Short-Term Actions to Accelerate the Deployment of Microgrids and Related Resiliency Solutions

California Public Utilities Commission Staff Proposal

Pursuant to Senate Bill 1339 (2018) and R. 19-09-009

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Prepared by:

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1. Executive Summary

In this document, the California Public Utilities Commission's (CPUC) Energy Division staff presents recommendations for actions to facilitate the deployment of microgrids and other resiliency solutions in 2020.

CPUC Energy Division staff recommends the following:

1. **Accelerate Interconnection of Resiliency Projects**
   - Use Pre-Approved Designs in Application Process: Require large Investor Owned Utilities (IOUs) to develop and implement the ability to use standardized, pre-approved system designs in interconnections applications for projects that can deliver energy services during broader grid outages.

   - Expedite Utility Sign-Off on Installed Projects: Require IOUs to take the following actions:
     - Publish the specific technical criteria used to determine under which conditions field inspections are necessary for the safety and reliability of the grid.
     - Eliminate inspections that are duplicative of those performed by local jurisdictions.
     - Consider "remote inspections" by accepting photos or videos provided by the contractor rather than requiring an in-person inspection.

   - Prioritize Interconnection of Key Location, Facilities, and/or Customers: Require IOUs to allow projects that meet certain eligibility criteria to bypass the interconnection queue.

   - Expand Interconnection Staffing and Information Technology Resources: Require IOUs to commit additional resources to their interconnection study and distribution upgrade teams, as well as to the information technology solutions that support these teams, in order to facilitate faster processing for all projects.

2. **Modernize Tariffs to Maximize Resiliency Benefits**
   - Allow Emergency Grid Charging of Net Energy Metering (NEM) Storage: Require IOUs to modify NEM tariffs to allow storage devices to charge from the grid during the pre- Public Safety Power Shutoff (PSPS) window.

   - Remove NEM Storage Sizing Limit for Islandable Systems**:** Require IOUs to modify NEM tariffs to remove storage sizing limit and to require islanding ability for energy storage systems larger than 10 kW.

3. **Share Information with Local Government Agencies**
    - Conduct Outreach on Utility Infrastructure: Require IOUs to conduct meetings to educate and inform local government agencies on vulnerable electric transmission and distribution infrastructure and critical operations that serve the local jurisdictions.
    - Develop Engagement Guide: Require IOUs to develop a guide to assist and engage local governments in navigating the IOUs' interconnection processes for deploying a resiliency project.
    - Dedicate Staff to Manage Intake: Require each IOU to create a dedicated team of staff to manage the intake of local government agency resilience project inquiries.
    - Create Separate Data Portal for Local Governments: Require IOUs create a separate access-restricted portal, available only to local government agencies, containing essential data for microgrid and resiliency project development.

2. Introduction

2.1 SB 1339 Background

Senate Bill (SB) 1339, enacted in 2018, directs the CPUC to undertake activities to further develop policies related to microgrids. On September 12, 2019, the Commission initiated Rulemaking (R.) 19-09-009 to design a framework surrounding the commercialization of microgrids, as well as to account for the Commission's commitment toward utilizing additional technologies and activities that may be useful for achieving overall resiliency goals.

On December 20, 2019, the Commission issued a scoping memo which divided the proceeding into three tracks. Track 1 of the proceeding encompasses the Commission's goal of deploying resiliency planning in areas that are prone to outage events and wildfires, with the goal of putting some microgrid and other resiliency strategies in place by Spring or Summer 2020, if not sooner. Track 2 of the proceeding will help accomplish the state's broader policy goals in the context of supporting microgrids and resiliency such as, but not limited to, developing standards, guidelines, rates, and tariffs to support and reduce barriers to microgrid deployment statewide. Lastly, Track 3 of the proceeding will consider the ongoing implementation requirements of SB 1339 as well as any future resiliency planning, such as but not limited to formation of working groups to codify standards and protocols.

See Appendix 4.3 for a complete copy of Senate Bill 1339.

2.2 Objectives and Scope

The intent of this staff proposal is to make recommendations for addressing the issues within the scope of Track 1 of R.19-09-009, as described above. Track 1 is expected to conclude by Spring 2020, with a decision giving direction ready for implementation by September 1, 2020. The issues included in the scope of Track 1 are:

1. Prioritizing and streamlining interconnection applications to deliver resiliency services at key sites and locations;

2. Modifying existing tariffs to maximize resiliency benefits;

3. Facilitating local government access to utility infrastructure and planning data to support the development of resiliency projects.

Separately, Track 1 also includes the following item: IOU proposals for immediate implementation of resiliency strategies, including partnership and planning with local governments. While the IOU proposals are on the same timeline as the issues listed above, they are not incorporated into this staff proposal and will be filed and served separately.

2.3 Document Overview

Chapter 1 presents an executive summary of the proposals staff recommends for implementation.

Chapter 2 provides information on the legislative and procedural background that gave rise to the staff proposal.

Chapter 3 presents details on various proposals for addressing the three issues in scope for Track 1 of R.19-09-009. Each issue is discussed using a standard structure beginning with the problem statement, guiding principles, individual proposals, staff recommendation, rationale in support of the recommendation, followed by details.

CPUC staff developed the proposals through review of comments, experience with inter-related proceedings, engaging existing working group activities with related proceedings, panel presentations from the December 12, 2019 Microgrids Order Instituting Rulemaking Workshop, and communications with parties and subject matter experts where time allowed. Staff has offered these proposals taking into consideration feasibility and practicality for short lead time implementation within 2020, and to vet additional ideas for future exploration.

3. Ruling Proposal Specifics and Discussion

3.1 Accelerate Interconnection of Resiliency Projects

Properly designed and configured systems of distributed energy resources, including microgrids, can provide energy services during widespread grid outages. This section addresses one barrier to the deployment of distributed energy resources: the length of time it can take to interconnect with the utility distribution system. The section begins with a short description of the problem and overall guiding principles (3.1.1 – 3.1.2). Next, several proposals for addressing the problem are presented in detail, along with staff recommendations (3.1.3 – 3.1.5).

3.1.1 Interconnection Problem: Lengthy Interconnection Time

The interconnection application review process for small generating facilities on the Net Energy Metering tariff take, on average, two to three days to review.[1] In addition, most interconnecting projects qualify for the Fast Track process within the IOUs' Rule 21 Tariffs, which allows for an expedited interconnection review.[2] However, during informal conversations, stakeholders have reported that the time required to interconnect certain, more complex types of distributed energy resource systems represents a significant constraint on the overall rate of statewide deployment of distributed energy resources. Moreover, projects that provide resiliency are more likely to experience interconnection delays than simpler projects that cannot provide resiliency. This is because, in general, resiliency-focused projects must have the ability to electrically island generation and energy storage assets. Projects that island require longer study processes to ensure that there is no inadvertent export of energy to the grid; validation of these systems often requires more extensive review of interconnection applications in order to protect worker safety and avoid creating a source of ignition.

3.1.2 Guiding Principles for Interconnection Proposals

- Reduce the amount of time required to interconnect distributed energy resources that support resiliency
- Maintain the safety and reliability of the electric grid
- Ensure just and reasonable rates for participating and non-participating customers

3.1.3 Proposal

Interconnection Proposal 1: Use Pre-approved Designs in Application Process

This proposal would require Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) (collectively, the "large Investor Owned Utilities" or

[1] https://www.sce.com/sites/default/files/inline-files/NEM%20Interactive%20FAQ%200119%20for%20WCAG_K.pdf
[2] Fast Track evaluation allows for rapid review of the Interconnection of those Generating Facilities that do not require Detailed Study. For reference, see PG&E's Rule 21 Tariff: https://www.pge.com/tariffs/index.page

"IOUs") to work with stakeholders to develop, if not already available, template-based application processes for the following project types: (1) Rule 21 non-export storage, (2), NEM + Paired storage (AC Coupled and DC coupled), and (3) Net Energy Metering (NEM) Solar. In order to allow for the development of these processes, single line diagram templates would be needed for each system type. Template development processes are described in the options listed below. The pre-approved designs and single line diagrams would be eligible for the Fast Track interconnection process. This proposal still allows for custom diagrams when deemed necessary. Energy Division has identified 3 potential options as part of this proposal:

> Option 1: Require the IOUs to informally consult with industry, develop, and publish pre-approved template single line diagrams.
>
> Option 2: Require the IOUs, along with stakeholders to convene an expedited technical working group to develop the single line diagrams.
>
> Option 3: Require the IOUs to develop a process to receive, review, and approve standard diagrams from individual contractors. The approved templates would be categorized by Contractor or Contractors State License Board Number.

Staff recommends Option 1 only. The rationale for staff's recommendation is provided in section 3.1.5 below.

