ALJ/CR2/kz1 7/23/2020

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07/23/20
01:46 PM

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

ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENT ON THE TRACK 2 MICROGRID AND RESILIENCY STRATEGIES STAFF PROPOSAL, FACILITATING THE COMMERCIALIZATION OF MICROGRIDS PURSUANT TO SENATE BILL 1339

Summary

This ruling seeks comment from interested parties on the attached staff proposal titled, "Facilitating the Commercialization of Microgrids Pursuant to Senate Bill 1339" (Staff Proposal). Parties who wish to provide formal comments in response to this ruling must file and serve them no later than August 14, 2020. Reply comments must be filed and served by no later than August 28, 2020.

1. Background

On September 12, 2019, the California Public Utilities Commission (Commission) initiated this Rulemaking to design a framework surrounding the commercialization of microgrids associated with Senate Bill (SB) 1339 (Stern, 2018), as well as account for the Commission's commitment toward utilizing additional technologies and activities that may be useful for achieving overall resiliency goals.

The initial Scoping Memo for Track 1 of this proceeding was issued on December 20, 2019. Since the issuance of the Track 1 Scoping Memo and Ruling, much activity occurred in this proceeding, including: (1) the issuance of a

Track 1 Energy Division Staff Proposal; (2) the submittal of Track 1 investor-owned utility (IOU) resiliency proposals for the 2020 wildfire season; and (3) the adoption of Decision (D.) 20-06-017, that promulgated an array of rules to accelerate microgrid deployment and provide resiliency solutions.

On July 3, 2020, the assigned Commissioner issued a Scoping Memo and Ruling for Track 2 of this rulemaking. Among other things in the Scoping Memo and Ruling, the assigned Commissioner directed the Commission's Energy Division to issue a staff proposal aimed at proposing potential solutions for the Track 2 issues.[1] The assigned Commissioner directed the Energy Division to file and serve its Staff Proposal on July 22, 2020, to this proceeding's service list.

Consistent with the assigned Commissioner's Scoping Memo and Ruling, this ruling seeks comment from interested parties on the Staff Proposal. Parties who wish to provide formal comments in response to this ruling must file and serve them no later than August 14, 2020. Reply comments must be filed and served by no later than August 28, 2020.

2. Request for Formal Comments

Attached to this ruling is the Staff Proposal. To guide parties' and the Commission's review of the material, this ruling directs parties to discuss their positions to the Staff Proposal's recommendations in response to the questions below. When responding to the questions below, parties shall organize and submit their comments in the same order in which the issues and questions are presented in this ruling.

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1 Assigned Commissioner's Scoping Memo and Ruling at 5.

2.1. Questions

Again, the Staff Proposal presents a variety of recommended actions for fulfilling the statutory requirements of SB 1339. Parties are directed to respond to the specific questions below. If applicable, describe any specific changes to the recommendations in the Staff Proposal that are necessary to fulfill the requirements of SB 1339.

2.1.1. Proposal 1: Direct the Utilities to Revise Rule 2 to Explicitly Allow the Installation of Microgrids as Special Facilities.

The Staff Proposal offers three options to facilitate the utilities' revision of Rule 2 to explicitly allow the installation of microgrids as special facilities. Staff recommends the adoption of Option 2. Parties are directed to discuss the following issues:

1. In response to Proposal 1 to direct the utilities to revise Rule 2 to explicitly allow the installation of microgrids as special facilities, please indicate support or opposition to Option 1, Option 2, or Option 3 and explain your support or opposition.
2. In response to the Staff Proposal's recommendation, should the Commission adopt Option 2? If not, what modifications should the Commission consider?
3. Is Option 2 reasonably tailored to support the broader statutory goal of SB 1339 to facilitate the commercialization of microgrids?
    a. Would adoption of Option 2 prevent utilities from developing microgrids per Section 8371.5?
    b. Would adoption of Option 2 cause unintended barriers to construction of other types of microgrids? If so, please discuss.
    c. Would adoption of Option 2 prevent cost shifting per the requirements of Section 8371(b) and (d).

4. Is there anything more the Commission should consider about revising Rule 2 to allow the installation of microgrids as added/special facilities? Should the Commission consider alternative approach to ease barriers to the development of added/special facility microgrids?
5. Do Pacific Gas & Electric Company (PG&E) and San Diego Gas & Electric Company's (SDG&E) respective Rule 2 added/special facilities sections present barriers to development of these types of microgrids as written? If so, how would they need to be amended to support construction of these types of microgrids?
6. What other considerations should the Commission give toward revising Rule 2, to explicitly allow the installation of microgrids as special facilities?

