-05-041.
- How will the remaining budget will be allocated among the IOUs to run their limited integration programs.
- Program implementation plans and design, including information on how they comply with requirements outlined in D.18-05-041.

**(END OF ATTACHMENT 1)**

## **Attachment 2 Emergency Load Reduction Program (ELRP)**

**This Attachment has been copied from Phase I Decision, D.21-03-056. The Attachment later received Corrections from D.21-06-027. This document incorporates the corrections from D.21-03-056 and shows all new changes as hard coded text.**

1. Pilot Program Duration
2. Out of Market Framework
3. Program Parameters
4. Eligible Customers
5. Program Event Triggers
6. Compensation
7. Other Program Elements
8. Balancing Accounts and Cost Recovery

Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) are each directed to administer the Emergency Load Reduction Program (ELRP) pilot as described in the following sections.

### **1. Pilot Program Duration**

ELRP duration will be five years (2021-2025), with years 2023-2025 subject to review and revision in the Demand Response (DR) Applications proceeding expected to be initiated May 2022.

ELRP design aspects that are subject to review and revision include minimizing the use of diesel backup generators where there are safe, cost-effective, and feasible alternatives; consideration of local air pollution impacts on disadvantaged communities; and other modifications to make the program more effective and consistent with the state's decarbonization goals. To this end, PG&E, SCE, and SDG&E should collect data on backup generator participation in ELRP, including as location, type of fuel used, minimum notification time required to dispatch the generator, and the capacity of the generator, for years 2021 and 2022.

## 2. Out of Market Framework

ELRP load reduction capacity will be excluded from the Resource Adequacy (RA) / California Energy Commission (CEC) peak forecast framework with no CAISO market obligations.

## 3. Program Parameters

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

As discussed below, the program parameters for Residential ELRP may differ.

## 4. Eligible Customers

Eligible participants for ELRP are divided into two groups with several subgroups:

- 🕒 Group A: Customers and aggregators not participating in Demand Response (DR) programs
  - A.1. Non-Residential Customers
  - A.2. Non-Residential Aggregators
  - A.3. Rule 21 Exporting Distributed Energy Resources (DERs)
  - A.4. Virtual Power Plants (VPP) Aggregators
  - A.5. Vehicle-Grid-Integration (VGI) Aggregators
  - A.6. Residential Customers
- ⊕ Group B: DR providers participating in market-integrated supply-side Demand Response (DR) programs
  - B.1. Third-party DR Providers (DRPs)
  - B.2. IOU Capacity Bidding Programs (CBPs)

At any time, a customer can participate in ELRP via either Group A or Group B, but not both groups at the same time. At any time, a Group A customer can participate in ELRP via only one sub-group under Group A.

Eligibility criteria for each group are defined below.

**GROUP A ELIGIBILITY: Customers and aggregators not participating in Demand Response (DR) programs.**

At the time of enrollment, or at designated times during the ELRP pilot, Group A participants, except residential customers enrolled in ELRP sub-group A.6 Residential customers described below, will nominate an estimated target load reduction quantity to be achieved during an ELRP event. Participation during an ELRP event is entirely voluntary, and no financial penalties will result from not meeting or exceeding the nominated target load reduction during the event.

If a customer qualifies for the ELRP under both sub-groups A.1. and A.3. criteria described below, the customer will make an election for participating in the ELRP as part of one or the other sub-group at the time of enrollment, or at designated times during the ELRP pilot.

**A.1. Non-Residential Customers Eligibility**

Bundled and unbundled non-residential customers of an IOU who meet the following criteria are eligible to enroll and participate in ELRP:

- ⌚ Customer meets the “Minimum Size Threshold” specified further below, and
- ⌚ Customer is not simultaneously enrolled in another supply-side DR program offered by an IOU, third-party demand response provider (DRP), or community choice aggregator (CCA), with the exception that dual enrollment in an IOU’s Base Interruptible Program (BIP) or SCE’s Agricultural and Pumping Interruptible program is permitted.

The Minimum Size Threshold parameter for each IOU is as follows:

- ⌚ For PG&E, the customer must be able to reduce load by a minimum one kilowatt (kW) during an ELRP event.
- ⌚ For SCE, the non-residential service account must have a peak demand of greater than or equal to 100 kW with an SCE approved interval meter.
- ⌚ For SDG&E, the customer agrees to drop a minimum of 50 kW during an ELRP event.