Interconnection Proposal 2: Expedite Utility Sign-Off on Installed Projects

This proposal seeks to reduce delays due to IOU site inspections. To that end, the options below identify possible opportunities for increasing the simplicity and transparency of the process by which IOUs inspect and sign-off on an installed project.

> Option 1: Require that the IOUs publish the specific technical criteria they use to determine where field inspections are necessary for the safety and reliability of the grid.
>
> Option 2: Require that the IOUs eliminate inspections that duplicate those conducted by local jurisdictions, if any.[3] Prohibit the IOUs from carrying out inspections of system elements that have been previously inspected by local jurisdictions unless the inspection is substantively different.
>
> Option 3: In cases where an inspection is deemed necessary, require that the IOUs must consider accepting photos or videos, along with an attestations of their accuracy, from the contractor rather than requiring an in-person inspection. The IOUs should also coordinate with local jurisdictions to enforce the same inspection requirements and eliminate duplicative efforts.

[3] For example, Tesla states that some duplicative inspections occur when the customer provides the IOU with a signed off permit from the local authority having jurisdiction but the IOU proceeds with a site inspection. In their experience this occurs when AC disconnects are installed on-site.

Staff recommends all three options. The rationale for staff's recommendation is provided in section 3.1.5 below.

Interconnection Proposal 3: Accelerate interconnections for key locations, customers, and/or facilities

Interconnection applications for larger, more novel, and/or more complex projects that require engineering review and possible interconnection upgrade cost responsibility are placed in the interconnection "queue" based on the date the application is deemed complete. In order to properly determine cost allocation, projects must be studied in order. A project at the bottom of the queue takes longer to complete the application process since the projects coming before it must be studied first.

The time required to move through the interconnection queue could mean that some newer projects may not be approved to operate in time to reduce the impact of PSPS or other outages in 2020. In order to minimize the impacts of outages due to PSPS events or other causes, an expedited queue process could be developed for projects that serve key locations, facilities, and/or customers. Staff does not propose specific criteria here for which projects would be eligible for expedited treatment but notes that several approaches to defining such criteria have been previously proposed and/or adopted in at least three different proceedings.[4]

> Option 1: While the existing queue is formed on a first-come-first-serve basis, require the IOUs to develop new rules to allow eligible projects to move ahead of other projects in the queue (often referred to as "queue jumping").
>
> Option 2: Require IOUs to develop a second "priority" queue for eligible projects, which effectively works in parallel with the existing queue. Further require IOUs to allocate dedicated staff and information technology resources to this "priority queue."
>
> Option 3: Rather than altering the queueing process, require the IOUs to commit additional staff and information technology resources to their interconnection study and distribution upgrade teams, as well as to the information technology solutions that support these teams, in order to facilitate faster queue processing for all projects.

Staff recommends Option 1 and 3. The rationale for staff's recommendation is provided in section 3.1.5 below.

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[4] "Assigned Commissioner's Scoping Memo and Ruling for Track 1" issued on 12/20/19 in R.19-09-009; D.19-05-042, Appendix A at A4, Appendix C at C2; D.19-09-027, COL 5-7, Attachment A at A1; and Decision adopting Self-Generation Incentive Program revisions pursuant to Senate Bill 700 and other program changes (January 16, 2020); (mailed on December 11, 2019 in R.12-11-005, Conclusions of Law 17 modification to definition of customers with "critical resiliency needs").

Interconnection Proposal 4: Allow the use of smart meters for electrical isolation

For a facility to safely form a microgrid during an outage event, it must have the ability to electrically island. Islanding requires that the facility: 1) be capable of complete electrical isolation from the wider grid to avoid risk of electric shock to utility workers; and 2) include generation and control systems that have the technical capability to operate independently from the grid. The switches currently required to achieve the electrical isolation function can add significant expense and installation time. Smart meters, however, include the technical capability to allow the utility to disconnect customers from the electric grid. In advance of outage events, the utility should be able to use their Advanced Metering Infrastructure network to send a disconnect signal to specific customers in order to electrically isolate them. This could allow customers to safely utilize back-up power within their homes without risking backfeed onto the grid.

Staff does not recommend this option for adoption at this time but recommends that Energy Division continue to monitor developments in this space.

3.1.4 Staff Recommendation for Interconnection Proposals

Summary of staff recommendations:

- Interconnection Proposal 1, Option 1: Use pre-approved designs in application process. Develop pre-approved designs by consulting informally with industry.

- Interconnection Proposal 2, Options 1, 2, and 3: Expedite utility sign-off on installed projects by
    - Publishing criteria for determining when field inspections are necessary;
    - Eliminating IOU inspections that unnecessarily duplicating inspections by local jurisdictions; and
    - Consider accepting photos or videos in lieu of physical site visits.

- Interconnection Proposal 3, Options 1 and 3: Accelerate interconnections for key locations, facilities, and/or customers by:
    - Allowing eligible projects to bypass the interconnection queue; and
    - Adding staff and information technology resources.

Staff does not recommend the adoption of Interconnection Proposal 4 at this time but recommends that Energy Division continue to monitor developments in this space. The rationale for staff's recommendations is provided in section 3.1.5 below.

3.1.5 Rationale for Staff's Interconnection Proposal Recommendations

Staff recommends Interconnection Proposal 1, Option 1 for the following reasons:

- Having a published set of single line diagrams will expedite the interconnection process and inform developers how to design their projects ahead of time.
- Only a limited set of single line diagrams are required -- All projects within each project category will be required to follow the same single line diagrams, which will reduce the total number of single line diagrams required.
- For simplicity, if individual developers were to submit their own single line diagrams, the IOUs may end up with a wide range of single line diagrams making the near-term solution for expedited interconnection burdensome.
- For an expedient implementation time, a working group (such as the one proposed in Option 2) may take several months to convene and deliver results.

Staff recommends Interconnection Proposal 2, Options 1, 2, and 3 for the following reasons:

- Option 1: Transparency – Published inspection criteria will give customers and developers a better sense of what inspection to expect and hence, how much additional time to build into their project schedules. For customers who intend to use their systems to provide backup power during outage events, this kind of information will be essential for planning and expectation setting.
- Option 2: Eliminate Duplicative Efforts – Delays due to field inspections that are duplicative of inspections performed by local jurisdictions are avoidable via coordination and communication.
- Option 3: Leverage Virtual Inspections – In-person inspections, while sometimes necessary, can cause project delays, increase project costs, and keep utility personnel from other essential tasks.

Staff recommends the adoption of Proposal 3, Option 1 and 3. Option 1 is most consistent with the goal of mitigating the impacts of PSPS events by directing IOU resources to benefit those locations, facilities, and/or customers who need it the most. Option 3 has the benefit of potentially increasing the speed of interconnection across all project types. Staff does, however, note several concerns with both Option 1 and Option 2:

- Wasted Effort – The interconnection studies that are required for projects that are assigned to the interconnection queue are highly interdependent, both technically and logistically. Allowing a new project to bypass the queue could require starting interconnection studies over in order to account for the presence of the new project. The time and effort previously expended by the utilities and customers in the queue would be lost.

- Delays and Cost Impacts – Directing interconnection study and upgrade resources towards priority projects would almost certainly create additional delays to the interconnection processes for those facilities not deemed eligible for priority interconnection. Those delays would cause financial harm by extending the time before projects can begin earning revenue. Significant delays may result in project cancellation.

- Uncertainty - Even the possibility of a new source of delay has the potential to create uncertainty for developers and customers already in the queue or considering projects. This could lead to project cancelation and decrease the appetite for investment.

At this time, staff does not recommend the adoption of Proposal 4. The technical and logistical elements of this proposal have yet to be fully clarified and will likely require significant time and stakeholder engagement to flesh out. Hence, staff does not believe it would be productive to take procedural action on this proposal at this time. Instead, Energy Division should continue to monitor developments in this space.

3.1.6 Details on Interconnection Proposals

The Interconnection Discussion Forum, established by Resolution ALJ-347 (approved October 12, 2017), provides an informal venue for utilities, developers, and other stakeholders to explore a wide variety of issues related to interconnection practices and policies. The Interconnection Discussion Forum meets in person quarterly and may be convened more frequently as needed. The Interconnection Discussion Forum is intended to meet the following objectives:

- Foster proactive, constructive communication between utilities, developers, and other impacted stakeholders about issues related to implementation of Rule 21 and other interconnection rules;
- Resolve informally and/or prevent interconnection disputes; and
- Share information and best practices across utilities and developers.