2.1.2. Proposal 2: Direct the Utilities to Revise PG&E Rule 18, SCE Rule 18 and SDG&E Rule 19 to Allow Microgrids to Serve Critical Customers on Adjacent Parcels.

The Staff Proposal offers three options to overcome a utility rule that prohibits one premise to supply electricity to another premise. The Staff Proposal reasons that this electrical rule could be perceived as a barrier by microgrid developers who wish to maximize the use and benefit of their microgrid by supplying power to adjacent premises in the event of grid outages, either owned by them or by someone else. The Staff Proposal also reasons that this rule could be a barrier for microgrids where islandable assets are located on multiple parcels of land. Staff recommends the adoption of Option 2. Parties are directed to discuss the following issues:

1. In response to Proposal 2 to revise PG&E Rule 18, SCE Rule 18 and SDG&E Rule 19, please indicate support or opposition to Option 1, Option 2, or Option 3 and explain your support or opposition.

2. In response to the Staff Proposal's recommendation, should the Commission adopt Option 2? If not, what modifications should the Commission consider?
3. Is Option 2 reasonably tailored to support the broader statutory goal of SB 1339 to facilitate the commercialization of microgrids?
4. What other considerations should the Commission give toward revising Rule(s) 18 and 19?
5. Is a subscription limit of 10 microgrid projects within the three IOU's territory sufficient? If not, what should the limit be? Discuss your reasoning for the new number. Alternatively, if 10 microgrid projects is sufficient, please discuss support.
6. Currently, the subscription of projects is limited by the number of projects. Is there another unit to consider and if so, what amount of unit? Please justify your answer.
7. Would the adoption of Option 1 or 2 cause unintended barriers? If so, what are they and how should the proposal be amended to avoid such unintended barriers? Please provide justification for your answer.
8. Critical information facilities are included in the list the IOUs are required to develop and maintain pursuant to D.19-05-042.[2] Are there other critical facilities or facilities that should be considered but are not part of D.19-05-042's list? Please justify your response.
9. Do you agree with the Staff Proposal's recommendation that the utilities should file a Tier 2 advice letter to implement the changes to Rule(s) 18 and 19? Please justify your response.

[2] *See* Appendix A at pages A4-A5.

2.1.3. Proposal 3: Direct the Utilities to Develop a Standardized Tariff for Combinations of Rule 21 Compliant Technologies

The Staff Proposal offers three options to support the development of a standardized tariff that would enable the installation of an array of component technologies that individually follow Rule 21 interconnection requirements to compromise a microgrid. Staff recommends the adoption of Option(s) 4 and 5. Parties are directed to discuss the following issues:

1. In response to Proposal 3 to develop a standardized rate schedule for combinations of technologies that are eligible for interconnection under Rule 21 and together comprise a microgrid, please indicate support of or opposition to Option 1, Option 2, Option 3, Option 4, and/or Option 5. Explain your support or opposition.
2. In response to the Staff Proposal's recommendation, should the Commission adopt Option 4? If not, what modifications should the Commission consider?
3. What other considerations should the Commission give in its consideration of developing a single, standardized rate schedule to govern microgrids and all their component technologies?
4. Should the Commission require that projects eligible for a single, standardized microgrid rate schedule meet any specific performance standards when operating as a microgrid, such as a minimum duration of islanding capability? If so, which specific performance standards should the Commission require and how should they be evaluated for the purpose of determining eligibility for the rate schedule?
5. Are Options 1-5 reasonably tailored to support the broader statutory goal of SB 1339 to facilitate the commercialization of microgrids while meeting other statutory requirements, including the requirement to avoid cost shifting?

