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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.	Rulemaking 19-09-009

OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON PARTY PROPOSALS IN REPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING ON POTENTIAL MICROGRID AND RESILIENCY SOLUTIONS FOR COMMISSION RELIABILITY ACTION TO ADDRESS GOVERNOR NEWSOM'S JULY 30, 2021, PROCLAMATION OF A STATE OF EMERGENCY

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Pursuant to the August 17, 2021 Assigned Commissioner's Amended Scoping Memo and Ruling issued in this Rulemaking (the "Track 4 Scoping Memo") and the Administrative Law Judge's Ruling On Potential Microgrid And Resiliency Solutions For Commission Reliability Action To Address Governor Newsom's July 30, 2021, Proclamation Of A State Of Emergency served on August 23, 2021 in this Rulemaking (the "ALJ Ruling"), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (together, the "Joint IOUs") submit these opening comments on the proposals submitted by parties in response to the ALJ Ruling.

I. INTRODUCTION

In this Rulemaking, the Track 4 Scoping Memo created a new, expedited Phase 1 within Track 4 to address potential of microgrid and resiliency strategies deployed in 2022 and 2023 to help address expected capacity shortfalls during net peak hours. The ALJ Ruling directed parties to submit proposals by September 10, 2021 in compliance with the Track 4 Scoping Memo using a standardized template and set of questions. Each of the Joint IOUs and several other parties submitted such proposals. The ALJ Ruling provided an opportunity for parties to file comments by September 24, 2021 on the proposals of other parties. These comments provide the Joint

IOUs' response to the other parties' proposals. Specifically, the Joint IOUs propose a general framework for evaluating such proposals in this introduction and then assess party proposals using that framework in Section II of these comments.

A. Principles for Evaluating Party Proposals

In its proposal filed on September 10, 2021, PG&E described in detail why microgrid solutions, while beneficial for resiliency use cases, are generally not well aligned with the objective of mitigating system capacity shortfall events. In short, while the distributed energy resources (DERs) that can supply power to such microgrids may be able to mitigate system capacity shortfalls by generating during such events, the effectiveness of these DERs in mitigating the system-level event could be greater if they can operate in parallel with the grid, rather than in an islanded microgrid configuration that could limit the capacity they can contribute toward the system need. Further, because the value of DERs in mitigating system capacity shortfalls can usually be realized without a microgrid configuration – and, in fact, that value may be hindered through islanding – the ability to form a microgrid is unlikely to be a necessary part of cost-effective strategies to mitigate system capacity issues.

With that context, the Joint IOUs offer the following principles that may guide the determination on whether to adopt any of the Track 4, Phase 1 proposals made by parties in this proceeding.

1. System reliability proposals unrelated to microgrids should be addressed in other open proceedings.

Parties' proposals submitted in response to the ALJ Ruling cover a wide range of objectives unrelated to microgrids. The Commission has multiple open proceedings to address system reliability. Many of these, including the Emergency Reliability proceeding (R. 20-11-003), the Integrated Planning Proceeding (R. 20-05-003), the Resource Adequacy proceeding (R. 19-11-009), and the High DER Future proceeding (R. 21-06-017), are more appropriate than this proceeding for the consideration of the general ways in which DERs can contribute to system reliability needs in both the short- and long-term. Moreover, the Commission has a variety of open proceedings, like this one, that focus more narrowly on a sector or type of solution that may be able to contribute to system reliability needs. These include the Energy Efficiency proceeding (R.13-11-005), the Self-Generation Incentive Program (SGIP) proceeding (R.20-05-012), the Transportation Electrification proceeding (R.18-12-006), and the Net Energy Metering (NEM) proceeding (R.20-08-020). Finally, the Commission has process-oriented proceedings that apply to all types of DERs, such as the Rule 21 Reform proceeding on the distribution-level interconnection of DERs (R. 17-07-007).

Within this broader context of ongoing proceedings at the Commission, this Microgrid and Resiliency Strategies proceeding should be focused on the ways in which microgrids and related strategies can mitigate the impacts of Public Safety Power Shutoff (PSPS) events and other planned and unplanned outages. Thus, if a proposal does not directly relate to the use of microgrids for resiliency, that proposal should be considered, if at all, in one of the other proceedings at the Commission examining system reliability needs, or focusing on specific types of DERs and/or DER interconnection to the grid. Referring the consideration of non-microgrid-related proposals to these other forums will help to ensure that key stakeholders have notice and an opportunity to comment, will help to ensure that all proposed solutions for systemwide reliability and capacity shortfalls are considered holistically, and will avoid the litigation of similar issues in different proceedings, which can lead to inconsistent orders or policy.