Energy Division hosted the 4th Quarter 2019 Interconnection Discussion Forum on December 16, 2019. The primary session focused on topics for Streamlining Interconnections for Resilience. The intent of the session was to discuss near-term actions and solutions to streamline the interconnection process ahead of Fall 2020.[5] The topics presented during the 4th Quarter 2019 Interconnection Discussion Forum included:

- Single Line Diagrams: In most cases, an interconnection application involves submitting detailed, site-specific diagrams depicting system design. In contrast, a template-based

[5] Presentations can be found at: https://www.cpuc.ca.gov/Rule21; Energy Division requested informal comments from Interconnection Discussion Forum participants on the Interconnection Discussion Forum presentations; informal comments were due on December 24, 2019.

interconnection application process allows developers to select their design from a clear set of options, including pre-established single line diagrams and pre-approved inverters and other equipment. The use of a template-based approach for various project types could simplify the overall interconnection application process, including the submission and review processes. Moving to a template-based approach would eliminate requirements to submit site specific design plans and facilitate deployment of systems that could support a customer's resilience needs during PSPS events. PG&E already deploys a standard single line diagram for NEM Photovoltaic (PV) applications less than or equal to 30 kW. SDG&E also uses single line diagram templates for stand-alone PV systems applying for interconnection. Neither PG&E nor SDG&E provide this for NEM-paired storage (DC or AC coupled) or for Rule 21 non-export storage. SCE currently does not use a template diagram for any scenario; consequently, all projects require a custom diagram to be submitted.

- Necessity of Utility Site/Field Inspections: Site inspection practices appear to be inconsistent across the IOUs, with the inspections often being performed at the discretion of the IOU staff studying the interconnection projects. When inspections are required, they can extend project timelines because the site inspections require the IOUs to coordinate site visits with the customer and contractor. Based on informal feedback, some of these inspections are duplicative of those performed by local building and safety departments (the Authorities Having Jurisdiction). Additionally, stakeholders report that they have worked with utilities outside of California[6] to utilize virtual photo inspections. The Self-Generation Incentive Program Administrators (PAs) are in the process of implementing virtual inspections for residential projects.

- Prioritizing of Interconnection for Key Locations, Facilities, and/or Customers: Following the submission of an interconnection application, projects that bear cost responsibility for the distribution upgrades required as a result of their interconnection (e.g., all non-NEM) are assigned a queue position. Queue position is assigned based on the date that IOU deems the interconnection application complete. According to existing Rule 21 language, each IOU must maintain a single queue.[7] Interconnection studies are conducted in the order dictated by the queue and cost responsibility is allocated according to a cost-causer model wherein the interconnecting facility that triggers an upgrade is responsible for the full cost of that upgrade. Stakeholders discussed both the possibility of eligible facilities being allowed to jump to the front of the queue and the formation of a second, priority queue for eligible facilities during the Interconnection Discussion Forum.

1) Use of Smart Meters for Intentional Islanding: During the Interconnection Discussion Forum, representatives from 33 North Energy and Connect California presented on a proposed technical solution that would rely on existing smart meters to electrically island behind the meter facilities. Connect California currently offers a hardware platform that mounts to utility meters,

[6] According to stakeholders, virtual inspections are allowed by the Los Angeles Department of Water and Power, National Grid (Massachusetts and Rhode Island) and CenterPoint Energy (Texas).
[7] Electric Rule 21, Section E.5.c.

allowing the meter to effectively serve as a backup power transfer system. Connect California proposes to initiate a pilot project in early 2020 to refine their currently available products and ensure their safety and reliability. During the Interconnection Discussion Forum discussion, stakeholders raised concerns about the reliability of the proposed solution, the ownership issues its implementation would raise, and various other complexities.

3.2 Modernize Tariffs to Maximize Resiliency Benefits

Properly designed and configured solar-paired energy storage systems are examples of distributed energy resources that can provide energy services during a wider grid outage customer-specific resiliency. This section presents two different barriers to broader deployment and use of energy storage systems for resiliency in the NEM tariff: 1) the limit on storage charging and 2) the limit on storage sizing/capacity. The section begins with a short description of each problem and overall guiding principles (3.2.1 – 3.2.2). Next, proposals for addressing the first problem are presented in detail, along with staff recommendations (3.2.4 – 3.2.7). Lastly, proposals for addressing the second problem are presented in detail, along with staff recommendations (3.2.8 – 3.2.11).

3.2.1 Tariff Problem 1: Storage Charging Limit

NEM is a tariff that allows a customer to self-generate at one time and use the generation at another time. Many energy storage systems qualify for NEM eligibility by including equipment that prevents electricity that has been imported from the grid from charging the storage device. Therefore, energy storage systems that are using NEM likely for its primary purpose of rate optimization, are also systems prevented from charging from the grid in advance of announced outage events, which can diminish their ability to provide resilience.

3.2.2 Tariff Problem 2: Storage Capacity Limit

Existing net energy metering (NEM) rules based in statute limit the size of a storage system that can be paired with a NEM-generating facility. Those rules limit the size of the storage system to 150 percent of the generating facility's maximum output capacity. This sizing requirement restricts a customer's ability to simultaneously participate in the NEM tariff and also to maximize the resiliency benefits that larger storage systems could provide during an extended grid outage. Under the existing set of statutory and tariff rules, it appears that a customer that has a primary purpose of resiliency should forgo the opportunity provided by NEM tariff to accelerate their financial investment payback.

3.2.3 Guiding Principles for Tariff Proposals

- Reduce tariff barriers for distributed energy resource use cases that support resilience
- Maintain the integrity of existing tariffs that are intended to reward production of on-site renewable energy
- Maintain the safety and reliability of the electric grid
- Ensure just and reasonable rates for participating and non-participating customers
- Provide flexibility to customers to improve their own resiliency

3.2.4 Proposals for Tariff Problem 1 - Storage Charging Limit

This proposal concerns energy storage systems employing power control systems to meet NEM metering requirements and prevent grid charging. The proposal would allow these energy storage systems to temporarily charge from the grid ahead of announced PSPS events (pre-PSPS window).

Following the conclusion of the PSPS event, power control system settings would be required to return to their default non-import settings.

Tariff Problem 1: Proposal 1 – Allow both export and import during pre-PSPS window

In order to allow energy storage systems to provide full resilience benefits, require the IOUs to allow energy storage systems to, in advance of PSPS events, both import from and export power to the grid.

Tariff Problem 1: Proposal 2 – Allow temporary transition to non-export mode during pre-PSPS window

In order to allow energy storage systems to provide full resilience benefits, require the IOUs to, in advance of PSPS events, allow energy storage systems to import from the grid, but not to export to the grid. This would be effectuated by transitioning into non-export mode ahead of PSPS events.

3.2.5 Staff Recommendation for Storage Charging Proposals

Staff recommends the adoption of Tariff Problem 1: Proposal 2.

3.2.6 Rationale for Staff's Storage Charging Proposal Recommendations

Staff recommends the adoption of Tariff Problem 1: Proposal 2 for the following reasons:

- Improved ability of energy storage systems to provide backup power – Both proposals 1 and 2 will ensure that NEM integrity requirements do not reduce the ability of solar-paired energy storage systems to provide backup power during PSPS events.

- Minimal risk to NEM integrity goals – Both proposals 1 and 2 are intended to be applicable only under specific circumstances that are expected to occur infrequently. As such, it is unlikely that it will have a significant impact on overall NEM integrity even if grid charging is allowed for storage that is typically designated for renewable charging only.

- Staff recommends Proposal 2 over Proposal 1 because it will best maintain NEM integrity – Proposal 2 will require that energy storage systems that are allowed to charge from the grid in advance of PSPS events are placed in non-export mode. Given that non-export settings are another acceptable way of satisfying NEM metering requirements, this will ensure that systems remain in compliance with NEM requirements even if they are not promptly reset following the conclusion of the PSPS event. In contrast, under Proposal 1, energy storage systems that are not properly reset after the PSPS event could continue to export energy that was derived from the grid, violating the intent of the NEM requirements.

3.2.7 Details on Storage Charging Proposals

According to current NEM rules, energy storage systems larger than 10 kW must adhere to one of the following metering configurations:

- Install a non-export relay on the storage device(s);
- Install an interval meter for the NEM-eligible generation, meter the load, and meter total energy flows at the point of common coupling;
- Install interval meter directly to the NEM-eligible generator(s);
- Use equipment that prevents electricity to be exported from the storage device to the grid; or
- Use equipment that prevents electricity imported from the grid to charge a storage device.

During the December 16, 2019 Interconnection Discussion Forum,[8] stakeholders noted that NEM Metering Configuration 5, as listed above, is one of the most common metering configurations. Given that this metering configuration prevents energy storage systems from using grid power to charge, it can reduce the resilience benefits of energy storage systems. For example, if solar irradiance were not sufficient to fully charge the energy storage system between the time a PSPS event was announced and the start of the PSPS, the customer would begin the event without the benefit of a fully charged energy storage system.

