Rulemaking No.: 20-11-003 .

Exhibit No.: JDRP-3

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PHASE 2 – RELIABILITY FOR 2022-23 – UPDATE: OPENING PREPARED TESTIMONY OF JOINT DEMAND RESPONSE PARTIES

(CPower and Enel X North America, Inc.)

Rulemaking 20-11-003
2021 Extreme Weather Event Reliable Electric Service
Phase 2 – Reliability for 2022-23 - Update

September 1, 2021

R.20-11-003 (Extreme Weather)
PHASE 2 – RELIABILITY FOR 2022-23 – UPDATE:
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I.
EXECUTIVE SUMMARY

Exhibit JDRP-3 is the opening prepared testimony of the Joint Demand Response (DR) Parties in "Phase 2 – Reliability for 2022-23 – Update" (Phase 2) of Rulemaking 20-11-003 (2021 Extreme Weather Event Reliable Electric Service ("Extreme Weather")). Exhibit JDRP-3 continues the numbering of previously admitted testimony of the Joint DR Parties in this proceeding that includes Exhibit JDRP-1 (Joint DR Parties Opening Testimony (served on January 11, 2021)) and Exhibit JDRP-2 (Joint DR Parties Reply Testimony (served on January 19, 2021)), both of which were admitted into evidence in this proceeding by Administrative Law Judge's (ALJ's) Email Ruling issued on February 10, 2021.

As previously detailed in Exhibit JDRP-1, the Joint DR Parties are comprised of two companies, CPower and Enel X North America, Inc. (Enel X), both of which currently aggregates commercial and industrial (C&I) electric customers to participate in a broad range of DR programs managed by grid operators and utilities across the United States and the world. In California, the Joint DR Parties have had long experience participating in DR programs offered by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E) (collectively, the Investor Owned Utilities (IOUs)) and also in deploying and managing Distributed Energy Resources (DERs), primarily in the form of behind-the-meter solar and storage at C&I customer sites and, in the case of Enel X, electric vehicle (EV) charging stations across residential and C&I customer segments. Exhibit JDRP-1 also details the background and experience of CPower and Enel X that make them uniquely and eminently qualified to address programs and steps that can and should be taken to meet demand during extreme heat events with reliance on clean energy resources.[1]

[1] Ex. JDRP-1, at pp. 1-2 (Joint DR Parties (Chamberlin/Monbouquette)).

By Exhibit JDRP-3, the Joint DR Parties address ways to source additional peak and net peak demand reduction in 2022-2023 that were included within the scope of Phase 2 by the Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2 issued on August 10, 2021, in R.20-11-003 (Phase 2 Amended Scoping Memo). In doing so, the Joint DR Parties have followed the direction of the Phase 2 Amended Scoping Memo, the ALJ's Email Ruling on Staff Guidance for Phase 2 testimony issued on August 11, 2021, and the ALJ's Email Ruling on a Staff Concepts Proposal Document for Comment in Phase 2 testimony issued on August 16, 2021 (Staff Concepts). Exhibit JDRP-3 addresses issues included in the Phase 2 scope of reducing demand in 2022-2023 by proposing modifications to existing program offerings, including (1) new proposals; (2) submission of revised proposals made by the Joint DR Parties in Exhibits JDRP-1 and JDRP-2 and addressed in their Opening and Reply Briefs filed on February 5 and February 12, 2021, respectively, that were not adopted in Decision (D.) 21-02-028 or D.21-03-056 and are needed to reduce demand in 2022-2023; and (3) responses to the Staff Concepts Proposal Document issued on August 16, 2021.

Based on the Joint DR Parties' experience, expertise, and analysis in Exhibit JDRP-3, as supported by Exhibits JDRP-1 and JDRP-2, the Joint DR Parties, in summary, strongly recommend that the Commission adopt and/or take the following actions in its Phase 2 decision in R.20-11-003 expected to be issued on November 18, 2021:[2]

1. For the Base Interruptible Program, and through the 2023 delivery year:
    a. Increase program incentives by an additional 30%;
    b. Decrease Excess Energy Charges by 75%; and
    c. Increase dispatch notification times from 15-to-30 minutes to up to one-to-two hours.
2. For the Capacity Bidding Program:

[2] Phase 2 Amended Scoping Memo, at p. 6.

a. Expand PG&E's Elect option to SCE and SDG&E, while relaxing the audit requirement during periods of acute supply shortages; and

b. Allow a 5-in-10 baseline for non-residential customers, and uncap the day-of baseline adjustment factor as CAISO has done for Proxy Demand Resources.

3. For the Demand Response Auction Mechanism (DRAM):

a. Approve the Staff Concepts proposals to initiate a supplemental auction for 2022 deliveries with a $13 million budget, and to launch a new auction for 2023 deliveries with a $27 million budget;

b. Reject Staff Concepts proposals 2.b.i, 2.b.ii, 2.b.iii, and 2.b.v;

c. Approve Staff Concepts proposal 2.b.iv; and

d. Use the rules governing 2020 DRAM for the additional DRAM auctions for 2022 and 2023.

4. Adopt the DRAM qualifying capacity process for use to qualify DR resources for stand-alone, non-program RA sales for the 2023 delivery year.

5. Reject Staff Concept Proposal 3 pertaining to requiring all third-party DR resources contracted with Community Choice Aggregators to adhere to certain DRAM requirements starting in 2022.

6. For the Emergency Load Reduction Program:

a. Adopt a reservation payment or minimum number of guaranteed dispatches for exporting behind-the-meter (BTM) storage (both standalone and V2G) as well as eligible back-up generation;

b. Order the Investor Owned Utilities (IOUs) to open an expedited interconnection review window for existing, non-exporting BTM storage resources and generation that wish to participate as exporting resources in the program, and to enable exporting resource participation across all ELRP groups in advance of the 2022 delivery season;

c. Add a day-of dispatch trigger, but do not cap real-time market bids for day-of compensation eligibility, for Group B;

d. Extend program eligibility to residential customers, but allow them to join on an opt-in basis rather than being automatically enrolled; and

e. Adopt the proposed vehicle-grid integration aggregation pilot, while:

    i. Extending an up-front EVSE rebate and reducing or eliminating interconnection fees, in exchange for guaranteed program participation; and

    ii. Removing the non-net-exporting proposal for virtual pairings of separately metered EVSE with parallel load.

7. Approve the Agricultural Demand Flexibility Pilot while extending the experimental rate to BTM storage, EV charging, and controllable loads.

8. Approve California Energy Commission (CEC)-certified, Renewable Portfolio Standard-eligible renewable fuels such as bio-diesel and renewable natural gas within the Prohibited Resources policy, for use during DR events.

II.
PHASE 2: 2022-2023 DEMAND REDUCTION

A. CONTEXT FOR JOINT DR PARTIES' PHASE 2 RECOMMENDATIONS

Q. *What has been the Joint DR Parties' experience in enrolling and managing customers in load reduction programs following the Commission's issuance of Decision (D.) 21-03-056?*

A. The Joint DR Parties responded in kind to the Commission and the State's imperative to increase the availability of curtailable customer loads following Phase 1 of this proceeding. Specifically, CPower and Enel X enhanced typical customer recruitment activities by marketing the increased incentives in the Base Interruptible Program (BIP) and Capacity Bidding Program (CBP), as well as compensation for incremental load reduction (ILR) under the newly-formed Emergency Load Reduction Program (ELRP), which were adopted by D.21-03-056.