## **A.2. Non-Residential Aggregators Eligibility**

BIP aggregators are eligible to participate in ELRP. If a BIP aggregator chooses not to participate, its customers may independently participate in ELRP under A.1, subject to the applicable criteria and requirements.

For SCE, participating BIP aggregators may add and nominate only non-residential customers eligible under A.1. in their ELRP portfolio.

Non-BIP aggregators with aggregated bundled or unbundled non-residential customer resources meeting the following criteria are eligible to participate in ELRP:

- ⌚ The aggregated resource is not simultaneously enrolled in a supply-side DR program offered by an IOU, third-party DRP, or 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 Minimum the Aggregation Size Threshold.

If a non-BIP aggregator of non-residential customers chooses not to participate, its customers may independently participate in ELRP under sub-group A.1 Non-Residential customers 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 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.

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

## **A.3. Rule 21 Exporting DER Eligibility**

Bundled and unbundled non-residential customers of an IOU who meet the following criteria are eligible to enroll and participate in ELRP:

- ⌚ Customer is not simultaneously enrolled in any market-integrated DR program offered by an IOU, third-party DRP, or CCA, and
- ⌚ Customer possesses a behind-the-meter (BTM) Rule 21-interconnected device (including Prohibited Resources) with an existing Rule 21 export permit, and
- ⌚ Customer's BTM Rule 21 interconnected device meets the "Minimum Export Threshold" specified further below for at least one hour in compliance with Rule 21 and other applicable regulations and permits during an ELRP event.

NEM customers meeting the above requirements are eligible to participate in ELRP.

The Minimum Export Threshold is set at 25 kW based on the physical interconnected capacity.

#### **A.4. Virtual Power Plant Aggregators Eligibility**

An aggregator managing a BTM virtual power plant (VPP) aggregation consisting of storage paired with net energy metering (NEM) solar or stand-alone storage deployed with residential (bundled or unbundled) or non-residential (bundled or unbundled) customers, whose VPP meet the following criteria, is eligible participate in ELRP:

- ⌚ The VPP or any customer site within the aggregation is not simultaneously enrolled in a market-integrated DR program offered by an IOU, third-party DRP, or CCA, and
- ⌚ A customer site within the aggregation is not currently taking service on a critical peak pricing (CPP) or real time pricing (RTP)-equivalent tariff, and
- ⌚ All sites within the VPP aggregation are located within the distribution service area of a single IOU, and
- ⌚ The aggregated BTM storage capacity of the VPP meets the "Minimum VPP Size Threshold", where the VPP size is determined by summing the Rule 21 interconnected capacity of the individual storage devices comprising the aggregation, and

The VPP aggregations shall be dispatched by the IOUs for at least the Minimum VPP Dispatch Hours per season. In addition to the Group A triggers defined below, the IOUs may exercise discretion to dispatch the VPP in response to other forecasted or anticipated grid stress conditions, such as, high locational marginal prices in the CAISO markets, extreme heat waves, etc., to achieve the Minimum Dispatch Hours. 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.

The Minimum VPP Size Threshold is set at 500 kW. The Minimum VPP Dispatch Hours is set at 20 hours per season.

#### **A.5. Vehicle-Grid-Integration Aggregators Eligibility**

An aggregator managing a Vehicle-Grid-Integration (VGI) aggregation consisting of any combination of electric vehicles and charging stations – including those that are capable of managed one-way charging (V1G) and bi-directional charging and discharging (V2G) deployed with residential (bundled or unbundled) or non-residential (bundled or unbundled) customers that meets the following criteria, is eligible to participate in ELRP:

- ⌚ 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, and
- ⌚ A customer site within the VGI aggregation is not currently taking service on a CPP or RTP-equivalent tariff, and
- ⌚ 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 (ILR), as defined below, equal to or greater than the Minimum VGI Aggregation Size Threshold for a minimum of one hour during an ELRP event.

NEM customers with electric vehicles meeting the above requirements are eligible to participate in the VGI aggregation.

