CPUC Docket: R.20-11-003, Phase 2
Exhibit Number: TURN-03
Witness: Florio

PREPARED REPLY TESTIMONY OF MICHEL PETER FLORIO

ADDRESSING SELECTED ISSUES REGARDING

ELECTRIC SYSTEM RELIABILITY FOR 2022-2023

THE UTILITY REFORM NETWORK

785 Market Street, Suite 1400
San Francisco, CA 94103

September 10, 2021

TABLE OF CONTENTS

PREPARED REPLY TESTIMONY OF MICHEL PETER FLORIO

I. INTRODUCTION

This reply testimony is sponsored by Michel Peter (Mike) Florio, an independent energy consultant, Senior Fellow at Gridworks, former commissioner of the California Public Utilities Commission (CPUC) from 2011 through 2016, and former member of the governing board of the California Independent System Operator (CAISO) from 1997 through early 2005.

In this testimony I will respond to a number of the issues discussed in the opening testimonies of other parties in Phase 2 of this proceeding. Given the incredible volume of opening testimony, I will not respond to every other witness, and the absence of comment on a particular point should not be construed as support or opposition to the views expressed.

I previously submitted opening and reply testimony in Phase 1 of this docket on January 11 and January 19, 2021, and generally stand by the recommendations offered in those exhibits, except as otherwise noted herein or mooted by the passage of time. A more complete summary of my qualifications was included as Appendix A to my direct testimony in Phase 1.

II. SUMMARY OF RECOMMENDATIONS

In this testimony I recommend that this Commission take the following actions, which will be addressed in more detail below:

(1) Focus its attention in this proceeding only on resources that can be available by the Summer of 2022, and not give further consideration to supply options that will not be available until the Fall of 2022 or 2023, because procurement already ordered by this Commission will be sufficient to provide adequate reliability by the Summer of 2023.

(2) Adopt the CAISO's recommendation to establish an additional system Resource Adequacy (RA) requirement to meet 8 p.m. (net peak) demand plus a planning reserve margin for the months of June through October 2022 and all of 2023, but do not increase the Planning Reserve Margin at this time beyond the actions it has already taken.

(3) Devote prompt attention to the resource interconnection issues raised by American Clean Power-CA, SDG&E, SEIA and the Joint DR Parties, which may constitute the greatest threat to successful procurement efforts over the next few years.

(4) Adopt SCE's suggestion to work with CAISO to establish a process to add monthly imports that are purchased after T-30 but otherwise meet applicable RA requirements to RA supply plans.

(5) Reject the Staff Concept Paper (SCP) "Utility-Scale Storage, Import, and Generation" proposals 1, 2, 3 and 5 as unnecessary and not helpful.

(6) Adopt PG&E's gas rate proposal in its Chapter 8 to displace the use of diesel in backup generation (BUGs) to the extent possible.

(7) Adopt a rule that any diesel BUGs allowed under the Emergency Load Reduction Program (ELRP) will be dispatched *last* after all other available resources, particularly in disadvantaged communities (DACs).

(8) Adopt the proposals presented in the opening testimony of OhmConnect.

(9) Extend the $2 per kWh ELRP payment to all customers, including residential customers.

(10) Adopt a residential customer default into ELRP, triggered by a Flex Alert, but only after holding an open season for other DR programs, and measure ELRP performance based on the SCE Meter Before/Meter After proposal.

(11) Direct SCE to follow the same simple procedures as PG&E to allow expedited action when a customer signs up for another DR program and leaves ELRP.

(12) Provide the guidance requested by PG&E to enable CCA customers to default into ELRP on the same basis as bundled customers.

(13) If active enrollment into ELRP is required for residential customers, adopt as simple an enrollment process as possible, such as a mailer with a return post card or a "one-click" online option in response to an email.

(14) Allow DR aggregators to provide smart thermostat and other Auto-DR incentives directly to customers at their own risk, and then recover the rebate from the utility once the device is activated.

(15) Conduct a supplemental DRAM auction for 2022 with a budget of $13 million, and budget a total of $27 million for the 2023 DRAM.

(16) Reject the "Additional Requirement for Future DRAM Auctions" proposed in the SCP, except for the penalty for shortfalls shown on monthly supply plans relative to the contracted capacity.

(17) If additional DRAM procurement is not authorized, require the IOUs to conduct a separate DR solicitation and accept any available DR capacity that costs less than the most expensive generation resource procured under their emergency authority.

(18) Suspend the 8.3% cap on Load Serving Entities' (LSE's) DR procurement for RA purposes, at least for 2022.

(19) Require all IOUs to offer a CBP-Elect option under their Capacity Bidding Programs (CBP), using the tiered capacity payment concept introduced by SDG&E.

(20) Explicitly authorize use of the CAISO's new DR baseline options for CBP and DRAM capacity settlements.

(21) Do not eliminate the current restrictions on ELRP compensation for Base Interruptible (BIP) customers during non-overlapping BIP and ELRP events.

(22) Reduce the Excess Energy Charges for all BIP customers to twice the CAISO bid cap.

(23) Approve the other IOU DR proposals endorsed in this testimony.

III. MEASURES TO ADDRESS SUMMER RELIABILITY PROBLEMS SHOULD FOCUS ON 2022, NOT 2023

The sense of urgency surrounding this proceeding was no doubt exacerbated by the "Draft CEC Preliminary 2022 Summer Supply Stack Analysis" issued by the CEC on August 11, 2021 and linked to ALJ Stevens' August 12 ruling in this docket. As noted in that ruling, the stack analysis "projects an additional 600 MW to 5,200 MW of resources may be required to ensure electric system reliability for peak and net-peak hours during summer 2022 without the use of contingency resources."