The Joint DR Parties have found that the increased incentives for programs like BIP and CBP have helped to enroll new customers and backfill some of the program attrition that resulted from the unprecedented concentration of consecutive dispatch days during the August and September 2020 heatwaves. CPower and Enel X also invested time and resources alongside the Investor Owned Utilities (IOUs) and program implementers to enroll existing customers in ELRP following the March 2021 decision.

In certain instances, however, enhancements made by D.21-03-056 had a counterproductive impact. CPower and Enel X experienced potential new BIP customers decide against participating in BIP in favor of directly enrolling in the IOU-administered ELRP (Group A.1). These customers were attracted to the voluntary program without penalties and decided not to become a committed BIP resource that can be counted on to perform.

In terms of managing customers, CPower and Enel X are now seeing the business realities stemming from the now 18-month COVID-19 pandemic affect customers' participation during dispatch events. Many large Commercial and Industrial (C&I) customers in California have faced significant financial challenges due to COVID-related shut-downs and cost increases, leading them to place even more importance on avoiding manufacturing or operational delays and maximizing and retaining their labor force. In other words, the opportunity cost of customer load curtailment has gone up as the economy struggles to shake off the effects of the pandemic.

Q. *Given this experience so far in 2021, how do you recommend further changes to demand-side programs and load flexibility to enhance the contribution of these resources to grid reliability in 2022 and 2023?*

A: As described in Governor Newsom's July 30, 2021 Emergency Proclamation and the California Energy Commission's (CEC's) Summer 2022 Stack Analysis (cited in the Phase 2 Amended Scoping Memo), the State is facing a forecasted supply shortage of up to 3,500 MW this summer and 5,200 MW in 2022 under the worst case scenarios due to climate-driven drought, wildfires, and extreme regional heatwaves.

The Joint DR Parties recommend honing program participation parameters, performance measurements, and incentives to make the conditions right to extract the maximum reliability contribution from demand response, load flexibility, and behind-the-meter (BTM) resources. Doing so is a critical element of what must be done to address these near-term capacity shortfalls and to contribute to grid resiliency and renewable integration over the mid- to long-term. In addition, while voluntary response during emergencies is helpful, it is essential to prioritize the increased development of firm resources that are committed to perform during emergencies in order to close the shortfall.

Until this shortfall is meaningfully addressed through significant new capacity coming online, the grid value of customer load curtailments (and battery discharges) has commensurately gone up as well. It is from this perspective, along with our experience in seeking to recruit and retain engaged participants in DR and load flexibility programs, that CPower and Enel X offer the following analysis and recommended actions for adoption by the Commission in its November 2021 decision in Phase 2 of this proceeding.

B. RECOMMENDATIONS BY PROGRAM AREA (INCLUDING RESPONSES TO STAFF CONCEPTS PROPOSALS)

1. Base Interruptible Program

Q. *What is the Base Interruptible Program?*

A. The Base Interruptible Program (BIP) is an IOU-tariffed reliability DR resource in which large customers can either directly enroll or have their participation managed by a third-party DR provider. BIP resources are dispatched on a 30- (or 15-) minute-ahead basis (i.e., in day-of or real-time market runs) to drop load to a registered Firm Service Level (FSL) in response to grid emergencies at all hours of all days. Dispatches can be triggered by CAISO when the market reaches emergency stage or by IOUs in response to a transmission or distribution emergency. BIP compensation is determined monthly based on a customer's enrolled curtailment capacity, calculated as the difference between a customer's monthly average peak demand and the FSL, which is reduced by Excess Energy Charges incurred for not fully reaching and sustaining an FSL during a dispatch. Customers must be able to curtail at least 100 kW, during dispatches to be eligible for the program.

Q. *Were any changes made to BIP as a part of Phase 1 of this proceeding?*

A. Yes. D.21-03-056 increased the statewide participation cap from 2% to 3% of historical peak load and allowed for year-round program enrollment (with six- or 12-month required participation if customers enroll before or after April 30, respectively), for the duration of the ELRP pilot (through 2026). The decision also increased incentive payments by 20% in SCE territory and by $1.50 / kW in PG&E territory for 2021 and 2022, and in SDG&E territory, removed the 100 kW minimum participation requirement to enable participation by all non-residential customers and re-aligned the hourly windows for measuring a customer's "monthly average peak demand" and for calculating the BIP capacity incentive.

Q. *What additional changes would you propose to BIP, based in part on your experience since D.21-03-056?*

A. The Joint DR Parties propose several additional changes to BIP pertaining to incentive and penalty levels, dispatch notification times, and eligibility of certain types of renewable fuels for back-up generation. The Joint DR Parties recommend that these changes are in put into effect through the 2023 delivery season at a minimum, given the forecasted capacity shortfalls through 2022, and also to provide a needed buffer in the plausible event of a delay in the capacity additions ordered by D.21-06-035, which are supposed to start coming online in summer 2023.

First, the Joint DR Parties recommend that: 1) BIP capacity incentives are increased by an additional 30%, and 2) that the Excess Energy Charge is reduced by 75% across all IOUs. These changes are needed for customer enrollment and retention purposes in what in our view is a critical, last-resort reliability product. As described above in Section A, we have experienced customers with large curtailment potential being lured away from this program by ELRP, a voluntary program with attractive compensation and no penalties, which is not a positive outcome for grid reliability. This is a clear example of an unintended consequence that resulted from the creation of ELRP, and has actually impeded to some degree the development of additional firm resources. Moreover, Excess Energy Charges have the potential to eliminate a customer's monthly incentive payments in a single instance of non-performance, even if that customer otherwise performs well over multiple consecutive days of dispatch.

The Joint DR Parties did not make a similar recommendation in Phase 1. Our view, then and now is that meaningful penalties for non-performance are generally appropriate to ensure performance under stressed conditions. However, due to the on-the-ground economic realities of late COVID, combined with the large capacity need, we also see the need for the program to provide slightly more "carrot" and considerably less "stick." This will ensure that penalties do not inhibit program participation in the first place, and will also give customers more reason to perform during in the latter days of a multi-day event if they do not perform on an earlier day. For instance, under current Excess Energy Charge levels, if there is a BIP event on a Tuesday and a participant cannot perform due to production reasons, they will incur significant erosion to their earnings. If there is another BIP event on Wednesday and they do not have the same production burden, they may still not curtail because their earnings have already been significantly decreased from the prior day's poor performance. Reducing Excess Energy Charges would reduce the likelihood of this occurring, as the incentive to respond to a dispatch would persist.

Second, the Joint DR Parties recommend that dispatch notification times are increased from 15-to-30 minutes ahead to up to one-to-two hours ahead. Increasing lead times is needed to ensure that curtailments can be executed safely for workers, guests, or other people on site, to ensure that equipment and production lines can be shut down correctly without risking damage, and to ensure quality control of the products or services being produced at the time of the curtailment. Customers have always weighed these concerns against participation in (and compensation from) DR events, and there is of course a trade-off between dispatch lead-time and reserving the BIP resource for higher-certainty contingencies, but providing greater lead times is especially needed now to help in program participation, retention, and performance during significant supply shortfalls and in the face of higher customer opportunity costs.