In recognition of a nascent market, any direct current (DC) V2G electric vehicle supply equipment (EVSE) that has been certified to UL 1741, but not the updated smart inverter certification standard required in Rule 21, may interconnect for the purpose of participating in the ELRP, subject to all other Rule 21 interconnection requirements. IOUs may request the termination of this interconnection pathway via Tier 2 AL after the 2024 ELRP season if the market has developed to provide multiple V2G capable EVSEs that meet the full smart inverter certification standards required in Rule 21. Termination of this pathway would not affect previously interconnected EVSE.

The VGI Aggregation shall be dispatched by the IOUs for at least the Minimum VGI Dispatch Hours. In addition to the Group A triggers defined below, the IOUs may exercise discretion to dispatch the VGI Aggregation in response to other forecasted or anticipated grid stress conditions, such as, high locational marginal prices in the CAISO markets, extreme heat waves, etc., to achieve the Minimum Dispatch Hours. The IOUs may negotiate agreements with the VGI aggregators to clarify other requirements as needed, including potential administration fees, to implement the Minimum Dispatch Hours and related ELRP compensation.

The Minimum VGI Aggregation Size Threshold is set at 25 kW. The Minimum VGI Dispatch Hours is set at 30 hours per season.

## **A.6. Residential Customer Eligibility**

### *Eligibility*

Bundled and unbundled residential customers of an IOU who meet the following criteria are eligible to enroll in ELRP by opting-in to participate:

- ⌚ The customer is not simultaneously enrolled in another supply-side DR program offered by an IOU, third-party DRP, or CCA; and
- ⌚ The customer is not taking service on CPP or SmartRate or similar tariff; and
- ⌚ The customer is not served by a CCA which has elected to exclude its customers from participation in ELRP.

### *Unenrollment*

A customer participating in ELRP is permitted, at any time, to enroll in a supply-side DR program offered by the IOU, third-party DRP, or CCA. The IOU shall arrange to promptly unenroll the customer from ELRP without any action needed on the part of the customer.

Customers can choose to opt-out at any time and IOUs shall ensure the process is simple and easy for customers using methods such as a 1-click digital form or an email or text message.

### *Opt-In Enrollment of Eligible Customers*

Eligible customers may opt-in to enroll in an IOU's Residential ELRP pilot. The IOUs shall ensure that the enrollment process is simple and easy for customers using methods such as a 1-click digital form or an email or text message.

*Auto-Enrollment of Select Customers*

PG&E's proposed Power Saver Rewards Program (Behavioral DR – Option A), with auto-enrollment of “customers who receive PG&E's Home Energy Reports” is approved, as modified herein, as PG&E's Residential ELRP pilot program for the duration of the ELRP pilot, except that Options B & C of PG&E's proposal 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,” is approved, as modified herein, as SCE's Residential ELRP pilot program for the duration of the ELRP pilot, except that SCE proposed dual participation with other supply-side DR programs or SCE's VPP Pilot is not permitted at this time.

SDG&E's “Peak Day” Behavioral DR program, with auto-enrollment of “existing Home Energy Report (HER) customers,” is approved, as modified herein, as SDG&E's Residential ELRP pilot program for the duration of the ELRP pilot.

In addition to the IOU-specific auto-enrolled set of select customers specified above, the IOUs shall auto-enroll residential customers on California Alternative Rates for Energy (CARE), and who meet the above specified eligibility criteria for Residential ELRP (sub-group A.6). Whether through email, phone call, text message, bill insert, or mailer, these customers shall be given an opportunity to opt-in to receive ELRP related messaging or opt-out from ELRP.

*Other Program Elements*

In their marketing, education, outreach, and event notification efforts focused on auto-enrolled customers as well as customers in DACs, the IOUs shall incorporate the marketing aspect of CEJA's Just Flex Rewards proposal, such as the following:

- *Accessibility, In-Language:* Marketing shall be done in accessible, in-language communication, when that information is known, whether that be through text, email, or phone messaging. The Disadvantaged Communities Advisory Group may choose if it wishes to evaluate the language of the communications for accessibility and make recommendations to the IOUs.

- *Specific Outreach for DAC and CARE customers:* Targeted marketing and messaging should be designed for CARE and DAC households. The IOUs shall partner with their Energy Savings Assistance (ESA) contractors and Community Based Organizations to help reach these customers, inform them of their enrollment status, potential compensation rate, and voluntary participation with no penalty.