2. Proposals must be able to materially mitigate potential system capacity shortfall events beginning in 2022 and 2023.

Parties making proposals should bear the burden of demonstrating that a particular proposal is able to be implemented in time to address any system needs in Summer 2022 and 2023. The ability to meet this timeline should be demonstrated on at least three dimensions: technical requirements; regulatory and permitting requirements; and utility system change requirements. First, is the proposal technically feasible to implement in the near-term? Is the technology on which it relies commercially ready and available for deployment, or does it depend on technological developments that are uncertain? Is the proposal realistic concerning any property acquisition, equipment availability, and construction timelines? Second, are any needed regulatory approvals able to be resolved in the near-term? Does the proponent of the proposal lay out a workable path for regulatory and permitting authority review and approval prior to Summer 2022 or Summer 2023? Finally, are any new utility processes or systems required to implement the proposal able to be created or modified in the near-term? For example, a proponent should acknowledge and address any incremental costs associated with, and the timeline for, any changes needed to utility billing systems, as such changes can take significant time.

3. A proposal should be cost-effective relative to other opportunities to address system capacity shortfall events.

Even if a proposal meets the prior two principles, the costs and benefits it provides in the capacity shortfall event use case should be compared with the costs and benefits that can be realized through other feasible solutions, including those being considered in other proceedings. Proposals should be evaluated in the context of the problem they are trying to solve, rather than finding a way to rationalize the addition of specific party proposals.

One way in which a microgrid-related proposal for system reliability might be cost-effective is when the same DERs can address multiple policy objectives, or provide multiple incremental value streams, without significant additional cost. For example, PG&E's proposal in this Phase 1 suggested reviewing locations at which PG&E is already staging temporary generators to power substation-level microgrids in the event of grid outages to determine if those same generators can provide system capacity in shortfall events at a reasonable incremental cost for necessary "make-ready" grid upgrades. In cases in which those upgrades are cost-effective, the same DERs that are providing resiliency value during grid outages can also be used to provide system capacity during shortfall events.

However, the Commission should guard against proposals that would result in customers paying more for the same benefit they would have received anyway under an existing program. For example, if a DER is already adequately incentivized to produce energy or reduce load during a capacity shortfall and would therefore have done so in any case, the fact that the DER can help to form a microgrid should not justify a higher payment for the benefits provided by the microgrid in supporting system reliability. Obviously, the question of whether there is a value of resiliency that should be compensated is a question within the scope of this proceeding, but that question is distinct from the one presented in this Phase 1 of Track 4: Here, the Commission is focused on whether microgrid-related resources can contribute to mitigating system capacity shortfall events, and any compensation should therefore be tied solely to those system reliability benefits. It should also be noted that there may be barriers to using the same assets to mitigate both resiliency and system reliability issues, since those events could overlap in time or take place in short succession, and the DERs may have a limited capacity to generate over time. Prior to approving any such multiple-use of time-limited DERs, the Commission should address and resolve such potential conflicts, perhaps as envisioned in the draft DER Action Plan.[1]

A corollary to this principle is that customers should only have to pay for system reliability benefits that are actually delivered. A proposal cannot be deemed cost-effective if the benefits it promises are elusive or uncertain. The benefits should be documented, and any compensation should be based on verified performance.

Cost-effectiveness determinations should also ensure that any party receiving funding or compensation is also bearing all costs necessary to implement the proposal. This includes ensuring that proponents pay for any necessary utility costs to support the proposal, including for metering, monitoring, and infrastructure improvements.

4. Senate Bill 1339 prohibits cost shifts.

As the parties to this proceeding are well aware, Senate Bill (SB) 1339, which is the legislation that the Commission is seeking to implement in this Rulemaking, prohibits the Commission from creating cost shifts between benefitting and non-benefitting customers as part of facilitating the commercialization of microgrids.[2] The Commission should continue to be

[1] See Draft DER Action Plan, issued July 23, 2021, Vision Element 3C.
[2] *See* Cal. Pub. Util. Code §§ 8371(b), (d).

mindful of this legislative direction when considering proposals to use microgrids or microgrid-related resiliency strategies for system reliability use cases.

More generally, any adopted proposals should be equitable across customer groups and classes and consider impacts on non-participants.