I have already testified that this type of stack analysis is a crude measure of system reliability at best, and that a probabilistic Loss of Load Expectation (LOLE) study offers a much more refined analytical basis for decision-making. Fortunately, CEC staff has now followed up on its earlier work with just such an LOLE study, which was included as part of its "Presentation for August 30 Lead Commissioner Workshop on Midterm Reliability Analysis."[1] That study

[1] TN239554_20210830T165516_Presentation%20for%20August%2030%20Lead%20Commissioner%20

showed that under all scenarios[2] except for the "No Build" comparison case, system reliability in 2023 and beyond is **well below** the 0.1 LOLE (one outage event in ten years) standard (Slides 32 and 33), due to the procurement that this Commission has already ordered LSEs to undertake. Even in 2022, there were shortfalls *under one-in-ten conditions* in only half of the scenarios, with the maximum shortfall totaling 1,306 MW under Scenario 6.

This more rigorous analysis presents a picture quite different from the 5,200 MW potential shortfall resulting from the earlier stack analysis. While 2022 is still likely to be challenging, there is simply no need for further supply procurement beyond what this Commission has already ordered *for 2023*. I therefore recommend that the CPUC focus its efforts here on the summer of 2022 and not give further consideration to supply options that will not be available until the fall of 2022 or 2023.

I note that Southern California Edison Company (SCE) agrees with me on this point. As stated on page 4 of the utility's opening testimony: "SCE suggests that the Commission should narrow the scope of supply-side efforts to summer 2022, given the lack of any demonstrated system reliability need for summer 2023 and ongoing procurement efforts that are already underway for summer 2023."

IV. THIS COMMISSION SHOULD CONSIDER ADOPTING A RESOURCE ADEQUACY REQUIREMENT FOR THE NET PEAK PERIOD, BUT NEED NOT INCREASE THE PLANNING RESERVE MARGIN AT THIS TIME

The California Independent System Operator (CAISO) presented two recommendations in its opening testimony: 1) establish an additional system Resource Adequacy (RA) requirement to meet 8 p.m. (net peak) demand plus a planning reserve margin for the months of June through

---

Workshop%20on%20Midterm%20Reliabilit%20(2).pdf

[2] The CEC staff scenarios are explained on Slide 26.

October 2022 and all of 2023 (*in addition* to the current RA requirement based on gross peak hour demand); and 2) increase the existing planning reserve margin at a minimum from 15% to 17.5% with consideration being given to increase to 20%. I agree with the first proposal but not the second.

CAISO states, at page 2, that "8:00 p.m. serves as a proxy for the critical net demand peak period, when demand is relatively high but resource availability is limited, primarily due to the unavailability of solar resources. Setting resource adequacy requirements to meet demand and the reserve margin at 8:00 p.m. will incent LSEs to procure sufficient resources to meet system needs during this critical period." CAISO further explains, at page 6, that "the resource adequacy showings for June, July, August, and September 2021, which are based on monthly gross peak load, provided effective resources significantly lower than the level necessary to maintain a 15% planning reserve margin at 8:00 p.m."

Establishing a second System RA requirement for the net peak period would go a long way toward addressing one of the key issues identified in the Root Cause Analysis of the August 2020 rolling blackouts. It is also noteworthy that nearly all of the resource shortfalls identified in the August 11 CEC staff stack analysis arose during the 6-9 p.m. net peak period (hourly breakdowns are not yet available for the LOLE analysis).

Importantly, CAISO has also provided, at pages 9 through 11 of its testimony, a detailed step-by-step procedure for implementing a Net Peak RA requirement. While that proposal may not be perfectly precise, it will certainly do a better job of ensuring reliability than simply ignoring the issue and relying solely on the current peak-demand-based RA requirement.

With respect to its Planning Reserve Margin (PRM) proposal, however, I submit that CAISO has jumped the gun. A change in the PRM should be based on probabilistic LOLE analysis, not simply a stack analysis of the sort that CAISO has presented. While such a study should certainly be undertaken and work may actually be underway, no results have been made available at this time. Further, this Commission's decision in D.21-03-056 to ask the IOUs to procure additional resources to approximate an effective 17.5% PRM has adequately addressed that issue for 2021 and 2022 and should remain in place.

V. RESOURCE INTERCONNECTION ISSUES REQUIRE THIS COMMISSION'S ATTENTION TO ENSURE THAT PROCURED RESOURCES COME ONLINE

Perhaps the greatest threat to reliability in the near term may be difficulty that new resources are facing in securing interconnection to the grid in order to deliver their output. American Clean Power-California devoted its entire opening testimony to this issue, and I endorse their recommendations. SDG&E raises similar themes and offers further suggestions that merit consideration (Ex. SDGE-7, pp. 10-13). Likewise, SEIA (pp. 11-16) and the Joint DR Parties (p. 25) make proposals regarding interconnection. I do not purport to be an expert on these interconnection processes, but it is not difficult to see that this topic will need to be addressed quickly if this Commission's goals are to be achieved. Procurement of new resources alone will not help if those resources cannot achieve connection to the grid.