6. For Options 1-5, is adequate time allowed to accomplish tasks?
7. For Options 1-4, is the proposed individual project size cap of 10 megawatts in Options 1-4 appropriate? If not, what amount would be appropriate and why?
8. For Options 1-3, would allowing exemptions from cost responsibility surcharges, represent cost shifting prohibited by SB 1339?
9. For Options 1-3, is it reasonable to allow a microgrid facility to be exempt from non-bypassable charges in return for providing resiliency services to critical facilities?
10. For Options 1-3, would allowing an interim period in the early commercialization of microgrids during which critical resilience projects can be exempted from specific cost responsibility surcharges be in the public interest? Explain your answer.
11. For Options 1-3, should there be a different method for accounting for the public benefit provided by microgrids when they support critical facilities, other than exempting them from non-bypassable charges?
12. For Options 1-3, are the criteria for determining cost responsibility surcharge exemptions presented in Table 3-3 reasonable? Please justify your answer.
13. For Options 1-3, are the definitions and requirements presented in Table 3-4 reasonable? Please justify your answer.
14. For Option 3, is the statewide enrollment cap of 1,200 megawatts 3 an appropriate amount? If not, what amount would be appropriate and why?
15. For Option 3, is the method for allocating a statewide enrollment cap of 1,200 megawatts according to load share appropriate? If not, what alternative allocation method should be used?

2.1.4. Proposal 4: Direct the Utilities to Develop a Microgrid Pilot Program.

The Staff Proposal recommends that the utilities develop an incentive program to fund clean energy community grids that support the critical needs of vulnerable populations most likely to be impacted by grid outages. Under this proposal, Staff recommends the adoption of: (a) Option 2; (b) Option 1; (c) Option 2; (d) Option 1; and (e) Option 1. Parties are directed to discuss the following issues:

1. In response to Proposal 4 to direct the utilities to develop a microgrid pilot program, please indicate support or opposition to each of the options. Explain your support or opposition.
2. Should the Commission adopt Staff's recommended options? If not, what modifications to Staff's recommended options should the Commission consider?
3. Is Proposal 4 reasonably tailored to support the broader statutory goal of SB 1339 to facilitate the commercialization of microgrids?
4. To support the public health and welfare for disaster response mitigation and resiliency efforts, should the Commission authorize rate recovery for such a pilot program?
5. What other considerations should the Commission give to support the development of a utility microgrid pilot program?
6. How should the utilities track costs associated with the actions the Commission orders utilities to undertake pursuant to the staff proposal?
7. Are there other options that have not been listed and should be? If so, please discuss the option(s) that should be considered. Include as much detail as possible.

8. Are there any other objectives and goals that should be included? Alternatively, are there any that should be excluded? Please provide justification.
9. Are there any other project criteria that should be included? Alternatively, are there any that should be excluded? Please provide justification.
10. Are there any other community criteria that should be included? Alternatively, are there any that should be excluded? Please provide justification.
11. Are there any technology performance criteria that should be included? Alternatively, are there any that should be excluded? Please provide justification.
12. Is the cost cap per project of $15 million reasonable? If not, please provide another amount estimate and justification for that amount.
13. Is the requirement to reach commercial operation by January 31, 2022 reasonable? If not please provide another deadline and justification for that date.
14. There is a milestone of June 1, 2022 or six months after the commercial operation date of the last project to conduct a cost-effectiveness analysis. Is this date reasonable? Please provide justification.
15. Do you agree with staff's proposal that the IOUs file a Tier 3 Advice Letter to implement this program? Please justify your response.

2.1.5. Proposal 5: Direct the Utilities to Conduct Pilot Studies of Low Cost Reliable Electrical Isolation Methods

The Staff Proposal recommends that the utilities conduct pilot studies of low cost reliable electrical isolation methods. Staff reasons that such a pilot program will assist with the assessment of the safety and reliability of utilizing smart meter integral disconnection switches to provide low-cost electrical isolation for backup power applications and to identify and resolve any implementation and deployment issues. Staff also reasons that lessons learned from a pilot program could provide a means of lowering costs for electrical isolation as well. Parties are directed to discuss the following issues:

1. In response to Proposal 5 to direct the utilities to conduct pilot studies of low cost reliable electrical isolation methods, please indicate support or opposition to Option 1 or Option 2. Explain your support or opposition.
2. Should the Commission adopt Option 2 under Proposal 5? If not, what modifications should the Commission consider?
3. Is Proposal 5 reasonably tailored to support the broader statutory goal of SB 1339 to facilitate the commercialization of microgrids?
4. To support the public health and welfare for disaster response mitigation and resiliency efforts, should the Commission authorize rate recovery for such a pilot study?
5. What other considerations should the Commission give to support the development of a utility pilot program to evaluate low-cost, reliable electrical isolation methods?
6. Are the proposed expenditure cap and proposed program criteria reasonable? Are there additional program criteria that should be included?
7. Are there additional approaches, beyond those discussed in Option 1 and Option 2, to provide low-cost, reliable electrical isolation that should be considered for the proposed pilot program?