5. Before creating new programs, the Commission should consider whether existing programs can be modified.

Given the desire expressed in the ALJ Ruling to have solutions in place by Summer 2022 or Summer 2023, the Commission should generally focus on using or modifying existing mechanisms, methods, or programs rather than creating entirely new programs or tariffs. For example, demand response (DR)-related proposals should be assessed in the context of existing DR programs to determine if relatively simple modifications to those programs can address the need for incremental system capacity during summer net peak periods.

II. THE JOINT IOUS' REPLIES TO SPECIFIC PARTY PROPOSALS

In the following sections, the Joint IOUs reply to some of the proposals made by parties. While the number of proposals requires focusing on those that raise the most concern under the principles articulated in Section I, above, the lack of a specific response to any particular party's proposal does not indicate support by the Joint IOUs for that proposal.

A. New Tariff or Incentive Compensation Proposals for DERs

The Joint IOUs have been supportive of considering the development of separate compensation that appropriately values the services provided by a microgrid, but do not support compensation where cost shifting or duplication of charges to customers would occur. Additionally, in support of considering compensation consistent with any incremental benefits provided,[3] the Joint IOUs urge the Commission to not consider these proposals in this expedited

[3] *See* Opening Comments Of Pacific Gas And Electric Company (U 39-E), San Diego Gas And Electric Company (U 902-E), And Southern California Edison Company (U 338-E) On Proposed Decision Adopting A Suspension Of The Capacity Reservation Component Of The Standby Charge For Eligible Microgrid Distributed Technologies, filed in R.19-09-009, June 29, 2021, pp. 5-6 (noting that if the Commission provides a suspension from standby charges without reducing the need for standby service, it must first identify and quantity specific benefits that accrue to non-participants).

Phase 1 of Track 4 as there is not adequate time to fully evaluate the proposal for cost-effectiveness and alignment with long-term policy goals.

Additionally, the Joint IOUs note that any compensation proposal would most likely require the installation of a net generation output meter (NGOM) or dual meter to allow for time variant measurement of imported and exported energy to appropriately settle compensation on various tariff structures. The cost of these meters should be borne by the participating customers themselves and not paid by customers generally.

Many parties' proposals include a compensation component. The Joint IOUs first address those parties that suggest compensation in the form of a capacity payment and/or energy payment. The Microgrid Resources Coalition (MRC), Bloom Energy (Bloom), California Energy Storage Alliance (CESA), Southern California Gas Company (SCG), and Unison Energy (Unison) all propose some form of compensation structure in either a dollar per kilowatt (kW), dollar per kilowatt-hour (kWh), or both form of payments to the resource(s).[4] As noted above, the Joint IOUs do not oppose a compensation structure that is designed to appropriately value the service offered. However, the proposals provided in response to the ALJ Ruling pose the following main issues:

- Risk of cost-shift;
- Risk of double compensation; and
- Lack of proposal detail to fully evaluate under this expedited Phase 1 of Track 4.

The Joint IOUs note that these comments will not address every issue with each party's proposal, but instead will discuss in detail these main issues regarding compensation proposals below.

1. Risk of cost-shift

With regard to the cost-shift issue related to compensation structures, SB 1339 clearly prohibits shifting of costs from participating customers to non-participating customers to

[4] MRC Proposal, p. 4; Bloom Proposal, p. 6; CESA Proposal, p.7; SCG Proposal, p. 4; Unison Proposal, pp. 2-3.

facilitate the commercialization of microgrids. The Joint IOUs are not opposed to providing compensation for incremental and quantifiable services as appropriate. What is needed to be determined is the appropriate structure of compensation and the amount of compensation to ensure that all customers are paying their fair share of costs and that no customer bears the burden of another customer's choice.

Cost-shift can occur in multiple forms such as the exemption of charges or imposing of charges not equal to services received. For example, MRC's proposal, which includes the exemption of departing load charges and eventually public purpose charges and wildfire fund charges, is in violation of SB 1339, which prohibits cost shifting.[5] MRC supports this proposal by footnoting that:

> The governor's emergency declaration illustrates the folly of departing load charges. The system has more load than it can handle, and Customers are being penalized for providing additional capacity. A number of states adopted departing load charges to cover stranded assets costs during a move to retail competition, but they were specific to the one-time costs, and we are not aware of any other state that continues to rely on them to fund their system.[6]

MRC has mischaracterized what is captured in a departing load charge. Public Utilities Code Section 365.2 requires that "[t]he commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers. The commission shall also ensure that departing load does not experience any cost increase as a result of an allocation of costs that were not incurred on behalf of the departing load." As such, each utility provides the costs that make up the departing load charge, or Power Charge Indifference Adjustment (PCIA), in their annual Energy Resource Recovery Account (ERRA) forecast proceeding for the Commission and parties to review and confirm that both bundled and departing load customers

[5] Unison also proposes the use of standby charge exemption as a compensation mechanism. Unison Proposal, p. 5.