VI. NEW UTILITY-SCALE RESOURCES NOT ALREADY UNDER DEVELOPMENT ARE UNLIKELY TO BE FEASIBLE BY SUMMER 2022 BUT INCREASED IMPORTS ARE POSSIBLE

In terms of new supply resources for 2022, SCE's opening testimony states as follows:

> SCE is exploring opportunities to expedite any mid-term reliability projects to come online by summer 2022. However, the market for new resources able to come online by summer 2022 is already limited, and when combined with the lengthy CAISO interconnection queue, there are a limited number of resources that may be able to come online by summer 2022. As the ED Staff Concept Proposals recognize, "there will be significant challenges associated with LSEs successfully accelerating the online dates of significant quantities of IRP resources by summer 2022. (Id. at 54)

SCE does offer some hope, however, with respect to additional imports:

> SCE is already procuring non-RA imports to help enhance system reliability at the peak and net peak under its existing D.21-03-056 authority. However, SCE suggests that the Commission work with the CAISO to determine a process to put monthly imports purchased after T-30 on RA supply plans. Monthly import products are often available in the market closer to the flow date, but after the compliance filing deadline. If these resources meet RA requirements, including being paired with import allocation rights and sourced outside the CAISO balancing authority, there should be a process to reflect them on supply plans. (Id. at 57)

I endorse SCE's helpful suggestion.

On the other hand, SDG&E witness McKay presents a proposal in Exhibit SDGE-9, at pages 2 through 7, to adopt a series of procedural shortcuts in order to bring new utility-owned storage projects online. That proposal would eliminate or water down a number of regulatory safeguards in pursuit of utility-owned projects ONLY, but still only offers the possibility of "online dates in late 2022 and early 2023" (p. 6). As I indicated above, the only real remaining reliability need, considering recent CPUC procurement orders, is for *summer* 2022, not "late 2022 and early 2023." Therefore, I oppose SDG&E's attempt to eliminate important existing ratepayer protections in pursuit of projects that cannot meet the real needs of the system.

VII. NEW PENALTIES OR INCENTIVES ARE UNLIKELY TO HELP

The Staff Concept Paper (SCP) includes several proposals regarding: 1) penalties for delays to D.19-11-016 procurement; 2) increased RA penalties; 3) incentives for accelerating IRP Mid-Term procurement; and 4) Bundled Procurement rules modifications with respect to the dispatch of hydro resources. SCE (pp. 76-80) and PG&E (pp. 9-1 – 9-6) have both opposed those proposals for what I believe to be good and substantial reasons. Project delays or accelerations are under the control of developers, not the LSEs who would be subject to any penalties or incentives. Those LSEs have already entered into contracts for new resources which typically contain project delay provisions, and those contracts would have to be modified, likely with additional costs to ratepayers. RA penalties were just recently modified in D.21-06-029 and should not be changed yet again so soon thereafter. Thus, additional penalties and/or incentives are as likely to hurt as they are to help, as the utilities have explained. Similarly, hydro resources are already dispatched based on opportunity costs, which results in water being held back for the critical late summer period to the extent feasible. These staff concepts do no merit further consideration by this Commission.

VIII. PG&E'S GAS RATE PROPOSAL OFFERS THE POTENTIAL TO REDUCE DIRTY DIESEL BACK-UP GENERATION AND SHOULD BE ADOPTED

In Chapter 8 of its opening testimony, PG&E has offered a creative and well-considered proposal that would allow electric customers who would otherwise rely on diesel back-up generators (BUGs) to support their operations during PSPS and other outage events to take core gas service for their electric generation needs instead, thereby providing them with a cleaner alternative to diesel BUGs. While such customers would receive highly reliable core-level priority for their gas transportation service and pay core transport rates, they would still be required to purchase their own gas and would not become eligible for core portfolio gas supplies. As designed, PG&E's proposal would protect core gas customers from any adverse impacts on their gas transportation or commodity rates, and the customers choosing this option would pay the costs of any additional facilities required to provide core-level service.

I support PG&E's enlightened proposal and urge this Commission to adopt it. Any reasonable effort to reduce polluting diesel generation while maintaining adequate back-up power is well worth pursuing.

IX. PROHIBITED RESOURCES, ESPECIALLY DIESEL BACK-UP GENERATION, SHOULD BE DISPATCHED *LAST* UNDER THE ELRP

Sierra Club witness White proposes that this Commission formalize the statements made by President Batjer and Commission Rechtschaffen at the Commission meeting on March 25, 2021, when D.21-03-056 was approved. He recommends the development of a dispatch order for ELRP participants that would require that Prohibited Resources (PRs), especially diesel BUGs, be held back and used only under the most extreme emergency conditions, with PRs located in disadvantaged communities being the last dispatched. All other available resources, including emergency demand response, would be dispatched *before* diesel BUGs are utilized.

I support this recommendation as a logical extension of the comments made at the March 25 meeting. It makes no sense from an environmental justice perspective to deploy backup diesel generation when there are other cleaner alternatives available. I note that PG&E's gas rate proposal, discussed above, would provide another alternative to the burning of diesel fuel.

X. DEMAND RESPONSE – PARTICULARLY THIRD-PARTY DR -- OFFERS THE FASTEST AND CLEANEST MEANS OF INCREASING SYSTEM RELIABILITY BY SUMMER 2022 AND MERITS THIS COMMISSION'S STRONG SUPPORT

I was quite frankly disappointed by the failure of D.21-03-056 to take the opportunity to further promote the many innovative and cost-effective Demand Response (DR) solutions offered by third-party DR aggregators in the record of Phase 1. Instead the decision focused almost entirely on utility-sponsored programs. This Phase 2 offers the Commission the chance to correct that error and unleash the creativity of what could be a truly dynamic market. As the Commission stated several years ago in adopting "guiding principles" for DR in D.16-09-056:

> Demand response shall be market-driven leading to a competitive, technology-neutral, open-market in California with a preference for services provided by third-parties through performance-based contracts at competitively determined prices, and dispatched pursuant to wholesale or distribution market instructions, superseded only for emergency grid conditions. (Id. at 46, 52-56)

Once again in this Phase 2, the Commission has been presented with a plethora of constructive proposals from a variety of parties for advancing DR in California. In this context, I note with favor the testimony of PG&E, at page 1-2, that: "PG&E observes that the role of third-party DR is crucial in supporting California's grid needs."