In order to allow energy storage systems to provide maximum resilience benefits, Interconnection Discussion Forum stakeholders proposed that energy storage systems that meet NEM metering requirements via NEM Metering Configuration 5, typically by employing a power control system that prevents grid charging, should be allowed to charge from the grid ahead of announced PSPS events.

Staff notes that the full value proposition of this proposal is not well quantified. For example, the need for grid charging of an energy storage system would depend on the length of the pre-PSPS window and the available solar irradiance during that window. PSPS events evolve rapidly and evoke the need for swift action to provide resilience options. This proposal could be piloted for the next 2-3 years and revisited after additional experience has been collected. Utilities could monitor the number of systems that changed configurations and repeat to commission.

3.2.8 Proposals for Tariff Problem 2 - Storage Capacity Limit

Tariff Problem 2: Proposal 1 - Modify NEM tariff to remove storage sizing limit and to require islanding ability for energy storage systems larger than 10 kW

Modify NEM tariffs to:

1. Remove the storage sizing limit for NEM-paired storage sized larger than 10 kilowatts (kW).[9]

[8] This stakeholder forum is discussed in greater detail in section 3.1.6.
[9] There is no NEM storage sizing limit for storage sized 10 kW and smaller.

2. Maintain the existing requirement that a NEM-paired storage system sized larger than 10 kW adhere to one of the following metering requirements:

   - Install a non-export relay on the storage device(s);
   - Install an interval meter for the NEM-eligible generation, meter the load, and meter total energy flows at the point of common coupling;
   - Install interval meter directly to the NEM-eligible generator(s);
   - Use equipment that prevents electricity to be exported from the storage device to the grid; or
   - Use equipment that prevents electricity imported from the grid to charge a storage device.

3. Require that a NEM-paired storage system larger than 10 kW that is sized to more than 150 percent of the NEM generating facility's maximum output capacity be specifically designed to operate independently from the grid in the event of a grid outage.

Tariff Problem 2: Proposal 2– Modify NEM rules to remove storage sizing limit

Modify NEM rules to:

1. Remove the storage sizing limit for NEM-paired storage sized larger than 10 kilowatts (kW).[10]

2. Maintain the existing requirement that a NEM-paired storage system sized larger than 10 kW adhere to one of the following metering requirements:

   - Install a non-export relay on the storage device(s);
   - Install an interval meter for the NEM-eligible generation, meter the load, and meter total energy flows at the point of common coupling;
   - Install interval meter directly to the NEM-eligible generator(s);
   - Use equipment that prevents electricity to be exported from the storage device to the grid; or
   - Use equipment that prevents electricity imported from the grid to charge a storage device.

[10] There is no NEM storage sizing limit for storage sized 10 kW and smaller.

3.2.9 Staff Recommendation for Storage Capacity Limit Proposals

Staff recommends Tariff Proposal 1.

3.2.10 Rationale for Staff's Storage Capacity Limit Recommendations

The existing NEM-paired storage tariffs were originally approved to ensure that only energy generated by a renewable generating facility could receive the economic benefit of the bill credit provided under the NEM tariff. The CPUC determined via D.16-04-020 (later modified by D.18-02-008) it would not be appropriate for a NEM customer to receive a bill credit for energy sent to the grid that was charged from the grid that was intended to compensate a customer for renewable energy.

As the main focus of the decision imposing the sizing and metering rules on NEM-paired storage was on maintaining the integrity of the policy that NEM bill credits be provided as a reward for on-site renewable generation, the storage sizing and metering requirements were oriented for ensuring that outcome. With the recent PSPS events, and the potential for renewable energy paired with storage to provide backup power in the event of a grid outage, the CPUC has the opportunity to revisit these rules to consider how they may be augmented to enhance resiliency benefits while still maintaining the integrity of NEM bill credits.

The existing Rule 21 tariff language that limits storage sized larger than 10 kW to 150 percent of the maximum output capacity of the renewable generator is a reasonable backstop limitation to place on a storage system when developing a requirement intended predominantly to maintain the integrity of the NEM credit. However, limiting the size of the storage limits the ability for customers to size their storage to provide for more robust resiliency during an extended grid outage. Removing the storage system sizing limit, while maintaining the requirement that NEM-paired storage sized larger than 10 kW adhere to one of the existing metering requirements will ensure that a NEM-paired storage system only receives NEM bill credits for exported generation from 100 percent renewable energy. In addition, since the augmentation of these existing rules is intended to facilitate the provision of resiliency benefits to customers in a grid outage event, staff finds it appears reasonable to require the utilities to require the interconnecting customer to demonstrate that their system is designed to operate independently of the grid in an outage event, so that the intended resiliency benefits of the addition of the storage may be realized.

3.2.11 Details on Storage Capacity Limit Proposals

D. 14-05-033 placed certain limitations on storage system sizing and implemented metering requirements for NEM interconnection eligibility for storage devices paired with NEM generation facilities. That decision was subsequently modified by D.19-01-030. D.16-04-020 established a generation estimation methodology for small NEM paired storage systems. That decision was subsequently modified by D.18-02-008. Each of the decisions was implemented via Advice Letters where the utilities submitted conforming tariff language modification to their CPUC reviewed Rule 21 tariffs. The current applicable rules[11] are:

- Storage systems 10 kW and smaller:
  - Renewable generation estimation methodology, which caps maximum allowable NEM bill credits based on a monthly output profile, or on a single monthly kilowatt hour (kWh) per kW scalable profile for each climate zone.

- Storage systems larger than 10 kW:
  - Must be sized to have a maximum output power no larger than 150 percent of a renewable NEM generator's maximum output capacity.
  - Required to adhere to one of the following metering requirements:
    - Install a non-export relay on the storage device(s);
    - Install an interval meter for the NEM-eligible generation, meter the load; and meter total energy flows at the point of common coupling;
    - Install interval meter directly to the NEM-eligible generator(s);
    - Use equipment that prevents electricity to be exported from the storage device to the grid; or
    - Use equipment that prevents electricity imported from the grid to charge a storage device.

To maintain consistency across other NEM-related tariffs that derive energy storage system sizing restrictions from D.14-05-033 and its subsequent modifications mentioned above, it will be necessary for utilities to update those tariffs. For example, Virtual Net Energy Metering (VNEM) and Net Metering Aggregation (NEM-A) both references said decisions and would need be to be updated to reflect any new decision that may be issued to implement this proposal.

However, for some tariffs, modifications to these restrictions will have minimal impacts. For instance, if a customer on the Renewable Energy Self-Generation Bill Credit Transfer tariff (RES-BCT) intended to install an energy storage system, the customer would take service on Net Energy Metering Multiple Tariff (NEMMT). NEMMT allows the customer to bifurcate their system into NEM (energy storage system and on-site renewable energy generation sized to-site load) and RES-BCT (for additional on-site renewable energy generation capacity sized to cover additional non-contiguous benefitting accounts).

[11] PG&E Electric Schedule NEM2 Special Condition 9, SDG&E Schedule NEM-ST Special Condition 10, SCE Schedule NEM-ST Special Condition 6

3.3 Share Information with Local Government Agencies

This section presents barriers to local government access to distribution and infrastructure data to facilitate development of resiliency projects. The section begins with a description of the problem and overall guiding principles (3.3.1 – 3.3.2). Next, proposals for addressing the first problem are presented in detail, along with staff recommendations (3.3.4 – 3.3.6).

3.3.1 Information Access Problem

Local government agencies, including cities and counties, and tribal governments and community choice aggregators, have expressed interest in distributed energy resources, including microgrids, as a community resiliency solution to minimize the impact of de-energization events.[12] In order to plan, design, budget, and implement cost-effective and efficacious resiliency solutions for their communities, local government agencies have articulated an interest in being provided access to various types of utility information, including but not limited to:

- The location of transmission lines serving their communities, and likelihood that a transmission line might be de-energized in the future;
- Technical and customer data related to the distribution circuits serving their communities, and likelihood that a circuit might be de-energized in the future;
- Identity and location of critical facilities (i.e., which specific facilities are included the list the IOUs are required to develop and maintain per D.19-05-042, Appendix A, p. A4-A5)
- Scope and schedule of IOU plans to re-configure, sectionalize, switch, or harden lines/circuits to reduce or eliminate future PSPS events.

Broadly, there are two types of decisions that local governments, CCAs, and tribal governments must make that would benefit from the utility information:

- Investment decisions well in advance of outage events such the procurement of back up generation, microgrids, or other resilience solutions; and
- Operational decisions immediately prior to outage events to ensure energy services are available for critical facilities and vulnerable customers.

According to the local government and CCA representatives, barriers to accessing and using information currently provided by utilities include:

- Data sets currently available do not contain all required information;
- Data points are obscured or in unusable formats; and
- Data is not in a centralized location and/or must be access via different applications or portals.