[6] MRC Proposal, p. 5, footnote 3.

remain indifferent to the choices made by retail customers in regard to their load-serving entity (LSE). Additionally, the Public Purpose Charge (PPP) and the California Wildfire Fund Non-Bypassable Charge (Wildfire NBC) are both established NBC charges for all customers, including NEM 2.0 customers. To allow customers under MRC's proposed tariff to bypass NBCs would be unfair to all ratepayers as it would result in shifting of costs from participating customers to non-participating customers.

2. Risk of double compensation

Parties' proposals for compensation in the form of a capacity payment[7] pose the risk of duplication of charges by proposing that the customer is eligible for resource adequacy (RA) compensation outside of the existing capacity procurement process. This suggestion would result in ratepayers paying twice for capacity – once through the LSE RA obligation procurement process and then again under the various parties' tariff proposals that include capacity payments. Parties' suggestions of an annual capacity payment have two main issues: 1) it would result in capacity payment outside of an LSE's RA obligation procurement process; and 2) there is no proposal to address what happens if the capacity is not available when needed, which could effectively result in customers paying for nothing. In the current RA process, LSEs are subjected to penalties if they do not meet their obligations. Paying for RA outside of that process would result in duplication of charges to ratepayers with no ability to ensure those resources' availability.

3. Lack of proposal detail to fully evaluate under this expedited Phase 1 of Track 4

Any proposal that impacts customers should undergo a thorough review and evaluation before adoption. The evaluation should ensure the proposals that are adopted result in the benefits targeted and do not impose unintended negative consequences on customers, the market, or other programs. Many of the compensation proposals lack detail to fully understand the benefits and implications to customers as discussed in these comments.

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[7] MRC, p. 4; Bloom, p. 6; Unison, p. 2; Vote Solar, pp. 3-4.

MRC's Resilience Payment for Critical Facility Microgrids proposal lays out a rough payment scheme but fails to address key legal and operational issues, including: whether this proposal would create cost shifting, which is explicitly prohibited by SB 1339; whether free-riders would be eligible for compensation; how free-riders would be identified if they are ineligible; whether duplicative payments for the same capacity and generation under other programs (e.g., SGIP and NEM) would be allowed; whether payments would be made in perpetuity or if they would sunset; why the PG&E temporary generation costs are the right proxy for determining payments under their program; whether testing should be required to ensure availability of resources; whether penalties should be included for non-performance; whether and how such a proposal would lead to equitable outcomes that ensure critical facility resilience for disadvantaged and vulnerable customers; whether islanding such resources would be beneficial in a system capacity shortfall versus simply having those customers export energy onto the grid; what types of resources would be eligible for compensation; why 96 hours is the correct islanding duration; what impact a 96 hour requirement would have emissions profiles of these microgrids; and so on. For these reasons, the Joint IOUs urge, at a minimum, that the Commission not adopt these compensation tariff proposals in this expedited Phase 1 of Track 4.

B. Proposals duplicative or similar to existing programs for behind the meter (BTM) DERs

The Joint IOUs next address parties' proposals that appear duplicative of existing programs. Some parties' proposals also appear to duplicate recently approved or other existing programs. Any suggestions to change those programs should be addressed in the relevant open proceedings as noted in Principle 4 above. As noted above, many of the compensation tariff proposals suggest a duplication of costs to the existing RA program. In addition to proposals around exported energy and capacity, some parties suggested changes to existing demand response programs (*e.g.*, the Emergency Load Reduction Program (ELRP) or the Base Interruptible Program (BIP)), while other parties proposed a new demand response program.[8]

[8] CESA, pp. 7-8; Center for Sustainable Energy (CSE), pp.7-8; Fuel Cell Energy (FSE), p. 6.

Changes to existing programs are appropriate to be addressed in the relevant open proceeding and proposals for new demand response programs should be addressed in the appropriate demand response proceeding.

Primarily, these proposals attempt to duplicate features of existing DR programs in that they would provide support during times of grid need (i.e., supply and/or transmission/distribution). Procedurally, proposals for new DR programs or modifications to existing ones should be advanced in separate DR-related proceedings and forums. This would include the IOUs' upcoming DR funding application for 2023 – 2027,[9] or more recently in the Emergency Reliability Rulemaking (R.20-11-003).