The IOUs shall establish a process for a CCA to inform the IOU of its election to exclude its customers from ELRP. The CCA shall 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 that limits customer confusion with state-wide Flex Alert campaign, and state-wide unified branding. The IOUs shall file a Tier 2 Advice Letter within 60 days of issuance of this decision to establish the parameters for its ELRP Residential pilot program and advise the CPUC of the associated costs.

### **GROUP B ELIGIBILITY: DR providers participating in market-integrated supply-side Demand Response (DR) programs**

At the time of enrollment, or at designated times during the ELRP pilot, Group B participants will list the Proxy Demand Resources (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 penalties will result from not meeting or exceeding the nominated target load reduction quantity during the event.

#### **B.1. Third-party DR Providers (DRPs) Eligibility**

A third-party DRP with a market-integrated proxy demand resource (PDR) is eligible to participate in ELRP.

#### **B.2. IOU Capacity Bidding Programs (CBPs) Eligibility**

An IOU's Capacity Bidding Program's PDRs are eligible to participate in ELRP.

## 5. Program Event Triggers

ELRP will utilize both day-ahead (DA) and day-of (DO) triggers.

### **Day-Ahead (DA) Trigger**

The ELRP DA trigger for Group B resources is activated when a DA Alert, per the “Alert, Warning, Emergency (AWE)” process defined by the CAISO Operating Procedure 4420, is declared by the CAISO. The start time and duration specified in the DA Alert defines the Group B ELRP event window.

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

In addition to the Group A Day-Ahead trigger as described above, the IOUs shall dispatch the Residential ELRP customers (sub-group A.6) in response to a CAISO Flex Alert declaration.

### *Backup Generation Dispatch Sequence*

If Group B is triggered in the DA, backup generators associated with customers participating in Group B and not exempted under the Prohibited Resources policy and located in Disadvantaged Communities<sup>3</sup> shall not be dispatched.

If Group A is triggered in the DA, 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 if in the day-of following a DA trigger, the IOUs through Joint ELRP Operations Board consultations determine that backup generators support may be needed based on anticipated grid stress conditions.

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<sup>3</sup> Pursuant to Section 39711 of the Health and Safety Code, the California Environmental Protection Agency (CalEPA), 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.

### **Day-Of (DO) Trigger**

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

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

### *Backup Generation Dispatch Sequence*

If Group A or B is triggered in the DO, backup generators associated with the customers participating in the respective 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.

### **Other Trigger Related Guidelines**

An ELRP event cannot be triggered by an IOU for a localized transmission or distribution emergency.

For coordination among and guidance to the IOUs in the exercise of discretion for Group A trigger activation, the IOUs shall continue to work with the "Joint ELRP Operations Board," consisting of representatives from each IOU's grid operations group and an invited representative from the CAISO's grid operations group. Following an AWE declaration by the CAISO, the Board will periodically assess the current and forecasted grid conditions and provide guidance on target load reductions to be sought by the IOUs from Group A participants.

The IOUs are directed to coordinate with the CAISO in providing timely information on the status and expected load reduction under ELRP from Group A.

### **Future Alert Warning Event (AWE) Declarations**



In the future, when the CAISO completes the transition from the current AWE process to the North American Electric Reliability Corporation (NERC) Energy Emergency Alert (EEA) standards, then the AWE declarations shall be replaced by the equivalent CAISO issued day-ahead EEA level notices in the above guidelines, per the following table:

**Table. Alert Warning Event Levels**

AWE Levels	NERC EEA Levels	Comments
Restricted Maintenance Operations		Issued in real time or in advance
Transmission Emergency		Issued in real time
Notifications of forecasted reserve deficiencies		
Alert	EEA-1	Issued in advance – day ahead by 1500
Warning	EEA-1	Issued in real time
Warning – triggering DR programs	EEA-2	Issued in real time
Stage 1	EEA-2	Issued in real time
Stage 2	EEA-3	Issued in real time
Stage 3	EEA-3	Issued in real time

## 6. Compensation

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

Any load reduction technology may be used during an ELRP event to achieve ILR. Prohibited resources may be used in compliance with Rule 21 and other applicable regulations and permits, subject to the backup generation dispatch sequence described earlier, during an ELRP event to achieve ILR, including during the overlapping period with an independently triggered event in a dual-enrolled DR program, but only for achieving load reduction incremental to any other existing commitment (e.g., under a dual-enrolled DR program).