1. THE PROPOSALS OF OHMCONNECT SHOULD BE ADOPTED

Over the last several years, OhmConnect has proven itself to be the most successful aggregator of residential customer DR in California, introducing tens of thousands of customers to the benefits of providing demand response. In its relatively brief testimony here, OhmConnect offers several important recommendations that this Commission should adopt:

- ELRP Design Should Incentivize Emergency Load Drop <u>and</u> Encourage Enrollment in Higher-Impact DR Programs.
- A Customer Defaulted into the ELRP Should Be Able to Sign Up for Another DR Program without Friction or Delay.
- The ELRP Trigger for Group B Should Be Both the Flex Alert and the CAISO Alert.
- Residential Households – Especially CARE Customers and Customers Residing in Disadvantaged Communities – Should Receive a $2/kWh Payment for Reducing Load During ELRP Events.
- Third-Party DRPs Should Be Permitted to Administer the AutoDR Incentives for Their Own Customers

TURN strongly supports these well-reasoned proposals and urges this Commission to adopt them.

//

2. EMERGENCY LOAD REDUCTION PROGRAM (ELRP) MODIFICATIONS AND ENHANCEMENTS

The Staff Concept Paper recommends increasing the ELRP energy-only payment from $1 per kWh to $2 per kWh, but only for a certain subset of participants (Groups A.1 and A.2) who "commit" to providing a certain load reduction. The notion of a "committed" load drop is inconsistent with the energy-only nature of the ELRP, however, and the paper provides no detail on how such a commitment would be implemented. If a customer is willing and able to provide a *committed* load drop, they should be enrolled in a more typical DR program that offers a capacity payment, and not ELRP. Given the tepid response to the introduction of ELRP thus far, I recommend that ALL participants receive the $2 per kWh incentive. Any other approach in a "no-penalty" type of program would be discriminatory and unduly preferential to the favored groups. SCE (p. 10) also notes that "equity" supports providing equal compensation to all participants in voluntary energy-only DR, and PG&E states that if the incentive is increased, it should apply to all categories of ELRP participants (p. 2-1, lines 22-26).

Staff also recommends expanding ELRP eligibility to include residential customers, triggered by a Flex Alert or Grid Alert in the day-ahead, a proposal that I **STRONGLY** support. As discussed in my Phase 1 testimony, a simple rewards-only program like ELRP will offer an easy introduction to DR for the millions of individual customers who have not participated in DR to date, but are able to provide meaningful load relief to the grid under stressed conditions. As the staff paper notes, residential customers have not been offered very many such program opportunities in the past, yet are regularly called upon to provide uncompensated load reductions during Flex Alerts (and to pay for DR programs that are not even open to them).

I agree with OhmConnect (p. 4), however, that: "A successful ELRP will incentivize customer response during emergency grid conditions ***and*** serve as a conduit for enrollment in higher-impact and higher-reward demand response programs." Accordingly, OhmConnect proposes a three-month open enrollment period in which customers would be solicited to participate in other available DR programs (not just utility programs), with a default to ELRP occurring only for those customers who do not choose another program. Along with other forms of publicity for this open season, the Flex Alert webpage should include cross-marketing of all utility and third-party demand response programs, to further encourage customers to enroll in those programs, as explained in my Phase 1 reply testimony. The Joint Parties (p.14) also support this type of cross-marketing.

Importantly, OhmConnect adds (at p. 5) that: "It is important that a customer be able to choose another DR program at any point, even after they are automatically enrolled in the default ELRP option. Once such a customer initiates enrollment in another DR program, they should be automatically disenrolled from the default ELRP option."

This two-step approach – a DR "open season" followed by the default of the remaining residential customers to ELRP -- should help to maximize the participation of residential consumers in all forms of DR.

The utilities raise concerns that default ELRP could simply represent a repeat of the largely unsuccessful Peak Time Rebate program that was attempted several years ago, which resulted in numerous "free riders" who received an incentive payment without taking any action. That is a valid concern, but I believe that a significant portion of the free rider problem could be addressed through the adoption of the **Meter Before/Meter After** measurement approach described by SCE at page 10 of its opening testimony (albeit in connection with its own proposed Whole Home Savings Pilot (WHSP) and not ELRP).

The multi-day baselines used for most other DR programs would be less effective for preventing free riders under ELRP, because a customer who happened to be away from home on an event day could still show significant "savings" when compared to the multi-day baseline, even though they did *nothing* in response to a call for load reduction. In contrast, by looking only at usage in the hour before the event begins, the Meter Before/Meter After approach would indicate savings only for those customers who actually reduced their usage at the time of need. There could still be some amount of free ridership under this approach, but certainly much less than under a multi-day baseline calculation. This method also meets the staff recommendation for a "simple" baseline, which in this case would be the customer's usage in the hour before the alert takes effect. Indeed, in this context, a customer who "cranked up the AC" in the hour *before* the event and then cut back during the alert period in order to receive an ELRP incentive, allowing the temperature in the home drift up during the event period, would actually be helping the grid, not gaming the system.

The Meter Before/Meter After approach would also appear to mitigate SCE's concern, discussed at page 67 of its testimony, regarding the need to otherwise "develop a baseline for 4.2 million residential customers and calculate the ILR for each customer on a monthly basis." Under SCE's proposed WHSP, the Meter Before/Meter After method would be employed for "approximately two million customers" (p. 10), which indicates that is implementable for a very large number of customers. Thus, Meter Before/Meter After is not only simpler for customers to understand, it also appears to be much easier for the utility to manage than a traditional 5-in-10 or 10-in-10 baseline calculation.