2. Capacity Bidding Program

Q. *What is the Capacity Bidding Program*?

A. The Capacity Bidding Program (CBP) is an IOU-tariffed economic DR program in which customers enroll with an approved aggregator (or enter into their own Aggregator agreement with the host utility) and nominate an amount of capacity on a monthly basis they agree to curtail during a DR event. CBP resources are bid into CAISO energy markets and dispatched between specified weekday, non-holiday hours, either on a day-ahead or day-of basis. CBP resources can be dispatched on a number of triggers, but primarily, depending on the utility, are dispatched based on either administratively-set or customer-elected (e.g., PG&E CBP "Elect" and "Elect Plus") wholesale energy prices. Relatedly, different IOUs' CBP tariffs compensate dispatched resources based on an administratively-set energy payment (SCE or SDG&E) or the actually awarded wholesale energy price (PG&E CBP Elect). CBP resources can be dispatched no more than once per day, more than three consecutive days, or more than five days a month (24 hours for PG&E CPB Elect), and receive a capacity payment for availability and also an energy payment for curtailment performance against a 10-in-10 trailing baseline with a modest weather adjustment.[3]

Q. *Have any changes been made to CBP as a part of Phase 1 of this proceeding?*

A. Yes. For SCE, D.21-03-056 increased CBP incentives by 20% and added residential customer eligibility, with a 5-in-10 baseline and +/- 40% day-of adjustment. For PG&E, the decision increased monthly maximum events from five to six, added a weekend participation option with a 25% capacity incentive adder in 2021 and 2022, and increased October capacity incentives from $2.27/kW to $6.80/kW in 2021 and 2022. For SDG&E, the decision increased monthly maximum events from six to nine (with the additional three saved for CAISO or SDG&E emergencies and entailing no penalties for non-performance), set the notification time for the day-ahead product at 5:00 PM, set a 40-minute dispatch notification for the day-of product, and approved a CBP residential pilot to be launched in 2021.

Q. How have these proposals been received? Are there additional proposals you made in Phase 1 that you would renew in Phase 2 of this proceeding?

A. In general, the increased CBP incentives have been well received by customers and have assisted in customer recruitment activities. Otherwise, the Joint DR Parties renew and refine two additional proposals for the Capacity Bidding Program to improve customer expansion, program participation, and retention. First, SDG&E and SCE should amend their CBP tariffs to include the CBP Elect option offered by PG&E. Second, the suite of baseline options utilized in the capacity bidding program should be expanded.

Q. *What is the CBP elect option, and how would it enhance program participation?*

A. CBP "Elect" allows customers, or third-party aggregators on behalf of customers, to set the strike price used to dispatch CBP resources in the wholesale energy market. CBP Elect also passes actual wholesale energy clearing prices through to aggregators. This is beneficial compared to an administratively set strike price and payment, which does not allow customers and aggregators to tailor bids to

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[3] As originally proposed in Exhibit JDRP-1, at pp. 3-4 (Joint DR Parties (Chamberlin/Monbouquette)).

customers' opportunity costs and also fails to appropriately and symmetrically incentivize customers to curtail load based on grid needs.

As seen in August 2020, the low strike price and cap on monthly dispatches resulted in non-Elect CBP dispatches that occurred outside the hours of critical grid needs and prevented the resource from being available over a sustained heat wave, particularly in SCE territory where the program was exhausted early in August and did not have calls left as the heat wave continued later in the month. To that end, CBP Elect also allows aggregators to continue to bid resources into the market even if the 24-hour monthly dispatch maximum has been reached.

Finally, PG&E's CBP Elect has the option – but not a requirement – of testing the resource late each month if the resource is not triggered in the market to ensure the resource is available. This combination generally provides a beneficial balance of resource viability and reasonable dispatch use. The flexibility of the strike price lines up with customers' expectations on the value of their energy – predicated on the customer actually receiving that value for their performance in the wholesale energy market – while the testing provisions confirm that the resources are truly capable of providing load reductions even when market pricing has not lined up with customer energy value.

That said, the Joint DR Parties would recommend pausing CBP Elect audits during any period in which there is an acknowledged acute supply shortfall, such as the Emergency Proclamation issued on July 30, 2021 and in effect through October 31, 2021. It is likely not possible to relax this for the present period, but if similar states of emergencies arise in 2022 or 2023, audits should be paused to reduce customer fatigue and better ensure robust performance during critical dispatch periods.

In sum, expanding PG&E's CBP Elect to SCE and SDG&E customers would better enable resources to optimize program participation to the greatest benefit of customers and the grid, while permitting customers to know that their dispatch is not arbitrary but occurs during times of grid stress. And, judging from the Interruptible Load reports from July 2021 that show much greater participation in PG&E's CBP than in SCE's CBP,[4] the Joint DR Parties believe that expanding CBP Elect will make the program much more attractive and allow aggregators, like Enel X and CPower, to recruit new DR and DER customers to the program to provide critical reliability services in 2022 and 2023.[5]

Q. *Is it the case that not having a CBP Elect option has eroded the DR resource behind SDG&E or SCE?*

A. The use of the relatively low trigger price in SCE's CBP program caused significant exercise of the DR resource early in both May and June 2021, maxing out resource dispatch calls within the first two weeks of the month. CPower experienced several MW of DR resources opt not to participate in DR for the remainder of the summer as customers did not believe their curtailments were being used at a time of grid stress. These MW may not return to DR programs under the current conditions. There were also dispatches for CPower and Enel X customers in PG&Es CBP program throughout the summer thus far; however, the utilization of economic bidding under the Elect option reassured customers that there was a grid need associated with their curtailment efforts and there has been no portfolio erosion.

Q. *What baseline expansions are needed?*

A. The Joint DR Parties make two proposals here. First, the Joint DR Parties renew our recommendation from Exhibit JDRP-2 (Joint DR Parties' Phase 1 Reply Testimony) for adopting a 5-in-10 baseline for non-residential customers in CBP.[6] Second, we propose that the day of adjustment factors, currently capped at +/- 40% in CBP be uncapped. The CAISO, in its wholesale market, has allowed DRPs to request a waiver of their +/- 20% baseline adjustment in favor of an uncapped adjustment for market-integrated Proxy Demand Resources. This has provided much better recognition of customer performance in the heat events that have already occurred in Summer 2021. While we know there are other factors that

[4] PG&E and SCE July 2021 Monthly ILP and DR Report filed in accordance with R.13-09-011: PG&E ex post July MW: 18 (day-ahead non-residential); SCE Ex post July MW: 2.1 (day-ahead) and 1.3 (day-of).
[5] As originally proposed in Ex. JDRP-1, at pp. 5-6 (Joint DR Parties (Chamberlin/Monbouquette)).
[6] *See,* Ex. JDRP-2, at p. 6 (Joint DR Parties (Chamberlin/Monbouquette)).

provide differences between retail and wholesale market settlement, uncapping baseline adjustments has proven useful to DRAM and third-party DR resources and would obviate some of the concerns that many customers have expressed about performance calculations in CBP.