Notwithstanding the procedural aspects, the Joint IOUs maintain that their DR programs are already agnostic as to technology participation. That is, DR is a platform for transforming end use loads into grid response loads, including storage, rather than being tied to a specific end-use.[10] To this end, calls by parties, including MRC, to develop specific DR programs for BTM fuel cells is misplaced. The development of DR programs to meet the demands of niche participants is unrealistic, costly, and inconsistent with a technology-agnostic approach to DR. Furthermore, the Joint IOUs' current DR offerings are expansive in leveraging both CAISO market integrated economic (Proxy DR (PDR)) and emergency (Reliability Demand Response Resource (RDRR)) models. Also, as of this year, the ELRP offers a non-market integrated emergency program for interested participants. Specifically, the Joint IOUs' Capacity Bidding Tariff (CBP), which leverages the PDR model, which specifically for PG&E offers greater flexibility to participate through the Elect and Elect+ options. These options enable participants to determine their bids to optimize their resources to support DR as a compared to PG&E's Prescribed Option, which has a predefined bid price. Separately, the Joint IOUs' Base Interruptible Program (BIP) uses the RDRR model to provide emergency load reduction with a

[9] D.17-12-003, Ordering Paragraph (OP) 61.

[10] *See* PG&E's Opening Testimony for 2018-2022 DR funding, served in support of A.17-01-012, January 17, 2017, p. 1-9.

short notice period during grid needs. Finally, the ELRP offers a number of enrollment options, including those leveraging storage (A.3) and Virtual Power Plants (A.4). All told, each of the Joint IOUs offers an array of DR programs and pilots, which allow a multitude of participants to engage through both traditional load drop DR and those leveraging technology, including microgrids, to provide DR.

CESA notes that their proposal has "intersectional impacts" and suggests that "the Commission should closely coordinate across teams to consider these cross-cutting impacts."[11] The Joint IOUs urge the Commission to go beyond CESA's suggestion and ensure that party proposals are appropriately addressed in the relevant proceeding to ensure interested stakeholders have ample opportunity to weigh in.

Outside of demand response, Vote Solar proposes establishing a new microgrid battery reliability incentive program for BTM residential and commercial customers.[12] The program would be structured to have investor-owned utilities (IOUs) pay an upfront cash incentive to customers to add a battery to an existing or new BTM solar system in a structure similar to that used in the SGIP in which lower-income and medically vulnerable customers receive a higher incentive for battery storage.[13] The incentive (similar to SGIP) is a one-time up-front payment,[14] with no clear requirement that customers actually deliver the anticipated capacity value, nor any stated consequences if they do not. Similarly, Vote Solar's proposal is more appropriately addressed in the SGIP proceeding (R.20-05-012).

Lastly, Bloom also proposes that the Commission expand the existing Net Metering – Fuel Cell (NEMFC) tariff to allow the addition of storage at the same site as the fuel cell. This is not the appropriate proceeding for this proposal. The Commission has included the NEMFC

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[11] CESA, p. 8.

[12] Vote Solar Proposal, pp. 2-5.

[13] *Id.*, p. 3.

[14] *Id.*

tariff in the scope of the NEM Reform OIR (R.20-08-020).[15] Bloom is an active party in that proceeding.

Public Advocates Office (Cal Advocates) appropriately notes that proposals should not be adopted “until there is compelling evidence on the record demonstrating a distinction between the capacity benefits provided by the Resource Adequacy (RA) procurement process, existing demand response and load reduction programs, and a program that would procure microgrids specifically for the purpose of addressing system capacity needs.”[16] The Joint IOUs agree and urge the Commission to not adopt any proposals without an adequate demonstration that the proposal should not addressed elsewhere, that it is truly incremental to existing efforts, and will result in benefits to customers commensurate with the proposal costs.

C. Los Angeles County Proposal

Los Angeles County (County) proposes that the Commission approve the compensation of more than $41 million to deploy three County facility projects and one Regional Public Agency Microgrid Program for a total of 15.95 MW of estimated capacity available to be dispatched during net peak hours.[17] Although not explicitly stated, it appears the County proposes to have Commission-jurisdictional entities collect these funds from their retail customers and then remit the funds to the County as a grant.

As a threshold matter, it is unclear whether these projects would be located within the service area of a Commission-jurisdictional load-serving entity. If, for example, they are located in the service area of the Los Angeles Department of Water and Power (LADWP), a municipal utility not regulated by the Commission, then it appears that the County is proposing a cost shift. Specifically, the customers of LADWP would benefit from the resiliency benefits of the microgrids that are deployed, but non-LADWP customers would be paying a large portion of those project costs.