[12] Examples can be found in the press (https://www.washingtonpost.com/news/powerpost/paloma/the-energy-202/2019/11/05/the-energy-202-this-california-mayor-wants-to-decrease-dependence-on-pg-e-amid-planned-blackouts/5dc0734c602ff1184c3161c7/), in communications from CCAs to utilities (October 29, 2019 Letter "Joint CCA Request for Additional Information In 4013 and PSPS Disclosures"), and in public solicitations (https://ebce.org/wp-content/uploads/Final_Joint_LSE-Distributed_RA-RFP_with-Addenda-12_6_2019.pdf)

Additionally, local governments agencies and CCAs have indicated that they do not have access to the utilities' planned PSPS mitigation activities that may impact the need for their local resiliency projects.[13]

Local government agencies and CCAs have also expressed concern that they should be actively consulted about siting of resilience solutions. Local governments agencies want to be involved, have input and buy-in into siting decisions for solutions that minimize PSPS outages, such as PG&E's resiliency zones and preinstalled installation hubs related to resiliency zones, as well as the distributed generation-enabled microgrid solutions.

3.3.2 Guiding Principles

- Foster collaborative problem solving by utilities, local agencies, and state government
- Facilitate ability of local government agencies to protect the lives and health of their communities
- Support equitable access to utility information across local government agencies
- Build upon existing emergency planning exercises already conducted pursuant to General Order 166

3.3.3 Local Government and Access to Data Proposals

Local Government Proposal 1 – Outreach and Communication

1. This proposal would require the IOUs to:

    a. Develop or ensure effective internal communication processes exist for managing interfaces with local government, which may include but not be limited to:

    - Designating utility interfaces roles and responsibilities;
    - Managing engagement with local government, building and sustaining effective relationships;
    - Establishing and maintaining open, accurate and consistent lines of communication;
    - Involving local government in planning, and vetting of utility actions impacting local government;
    - Executing and follow-through on agreements impacting local government.

    b. Inform local governments about the utility electric transmission and distribution investment and operational plans. Specifically, this proposal would require each utility to fully inform local governments about the projects comprising its portfolio of projects intended to minimize use of public safety power shutoffs:

[13] "Decision Adopting Rules to Protect the Privacy and Security of Electricity Usage Data of the Customers of Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas and Electric Company", D.11-07-056, issued on 7/29/2011 in R. 08-12-009.

- Identify the projects (e.g., as applicable to individual utility: reconductoring, transmission line exclusion, transmission line switching, distribution segmentation, distributed generation enabled microgrids, temporary generation, substation make ready).
- Identify by County and provide geographic location.
- Describe scope, schedule, cost and number of customers impacted.
- Confirm potential for minimizing customer outages due to public safety power shutoff; and

c. Communicate and educate local jurisdictions, about the electric transmission and distribution infrastructure serving their communities by conducting face-to-face workshops.

The workshops would have the following characteristics:

- Semi-annual frequency;
- Representatives from city, county, tribal, and community choice aggregator personnel (e.g. county office of emergency services (OES), county planning, county department of public works);
- Utility operational and technical subject matter experts skilled at communicating how the electric system works to a general audience;
- Ground rules involving collaboration and consensus-building; and
- Completion of first semi-annual round by April 30, 2020.

The workshop agenda would include, but not be limited to, the following topics:

- Explanation how the electric transmission and distribution system operates in their area - basic grid topology and circuit configurations;
- Previous PSPS events;
- Weather and climatology analysis predictions of future PSPS events; and
- Case studies of outage scenarios the County may experience based on predicted weather events.
- Granular, local reporting of reliability events, similar to reliability reporting meeting required.

The workshop would conclude with a collaborative planning session about enhancing grid resilience within the county in and across all local government agency jurisdictions. Pursuant to R.14-12-014 via D.16-01-008, CPUC staff recommends this segment should be:

- Moderated by the county OES Administrator;
- Based upon relevant elements of a community-based collaborative planning framework such as the National Institute of Standards and Technology Community Resilience Planning Guide or its Resilient Communities Toolkit;[14]

[14] https://www.nist.gov/topics/community-resilience/planning-guide The planning guide recommends methods for forming collaborative planning teams to help a community improve their resilience by setting priorities and allocating resources to manage risks for their prevailing hazards.

- Based on best practices such as SDG&E community engagement;
- Monitored and supported by CPUC staff; and
- Evaluated by CPUC staff based on feedback, scorecard based on objective criteria, milestone development, progress to plans, and action plan implementation.

Staff notes that some utilities may have already conducted, or are currently implementing, various meetings with local governments regarding PSPS event planning. An example of how such existing activities could be expanded to implement this proposal is provided in the section below entitled "Details on Local Government and Data Needs Proposals."

Local Government Proposal 2 – Resiliency Project Engagement Guide

Local governments, CCAs, and tribal governments have expressed interest in distributed energy resources, including microgrids, that interconnect both behind and in front of the customer meter. While IOU websites do offer information relevant to developing behind-the-meter project development[15], less information is available regarding in-front-of-the-meter projects.

Generally, local and tribal governments can request service related to in-front-of the meter infrastructure from an IOU by contacting a designated point of contact or assigned account executive. To maximize the efficiency and effectiveness of both IOU and government resources in such engagements, this proposal would require IOUs to develop a written guide to help local and tribal governments navigate the IOUs' interconnection and other processes for deploying a resiliency project. Specifically, this proposal would require IOUs to develop a guide specifically for local and tribal governments that includes, but is not limited to, the following topics:

- Flowchart depicting how to engage the IOUs depending on the type of resiliency project being planned; and
- Best practices for successful project implementation.

Local Government Proposal 3 – Dedicated IOU Team for Local Government Projects

This proposal would require each IOU to create a dedicated team of staff to manage the intake of local and tribal government resilience projects. It would involve a dedicated IOU point of contact to ensure early engagement between the IOUs and the local or government agency. The point of contact will manage the delivery of pre-application consulting services to local jurisdictions. This may include but not be limited to:

- Providing advice and guidance before planning and proposal development begins;

[15] For example, see maps developed pursuant to Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies And Requirements; and (2) Authorizing Demonstration Projects A and B" issued on 05/02/2016 in R.14-08-013.

- Prioritizing projects to ensure that resources are directed to the most urgent for public health and safety and public interest;
- Assisting the local jurisdictions with consulting advice on the types of resiliency projects that can be expedited through the permitting and interconnection process; and
- Providing pre-project information about load points, customer connectivity, load profiles, and the relevant maps and infrastructure data to facilitate local jurisdiction planning.

The intended outcome for providing this IOU service would be to provide a one-stop resource that maintains awareness of microgrid deployment, develops expertise and provides reliable technical guidance, provides easy access, a consistent approach, and facilitates local and tribal government microgrid deployment. It would require a process for engaging, receiving, prioritizing, and processing of requests for assistance from local and tribal governments.

Local Government Proposal 4 – Developer Interconnection Training

This proposal would require IOUs to develop an interconnection orientation and training program for vendors and developers operating in California. The orientation and training will include understanding the IOU interconnection processes and requirements. The process ensures that developers initiating interconnection applications for the first time in California are educated, informed, and knowledgeable about interconnection with the IOUs and are able to follow the rules, tariffs, and processes in place resulting in higher quality interconnection applications which take less process cycle time for IOUs to approve.

The program would consist of:

- Training objectives;
- Training modules;
- Evaluation criteria for determining successful completion;
- Test and answer key;
- Certificate of completion;
- Certified vendor list; and
- Complaint and claims process including monitoring and resolving disputes related to certified vendor performance.

Local Government Proposal 5 – Separate Portal for Local Government

This proposal recommends IOUs create a separate access-restricted portal, available only to local and tribal governments, and containing essential data for identification of in front of the meter microgrid development opportunities. Access would be restricted to cities, counties, tribal governments and community choice aggregators. CPUC privacy rules enable provision of information under D.11-07-056 and the IOUs' CPUC approved privacy tariffs, as well as the California Consumer Privacy Act effective January 1, 2020. Community choice aggregators would receive equal access to protected IOU information related to PSPS events and infrastructure data consistent with executing an information non-disclosure agreement and CPUC privacy rules, without having to act as an agent of a local government. The portal should display the data requested in Appendix 4.4, as well as the following data requested by a joint group of community choice aggregators in their October 29, 2019 letter "Joint CCA Request for Additional Information In 4013 and PSPS Disclosures":

- Full detailed maps (as .KMZ or .KML files) of PG&E's distribution system identifying (by color) each circuit, sub circuit, and discrete circuit segment that can be individually de-energized through the use of a sectionalizing device; and
- For each transmission line that is located in or provides electricity to the CCA's service territory, a map (as a .KMZ or .KML file) that shows all distribution circuits, sub circuits, and substations that would lose power if the transmission line were to be de-energized.