3. Demand Response Auction Mechanism

Q. *Do the Joint DR Parties support the proposal by the CPUC staff for an incremental Demand Response Auction Mechanism (DRAM) auction for 2022 deliveries?*

A. Yes. In Phase 1, the Joint DR Parties proposed that additional budget be authorized for 2022 deliveries and supported similar recommendations made by other parties (e.g., TURN, CESA).[7] We continue to support a supplemental DRAM auction to increase the program's overall MW volumes.

Q. *What budget should be set for the supplemental auction?*

A. The incremental budget should be at least $13 million. This would return the 2022 delivery year budget to $27 million as recommended by the JDRP in Phase 1 of this proceeding.[8] In 2019, the Commission reduced the annual DRAM Pilot budget by almost 50% from $27 million to $14 million for the 2020-2023 delivery year period, which resulted in the loss of over 150 MW of DR capacity.[9] Expanding the DRAM budget for 2022 would be expected to add significant clean resource capacity – inclusive of multiple DR and DER approaches and technologies – that will be market integrated and bid into CAISO markets during the 4 p.m. to 9 p.m. period when solar resources are ramping down their availability.

Q. *Should any decision on authorizing a supplemental 2022 DRAM auction wait until November 2021?*

A. No. While the Phase 2 Amended Scoping Memo seeks a Proposed Decision in October and final decision in November, the sooner the Commission can seek to bring in new market integrated DR resources to play a much needed role in reliability

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[7] Ex. JDRP-1, at pp. 9-12 (Joint DR Parties (Chamberlin/Monbouquette)); Ex. JDRP-2, at pp. 11-12 (Chamberlin/Monbouquette)).
[8] Ex. JDRP-1, at p. 9 (Joint DR Parties (Chamberlin/Monbouquette)).
[9] A total of 369.94 MW of DRAM capacity was procured for the 2019 delivery year, whereas 206.05 MW were procured for the 2020 delivery year.

by launching a solicitation process and subsequent customer recruitment and market integration, the better. Given the timing needed for the IOUs to file ALs and conducting RFOs following the decision, there will likely only be a couple weeks between the solicitation results and supply plans being due for June, equating to much more conservative auction positioning than if there were more time to market the opportunity. We have already missed the opportunity to get additional DRAM resources online for 2021 as the Joint DR Parties and others recommended in Phase 1 and should not delay doing so again. We recommend fast-tracking a Proposed Decision on this and other time-sensitive procurement issues in early October following submission of Reply Briefs.

Q. *Do you support a budget being set in this proceeding for a 2023 delivery year DRAM Program?*

A. Yes. The Joint DR parties do not see a feasible way to authorize a timely 2023 DRAM auction outside of this rulemaking. There is no open DR proceeding that is considering the issues, and the IOU applications on the 2023-2027 program cycle expected to be filed in November 2021 will not proceed quickly enough to authorize and implement a DRAM solicitation on a timeline that is choreographed to mesh with the annual Resource Adequacy compliance process.

Q. *What budget should be set for a 2023 DRAM?*

A. The minimum logical budget for the 2023 auction is the previously authorized DRAM budget of $27 million. The Joint DR Parties and others have been advocating to return to this budget level for several years. This path is highly streamlined compared to the existing pathway for third-parties to qualify DR and DERs as a pure RA resource, due to the ability of DRPs to attest to the qualifying capacity of the resource, versus going through the Load Impact Protocol process.

Q. Turning to other CPUC Staff Concept Proposals on "Additional Requirements for Future Auctions,"[10] what are your responses to these proposals starting with 2.b.i. and 2.b.ii?

A. By Item 2.b.i., the Staff proposes: "Offered capacity that is only able to participate in the CAISO Day-Ahead Market (DAM) would be assigned a lower value in the bid evaluation process than offered capacity that is able to participate in the CAISO Real Time Market (RTM), unless the Demand Response Provider (DRP) commits to bidding the offered capacity at or lower than $500/MWh in the DAM at all times."[11]

First, the Joint DR Parties are concerned about the potential requirement to declare whether the resource being bid, particularly a system resource, will be available to the RTM prior to any DRAM award. DRPs often learn about customer capabilities as we recruit new customers, and some will have longer lead times than 52.5 minutes – the longest a block bid resource using the intertie model can have to participate in the RTM. Further, while we support economic bidding, there are times that a resource may need to bid above $500 to reflect the opportunity costs or use limitations later in a delivery month. DR is not granted any automatic use limitation and must use its economic bid to indicate any scarcity. Due to these concerns, the Joint DR Parties oppose adding this as a bid evaluation criterion for any new DRAM solicitations.

This concern continues with Staff Concepts Proposal 2.b.ii, which states "Proxy Demand Resources (PDRs) participating in CAISO Real-Time Market (RTM) must bid at or below $900/MWh to maintain some consistency with the triggering price for the reliability-based demand response programs, including the Base Interruptible Program (BIP), which are triggered at RTM price reaching $950/MWh."[12]

The Joint DR Parties oppose creating market bidding limitations for any resource. It is particularly problematic to set at a fixed $/MWh value. BIP is actually economically bid at 95-100% of the bid cap – currently at $1,000 – not at a firm

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[10] Energy Division Staff Concepts Proposal Document, ALJ's Email Ruling (August 16, 2021), at p. 11.
[11] *Id*.
[12] *Id*.

price. CAISO is applying to change those bid caps at FERC and thus BIP resources would economically bid at percentages of any revised bid cap. Setting an absolute $/MWh cap on market bidding would further separate different categories of DR. If a condition must be set by the Commission, it should, like BIP, be set as a percentage of the bid cap, not an absolute dollar value.

Q. *What response do the Joint DR Parties have to Staff Concepts Proposal Item 2.b.iii?*

A. Item 2.b.iii is ill-suited to achieve its desired objective. The Staff Concepts state: "Once a PDR Resource Identification (ID) is introduced on a supply plan, it must be maintained on the supply plan until it is removed; the PDR cannot be reintroduced into the supply plan during the remaining months of the contract. This requirement is in addition to the existing prohibitions on the customer and Resource ID movement within and across the contract."[13]

This appears to be an attempt to ensure that DRAM resources are used consistently throughout the contract period and do not move, for example, from a DRAM contract in one month to an RA contract with a different counterparty in another month, and back again. The goal appears to be avoiding having the resource being credited twice. The Joint DR Parties support ensuring there is no double-counting of RA resources either in the DRAM or other capacity programs. We note however that there are reasons a resource may not be available in a given month.

For instance, perhaps an underlying customer resource cannot be interrupted in a given month for business purposes and the DRP has not counted that resource as a part of meeting its contracted obligations in that same month. As that resource "sits out" during a busy period, e.g., peak season for food processing in the agriculture space, or the holiday shopping season for retailers, the RA compliance and supply plan verification systems do not allow a resource to be shown for "zero" in a month. Resources that do not have a contributing capacity value in a month are simply not shown as part of the compliance demonstration.

[13] Energy Division Staff Concepts Proposal Document, ALJ's Email Ruling (August 16, 2021), at pp. 11-12.

For these reasons, proposal 2.b.iii. should not be adopted. The Joint DR Parties recommend that this issue, to the extent the concern is valid, should be addressed through other means, such as a system to prevent duplicate registration of resources.