General ELRP compensation parameters for all customers include the following:

- ⌚ After-the-fact pay-for-performance will be made at a prefixed energy-only ELRP Compensation Rate applied to ILR.
- ⌚ There are no “capacity-like” payments.
- ⌚ There are no penalties for non- or under-performance.

The ELRP Compensation Rate for Group A is set at \$2 / kilowatt-hour (kWh) (or \$2000 / megawatt-hour (MWh)).

The ELRP Compensation Rate for Group B PDRs is also set at \$2 / kWh (or \$2000 / MWh).

## **GROUP A COMPENSATION**

For Group A eligible participants, the compensation for load reduction delivered during an ELRP event is determined by calculating the product of ILR and ELRP Compensation Rate.

### **A.1. Non-Residential Customer Compensation**

#### *Baseline*

The ELRP baseline will be constructed by all IOUs according to the method described below.

1. A customer’s Adjusted Energy Baseline (AEB) for an ELRP event is calculated by multiplying the energy baseline (EB) by the optional day-off (DO) adjustment.
2. The EB will be calculated on an hourly basis using the average of either 1) the previous 10 calendar days, or 2) the previous 10 similar days.
3. The days selected in step 2 above shall exclude days when a) the customer was subject to an ELRP event or an event in a dual-enrolled DR program, or b) there was a grid outage during similar hours.
4. The DO adjustment value shall be either 1) not less than 1.00 or greater than 1.40, or 2) not less than 0.60 or greater than 1.40. The DO adjustment is a ratio of (a) the average load of the first three hours of the four hours prior to the event to (b) the average load of the same hours from the last 10 days selected in accordance with step 2 above.

#### *Special Considerations*

1. In the case of overlapping BIP and ELRP events, only the incremental reduction below the customer's pre-committed firm service level (FSL) is counted in ILR.
  - a. Load reduction by dual-enrolled BIP customers during an ELRP event outside of a BIP event is excluded from ILR (and not eligible for ELRP compensation).
  - b. Load reduction by dual-enrolled BIP customers during an ELRP event on a day with no BIP event is excluded from ILR (and not eligible for ELRP compensation).
2. If the customer has a Rule 21 interconnected device with export capability and permit, the customer may choose to count exported energy in ILR. In that case, the applicable ELRP baseline is modified to account for exported energy during non-event days and count exported energy in ILR.
3. If the customer is currently taking a CPP or real-time pricing (RTP) equivalent tariff, any ILR during overlapping hours between the dynamic rate and the ELRP event is attributed to ELRP.

An IOU may choose to implement the ELRP baseline with only one option for the ten-day selection or one option for the DO adjustment by filing a Tier 1 AL.

#### **A.2. BIP Non-Residential Aggregators Compensation**

Same guidelines as A.1 apply.

#### **A.3. Rule 21 Exporting DER Compensation**

For a customer on a CPP or RTP equivalent tariff, the ELRP baseline is deemed to be zero and only exported energy is counted in ILR.

For a customer not on a CPP or RTP equivalent tariff, the ELRP baseline defined under A.1 is utilized and modified to account for exported energy during non-event days and exported energy is counted in ILR.

Only during ELRP dispatch hours, a customer with control over multiple electrically contiguous sites is permitted to virtually aggregate the load and generation to fully utilize the sum of the net export allowed by any Rule 21 permit(s) associated with the sites. Two sites are considered electrically contiguous when they have electric service derived from the same utility distribution transformer secondary and there are no devices on the utility distribution system that can interrupt power flow to only one site.

#### **A.4. Virtual Power Plant Aggregators Compensation**

The aggregator selected CPUC approved baseline for IOU's CBP is utilized and modified to account for exported energy, to the extent allowed by a site's Rule 21 export permit, during non-event days and count exported energy in ILR.

The above baseline method 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 ILR for the ELRP settlement.

#### **A.5. Vehicle-to-Grid Aggregators Compensation**

An EVSE meter, or EVSE sub-meter if the EVSE is taking service through the host site meter, may be used to determine the ILR for ELRP settlement. The EVSE sub-meter must meet applicable standards established by the CPUC when adopted.