Finally, the portal should also make available other pertinent information and data visualizations including:

- 2019 PSPS events and the impacted areas;
- Data visualizations of the IOU's PSPS mitigation initiatives such as transmission line exclusion, transmission line switching, distribution segmentation, and distributed generation enabled microgrids and areas it will affect that may impact the need for local government investment projects; and
- Predicted locations of future PSPS events based on multiple-year predictive modeling/climatology analysis.

3.3.4 Staff Recommendation

CPUC Energy Division staff recommends the adoption of Proposals 1, 2, 3 and 5. Staff recommends coordination with proposals being simultaneously considered in R.18-12-005.

Staff does not recommend the adoption of Proposal 4 at this time but recommends that Energy Division continue to encourage exploration and discussion of these topics and monitor developments in this space.

3.3.5 Rationale

Proposal 1 – Communication and Outreach

From interviews and comments, the uncertainty on how to work with the IOUs and access to data were reoccurring priority issues from multiple stakeholders. By understanding the nature of wind events and grid operations along with proposed PSPS mitigation initiatives, local jurisdictions will be able to make informed decisions on where to focus their resiliency planning efforts, capital investments, and pre-event operations.

Proposal 2 – Engagement Guide

In order to prepare for emergencies, including wildfires and PSPS outages, community members, local governments, tribal governments, and businesses are pursuing new types of resiliency solutions, including in-front-of-the-meter projects that historically were primarily implemented as part of IOUs' own grid management practices or as pilot projects. In-front-of-the-meter resiliency solutions can range widely in complexity from multi-customer in-front-of-the meter microgrids to individual distribution switches.

Currently, IOUs' web pages include NEM-specific information for customers intending to connect storage on net-energy-metering rate schedules, but little information is available on how to pursue other types of resiliency projects. IOU web pages do include information directing businesses to make a request for services or to contact the business services or project management services departments.

Creating a simple step-by-step guide that communicates best practices and lessons learned would guide local and tribal governments and their community members in the early stages of resiliency project planning. This proposal is consistent with suggestions to create a checklist for deploying microgrids that arose during the Microgrids OIR Workshop held on 12/12/19.

Anticipated benefits of a resiliency project engagement guide include:

- Assisting local and tribal governments with selecting configurations and project designs that are as economic as possible;
- Reducing interconnection delays associated with behind-the-meter projects by helping interested agencies identify locations where it is feasible to interconnect; and
- Minimizing costs and delays by pre-screenings projects for issues that require substantial redesign or cancellation.

Proposal 3 - Dedicated IOU Team for Local Government Projects

This proposal would require the IOUs to add additional positions to their distribution planning team for staff who specialize in resiliency project development for local and tribal governments. Establishing a dedicated team would build specialized expertise within each IOU and provide organizational stability to support community resiliency projects on an ongoing basis. This, in turn, would improve the confidence of local and tribal governments and market providers to explore and develop projects. A dedicated team with specialized expertise would also allow for the processing of a larger volume of projects at a more rapid pace. This focus should be achievable within existing GRC funding levels and subsequent GRCs may request augmentation to these resources.

Proposal 4 – Developer Interconnection Training

While improving vendor and developer knowledge would be beneficial to all parties, this option requires additional discussions on the details and execution of the orientation and training. This option would also likely be infeasible to achieve within the next several months and would have a timeline that extends beyond Summer 2020.

Moreover, the Interconnection Discussion Forum, discussed previously in this document, already exists as a venue for developers to explore issues related to interconnection practices and policies.

Proposal 5 – Separate Portal for Local Government

An access-restricted portal for local and tribal governments would be useful for displaying the information and data visualizations that would enable local and tribal governments to understand the structure and operation of IOU distribution infrastructure as well as planned IOU work on the system. Having this information would allow local and tribal governments to use IOU data on PSPS mitigations that are planned and underway, historical PSPS outage locations, historical climatology analysis and high fire threat district boundaries to identify development opportunities for in front of the meter microgrids. This data would also help determine whether a microgrid would be an appropriate solution for given conditions based on system work that is either planned or being performed by the IOUs. Identification of these opportunities using the data provided in the portal would allow local and tribal governments to productively engage with the IOUs during the microgrid development process.

The de-energization (or PSPS) proceeding has already established secure data portals for local and tribal government to access PSPS event data which could be adapted for this end use. As to requested data, CPUC staff have engaged multiple stakeholders to create the list of data needs for microgrid development shown in Appendix 4.4 highlighting the data that is currently publicly available through the Distributed Resources Plan maps and other public resources. The letter from the Joint CCAs also requested more information on PG&E's distribution system in order to better understand the structure and operation of the infrastructure within the CCA service territory. Access to this data is a valuable asset to local and tribal governments seeking for identifying opportunities to create resiliency.

3.3.6 Details on Local Government and Data Needs Proposals

The details within this section apply to all the information sharing proposals. Therefore, this section is intentionally organized by topics and not organized by individual proposal as in the interconnection and tariffs sections.

Local Government Needs

To facilitate the planning and implementation of such projects, local governments have expressed the need to understand the structure of the electric distribution grid networks serving their communities and the need to have easier access to accurate data. This includes but is not limited to grid topology (radial or networked), circuit location, historical load shapes, customers on each circuit and which circuits would likely be impacted by future de-energizations, especially circuits connected to critical facilities and customers with access and functional needs. Access to these data points allow local governments to determine optimal solutions for reducing loads through energy efficiency initiatives, incorporating behind the meter distributed energy resources, and siting community specific resiliency projects.

Current Availability of Distribution Data

Local governments have expressed that the available data is insufficiently robust, inaccessible and difficult to navigate. Some local governments expressed that there has been historically some level of difficulty in acquiring infrastructure data from one or more IOUs due to refusal, difficulty in navigating IOU organizations, administrative time to follow-up on data requests.

Additionally, some publicly available data elements may be inaccessible because it is marked 'confidential' and therefore obscured to protect customer privacy. The data may not be in a useful and/or consistent format. For example, the Integration Capacity Analysis (ICA) and Distribution Investment Deferral Framework (DIDF) maps allow users to download the map data in a format that will be supported by Geographic Information System (GIS) applications. Although, the PG&E Photo Voltaic Renewable Action Mechanism (PVRAM) map does not provide the data in a GIS format which presents challenges when viewing it in conjunction with other datasets, the ICA map supersedes the PVRAM.

Based on conversations with stakeholders, CPUC staff developed a preliminary analysis of the data available through various sources and have noted the data availability and their caveats. See Appendix 4.4, for a precursory table.

Constrained IOU Resources

The growing interest in community solutions to address energization events creates more demand for IOU resources to respond to inquiries. Simultaneously, IOUs are focused on Wildfire Mitigation Plan implementation and PSPS mitigation program endeavors.[16] Consequently, IOUs are focused on prioritizing resources towards providing the largest benefits in resolving outages and may not have staff resources to focus on smaller scale local or tribal government resiliency projects.

[16] Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018)" filed on 10/25/18 in R.18-10-007.

Local Government and Developers Knowledge Gaps

CPUC staff acknowledges that local governments may not always have a complete understanding of the IOUs' interconnection process and timelines. Until the recent advent of significant public safety power shutoffs, local government agencies had not sought distribution system level data to the same degree as they are now. Additionally, developers and consultants that local government partners with may also have knowledge gap, especially those new to the California energy system.

The varying levels of experience with the IOU process and available data sets causes delays for both the IOUs and developers working with local government agencies. Conversely, staff working collaboratively with experienced and technically qualified developers, as showcased in the Electric Program Investment Charge projects or as presented in the CPUC Workshop presentations on 12/12/19, such as the Schatz Energy Center, contributes immensely towards the success of a microgrid project.

Current IOU Outreach to Local Governments

On October 14, 2019, President Batjer ordered PG&E to implement immediate corrective actions after it encountered significant problems with communication, coordination, and management during the largest PSPS event in California history. President Batjer's letter[17] is the driver for PG&E to conduct "Listen & Share" sessions which:

- require PG&E to collect feedback from local governments (cities and counties);
- identify specific actions to be taken to address such feedback; and
- identify concerns with PG&E's coordination with local governments, specifically related to past PSPS events.

Staff proposes to expand the scope of PG&E's "Listen & Share" sessions to achieve additional objectives. PG&E's would explain how the electric transmission and distribution system operates, which would expand community awareness of how grid configuration influences why communities are impacted by PSPS. PG&E would also communicate its PSPS mitigation initiatives that affect any part of county where the meeting is held, identifying in particular those projects that would include system hardening, sectionalizing, distributed generation enabled microgrids, temporary generation, resilience zones, or remote grids.