Q. *What is the Joint DR Parties' response to proposal 2.b.iv that would include a penalty structure for shortfalls in contracted DR capacity at the time of monthly supply showings?*

A. The Joint DR Parties feel strongly that DRAM is a procurement mechanism of an RA resource and thus contracted resources need to show up on supply plans. While the Joint DR Parties generally think that changes to the DRAM contract should be considered holistically, we would support a reasonable penalty structure that will help ensure that supply plans clearly show what a DRP has prepared to put in the market and fully expects will perform on dispatch. The Commission should approve this proposal.

Q. *What is the Joint DR Parties' position on Staff Concepts Proposal 2.b.v, "Capacity awarded in the 2022 supplementary auction and the 2023 DRAM should be counted toward the Qualifying Capacity limit established for 2022 and 2023 through the 2021 and 2022 Load Impact Protocol (LIP) processes?"*[14]

A. The Joint DR Parties strongly oppose this proposal, as it is fundamentally unfair to DR providers who have been most actively working to develop the California market for DR resources. This proposal will result in disparities between DRPs who either did or did not engage in a LIP study to qualify non-program DR capacity for the 2022 delivery year. Those who engaged in a LIP study underwent considerable time and expense to develop a qualifying capacity (QC) value for an identified pool of resources for stand-alone RA. Those entities who underwent these studies did so at a particular point in time, with a specific set of resource characteristics in mind. Those same entities can also attract additional customers not counted in the LIP study to build a DRAM resource for a supplemental 2022 auction.

[14] Energy Division Staff Concepts Proposal Document, ALJ's Email Ruling (August 16, 2021), at p. 12.

Among the Joint DR Parties, one company underwent an LIP study and the other did not. If Staff Concept proposal 2.b.v. were adopted alongside a supplemental DRAM auction for 2022, one entity would have spent over $100,000 to establish a fixed amount of RA they could sell across the two programs through the LIP, while the other could end up with the same total amount of RA through the DRAM auction that it spent $0 to qualify. This would be patently unfair, would erode a lot of trust in the supplier marketplace, and would discourage anyone from participating in the LIP in future cycles – if it so persists following the CEC's live DR QC working group established by D.21-06-029.

Q. *Are there any other modifications you would make to DRAM participation for the additional 2022 and 2023 auctions?*

A. Yes. The Joint DR Parties recommend that the rules governing 2020 DRAM resources be used for the additional DRAM auctions for 2022 and 2023. The minimum Delivered Energy component has the potential to fatigue the resource by requiring dispatches outside of critical reliability hours, especially given the economic realities facing DR customers as described above. Plus, as we have seen thus far in Summer 2021, with major heatwave events occurring as early as June, it is likely the case that we will see resources naturally picked up in the bid stack across summer delivery months due to elevated prices. This obviates the need to arbitrarily require dispatches outside of these hours.

4. Demand Response and Distribution Energy Resources as Stand-Alone Resource Adequacy

Q. *Are there ways to enhance and expand the ability of third-party demand response (DR) and distributed energy resources (DER) to qualify to sell stand-alone Resource Adequacy (RA) in 2023?*

A. Yes, although current proceedings may inhibit realization of additional RA in 2023. Currently for 2022, only entities that engaged in the LIP process in 2021 can qualify DR or DER for pure RA outside of IOU DR programs (DRAM, CBP, BIP). While DRPs have not yet been notified of their QC value, that pool of 2022 RA supply is fixed at a maximum through a process that started for most providers nine or ten months ago, in Q4 2020. At the same time, DRPs are starting to consider whether to go through a LIP process in 2022, starting in Q4 2021, which would result in 2023 QC.

Per D.21-06-029, the CEC is overseeing a working group process to review different DR QC methodologies and make recommendations for the method to be used for all DR resources going forward. This process will not provide recommendations to the Commission until March 2022, long after the LIP process would be underway for 2023 QC development.

The Joint DR Parties are concerned that this confluence of factors may lock the state's DR and DER RA markets into a much smaller and less nimble set of resources through 2023, than is required to adequately respond to the state's immense capacity shortfall. Building physical assets, be they been generation or storage, requires long lead-times to bring online and as we have experienced first-hand in Summer 2021, often lags expected timelines.

The Commission should use Phase 2 of this proceeding to extend the DRAM QC process to stand-alone, non-program RA resources, for the 2023 delivery year, to increase the eligible pool of market-integrated, supply-side DR and DER to all load serving entities, while obviating the resource intensity, friction, and rigidity associated with the current LIP QC process.

The DR industry, via the California Efficiency and Demand Management Council (CEDMC), has put this proposal forward in previous RA dockets and through Phase 1 of this proceeding. The DRAM QC approach is also the backbone of industry's proposal in the CEC's DR QC Working Group, which cites QC methods in eastern RTOs such as PJM and NYISO that are comparable to DRAM's, based on DRP attestation and with reasonable penalty and de-rate structures. This temporary allowance would be ultimately acceded by any Commission decision on the March 2022 recommendations per D.21-06-029.

Q. *What is your reaction to Staff Concepts Proposal No. 3, "Third Party Demand Response Procured by Non-IOU Load Serving Entities (LSEs)?"*[15]

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[15] Energy Division Staff Concepts Proposal Document, ALJ's Email Ruling (August 16, 2021), at p. 12.

A: Proposal No 3. is as follows: “To continue to improve the visibility, utility, and performance of third-party DR, and apply a consistent framework of applicable policies to DR capacity procured via DRAM vs. non-IOU LSE DR contracts, the CPUC could consider requiring all third-party Demand Response (DR) resources contracted with Community Choice Aggregators (CCAs) to adhere to certain DRAM requirements, such as those related to market bid price caps, capacity counting and showing (including customer and Resource ID movement), and minimum dispatch activity, starting in 2022.”[16]

The Joint DR Parties oppose this proposal as written, particularly when combined with proposal 2.b.v. Staff seeks to mix and match portions of DRAM contract obligations and the RA rules governing stand-alone, non-program DR, without factoring in the different operational requirements and resource qualification methods employed by either construct.

If the Commission wants all non-program RA resources to behave like DRAM resources – including being subject to the extra DRAM evaluation and market bidding provisions Staff proposes in its Concepts to be “tested” in these additional DRAM RFOs – then at a minimum these “DRAM” resources should not have to be qualified for sale through the LIP process, nor should they have to compete in all-source solicitations against all other resources. Both of these elements are currently requirements for DR to provide non-program RA. However, DR that participates as pure RA has much more straightforward operational requirements, simply participating in the market with no minimum dispatch parameters, nor the penalty structures that exist for DRAM resources that make operating the pure RA resource favorable to DRAM requirements.

A more realistic and workable set of parameters to encourage more DR in the market would be to remove the burdensome LIP process for the 2023 program year, until the CEC makes its recommendations to the Commission in March 2022.

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[16] Energy Division Staff Concepts Proposal Document, ALJ’s Email Ruling (August 16, 2021), at p. 12.

Instead, DR resources would qualify to sell non-program RA to LSEs through the DRAM QC process, as recommended above.

As noted above for proposal 2.b.v., by proposing to make changes to non-program DR that would apply in 2022, Staff Concept no. 3 ignores and devalues the effort and expense many market participants have undertaken in undergoing a LIP study to qualify resources for 2022.