Only during IOU dispatched hours, the VGI aggregator is permitted to virtually aggregate separately metered EVSE with other load and generation (if any) at an electrically contiguous host site to allow export from the EVSE to reduce the host site's load and export from such aggregation up to the sum of the net export allowed by any available Rule 21 permits of the EVSE site and the host site.

Two sites are considered electrically contiguous when they have electric service derived from the same utility distribution transformer secondary and there are no devices on the utility distribution system that can interrupt power flow to only one site.

#### **A.6. Residential Customers Compensation**

The ELRP baseline will be similar to that used in SCE's residential CBP pilot authorized in D21-03-056: a 5-in-10 baseline with 40% day-of adjustment. The 5-in-10 baseline is the average load during the same hours as the DR event, of the 5 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.

### **GROUP B COMPENSATION**

*ELRP Baseline for Group B*

To construct the ELRP baseline for measuring a Group B PDR's ILR contribution during an ELRP event, the applicable CAISO baseline will be modified to account for the following:

- 1) Count net exports to the distribution grid by customer locations within the PDR aggregation that comply with Rule 21 and other applicable permits,
- 2) Exclude prior days with other ELRP events when selecting the set of "non-event, but similar" days when calculating the baseline,
- 3) Exclude applicable preceding hours with either CAISO market awards or another ELRP event on the day of the ELRP event when calculating the same-day adjustment to the calculated baseline in step 2, and
- 4) Allow the same day adjustment in step 3 to be no greater than 100%.

*ELRP Settlement for Group B*

For participation in ELRP under Group B, a DRP must construct a PDR Portfolio consisting of only 1) PDRs with RA assignment or PDRs without RA assignment (but not both) and 2) PDRs limited to the service area of one IOU (thus, a DRP may have up to six PDR portfolios participating in ELRP).

The CAISO settled aggregated load during an ELRP event is modified to count net energy exported to the distribution grid by any customer location within the PDR aggregation.

Following an ELRP event, the DRP's scheduling coordinator is responsible for determining the following:

1. ELRP Event Performance (total load reduction during the ELRP event) of each PDR in the DRP's PDR Portfolio by applying the applicable ELRP modified baseline to the PDR's modified aggregated load settled during the ELRP event.
2. ILR of each PDR by subtracting the CAISO scheduled award quantities, inclusive of day-ahead market (DAM) and real-time market (RTM), from the PDR's ELRP Event Performance. If the total market award for the PDR during the ELRP event is zero, then ILR of the PDR equals the ELRP Event Performance.

3. The ELRP Event Compensation due for each PDR by adding all interval-specific ELRP Compensations across all applicable intervals of the ELRP event, subject to the following:
  - a. The interval-specific ELRP Compensation in each applicable interval of the ELRP event is obtained by subtracting 1) any CAISO market payments for any portion of the load reduction counted in the interval-specific ILR and 2) the interval-specific CAISO Opportunistic Revenue (COR), defined below, from 3) the interval-specific Product of the ELRP Compensation Rate and the interval-specific ILR (see illustration below).

If the interval-specific ILR is negative, then the interval-specific ELRP Compensation is set to zero in that interval.

If the interval-specific COR is greater than the interval-specific Product, then the interval-specific ELRP Compensation is set to zero in that interval.

- b. The interval-specific COR is the product of the interval-specific Market Eligible Capacity (MEC), defined below based on the interval-specific CAISO Market Event Performance (MEP) determined under the applicable CAISO market baseline, and the interval-specific CAISO Clearing Price Delta (CCPD), defined below (see illustration below).

- i. MEC:

If the total CAISO scheduled award quantity in an interval is non-zero:

1. And if the interval-specific MEP is less than or equal to the total CAISO scheduled award quantity in the interval, then the interval-specific MEC is set to zero.
      2. And if the interval-specific MEP is greater than the total CAISO scheduled award quantity in the interval and less than or equal to the Qualifying Capacity (QC) of the PDR in that interval, then the interval-specific MEC is equal to the interval-specific MEP minus the interval-specific total CAISO scheduled award quantity.

3. And if the interval-specific MEP is greater than the Qualifying Capacity (QC) of the PDR in that interval, then the interval-specific MEC is equal to the interval-specific QC of the PDR minus the interval-specific total CAISO scheduled award quantity.

If the total CAISO scheduled award quantity in an interval is zero, then the interval-specific MEP in the above cases is set to the interval-specific ILR.