2.2. Secondary Proposals

Below are specific questions related to Staff's Proposals for addressing Section 8371(c) and (f).

2.2.1. Public Utilities Code Section 8371(c)

1. In response to the proposals for Section 8371(c), please indicate support of or opposition to Option 1, Option 2, and Option 3. Explain your support or opposition.

2. Should minimum technical specifications and operational capabilities for microgrid controllers be included in Rule 21?
3. Most interconnection issues will be addressed in the interconnection rulemaking (R.17-07-007) or its successor proceeding(s). Which, if any, specific interconnection issues for microgrids should be addressed in this rulemaking?
4. Are there any gaps in the existing interconnection studies process for analysis of behind-the-meter microgrids?
5. Please comment on what supplementation to the existing interconnection studies process will be necessary for analysis of in-front-of meter microgrids.

2.2.2. Public Utilities Code Section 8371(f)

1. In response to the proposals for Section 8371(f), please indicate support or opposition to Option 1 and Option 2. Explain your support or opposition.
2. Which of the direct current (DC) metering standards currently being developed should receive the most focus? What is the timeline for completion of this DC metering standard?
3. Does the Rule 21 allowance for use of power control systems adequately address net energy metering (NEM) integrity and non-export concerns related to DC-coupled photovoltaic and battery storage? Would an allowance for power control systems for other types of NEM-eligible DC-coupled generators (*e.g.,* certain approved fuel cells) and storage adequately address these concerns for those additional types of generators?
4. Please elaborate on additional use cases for DC metering beyond NEM integrity and non-export. Would these use cases typically be in the CPUC's jurisdiction?

2.3. Staff Concept Paper

In addition to the Staff Proposal, referenced above, this ruling includes a concept paper to inform the issues that may be considered in Track 3 of this proceeding, and beyond. In addition to responding directly to this ruling's questions on the Staff Proposals and the questions contained herein, parties may comment on the Staff Concept Paper for purposes of informing the Commission's information gathering in consideration of Track 3 and beyond. Comments on the Staff Concept Paper will not be considered as part of the record for Track 2 or any of the final outcomes for Track 2.

IT IS RULED that:

1. The Energy Division Staff Proposal titled "Facilitating the Commercialization of Microgrids Pursuant to Senate Bill 1339" (Staff Proposal) attached to this ruling is hereby entered into the formal record of this proceeding.

2. Parties who wish to file formal comments in response to this ruling and the Staff Proposal must file and serve them no later than August 14, 2020. Reply comments must be filed and served by no later than August 28, 2020.

Date July 23, 2020, at San Francisco, California.

/s/ COLIN RIZZO
Colin Rizzo
Administrative Law Judge

ATTACHMENT 1

Staff Proposal for Facilitating the Commercialization of Microgrids Pursuant to Senate Bill 1339

California Public Utilities Commission Energy Division

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

July 22, 2020

Contents

1. Executive Summary

In this document, the California Public Utilities Commission's (CPUC) Energy Division Staff presents recommendations for actions to facilitate the commercialization of microgrids pursuant to the requirements of Senate Bill (SB) 1339.

CPUC Energy Division Staff recommends the following:

- Direct Utilities to Revise Rule 2 To Allow IOUs to Install Microgrids as Special Facilities
- Direct Utilities to Revise Rule 18/19 to Allow Microgrids to Serve Critical Customers on Adjacent Parcels
- Direct Utilities to Develop a Microgrid Rate Schedule
- Direct Utilities to Develop a Microgrid Pilot Program
- Direct Utilities to Conduct Pilot Studies of Low Cost Reliable Electrical Isolation Methods

This document is intended to complement a separate companion paper, titled "Microgrids and Resiliency Staff Concept Paper". The concept paper establishes a conceptual foundation for the proposals in this report and the ongoing work related to facilitating the commercialization of microgrids pursuant to SB 1339. Staff anticipates that the specific proposals for implementing SB 1339 described in the this document will be addressed in the short term, while the conceptual issues and additional proposals articulated in the concept paper will be addressed over a longer period of time.