5. Emergency Load Reduction Program

a. Lessons Learned from Summer 2021

Q. *What were the Joint DR Parties' experiences in working to enroll in the Emergency Load Reduction Program (ELRP)? What steps were needed to get involved?*

A. While DR is the quickest supply resource that can be developed and commercialized, setting up a new program does not happen overnight. This is particularly true when the program managers and participants are working on implementation simultaneously, because there were many questions that remained to be answered during the implementation process.

When our companies evaluate offering customers a new program and then move into implementation we have a number of minimum basic steps in this process. We begin with ingesting program parameters to understand what we are asking of ourselves and our customers, do customer outreach, education, and evaluation, amend and resign customer agreements, work with customers on curtailment measures to ensure their participation and success during dispatches, and work dispatch notices and performance settlements into our market operations.

Q. *What about participation in ELRP events?*

A. The ink was still drying on the enrollment agreements for PG&E, and SCE and SDG&E did not even have ELRP aggregator agreements available yet, when the first dispatch took place in mid-June during Pacific Northwest heat dome. Since then, as of the submission date of this testimony, there have been two additional ELRP events. All events have been triggered by day-of CAISO Warnings, meaning that Group B participants (CBP and DRAM resources) have not yet been dispatched due to their day-ahead trigger. The Joint DR Parties otherwise only have resources in Group A.2 (BIP aggregators), but so far only one ELRP activation has escalated into a BIP dispatch such that those customers could get compensated for ILR.

Q. *D.21-03-056 confirmed the ability of otherwise-prohibited back-up generators to participate in ELRP dispatches. Since then, two Emergency Proclamations from Governor Newsom (July 9 and July 30) have further sought to relax restrictions on these resources during tight grid supply conditions. Did these waivers simplify the process of enrolling and operating customer sited generation in ELRP?*

A. No. As companies that help customers monetize load curtailment and use of back-up generation around the country, we take compliance with air quality regulations and permitting very seriously. While the ELRP allows back-up generators, it did not automatically override prevailing Environmental Protection Agency (EPA) and California Air Resources Board (CARB) permits. Similarly, while Governor Newsom's Emergency Proclamations deemed stationary or portable generators an acceptable "emergency use" during CAISO Grid Warnings or Emergencies on a temporary basis (including through October 31, 2021), these in-state clarifications do not supersede EPA requirements.

As much of our customer enrollment and generation inclusions in ELRP would be incremental to the fossil-free curtailment in existing programs, we have had to carefully document usage to ensure that there are no situations in which we dispatch for ELRP, or per the Governor's allowances, that could appear like the generation was meeting the underlying DR program curtailment, for purposes of future Prohibited Resource audits. This has greatly slowed down the inclusion of back-up generators in the ELRP.

b. ELRP Modifications

Q. *How do you view the role of ELRP versus offerings that provide supply-side RA? How has the program worked in practice?*

A. The Joint DR Parties understand ELRP's objective as being to improve upon the uncompensated nature of voluntary load response that was widely credited in preventing additional rotating outages in August 2020 and to try to provide an additional buffer of reliability beyond RA resources during grid emergencies. As described above, however, we have experienced the unintended consequence of prospective customers enrolling in ELRP instead of supply-side RA programs. This in our view detracts from, rather than enhances, overall grid reliability, given that supply-side program participants generally receive higher incentives (including capacity or availability payments), have performance obligations, and incur penalties for non-performance, all of which work to encourage robust event response.

It is too soon to judge the effectiveness or value of the overall ELRP offering, both in terms of enrollment and performance, compared to supply-side programs. Many aspects of the program have not yet been fully implemented or require modifications to better enable participation based on the few months of program experience that the state has gained thus far. For instance, owing to pressure to fast-track any and all available capacity, PG&E filed an Advice Letter on July 7, 2021[17] to enable Groups A.3 and A.4 (exporting BTM Rule 21-interconnected resources and NEM-tariffed virtual power plants, respectively) far earlier than the originally anticipated date of May 1, 2022. To our knowledge, exporting provisions have not yet been extended to Group B customers, even though there are many battery-backed DRAM and CBP resources that, generally speaking, are prime candidates to export to the grid and collect ILR compensation, with the caveat that these systems were not sized with grid exports in mind and may not have much spare discharge capacity with which to produce ILR. Extending a day-of ELRP trigger to Group B would also help these resources participate in events.

Q. *Given these perspectives, what general modifications would you make to ELRP?*

A. The Joint DR Parties are primarily concerned with enrolling, managing, and retaining customers in supply-side DR programs. This is because the capacity or reservation payment included in these programs de-risks participation on behalf of aggregators and customers alike while providing a reliable source of capacity to the grid. The experience in standing up our customers in ELRP has so far played out in an expected manner: it is uncertain whether up-front investments in customer outreach

[17] *See, e.g.*, PG&E Advice Letter 6174-E-A, approved August 17, 2021.

and enrollment will be paid back by ILR compensation for customers and aggregators.

Extending a capacity or reservation payment, or setting a minimum number of dispatches, for ELRP would reduce the risk of program participation and would likely attract more robust participation, though it would indeed start to mimic the structure and purpose of existing DR programs. We would generally rather see improvements to existing programs rather than structuring ELRP to increasingly become a competing new offering with looser requirements, which can become burdensome and confusing for program administrators, aggregators, and customers.

However, a key difference between ELRP and existing supply-side programs is the former's allowance and compensation for grid exports from BTM storage resources (inclusive of standalone storage and V2G). Providing a reservation payment or minimum number of dispatches in ELRP can start to provide a much-needed signal for storage providers and customers to size and operate batteries in a way that extracts a much higher reliability contribution than is currently realized by BTM batteries that participate in curtailment-only DR constructs. Similarly, minimum dispatches or reservation payments can signal to large C&I DR customers to make existing generators available for ELRP dispatches, including through retrofits to enable fuel switching with eligible renewable fuels.

The Joint DR Parties thus support establishing an ELRP reservation payment or minimum dispatch guarantee to customers with BTM storage resources and eligible back-up generation. Storage customers could then stack curtailment discharges for DRAM or CBP with ELRP payments for grid exports, with the revenue certainty providing the signal for customers and aggregators to invest in battery cycling capabilities, or to install or retrofit back-up generators.

Of course, with ELRP slated as a five-year pilot, this would only get part of the way there towards providing the type of longer-term revenue certainty needed for developers and customers to work guaranteed payments into financing for capital-intensive projects. The Commission could however start to signal this by adopting these provisions for ELRP in the Phase 2 decision (anticipated November 2021) and then indicating its intent to maximize the grid and ratepayer value of BTM DER deployment, both in this decision and in related proceedings and initiatives,[18] by building off of this foundation and working to reduce barriers to formally bringing exporting DERs into the RA construct.

To enable exporting BTM resources in the ELRP as soon as possible, the Joint DR Parties recommend that the IOUs open an expedited interconnection review window for existing, non-exporting BTM storage and generation resources that wish to participate as exporting resources in the program, and to allow exporting resource participation across all ELRP groups in advance of the 2022 delivery season. This is aside from our general support for the Commission to direct expanded hiring and staffing within IOU interconnection divisions, which is needed to accommodate the rapid deployment of DER and electrification technologies.

c. Response to Staff Concepts Proposals

Q. *Do you support increased compensation rates for ELRP Groups A.1 and A.2?*

A. Increasing event compensation rates from \$1 / kWh to \$2 / kWh may help attract new customers to the program, but it would also likely exacerbate the issue of prospective supply-side customers instead enrolling in ELRP Group A.1 due to the lack of penalties.