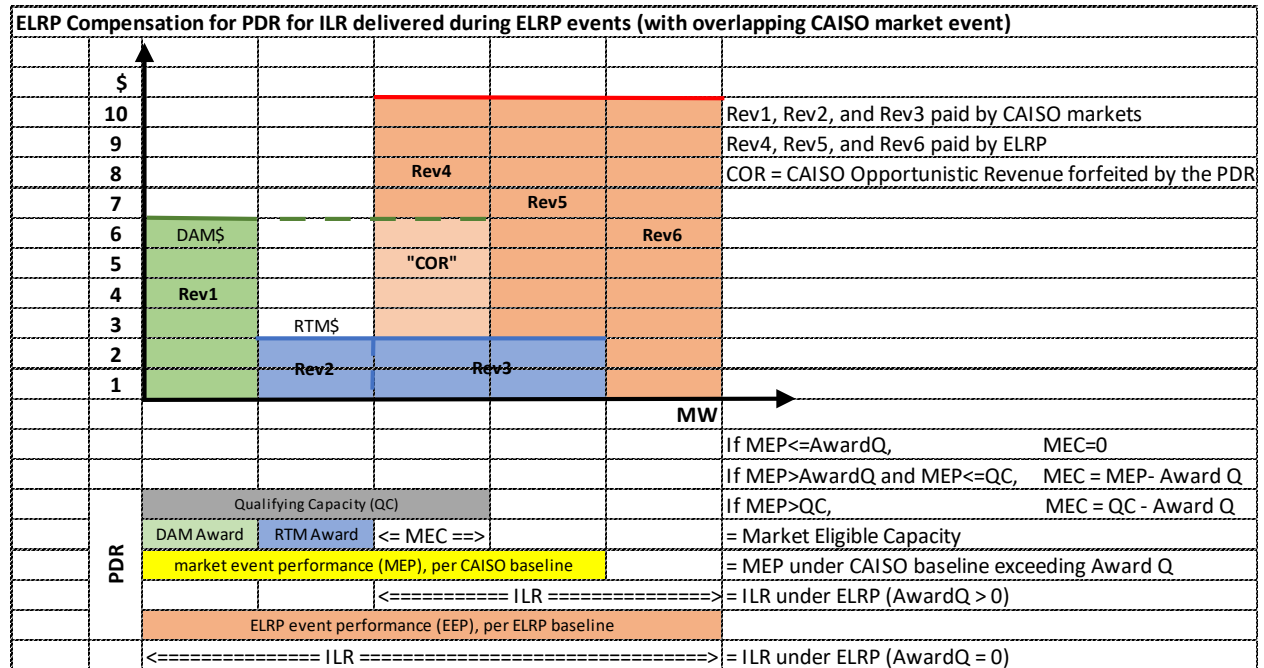
If the PDR has no assigned QC in the above cases, then the QC is replaced by the PDR's "PMin" parameter on record in the CAISO Master File applicable to the interval. Additionally, if the PMin value is less than the total CAISO scheduled award quantity in an interval, then the interval-specific MEC is set to zero.

- ii. CAISO Clearing Price Delta (CCPD):

For a PDR participating in the DAM only (that is, "long-start" PDR), the interval-specific CCPD is the DAM clearing price in that interval.

For a PDR participating in the RTM, the interval-specific CCPD is equal to the higher of the DAM or RTM clearing price in that interval minus the lower of the DAM or RTM clearing price in that interval.

4. Portfolio Level Net Event Compensation across all PDRs in the third-party DRP's Portfolio.



To receive ELRP compensation, the third-party DRP shall submit an aggregate invoice for the Cumulative Portfolio Level Net Event Compensation of each PDR Portfolio for May-June-July (First Quarter) period by September 30 and for August-September-October (Second Quarter) by December 31 of the program year. for each of its PDR Portfolio to the applicable IOU’s team administering Demand Response Auction Mechanism invoices. The Cumulative Portfolio Level Net Event Compensation of a PDR Portfolio over one Quarter is determined by summing the Portfolio Level Net Event Compensation across all ELRP events in that Quarter.