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[15] See Order Instituting Rulemaking R.20-08-020, dated September 3, 2020, p. 9.

[16] Cal Advocates Proposal, pp. 1-2.

[17] County Proposal, pp. 2-3.

The County's proposals are also speculative, leaving considerable doubt regarding whether they could be implemented by Summer 2022. For example, the County asks for more than $22 million to build a Regional Public Agency Microgrid Program that "aims" to deliver 9.7 MW in incremental capacity over the next two years.[18] The County does not explain why this 9.7 MW in incremental capacity needs to be in a microgrid configuration in order to support broader system capacity during summer net peak hours, nor does it offer any evaluation of cost-effectiveness to demonstrate that $22 million invested in this program is more effective at mitigating the risk of system capacity shortfall events than other potential capacity procurement opportunities.

The County's proposals may well meet important local government objectives and provide local resiliency, employment, and other benefits. However, to the extent these projects contribute to broader system reliability, there are currently market mechanisms in place to compensate them for that service. For example, these DERs could produce RA-qualifying capacity, which could be sold to LSEs, or they could sell energy into the wholesale market. There are also programs like the ERLP and other existing DR programs that may provide revenue opportunities for aggregations of DERs contemplated by the County. In light of these existing revenue generation opportunities, the County's proposal generally fails to ensure against double recovery for the same activity and the associated cost shift that might occur. It appears that the County is simply requesting that customers across the state contribute financially to the County's preferred resource plan, without demonstrating the specific need, benefit, or cost-effectiveness of that investment. For these reasons, the Joint IOUs recommend against adopting the County's proposals.

D. Section 218 and Rule 18/19 Changes

1. City of Long Beach Proposal

The City of Long Beach continues to advocate for changes to approved utility rules that

[18] *Id.*, p. 4.

prohibit the resale by a customer of electricity originally provided by the utility.[19] As litigated extensively in Track 2 of this proceeding and in a subsequent Application for Rehearing by the City of Long Beach, the Commission has denied this request multiple times[20] and nothing in the Emergency Proclamation or the Amended Scoping Memo provides a basis for changing that position now. Under revisions to utility Electric Rules adopted in Track 2 of this proceeding, the Port of Long Beach is already able to use its microgrid to supply electricity to a critical facility operated by a municipal corporation on an adjacent premise to conduct emergency and/or critical operations during a grid outage.[21] In its proposal, the City of Long Beach simply asks to be able to sell that electricity to the adjacent facility, rather than to supply it without charge during emergencies.

This proposal should not be considered again in this Phase for two reasons. First, the City of Long Beach does not articulate how its ability to re-sell electricity provided by a utility during grid outages will or could address system-wide capacity shortfall events. In a grid outage, the reduction of load from serving the adjacent critical facility will not mitigate the capacity shortfall on the grid since the facilities would already be isolated from the grid. While the provision of electricity to the adjacent facility may make that facility more resilient to a rotating outage caused by a system capacity shortfall (assuming that the critical facility is even subject to a rotating outage), the Port of Long Beach is already able to serve that adjacent facility under the revisions to the Electric Rules ordered in Track 2. The sole issue raised again in this Phase, where it does not belong, is whether the Port of Long Beach should be able to make unregulated resales of utility-provided electricity to an adjacent facility. For all of the same reasons that the Commission has rejected this request in the past, and because the proposal does not address the system capacity shortfall concern, the Commission should reject this proposal again now.

[19] *See* City of Long Beach Proposal, pp. 1-4.

[20] *See, e.g.,* D.21-04-021 (denying City of Long Beach Application for Rehearing on this issue).

[21] D.21-01-018, pp. 27-36, 102-103 (Findings of Fact 9-14), 107-108 (Conclusions of Law 14 & 15), 112-113 (OP 2).

Separately, the City of Long Beach proposes that the Commission consider ordering that non-exporting interconnection agreements be modified to allow export during system capacity shortfall events.[22] The City of Long Beach acknowledges that any such changes would need to be studied by the utilities to ascertain whether there could be safety or reliability impacts from the export.[23] What the City of Long Beach fails to point out is that the non-export interconnection process is specifically designed to not study the potential for export. Separate interconnection study processes already exist for customers who wish to export from their behind-the-meter generation or storage facilities. Customers with a non-export interconnection can today, without the need for Commission action, seek to convert those interconnections to allow export, subject to the necessary studies and facility upgrades.