The Staff Concept also states, "at the higher compensation rates commitment of load reduction should be more certain, thus the increased compensation values should be limited to customers who commit to providing a certain load reduction performance level."[19] It is unclear what exactly is contemplated by a "commitment of load reduction," but such commitments are already provided by supply-side programs. As described above, we generally would not support including reservation payments for ELRP unless it helps customers participate with relatively capital-intensive technologies such as BTM storage or generation, and would instead recommend the supply-side DR program modifications as suggested above.

[18] Such as the DER Action Plan 2.0, R.21-06-017 on a High DER Future, and a stakeholder working group to recommend barriers to DERs in supply-side RA per D.21-06-029 (at p. 55).
[19] Energy Division Staff Concepts Proposal Document, ALJ's Email Ruling (August 16, 2021), at p. 7.

Q. *Do you support removing minimum size thresholds and compensation collars for Group A.1?*

A. The Joint DR Parties do not oppose removing minimum size thresholds and compensation collars for Group A.1.

Q. *Do you support adding a day-of dispatch trigger for Group B, and setting a $900 / MWh bid cap for real-time market bids in order for Group B participants to be eligible for ELRP compensation?*

A. The Joint DR Parties support adding a day-of trigger for Group B ELRP participants. Similar to Staff Concepts Proposal 2.b.ii. however, we do not support capping market bids to be eligible for day-of ELRP payments, or at least would suggest capping market bids as a percentage of the bid cap, not an absolute dollar value.

Q. *Do you support expanding ELRP eligibility to include residential customers, should those customers be defaulted into the program, and should they be dispatched on a day-ahead Flex Alert or Grid Alert?*

A. The Joint DR Parties support expanding ELRP eligibility to residential customers. However, these customers should be able to join on an opt-in basis and should not be automatically enrolled. The latter would entail significant competitive implications and program administration challenges.

Q. *Do you support the proposed electric vehicle (EV) / vehicle-grid integration (VGI) aggregation pilot?*

A. Yes. Along with extending eligibility to residential customers, the Joint DR Parties support confirming the eligibility for V1G or V2G aggregations of at least 25 kW ILR in a single IOU territory to participate in Group A.3 as part of a standalone VGI-focused pilot. We also support the proposals to base ILR settlements on EVSE submetering data if located behind a host site meter, to review interconnection rules to enable streamlined and affordable access to EVSE with bi-directional capabilities, and to guarantee at least 30 hours of ELRP dispatches per season.

As discussed above, this latter piece on guaranteed revenue is particularly important if the Commission wants to encourage customers to install EVSE with bi-directional capabilities, which can be considerably more expensive than existing deployed smart EVSE that are solely capable of V1G functionality. To further encourage VGI pilot participation, the Joint DR Parties recommend establishing an up-front rebate for bi-directional EVSE purchase and installation, as well as reduced (or eliminated) interconnection application fees, in exchange for agreeing to participate through the duration of the ELRP pilot.

The Joint DR Parties would, however, modify, or at least seek clarification on, proposed pilot element 1.3.iii. pertaining to virtual aggregations being "permitted" between separately-metered EVSE and a parallel host site meter. As proposed, these virtual pairings would never be allowed to result in a negative (net exporting) billing interval. Given that the pilot would be housed within Group A.3 that enables compensation for exporting Rule 21 resources, we question why this element was included in the proposal. If the rationale stems from a billing system issue, we recommend that the Commission focus on resolving this issue, rather than not allowing net exports in this instance.

6. Agricultural Demand Flexibility Pilot

Q. *What is the Staff Concepts Proposal related to the Agricultural Demand Flexibility Pilot? Do you support this?*

A. The Staff Concepts respond to Valley Clean Energy's proposal in its Phase 1 testimony for an Agricultural Demand Flexibility Pilot by proposing an experimental rate based on Energy Division Staff's workshop proposal and forthcoming whitepaper on a real-time pricing (RTP)-based transactional energy framework. The Joint DR Parties support this, but also recommend making the experimental rate available to other types of smart enabling technologies such as EV charging, BTM batteries, and controllable loads.

7. Modifications to Renewable Fuels Allowed in Prohibited Resource Policy

Q. *In Section 5 above, you describe the challenges in using otherwise-prohibited back-up generation in the ELRP, and following the Governor's Emergency Proclamations. What would you recommend to better utilize these existing resources?*

A. The Joint DR Parties recommend that the Commission approve the eligibility of CEC-certified, Renewable Portfolio Standard (RPS)-eligible fuels such as bio-diesel and renewable natural gas for back-up generator (BUG) participation during DR events, and on an ongoing basis. The current allowance for fuel switching between Prohibited Resources and renewable fuels certified by the California Air Resources Board (CARB) does not adequately cover such common renewable fuels for BUG usage. This will enable aggregators like CPower and Enel X to very quickly re-recruit tens of MWs worth of customers to DR programs, who have not participated since the Prohibited Resource Policy was initiated by D.16-09-056, while also obviating the permitting challenges associated with operationalizing BUGs in ELRP described in Section 5.

III.
CONCLUSION

As stated in Section I and supported by this testimony, Exhibit JDRP-3, along with Exhibits JDRP-1 and JDRP-2, the Joint DR Parties strongly recommend that the Commission adopt and/or take the following actions in its Phase 2 November 2021 decision in R.20-11-003:

1. For the Base Interruptible Program, and through the 2023 delivery year:
   a. Increase program incentives by an additional 30%;
   b. Decrease Excess Energy Charges by 75%; and
   c. Increase dispatch notification times from 15-to-30 minutes to up to one-to-two hours.
2. For the Capacity Bidding Program:
   a. Expand PG&E's Elect option to SCE and SDG&E, while relaxing the audit requirement during periods of acute supply shortage; and
   b. Allow a 5-in-10 baseline for non-residential customers, and uncap the day-of baseline adjustment factor as CAISO has done for Proxy Demand Resources.
3. For the Demand Response Auction Mechanism (DRAM):
   a. Approve the Staff Concepts proposals to initiate a supplemental auction for 2022 deliveries with a $13 million budget, and to launch a new auction for 2023 deliveries with a $27 million budget;
   b. Reject Staff Concepts proposals 2.b.i, 2.b.ii, 2.b.iii, and 2.b.v;
   c. Approve Staff Concepts proposal 2.b.iv; and
   d. Use the rules governing 2020 DRAM for the additional DRAM auctions for 2022 and 2023.