While SCE's WHSP proposal closely resembles the ELRP, except for a target customer base approximately half as large, it would be wildly expensive. The company forecasts costs of

$73.9 million over two years (p. 12), for load reductions of *at most* 160 MW per year (pp. 10-11). That works out to a cost of $230 per kW ($73.9 million divided by 320 MW), far greater than the payments under any other DR program, and about twice the BIP incentive on a per kW basis. There is simply no reason for this Commission to authorize such excessive spending, when comparable savings could be achieved much more economically under the ELRP. It is noteworthy that the DRAM program, which SCE so vehemently opposes, procured approximately 200 MW of August 2022 capacity with a budget of $14 million, which equates to about $70 per kW – a virtual steal when compared with SCE's proposal for a WHSP. Once again, I urge this Commission to reject the efforts of utilities to monopolize the inherently competitive DR market to the disadvantage of third-party aggregators and ratepayers.

It will be important to structure a residential ELRP program in a manner that does not discourage or frustrate participation in other more traditional (and valuable) DR programs, a point also emphasized by OhmConnect as noted above. For PG&E at least, this does not appear to present a problem. As that utility states at page 2-9:

> With regard to handling dual participation, customers under ELRP A.5 would not be registered by PG&E in the CAISO Demand Response Registration System (DRRS). Additionally, PG&E's daily system process checks for event eligibility would omit any customers who are registered in DRRS and/or participating in a non-market integrated program.
>
> Customers do not have to "unenroll" in order to join other DR programs or dynamic rates because they are not registered with PG&E as with traditional DR programs.

In rather stark contrast, SCE's testimony, at pages 65-66, foresees major difficulties for customers attempting to exit ELRP for another DR program:

> The Staff Concept Paper proposes that all residential customers would be automatically enrolled in ELRP, except customers currently enrolled in supply side DR programs. Though not explicitly stated, the staff proposal implies the traditional rules barring dual participation should be upheld between programs. If adopted, this would be a future recruitment barrier for customers, IOUs, and Demand Response Providers (DRP)

> because every customer would have to unenroll from the ELRP program before they could enroll on another DR program. This will result in a cumbersome process for customers and could result in frustration and unwillingness to participate in DR programs. This outcome should be avoided as programs advance toward enabling DR participation by removing unnecessary barriers and enabling a positive customer experience.

What these statements suggest to me is that SCE employs a far less user-friendly system than PG&E, one almost designed to dissuade customers from unenrolling in a (utility) DR program. Rather than rejecting residential ELRP on this basis, this Commission should instruct SCE to modify its internal processes such that they would follow the same approach as PG&E, which foresees no such problems.

PG&E does raise, at pages 2-8 to 2-9, one important issue with respect to the participation of CCA residential customers under a default ELRP structure:

> PG&E requests guidance on whether the program should automatically default Community Choice Aggregation (CCA) customers in this program. If the CPUC thinks that the IOUs should auto-enroll CCA customers, PG&E requests that it specify the procedure for PG&E to work with all the CCAs in PG&E's territory to resolve outstanding actions, such as disqualifying CCA customers that are part of an existing CCA Load Modifying Program or dynamic rates. In addition, PG&E strongly recommends that any auto-enrollment of CCAs should be "all or nothing" (i.e., all CCA providers participate or no CCA providers) in order to streamline the enrollment process and ensure availability by June of 2022.

I strongly suggest that CCA customers should be able to participate in default ELRP on the same basis as PG&E bundled service customers. Accordingly, the Commission in its decision here needs to provide the guidance that PG&E has requested.

In my January 11, 2021 direct testimony in Phase 1, I had suggested a system in which residential and other customers would be required to *actively enroll* in ELRP, in a manner similar to an opt-in PTR program. I now believe that the default approach proposed by staff, and as modified by OhmConnect, would be the better option. That is because the Meter Before/Meter

After method proposed by SCE would do a better job of preventing the free rider problems that plagued the default PTR program. However, if the Commission decides to require affirmative enrollment by customers, that process should be as straightforward as possible to encourage maximum participation. In that regard, an approach as user-friendly as a simple mailer with a return post card or a "one-click" online option in response to an email should be utilized to enroll customers. The more hoops (or clicks) a customer has to jump through in order to enroll, the more participation will be depressed, to the detriment of the grid.

3. AGGREGATORS SHOULD BE ALLOWED TO ISSUE AUTO-DR REBATES AT THEIR OWN RISK AND SEEK RECOVERY FROM THE IOU ONCE THE DEVICE IS ACTIVATED

This is the same issue addressed by OhmConnect at pages 8-10 of the testimony cited above. Simply stated, DR aggregators should be authorized to issue Auto-DR rebates (including smart thermostat rebates) to the customer up front, AT THEIR OWN RISK, and then complete the IOU process to recover the rebate once the device is activated for DR purposes. The Joint Parties offer a nearly identical proposal at pages 20-24 of their testimony. It is mystifying to me why the Commission would not enthusiastically embrace this approach to simplifying the rebate process for customers – there would be absolutely NO RISK to the utilities or their ratepayers! The risk would fall entirely on the Demand Response Provider (DRP) to ensure that the customer followed through on installing the device and signing up for a DR program. Approving this straightforward proposal would only accelerate the installation of Auto-DR devices. Nothing but the utilities' desire to control everything stands in the way of this common sense approach.

With respect to Auto-DR incentives, I also support SCE's proposal to increase its smart thermostat rebate from $75 to $125 for 2022 and 2023 (pp. 26-27) as well as that company's proposal to remove the 60/40 incentive payment split for Custom Auto-DR incentives and increase the DR enrollment requirement to five years instead (pp. 40-42). These recommendations will only help to expedite the movement toward automated demand response.