[17] President Marybel Batjer, letter to PG&E, 15 Oct. 2019. https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/PGE%20Letter%20-%20PSPS%2010-14-19.pdf

4. Appendices

4.1 Definitions

The definitions below are meant to communicate how these terms are being used within this document. Some definitions used in this document may not encompass all aspects that are relevant to future resilience and microgrid policy development (see notes under definition of microgrid and resilience/resiliency).

Critical facilities: has the meaning as defined in D.19-05-042, Appendix A at A4 and Appendix C at C2. From Appendix C:

"Facilities that are essential to the public safety and that require additional assistance and advance planning to ensure resiliency during de-energization events. The terms 'critical facilities' and 'critical infrastructure' can be used synonymously. Police Stations; Fire Stations; Emergency Operations Centers; Medical facilities including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers and hospice facilities; Schools and licensed daycare centers; Public and private utility facilities vital to maintaining or restoring normal service, including, but not limited to, interconnected publicly-owned utilities and electric cooperatives; Facilities associated with the provision of drinking water including facilities used to pump, divert, transport, store, treat and deliver water; Communication carrier infrastructure including selective routers, central offices, head ends, cellular switches, remote terminals and cellular sites (or their functional equivalents); Jails and prisons."

Key locations, facilities, and/or customers: geographic areas, buildings, equipment, or individual customer accounts that merit preferential attention during grid outages; may include but are not limited to "critical facilities" or customers with "critical resiliency needs" as defined in D.19-09-027. Several different approaches to criteria that could be used to prioritize actions resulting from this staff proposal have been previously proposed and/or adopted:

- "Assigned Commissioner's Scoping Memo and Ruling for Track 1" issued on December 20, 2019 in R.19-09-009 ("key sites and locations");
- D.19-05-042, Appendix A at A4 and Appendix C at C2 (definition of "critical facilities");
- D.19-09-027, Conclusions of Law 5-7, Attachment A at A1 (definition of customers with "critical resiliency needs" for purposes of incentive eligibility under the Self-Generation Incentive Program); and
- Decision adopting Self-Generation Incentive Program revisions pursuant to Senate Bill 700 and other program changes (January 16, 2020); (mailed on December 11, 2019 in R.12-11-005, Conclusions of Law 17 modification to definition of customers with "critical resiliency needs").

Microgrid: a small electric grid that can balance generation and load independently

(Note: Public Utilities Code 8370(d), reproduced in section 4.3 below, provides a more technical definition of microgrid that is not inconsistent with the simpler definition used here, but introduces additional concepts not necessary to address in this proposal.)

Pre-PSPS window: the time between a PSPS event is announced and the start of the PSPS

Resilience/Resiliency: the ability to provide energy services during a wider grid outage

(Note: “resilience” is a concept that can include activities undertaken to prepare for, withstand, and recover from disturbances. Both the range of activities and the types of disturbances that are included in discussions about resilience can vary widely depending on the context. In this staff proposal, we use a narrow definition.)

4.2 Acronyms

AHJ	Authority Having Jurisdiction
CCA	Community Choice Aggregation
CEC	California Energy Commission
CES	California Electric Substation
CETL	California Electric Transmission Line Map
CPUC	California Public Utilities Commission
D.	Decision
DER	Distribute Energy Resource
DIDF	Distribution Investment Deferral Framework Map
DRP	Distributed Resources Plan
ESS	Energy Storage Systems
GIS	Geographic Information System
ICA	Integration Capacity Analysis
IOU	Investor Owned Utility
kW	Kilowatts
kWh	Kilowatt hour
NEM	Net Energy Metering
NEM-A	Net Metering Aggregation
NEMMT	Net Energy Metering Multiple Tariff
OES	Office of Emergency Services
OIR	Order Instituting Rulemaking
PCS	Power Control Systems
PG&E	Pacific Gas & Electric
PSPS	Public Safety Power Shutoff
PVRAM	Solar Photovoltaic and Renewable Auction Mechanism Map
RES-BCT	Renewable Energy Self-Generation Bill Credit Transfer Tairff
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SGIP	Self-Generation Incentive Program
VNEM	Virtual Net Energy Metering

4.3 Senate Bill No. 1339

CHAPTER 566

An act to add Chapter 4.5 (commencing with Section 8370) to Division 4.1 of the Public Utilities Code, relating to electricity.

[Approved by Governor September 19, 2018. Filed with Secretary of State September 19, 2018.]

LEGISLATIVE COUNSEL'S DIGEST

SB 1339, Stern. Electricity: microgrids: tariffs.

(1) Under existing law, the Public Utilities Commission (PUC) has regulatory authority over public utilities, including electrical corporations, while local publicly owned electric utilities, as defined, are under the direction of their governing boards. Existing law authorizes the commission to fix the rates and charges for every public utility and requires that those rates and charges be just and reasonable.

This bill would require the PUC, in consultation with the State Energy Resources Conservation and Development Commission and the Independent System Operator, to take specified actions by December 1, 2020, to facilitate the commercialization of microgrids for distribution customers of large electrical corporations. The bill would require the governing board of a local publicly owned electric utility to develop and make available a standardized process for the interconnection of a customer-supported microgrid, including separate electrical rates and tariffs, as necessary.

Under existing law, a violation of any order, decision, rule, direction, demand, or requirement of the commission is a crime.

Because the provisions of this bill would require an order or other action of the commission to implement, and a violation of that order or action would be a crime, the bill would impose a state-mandated local program.

In addition, by placing requirements upon local publicly owned electric utilities, the bill would impose a state-mandated local program.

(2) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for specified reasons.

DIGEST KEY

Vote: majority   Appropriation: no   Fiscal Committee: yes   Local Program: yes

BILL TEXT

The people of the state of California do enact as follows:

SECTION 1.

The Legislature finds and declares all of the following:

(a) Many electricity customers are seeing the potential benefits of investing in their own distributed energy resources as part of microgrids, both to ensure their own level of reliability and to better manage their own usage.

(b) Allowing the electricity customer to manage itself according to its needs, and then to act as an aggregated single entity to the distribution system operator, allows for a number of innovations and custom operations.

(c) Electrical corporations and local publicly owned electric utilities are also seeing and exploring the potential benefits of investments in microgrids.

(d) Key issues facing commercializing microgrids that must be addressed include all the following:

(1) How microgrids operate and their value.

(2) Improving the electrical grid with microgrids.

(3) How microgrids can play a role in implementing policy goals.

(4) How microgrids can support California's policies to integrate a high concentration of distributed energy resources on the electrical grid.

(5) How microgrids operate in the current California regulatory framework.

(6) Microgrid technical challenges.

(e) The Public Utilities Commission, Independent System Operator, and State Energy Resources Conservation and Development Commission must take action to help transition the microgrid from its current status as a promising emerging technology solution to a successful, cost-effective, safe, and reliable commercial product that helps California meet its future energy goals and provides end-use electricity customers new ways to manage their individual energy needs.

SEC. 2.

Chapter 4.5 (commencing with Section 8370) is added to Division 4.1 of the Public Utilities Code, to read:

CHAPTER 4.5. Microgrids

8370.

For purposes of this chapter, the following definitions shall apply:

(a) "Customer" means a customer of a local publicly owned electric utility or of a large electrical corporation. A person or entity is a customer of a large electrical corporation if the customer is physically located within the service territory of the large electrical corporation and receives bundled service, distribution service, or transmission service from the large electrical corporation.

(b) "Distributed energy resource" means an electric generation or storage technology that complies with the emissions standards adopted by the State Air Resources Board pursuant to the distributed generation certification program requirements of Section 94203 of Title 17 of the California Code of Regulations, or any successor regulation.

(c) "Large electrical corporation" means an electrical corporation with more than 100,000 service connections in California.

(d) "Microgrid" means an interconnected system of loads and energy resources, including, but not limited to, distributed energy resources, energy storage, demand response tools, or other management, forecasting, and analytical tools, appropriately sized to meet customer needs, within a clearly defined electrical boundary that can act as a single, controllable entity, and can connect to, disconnect from, or run in parallel with, larger portions of the electrical grid, or can be managed and isolated to withstand larger disturbances and maintain electrical supply to connected critical infrastructure.

8371.

The commission, in consultation with the Energy Commission and the Independent System Operator, shall take all of the following actions by December 1, 2020, to facilitate the commercialization of microgrids for distribution customers of large electrical corporations:

(a) Develop microgrid service standards necessary to meet state and local permitting requirements.

(b) Without shifting costs between ratepayers, develop methods to reduce barriers for microgrid deployment.

(c) Develop guidelines that determine what impact studies are required for microgrids to connect to the electrical corporation grid.

(d) Without shifting costs between ratepayers, develop separate large electrical corporation rates and tariffs, as necessary, to support microgrids, while ensuring that system, public, and worker safety are given the highest priority. The separate rates and tariffs shall not compensate a customer for the use of diesel backup or natural gas generation, except as either of those sources is used pursuant to Section 41514.1 of the Health and Safety Code, or except for natural gas generation that is a distributed energy resource.