2. CESA Proposal

CESA proposes further modifying Rules 18/19 from the changes made in Track 2 in three ways: (1) Allowing for "cross-the-fence" transmission of electricity from microgrids during "gray-sky" operations (e.g., when the CAISO has activated its Alert, Warning, Emergency (AWE) system; (2) allowing electricity transmission by microgrids beyond an adjacent property; and (3) removing the limit on ten projects under the Rules 18/19 modification "if additional projects commit to supporting system reliability."[24] CESA advocates for otherwise maintaining the bounds of the Rule 18/19 exemption related to customer eligibility.[25]

Unlike the City of Long Beach, CESA's proposal to allow "gray-sky" provision of electricity by a microgrid to another critical facility at least articulates a way that could theoretically mitigate a capacity shortfall event, if the additional customer served by the microgrid can reduce its demand on the larger electric grid. However, the outcome is not guaranteed. If the DERs supporting the microgrid in question are already exporting their full

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22 City of Long Beach Proposal, p. 5.

23 *Id.*

24 CESA Proposal, p. 4.

25 *Id.*

capacity to the grid during such "gray-sky" conditions, then islanding those DERs within the microgrid, even if the microgrid also serves another customer, may actually increase the net demand on the grid. As discussed in more detail in PG&E's September 10, 2021 Proposal filing, this is because the DERs, when operating in islanded mode, may be more constrained in their ability to generate because they have to match the load within the island, while the same DERs, depending on the interconnection arrangements and system constraints, may be able to provide their full generating capacity to the grid if they continue to operate in parallel. This suggests that a better solution than expanding Rule 18/19 exemptions for "gray-sky" conditions would be to ensure that the DERs within the microgrid are able to export their full capacities to the grid during gray-sky as well as blue-sky conditions, reserving the islanding configuration only for grid outages. CESA fails to demonstrate that its "gray-sky" proposal would address a system capacity shortfall need in all circumstances.

With regard to CESA's additional proposed modifications to Rules 18/19, such expansions of the exemption would only make sense if the first argument – for use during "gray-sky" conditions – could demonstrably mitigate grid capacity shortfall events. Since there is no guarantee of that being true, the additional expansions of the use of microgrids to serve other customers also does not necessarily assist in grid capacity shortfall events, and so they should not be adopted. It is also important to note that since the Commission cannot modify Sections 216 and 218 of the California Public Utilities Code, which generally limit the ability of non-utility private entities to serve other, non-contiguous customers, any modification adopted by the Commission related to CESA's proposal would have to be very narrowly tailored to fit within those statutory restrictions.[26]

[26] *See Administrative Law Judge's Ruling Requesting Comment on the Track 2 Microgrid And Resiliency Strategies Staff Proposal ("Staff Proposal"), Facilitating the Commercialization of Microgrids Pursuant to Senate Bill 1339,* issued in R.19-09-009 on July 23, 2020, p. 41 ("[Public Utilities Code Section] 218 serves an important public purpose, in assuring fair and reasonable rates, safe and reliable electricity available to all. Public utilities are responsible for safety, reliability and interconnections to the larger grid, thus consideration must be given to utilities' grid responsibilities, control, operation and maintenance of their distribution infrastructure, and transparency of microgrid operations that may

3. Applied Medical Resources (AMR) Corporation Proposal

AMR proposes "to develop a standardized interconnection process for microgrids to safely distribute electricity using private power lines across a public street to another Premise."[27] AMR argues that it and other customers who have facilities on a campus with intervening public streets could make greater use of microgrids if there was a clear process allowing the connection of parts of the campus across those public streets.[28] AMR does not articulate a clear rationale for why private distribution line crossings of public streets in order to expand campus-style microgrids would necessarily mitigate system capacity shortfall events. Presumably, the expansion of existing campus microgrids or the building of new campus microgrids could reduce demand on the grid during net peak hours if the microgrids are operated in islanded mode. However, this logic suffers from the same problem articulated throughout these comments: There is no guarantee that islanding a microgrid will benefit the larger electric grid more than simply operating the DERs in parallel with the grid so that their full capacity can contribute to supply.

Aside from the lack of a clear connection to capacity shortfall event mitigation, AMR's proposal raises significant concerns regarding consistency with Section 218 of the California Public Utilities Code and, more generally, with ensuring the safety of electric distribution facilities running through, over, or across streets used by the general public. Section 218 has limited exceptions to the fundamental requirement that only public utilities can distribute electricity in California. One such exception is when the electricity is distributed "solely for

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affect grid operations. If energy exchange were to be allowed between more than 3 contiguous property owners or that cross a public street, an important concern to address is the administration of fair and reasonable rates between microgrid participants, equitable distribution of costs and charges as well as potential cost-shifting concerns between microgrid and non-microgrid participants. If energy exchange becomes allowed behind the point of interconnection, but is not subject to regulatory oversight, 'private control over basic necessities [such as power] mean[s] that these private firms could effectively subordinate, dominate, and exploit ordinary users.' (Rahman n.d.)".).