4. THE DRAM BUDGET SHOULD BE INCREASED FOR 2022 AND MAINTAINED AT THAT LEVEL FOR 2023

The Staff Concept Paper suggests conducting a supplemental DRAM auction for June through December 2022 and potentially increasing the budget for 2023. The Joint Parties supported this proposal at pages 14 through 15 of their testimony, recommending a specific schedule for the 2022 supplemental auction and proposing an incremental budget of $13 million for 2022 (bringing the total to $27 million) and the full $27 million for 2023. I wholeheartedly agree. In the initial 2022 DRAM auction the cost to customers of the procured capacity was only about $70 per kW ($14 million for 200 MW), compared to payments of over $100 per kW under BIP. Thus, even if actual DRAM performance was only 60-70% of contracted capacity (PG&E, p. 6-2), the cost per delivered kW of load drop was comparable as between DRAM and BIP. Payments under the Capacity Bidding Program (CBP) are also well above those that resulted from the DRAM.

On the other hand, the SCP suggests a number of additional requirements for future DRAM auctions that are largely misplaced. Staff first offers a round-about attempt to impose a $500 per kWh bid cap on Day-Ahead market bids, which would be counter-productive for all of the reasons explained in my Phase 1 testimony. I could, however, support a higher cap in the range of 90-95% of the CAISO bid cap. I recommend using a *percentage* of the bid cap rather than a flat dollar amount, because the CAISO bid cap may change (see PG&E testimony, p. 2-4, lines 15-19), and the point of the cap would be to ensure that economic Proxy Demand Resources (PDRs) are dispatched prior to reliability-only RDRR resources. The Joint DR parties (pp. 15-16) also prefer a percentage approach rather than a fixed dollar amount. However, it should be noted that PG&E has testified (p. 2-4, fn 9) that it "does not have visibility into the bidding options utilized by third-party demand response (DR) providers who are either participating in the Demand Response Auction Mechanism (DRAM) or outside of DRAM," so it may be difficult to enforce a bid cap requirement at any price level.

Staff also suggests that once a PDR Resource ID is introduced on a supply plan, it must be maintained until it is removed and cannot thereafter be re-introduced in later months. This proposal ignores the fact that some PDRs contain primarily weather-sensitive loads that may not be available in all months. Even PG&E notes, at page 6-4, that the: "recommendation to require a Proxy Demand Resource to be maintained on a supply plan in each month since it is introduced suggests *stricter requirements on DRAM participants than seem reasonable* in managing a portfolio of customers with weather-sensitive DR capabilities" (emphasis added).

The SCP also suggests that a shortfall in the DR capacity shown on a monthly supply plan relative to the contracted capacity should be subject to a penalty based on the level of that shortfall. I could support such a requirement as a measure to improve the perceived under-performance of DRAM resources, although care must be taken to ensure that suppliers are not penalized simply because the loads they have aggregated are weather-sensitive.

Finally, the SCP suggests that capacity awarded in any supplemental 2022 or calendar year 2023 DRAM auction be counted against the Qualifying Capacity (QC) limit established via the 2021 and 2022 Load Impact Protocols (LIPs). I oppose that proposal, because to date the LIPs have not applied to DRAM resources. Parties have had no notice of the potential need to include DRAM resources in their LIP showings, and this idea would thus be mixing apples and oranges. In any event, the LIPs are a slow and cumbersome method of establishing QC that serves to artificially limit the amount of DR that can be sold. Moreover, as the Joint Parties point out at page 17, “the CEC is already in the process of developing a DR QC methodology that would replace the LIPs, so linking DRAM QC values to a process that may not be utilized for much longer could very likely render this proposal moot, if adopted.” Finally, a penalty for supply plan shortfalls from contracted amounts would effectively achieve the same result.

In the event that additional DRAM procurement is not authorized, I would support the proposal by the Joint Parties (p.18) for the IOUs to conduct a separate DR solicitation:

> Should the Commission choose not to approve a supplemental DRAM budget for 2022 and 2023, the Joint Parties propose that the IOUs be directed to issue RFOs for bilateral DR RA contracts. This would allow the IOUs to more easily tailor the resulting contracts to meet their specific needs rather than relying on the standard DRAM Purchase Agreement. This procurement method is well-established through the now expired Aggregator Managed Portfolio (“AMP”) program and is another effective way for the Commission to direct procurement of a specified amount of DR capacity.

If this approach is followed, the IOUs should be directed to purchase any DR capacity available at a cost per kW that is less than the most expensive generating capacity resource that they have procured under their emergency procurement authority. California’s Loading Order and other clean energy policies have established energy efficiency and demand response as the highest priority resources, so DR should always be purchased first, before more expensive supply.

5. THE COMMISSION SHOULD RAISE, ELIMINATE, OR SUSPEND THE 8.3% DR PROCUREMENT CAP

At a time when the State is beating the bushes for any resources it can find for the summer of 2022, it simply makes no sense for the Commission to artificially limit LSEs’ ability to purchase DR resources to meet their RA requirements, which is exactly what the 8.3% demand response procurement cap adopted in D.20-06-031 does. The Joint Parties explain this issue in detail at pages 25-29 of their testimony, and I support their recommendations.