(e) Form a working group to codify standards and protocols needed to meet California electrical corporation and Independent System Operator microgrid requirements.

(f) Develop a standard for direct current metering in Electric Rule 21 to streamline the interconnection process and lower interconnection costs for direct current microgrid applications.

8371.5.

Nothing in this chapter shall discourage or prohibit the development or ownership of a microgrid by an electrical corporation.

8372.

(a) Within 180 days of the first request from a customer or developer to establish a microgrid, the governing board of a local publicly owned electric utility shall develop and make available a standardized process for the interconnection of a customer-supported microgrid, including separate electrical rates and tariffs, as necessary. The separate rates and tariffs shall not compensate a customer for the use of diesel backup or natural gas generation, except as either of those sources is used pursuant to Section 41514.1 of the Health and Safety Code, or except for natural gas generation that is a distributed energy resource.

(b) The governing board shall ensure the microgrid rates and charges do not shift costs to, or from, a microgrid customer or nonmicrogrid customer, and shall ensure each microgrid and its components comply with the local publicly owned electric utility's applicable regulatory requirements.

SEC. 3.

No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because a local agency or school district has the authority to levy service charges, fees, or assessments sufficient to pay for the program or level of service mandated by this act or because costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

4.4 Availability of Data Required for Microgrids

Note: Data Needs were identified through CPUC staff engagement with stakeholders. Data Need Priority is done on a first-glance basis and will require more input and discussion to refine. Additionally, the IOU data on this table was sourced from PG&E maps only; no other IOU's data was used.

Public Sourcing Explanation
Y = Yes
Y(b) = Yes, but with caveat(s)
N = No
N(b) = No, but with caveat(s)

Data Need Priority (Relative)
H = High/essential data
M = Medium/less essential data
L = Low/non-essential data

Source Maps
ICA = Integration Capacity Analysis Map (PG&E)
DIDF = Distribution Investment Deferral Framework Map (PG&E)
PVRAM = Solar Photovoltaic and Renewable Auction Mechanism Map (PG&E)
CETL = California Electric Transmission Line Map (CEC)
CES = California Electric Substation (CEC)
CPUC PSPS = CPUC De-Energization Webpage

SUBSTATIONS

	Description	Can be publicly sourced (Y(b)/N(b))?	Source	Data Need Priority	Note
1	Location	Y	ICA/DIDF/PVRAM/CES	L	Displayed as red triangles
2	High Side Voltage	Y	PVRAM/CES	L	Transmission line data provided
3	Low Side Voltage	Y(b)/Y	ICA/PVRAM/CES	L	Feeder level data included on ICA map, but the map automatically switches from voltage to capacity data when zoomed in, and data not very granular
4	Rating	Y	PVRAM	L	Data on PVRAM map
5	Max Load	Y	PVRAM	M	Data on PVRAM map
6	Load Profile	Y(b)	ICA	H	Some substations/feeders have load profiles redacted, and load profile is only a graph, not a data set
7	Transformer Bank(s)	Y(b)	DIDF	L	Data on DIDF map as "BANK" data in substation footers
8	Feeder	Y	DIDF	M	Feeders identified by substation in DIDF map
9	Planned or installed storage or generation	N	-	M	No data on substation info tabs
10	Is a transmission line feeding the substation through a high fire threat	N(b)	-	M	Transmission line map data available PVRAM/CETL, but no HFTD overlay; GIS tools can be used to overlay these two datasets

	district (HFTD)? What Tier?				
11	Substation PSPS history	N(b)	CPUC PSPS	L	No PSPS data available by substation, but available by feeder on CPUC de-energization spreadsheet
12	Other planned work	N	-	L	No planned work data available by substation

DISTRIBUTION LINES

	Description	Can be publicly sourced (Y(b)/N(b))?	Source	Data Need Priority	Note
13	Substation origin	Y(b)/Y(b)	ICA/PVRAM	H	ICA map needs to be zoomed out far enough to get to feeder level layer; PVRAM lists it but not explicitly
14	Transformer bank origin	Y	PVRAM	L	PVRAM map shows bank origin and bank capacity
15	Feeder or circuit identity	Y	ICA/PVRAM	H	Feeder name and ID provided
16	Physical location	Y	ICA/PVRAM	H	Feeder lines are traced on the maps
17	Overhead or underground distribution infrastructure?	N	-	H	No data is provided
18	If overhead infrastructure, is it covered conductor and what insulation type?	N	-	L	No data is provided
19	If underground infrastructure, conduit or no?	N	-	L	No data is provided
20	Conductor material	N	-	L	No data is provided
21	Voltage	Y(b)/Y	ICA/PVRAM	H	Feeder level data included, but map automatically switches to the capacity layer when you zoom in enough, PVRAM map needs to be zoomed in to see individual feeder voltages
22	Rating	Y	PVRAM	L	PVRAM map calls out circuit capacity
23	Max Load	Y	ICA/PVRAM	H	Load hosting capacity called out on both maps
24	Load profile	Y(b)	ICA	H	Data available on ICA map unless redacted
25	Generation hosting capacity	Y(b)	ICA	H	Data available on ICA map unless redacted
26	Protection scheme	N(b)	-	M	No protection scheme data given, however in downloadable data feeder capacity limited by line protection data available (ICA)

27	Can be energized if in wind polygon?	N	-	H	No data is provided
28	Fused cutout locations	N	-	M	No data is provided
29	Planned work? (Utility cleared)	N	-	H	No data given
30	Solar and energy storage systems installed along line?	Y(b)	ICA/PVRAM	M	Data given about quantity of distributed generation that can be interconnected to line, line capacity, and quantities of existing and queued distributed generation; no exact locations provided and no data on energy storage explicitly provided
31	Number of customers and location	Y(b)	ICA/PVRAM	L	On ICA map numbers of customers by type given for feeders, but map automatically switches to capacity analysis data when it is zoomed in enough; PVRAM provides data when zoomed in. Neither provides location data for customers
32	Physical space for dedicated microgrid line (street, sidewalk), and known obstructions	N(b)	-	M	Satellite layers are available on the ICA/DIDF/PVRAM maps, but they can't be zoomed in past a certain point
33	Underground space for microgrid equipment (switches, etc.)	N	-	M	No data given
34	PSPS data by circuit	Y(b)	CPUC PSPS	M	Data provided in spreadsheet form, and can be sorted by circuit name
35	Can feeders be switched to alternate substation?	N	-	M	IOU does not provide switch plans

SWITCHES

	Description	Can be publicly sourced (Y(b)/N(b))?	Source	Data Need Priority	Note
36	Physical location	N	-	H	No switch location data provided; data will need to be acquired from IOUs
37	Switch type	N	-	H	No switch type data provided; data will need to be acquired from IOUs
38	SCADA or manual	N	-	H	No switch control scheme data provided; data will need to be acquired from IOUs
39	Feeder or circuit?	N	-	H	No feeder/circuit data provided; data will need to be acquired from IOUs
40	Rating	N	-	H	No switch rating data provided; data will need to be acquired from IOU
41	Connected circuit/feeder IDs	N	-	H	No switch connection data provided; data will need to be acquired from IOU

42	Planned work?	N	-	H	No switch planned work information provided, data will need to be acquired from IOU
43	Preferred location for interconnection switchgear/metering?	N	-	H	No preferred interconnection switch location data provided; data will need to be acquired from IOU
44	Grid sectionalization queue/plans/prioritization	N	-	M	No sectionalization plan data shared

TRANSFORMERS

	Description	Can be publicly sourced (Y(b)/N(b))?	Source	Data Need Priority	Note
45	Location of existing vaults	N	-	H	Substation locations called out with data about voltages, but distribution transformers not called out
46	Preferred location of new vaults?	N	-	M	Data will need to be acquired from IOU
47	Type	N	-	H	Distribution transformer data will need to be acquired from IOU
48	Feeder or circuit?	N	-	M	Distribution transformer data will need to be acquired from IOU
49	Rating	N(b)	-	H	Substation transformer voltages called out in CES map, but distribution transformers not called out
50	Max load	Y(b)	DIDF/PVRAM	H	Substation transformer bank ratings are called out, but distribution transformers are not called out
51	Load profile	Y(b)	ICA	H	Data available on ICA unless redacted
52	Buildings served	N	-	H	No data provided, likely for customer confidentiality purposes
53	Accounts served (#, aggregate load)	Y(b)	ICA/DIDF/PVRAM	M	Feeder customer accounts served called out on ICA map unless redacted, substation transformer bank loading/load profiles called out in DIDF map unless redacted, but no direct data correlation between # and aggregate load; no data on distribution transformers
54	Planned work?	N	-	M	Planned work data will need to be acquired from IOU