4. Adopt the DRAM qualifying capacity process for use to qualify DR resources for stand-alone, non-program RA sales for the 2023 delivery year.
5. Reject Staff Concept Proposal 3 pertaining to requiring all third-party DR resources contracted with Community Choice Aggregators to adhere to certain DRAM requirements starting in 2022.
6. For the Emergency Load Reduction Program:
    a. Adopt a reservation payment or minimum number of guaranteed dispatches for exporting behind-the-meter (BTM) storage (both standalone and V2G) as well as eligible back-up generation;
    b. Order the IOUs to open an expedited interconnection review window for existing, non-exporting BTM storage resources and generation that wish to participate as exporting resources in the program, and to enable exporting resource participation across all ELRP groups in advance of the 2022 delivery season
    c. Add a day-of dispatch trigger, but do not cap real-time market bids for day-of compensation eligibility, for Group B;
    d. Extend program eligibility to residential customers, but allow them to join on an opt-in basis rather than being automatically enrolled;
    e. Adopt the proposed vehicle-grid integration aggregation pilot, while:
        i. Extending an up-front EVSE rebate and reducing or eliminating interconnection fees, in exchange for guaranteed program participation; and
        ii. Removing the non-net-exporting proposal for virtual pairings of separately metered EVSE with parallel load.
7. Approve the Agricultural Demand Flexibility Pilot while extending the experimental rate to BTM storage, EV charging, and controllable loads.

8. Approve CEC-certified, Renewable Portfolio Standard-eligible renewable fuels such as bio-diesel and renewable natural gas within the Prohibited Resources policy, for use during DR events.

APPENDIX A

STATEMENTS OF QUALIFICATIONS (i.e., Rule 13.7(e) Compliance)

Jennifer A. Chamberlin
Marc R. Monbouquette

STATEMENT OF QUALIFICATIONS OF JENNIFER A. CHAMBERLIN

Q1 *Please state your name and business address.*

A1 My name is Jennifer A. Chamberlin, and my business address is 2475 Harvard Circle, Walnut Creek, California 94597

Q2 *Briefly describe your present employment.*

A2 I am employed by CPower, Inc., as the Executive Director of Market Development. In this role, I represent CPower's interest in Demand Response and other related energy proceedings at state Commissions, regional RTOs, and governmental agencies seeking to promote the utilization of Demand Response, energy storage, and other distributed energy resources in maintaining grid reliability. I additionally am responsible for managing our wholesale DR portfolio including market integration, market bidding and program/contract compliance. I am CPower's representative to the California Efficiency and Demand Management Council and serve on the Board of Directors of that organization.

Q3 *Please summarize your professional and educational background.*

A3 I have worked in the competitive energy space since 1997 focusing on market development and regulatory affairs for direct access and clean energy companies. Most recently I have been employed by CPower since its acquisition of Johnson Controls Integrated Demand Resources business unit in April 2016. I was employed by Johnson Controls as the Director of Regulatory Affairs since 2014 focusing on demand response and behind-the-meter storage issues. Prior to this, I worked with LS Power as the Director of Government and Regulatory Policy, with Direct and Strategic Energy as the Manager of Regulatory Affairs, and with PG&E Energy Services as the Manager of Market Development. I hold a BA from University of California Davis in Political Science.

Q4 *Have you previously testified on behalf of CPower or the Joint DR Parties, before the California Public Utilities Commission?*

A4 Yes. I have testified in this proceeding (R.20-11-003) in Exhibits JDRP-1 and JDRP-2, and in A.17-01-012, et al., the IOUs' 2018-2022 DR Program applications. I have also actively and broadly participated in Commission Workshops and Working Groups and in providing formal filings in multiple Commission proceedings on behalf of CPower and the Joint DR Parties.

Q5 *What is the purpose of your testimony?*

A5 The purpose of my testimony is to jointly sponsor with Joint DR Parties' witness Marc R. Monbouquette (Enel X North America, Inc.) Exhibit JDRP-3, the Opening Prepared Testimony of the Joint DR Parties in Phase 2 – Reliability for 2022-23 – Update of R.20-11-003 (Extreme Weather).

Q6 *Was Exhibit JDRP-3 prepared by you or under your supervision jointly with Mr. Monbouquette?*

A6 Yes.

Q7 *Are the statements made in your testimony true and correct to the best of your knowledge and belief?*

A7 Yes.

Q8 *To the extent that Exhibit JDRP-3 contains expressions of opinion, do they represent your best professional judgment?*

A8 Yes.

Q9 *Do you adopt Exhibit JDRP-3 as your sworn testimony in Phase 2 of R.20-11-003 (Extreme Weather)?*

A9 Yes.

Q8 *Does this conclude your statement of qualifications?*

A8 Yes, it does.

STATEMENT OF QUALIFICATIONS OF MARC R. MONBOUQUETTE

Q1 *Please state your name and business address.*

A1 My name is Marc R. Monbouquette, and my business address is 360 Industrial Road, San Carlos, CA 94070.

Q2 *Briefly describe your present employment.*

A2 I am currently employed by Enel North America, Inc., the regional organization of Enel S.p.A., as the Regulatory Affairs Manager focused on California and the western United States. In this role, I am charged with representing the business interests of all Enel business lines, including Enel X, at regulatory agencies and wholesale energy markets.

Q3 *Please summarize your professional and educational background.*

A3 I have more than eight years of experience in energy policy and regulation. This work has included more than five years as an analyst at the California Public Utilities Commission, where I worked on General Rate Cases and other ratemaking and cost recovery issues, followed by leading regulatory work on planning, interconnection, and technical standards for distributed energy resources. In 2018, I joined eMotorWerks, Inc. – which had been acquired by Enel and has since been integrated into the Enel X business – to lead the company's North American policy engagements pertaining to electric vehicle infrastructure investments, vehicle-grid integration, and carbon markets, before assuming my current role for Enel North America. I hold a master's degree in Energy and Environmental Management from Duke University and a bachelor's degree in Geology from Carleton College.

Q4 *Have you previously testified on behalf of Enel X or the Joint DR Parties, before the California Public Utilities Commission?*

A4 Yes. I have testified in this proceeding (R.20-11-003) in Exhibits JDRP-1 and JDRP-2, and have testified recently in three utility applications on Real Time Pricing pilots and programs (A.19-11-019 (Pacific Gas and Electric Company

(PG&E) General Rate Case Phase 2 (GRC 2)); A.20-10-011 (PG&E (Commercial Electric Vehicle Day Ahead RTP Pilot)); and A.20-10-012 (Southern California Edison Company (SCE) GRC 2). I have also authored numerous comments and participated in Commission stakeholder initiatives on behalf of Enel X and the Joint DR Parties.

Q5 *What is the purpose of your testimony?*

A5 The purpose of my testimony is to jointly sponsor with Joint DR Parties' witness Jennifer Chamberlain (CPower) Exhibit JDRP-3, the Opening Prepared Testimony of the Joint DR Parties in Phase 2 – Reliability for 2022-23 – Update of R.20-11-003 (Extreme Weather).

Q6 *Was Exhibit JDRP-3 prepared by you or under your supervision jointly with Ms. Chamberlin?*

A6 Yes.

Q7 *Are the statements made in your testimony true and correct to the best of your knowledge and belief?*

A7 Yes.

Q8 *To the extent that Exhibit JDRP-3 contains expressions of opinion, do they represent your best professional judgment?*

A8 Yes.

Q9 *Do you adopt Exhibit JDRP-3 as your sworn testimony in Phase 2 of R.20-11-003?*

A9 Yes.

Q8 *Does this conclude your statement of qualifications?*

A8 Yes, it does.