The invoice shall be accompanied with the supporting data for each event, including but not limited to PDR-specific ELRP Event Performance, ILR, applicable market awards during the event, applicable CAISO market payments for load reductions counted in the ILR, and ELRP Event Compensation. The IOU may audit and verify the invoice as needed. The aggregate invoice amount must be equal to or larger than the ELRP Minimum Invoice Threshold to be eligible for compensation by the IOUs. The IOU shall settle the invoice within 60 days of the invoice date.

The ELRP Minimum Invoice Threshold is set at zero at this time.

## 7. Other Program Elements

### Test Events



The IOUs shall conduct one test event, with two-hour duration, per year for Group A participants.

ELRP Group A.1 and A.3 participants, except for those relying exclusively on prohibited resources, are required to participate in the test events. Use of prohibited resources during a test event is not permitted and will not be compensated. Incremental load reduction (ILR) delivered during an ELRP test event is eligible for ELRP compensation.

ELRP sub-group A.6 Residential customers are exempt from testing requirements.

The IOUs are directed to collaborate with the CAISO and the CEC in the testing process and provide data regarding ELRP response to the CAISO and the CEC to facilitate forecasting.

#### *Advice Letters*

Within 30 days of this Decision, the IOUs shall jointly file a Tier 1 AL incorporating the modifications by this Decision ELRP terms and conditions for Group A. 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 and customer acknowledgment, ILR measurement, and settlement.

Within 60 days of this Decision, the IOUs 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.

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

As experienced 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. The change request shall be limited to technical aspects of the program design related to program eligibility criteria or requirements (including various minimum size threshold parameters), dual participation between ELRP and another DR program, program trigger(s), minimum dispatch hours, Group A baselines and settlement, and Group B baselines, settlement, and invoicing guidelines. A request to allow a particular dual participation option should be accompanied with an explanation and methodology to demonstrate how the ILR during overlapping event could be attributed uniquely to ELRP participation and avoid double compensation.

## 8. 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. Customer compensation costs for each IOU assume the ELRP Compensation Rate specified earlier for both Groups A and B, for up to the 60-hour annual limit; however, if no ELRP events are called, customer compensation costs are assumed to be zero.

These balancing accounts shall have the following annual caps 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.

**(End of Attachment 2)**

### ATTACHMENT 3 - PARTIES

<b>Parties who submitted testimony/reply testimony</b>	<b>Abbreviation</b>
Pacific Gas and Electric Company	PG&E
American Clean Power- California	ACP-CA
Advanced Energy Economy	AEE
Bloom Energy Corporation	N/A
California Independent System Operator Corporation	CAISO
California Community Choice Association	CalCCA
Calpine Corporation	Calpine
California Solar & Storage Association	CALSSA
California Wind Energy Association	CALWEA
Center for Energy Efficiency and Renewable Technologies	CEERT
California Environmental Justice Alliance	CEJA
California Energy Storage Alliance	CESA
California Large Energy Consumers Association	CLECA
Diamond Generating Corporation	N/A
Enchanted Rock, LLC	Enchanted Rock
Ev.Energy Corp	Ev.Energy
Fuel Cell Energy, Inc.	Fuel Cell Energy
Google LLC	Google
Green Power Institute	GPI
Grid Alternatives	N/A
Independent Energy Producers Association	N/A
Joint Demand Response Parties	Joint DR Parties
Joint Parties	Joint Parties
LS Power Development, LLC	LS Power
Marin Clean Energy	MCE
Microgrid Resources Coalition	N/A
Middle River Power LLC	Middle River Power
OhmConnect, Inc.	OhmConnect
Oracle Utilities	Oracle
Protect Our Communities Foundation	PCF
Peninsula Clean Energy	Peninsula Clean Energy
Polaris Energy Services	Polaris
Public Advocates Office	N/A
Recurve Analytics, Inc.	Recurve
Saavi Energía	N/A

Southern California Edison Company	SCE
San Diego Gas & Electric Company	SDG&E
Solar Energy Industries Association	SEIA
Sierra Club	Sierra Club
California Association of Small and Multi-Jurisdictional Utilities	SMJU
Sunrun, Inc.	Sunrun
TeMix, Inc.	TeMix
The Utility Reform Network	TURN
Union of Concerned Scientists	UCS
Valley Clean Energy	VCE
Vehicle Grid Integration Council	VGIC
Voltus, Inc.	Voltus
Wärtsilä North America, Inc.	Wärtsilä
Western Power Trading Forum	N/A

**(End of Attachment 3)**