6. CAPACITY BIDDING PROGRAM (CBP) CHANGES

I agree with the Joint Parties that SCE and SDG&E should be required to offer a CBP-Elect option modeled on PG&E's program. As the Joint Parties explain at page 31:

> CBP Elect allows customers, with their aggregators, to specify at what price they would like to be bid by the IOU into the CAISO market. This option is attractive to customers because they have more control over how they are dispatched by ensuring that their respective opportunity costs are reflected in PG&E's CAISO market bids. Ninety-nine percent of customers participating in PG&E's CBP were enrolled in CBP Elect in 2019, so it is clear that there is significant interest in it. According to PG&E, CBP Elect resulted in a 35% increase in active customers in its program. SCE and SDG&E should be directed to create their own CBP Elect programs to grow enrollment and associated capacity. (footnotes omitted)

SDG&E has in fact offered its own version of this concept, with a very thoughtful wrinkle. As described in Exhibit SDGE-8, at pages 7 through 9:

> SDG&E proposes to add "Elect" products in which a customer or aggregator may offer any one of the following three nomination trigger price options: at $200/MWh, $400/MWh, and $600/MWh. Specifically, SDG&E proposes to add the products defined in Table EBM-1 below to the CBP:

Table EBM-1
Proposed Elect Products for CBP

DAY AHEAD PRODUCTS	DAY OF PRODUCTS
CBP – Day Ahead – 1 p.m. to 9 p.m., $200	CBP – Day Of – 1 p.m. to 9 p.m., $200
CBP – Day Ahead – 1 p.m. to 9 p.m., $400	CBP – Day Of – 1 p.m. to 9 p.m., $400
CBP – Day Ahead – 1 p.m. to 9 p.m., $600	CBP – Day Of – 1 p.m. to 9 p.m., $600

> For example, if the customer nominated its trigger to be $200 and that trigger is reached (i.e., the CAISO market price reaches $200), the customer would be asked to shed the load nominated or else it would pay the penalty. The higher the trigger price, the lower the likelihood of the market reaching that trigger price, thus making it less likely that the customer will be called upon to shed load. In this way, the customer can manage how frequently they may be called upon to shed load, which may serve their business needs in a more flexible manner. The intent is to provide more flexibility and choices to customers to participate in CBP at the frequency they can handle. The additional flexibility also allows aggregators in the program to plan their portfolio of existing customers and new customers to make adjustments and strategically align with the new Elect options.
>
> . . . . .
>
> Under this proposal, aggregators in CBP would be allowed to select a mix of different trigger prices of $200, $400 or $600 each month during the standard nomination window. For example, one month an aggregator could nominate one or all their

> customers at the $200 market price trigger, then in another month during the nomination window, the aggregator could choose a different price trigger of $400 or $600, thus providing aggregators with flexibility to respond to customer availability, feedback provided to the aggregator, etc. By offering the Elect options of CBP products, SDG&E hopes to create more choices for additional new customers, along with greater flexibility, while reducing the number of events for existing customers who might opt out of CBP if they experience 'customer fatigue' or too many events during extreme weather events such as those experienced in California in 2020.

Under this proposal, the monthly capacity payment for the price trigger at the $200/MWh level would be the same as the existing 1 p.m.-9 p.m. incentive, with a 5% capacity price reduction for the $400/MWh trigger and an additional 5% reduction for the $600/MWh trigger.

I strongly endorse this concept, which recognizes that economically-bid demand response is closely analogous to a call option for the energy the customer would otherwise have consumed, at a specified strike price. Logically, the higher the strike price of the call option, the lower the upfront capacity payment, because a call option with a lower strike price is more valuable to the buyer than one with a higher strike price. Varying the capacity payment in this manner provides a much more sensible way of assigning a greater value to lower-priced energy offers, without the distorting effect of an arbitrary bid cap such as that suggested in the SCP, which I have explained previously would only serve to eliminate customers with a higher value of service from participation in demand response.

While I support the general structure of the SDG&E proposal, I would suggest somewhat wider pricing bands, for example, 25% of the CAISO bid cap, 50% of the bid cap, 75% of the bid cap, and 95% (to ensure dispatch of PDR prior to RDRR). Percentages are better than fixed dollar amounts in this context, because of the possibility of changes to the CAISO bid cap. Along with this, the capacity payment would be reduced by 10% in each step, with full payment at the 25% level, 10% less at the 50% level, and 10% less for each succeeding step. The actual amount of the capacity price "discount" at higher energy prices would probably need to be refined over time, based on actual experience, but the overall structure is logical and merits adoption, both for SDG&E and for SCE, which still does not offer a CBP-Elect option.

I also agree with the Joint Parties (pp. 30-31) that this Commission should explicitly authorize use of the CAISO's new baseline options for CBP and DRAM capacity settlement purposes. As the Joint Parties explain:

> In D.21-03-056, in response to parties' concerns that the day-of adjustments to retail and wholesale DR baselines were causing DR performance to be undercounted during extreme heat events, the Commission directed the IOUs to work with the CAISO to explore baseline options during stressed system conditions. The IOUs were permitted to use the new baseline options for their respective CBPs, and DRPs were permitted to utilize them for the DRAM. The CAISO subsequently convened the DR Customer Partnership Working Group on April 22 where it proposed to allow DRPs to request an alternative day-of adjustment factor for May-October 2021 while the CAISO developed a broad-based control group methodology that could be used by all DRPs.
>
> This decision language was unclear in whether it was the intent of the Commission that the CAISO's alternate baseline be applicable to energy market settlement only or capacity payment settlement as well. The Joint Parties request the Commission specify that the CAISO's alternative baselines are applicable to the calculation of CBP capacity incentive payment and DRAM contract payments. Because the alternative day-of adjustment factor is currently only approved by the CAISO for use in 2021, the Joint Parties request that the Commission request the CAISO to extend its alternative day-of adjustment factor for the May-October 2022 and 2023 period.

The requested clarification with respect to CBP capacity incentive payments and DRAM contract payments is reasonable and sensible, and should be adopted. The alternative day-of adjustment factor should also remain in place until a replacement is established.