[27] AMR Proposal, p. 6.

[28] *Id.*, pp. 5-6.

[the] own use" of the customer across private property.[29] Here, however, AMR is proposing to distribute electricity across a public right of way, which by definition is not the private property of AMR. A second exception under Section 218 applies where AMR is only distributing power to itself or its tenants generated by "other than a conventional power source," which does not include natural gas-fired generators like those AMR states it needs to use, unless they are qualified cogeneration facilities.[30] Thus, Section 218 significantly limits the ability of a private, non-utility entity to transmit electricity, especially when that transmission occurs across public rights of way. The Commission must be mindful not to commit legal error under Section 218 if it entertains AMR's proposal.

E. Proposals Related to Interconnection Processes

1. CESA Proposal 3

CESA's Proposal 3 requests that the Commission authorize additional utility interconnection staffing to support timely deployment of larger projects, including microgrids.[31]

The need for additional utility staffing for microgrid interconnections was already addressed in advice letters submitted by each utility pursuant to Ordering Paragraph 3 of D.20-06-017. For example, in Advice Letter 5917-E PG&E noted: "With regards to interconnection staffing levels, PG&E's Electric Generation Interconnection (EGI) and Distribution Planning teams plan to acquire additional staff as needed, or modify internal processes as needed." In fact, PG&E significantly increased its interconnection staff in the first half of 2021. The Commission took additional steps to confirm that each of the Joint IOUs had adequately addressed interconnection processes for microgrids. Ordering Paragraph 4 of D.20-06-017 ordered the utilities to report, in a compliance filing submitted by February 15, 2021, the results

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[29] Cal. Pub. Util. Code § 218(a).

[30] *Id.*, § 218(b) (" 'Electrical corporation' does not include a corporation or person employing cogeneration technology or producing power from other than a conventional power source for the generation of electricity solely for any one or more of the following purposes: (1) Its own use or the use of its tenants. . . .") (emphasis added). *See also id.*, § 2805.

[31] CESA Proposal, pp. 3 and 8.

of the required actions the utilities took to meet the interconnection-related goals set in D.20-06-017. Consequently, the issue raised by CESA is already being addressed.

2. Green Power Institute (GPI) Proposal

GPI recommends at least partially automating the Initial Review and Supplemental Review Rule 21 study processes to reduce interconnection timelines and to frontload (which the Joint IOUs understands to mean pre-populate with data) and further automate the execution of the Generation Interconnection Agreement (GIA).[32]

GPI has raised this topic several times previously in different proceedings, and the proposal should continue to be addressed in interconnection-focused proceedings like the Rule 21 reform proceeding, rather than in this Microgrid OIR. Although this is not the best venue to address this proposal, the Joint IOUs will briefly note here that many of the Joint IOUs' GIA process are already frontloaded and automated (e.g. NEM paired storage and stand-alone storage.) The Joint IOUs are also taking steps to further streamline these processes. However, for this to happen by 2023 or sooner is not realistic. Automation of the Supplemental Review is complex to implement because it requires the integration of multiple vendors' software systems. Additionally, the Joint IOUs are currently dedicating its resources to implementation of numerous other integration projects ordered in the Rule 21 proceeding (R.17-07-007) that are expected to result in interconnection improvements. In order to consider the relative priority and importance of potential interconnection process modifications in a holistic and efficient manner, it is critical that the Commission consider GPI's proposal, if anywhere, together with other reform proposals in the Rule 21 proceeding.

III. CONCLUSION

The Joint IOUs appreciate the opportunity to provide these comments on the other parties' proposals. For the reasons discussed in more detail above, the Commission should adopt the guiding principles and evaluation framework proposed in Section I of these comments for

[32] GPI Proposal, p. 5 (Frontloading and Automating the Generator Interconnection Agreement").

consideration of the parties' proposals. Applying those principles, the Joint IOUs have evaluated key proposals made by the parties and recommend against approval in this proceeding of those discussed above based on that evaluation.

Respectfully Submitted on behalf of the Joint IOUs,[33]

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[33] SDG&E and SCE have authorized PG&E to file these comments on their behalf pursuant to Commission Rule 1.8(d).