7. BASE INTERRUPTIBLE PROGRAM (BIP) CHANGES

A number of parties have requested that this Commission eliminate the existing restrictions on ELRP compensation for BIP customers during non-overlapping BIP and ELRP events. For example, PG&E states at pages 2-4 – 2-5 that:

//

> PG&E recommends that the CPUC reconsider and remove parts (a) and (b) of the "Special Considerations" provision in D.21-03-056. Parts (a) and (b) of the provision diminishes the ability for dual enrolled BIP and ELRP participants to be compensated for ELRP during non-overlapping events. PG&E has observed that less than 1 percent of all Group A enrolled service agreements were from BIP customers as of mid-August 2021. PG&E believes the limited enrollment by BIP participants in ELRP may be a result of Special Considerations Parts (a) and (b). Removing these limitations could create additional participation by large customers who are enrolled in BIP.

I urge this Commission to exercise extreme caution in considering this request. Allowing BIP customers to be compensated for ELRP reductions when BIP has not been called would tend to cannibalize the load reductions otherwise achievable via a BIP dispatch. Today the CAISO can estimate within a reasonable range the amount of load reduction that can be achieved by triggering BIP during near-emergency conditions. If those BIP customers were instead already reducing their load in order to garner ELRP payments, there might be very little load left to drop when BIP is finally called. Since BIP is one of the last lines of defense before rolling outages must be triggered, creating much greater uncertainty around the number of MWs achievable via a BIP call – as this proposal would do -- may create serious reliability issues. At minimum this Commission should consult with CAISO before considering such a significant change relative to the BIP program, whose participants already receive the highest DR compensation available.

On another BIP topic, the Joint DR Parties suggest (at page 8) that the Excess Energy Charges (penalties) imposed on BIP customers for usage in excess of their Firm Service Levels during a BIP event be reduced by 75% across all IOUs. I agree that these charges are excessive, but they also vary widely across the three major IOUs such that an across-the-board percentage reduction makes little sense. SCE's charges range from $12,000 to $15,000 per MWh for different types of customers, PG&E's charge is $6,000 per MWh, and SDG&E is the lowest at $4,500 per MWh. Instead of reducing these wildly disparate charges by a uniform percentage, the Excess Energy Charge for all of the utilities should be set at twice the applicable CAISO bid cap, as I suggested in my Phase 1 testimony. This would reduce the charges for BIP customers of all three IOUs and help mitigate program attrition, while retaining a high enough charge to incent compliance with curtailment orders.

8. CERTAIN UTILITY DR PROPOSALS MERIT APPROVAL

There were several other proposals offered by various utilities that I believe should be adopted by the Commission. For example, SCE (pp. 30-34) seeks approval (and funding) to extend its Virtual Power Plant (VPP) Phase II Pilot through 2023, and also seeks to reinstate pre-cooling prior to Smart Energy Program (SEP) events (p. 23). I support both of those sensible proposals.

Likewise, PG&E (p. 5-1) seeks an additional $1.2 million for Information Technology enhancements to its "Share My Data" platform in order facilitate expansion of the number of third-party DR customers the system can accommodate:

> Pacific Gas and Electric Company (PG&E) appreciates the recognition in the California Public Utilities Commission (CPUC or Commission) Staff Concept Paper of the role of third-party Demand Response (DR) in supporting grid needs. In this chapter, PG&E elaborates on its comments filed with the Commission on August 6th in response to the *Email Ruling Seeking Responses Regarding a Proposed Amended Scope and Schedule to Address Reliability Issues in 2022 and 2023* pertaining to Information Technology (IT) enhancements needed in 2022 to PG&E's Share My Data (SMD) system to meet the customer enrollment growth projections of third-party DR Providers (DRP) in PG&E's Electric Rule 24 (Rule 24) program. The SMD platform is essential for DRPs to be able to deliver resource adequacy from DR for PG&E and other Load-Serving Entities in PG&E's service territory, as well as to participate in Group B of the Emergency Load Reduction Program pilot.
>
> In Section B below, PG&E seeks cost recovery approval in the amount of $1.2 million for a set of targeted IT system enhancements to bolster the SMD platform so that it can meet the projected rapid and significant increase in third party DR enrollments and data access needs of third-party DRPs. In Section C, PG&E also recommends the Commission issue a timely decision on PG&E's proposal improvements described in PG&E's Improvements to Click Through Customer Data Access Application ("Click-Through Application"), Application (A.) 18-11-015. (footnotes omitted)

These modest IT investments are vital to the expansion of DR in PG&E's service territory and I support them, along with PG&E request for a timely decision in the Click Through Customer Data Access Application 18-11-015.

Finally, PG&E requests (pp. 7-1 – 7-3) an additional $10 million in each of 2022 and 2023 to support its Demand Response Emerging Technology (DRET) program. This program supports assessments and studies of new technologies and applications, such as "smart" devices behind customers' meters, new supply-side and load modifying demand response (DR) program design, tools, channels, and features to enhance customers' ability to perform in DR and dynamic rates. These are the types of cutting-edge efforts in which the California utilities can and should be leaders, and I support continuation of the program, but take no position on the appropriate size of the budget.

XI. CONCLUSION

I respectfully request that this Commission take actions in this proceeding consistent with the recommendations set forth above.

This completes my prepared reply testimony.

//

VERIFICATION

I, Michel Peter Florio, prepared the attached "Prepared Reply Testimony of Michel Peter Florio" on behalf of The Utility Reform Network (TURN). The factual material in this testimony is true and correct to the best of my knowledge, and the statements of opinion or judgment express my expert opinion and best judgment.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this 10th day of September, 2021, at Oakland, California.

/s/ Michel Peter Florio

Michel Peter Florio