2. Primary Proposals

SB 1339 requires the CPUC to take a series of steps to facilitate the commercialization of microgrids. Staff proposes five primary activities to be undertaken by the large electrical corporations to implement the requirements of SB 1339. These five primary proposals are focused on fulfilling the requirements of Public Utilities Code (P.U.C.) 8371(b) and (d) and P.U.C. 8371.5. This section provides background on those statutory requirements and then details each of the five primary proposed activities. Staff's proposals for fulfilling the requirements of the other parts of P.U.C. 8371 are provided in the next section of this document.

Background

P.U.C. 8371(b) directs the CPUC to "…Develop methods to reduce barriers for microgrid deployment."

P.U.C. 8371(d) directs the CPUC to "…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."

Both P.U.C. 8371(b) and 8371(d) stipulate that implementation of each respective section shall be done "Without shifting costs between ratepayers." Furthermore, P.U.C. 8371(d) prohibits implementation of that section in any way that would provide compensation "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."

P.U.C. 8371.5 requires, in essence, that implementation of P.U.C. 8371 shall not "discourage or prohibit the development or ownership of a microgrid by an electrical corporation."

Taken together, these directives require the CPUC to identify ways to reduce barriers to microgrid commercialization, including, as appropriate, dedicated rates and tariffs, without shifting costs among ratepayers, compromising system, public, or worker safety, or interfering with the ability of utilities to also develop microgrids.

All five proposals presented below address barriers to the commercialization of microgrids, and therefore fulfill the requirements of P.U.C. 8371(b). Proposals 1-3 all involve changes to the large electrical corporations' tariffs, while also prioritizing system, public, and worker safety. As such, they fulfill the requirement of P.U.C. 8371(d). Proposal 1 explicitly affirms the ability of electrical corporations to develop and own their tariffs, fulfilling the requirement of P.UC. 8371.5. Therefore, these five proposals, together with the secondary proposals presented in the next section, fulfill all requirements of SB 1339.

Proposal 1: Direct Utilities to Revise Rule 2 To Explicitly Allow IOUs to Install Microgrids as Special Facilities

Table 1 Attributes of microgrids expected to benefit from Proposal 1

Name of Attribute	Attribute
Size and Type of Generation and Storage and Fuel	Within statutory limitations of P.U.C. 8371(d): • Applicable for all MWs and all types of technology • Applicable for all types of fuel
Location of Assets	• Customer Sited
Ownership of Assets	• Utility Owned
Real Property	• Single parcel
Operational Responsibilities	• Split operation
Relationship to Grid	• Grid-tied
Market Orientation	• N/A
Islanding Duration	• All
Greenhouse Gas and Criteria Air Pollutant Emissions	• All
Asset Portability	• Stationary

Summary of Barrier

In each large investor owned utility's (IOU) version of electric Rule 2, there is a section that describes added/special facilities.[1] These are defined by the IOUs as equipment that is in addition to or a substitute for standard equipment required to interconnect to the IOU's system. This definition includes standard equipment such as transformers and poles but can also include assets that reside on the customer side of the point of interconnection (Southern California Edison (SCE) Rule 2, Section H specifies load control devices and meters).

This rule could pose a barrier to microgrids where control systems for islandable assets are installed in an added/special facilities agreement. These systems are installed on the customer side of the point of interconnection and are usually deeded to and controlled by the IOU who can collect ownership fees to recover asset capital cost and operations and maintenance expenses. The rule could act as a barrier to microgrid development because the IOUs do not specifically refer to generation control devices or microgrid controllers in their versions of this rule. As a result, IOUs may feel obligated to seek permission directly from the CPUC to enter into arrangements to install microgrid facilities for customers who request them. The perceived need to seek explicit authorization from the CPUC can add regulatory uncertainty, delays, and complexity to the project development process.

[1] PG&E is Section I, Special Facilities; SCE is Section H, Added Facilities; SDG&E is Section I, Special Facilities and Maintenance (PG&E Rule 2, SCE Rule 2, and SDG&E Rule 2)

The primary example of this type of microgrid is the Fort Irwin National Training Center Microgrid which was authorized by CPUC resolution to an SCE Advice Letter[2] and is currently under construction. In this arrangement, SCE was deeded infrastructure behind the customer point of interconnection and will operate the microgrid in a grid outage condition.

Proposals

Option 1: Require the IOUs to amend their respective versions of Rule 2 to explicitly state that IOU operated microgrid controllers and generation and storage control devices are covered as added/special facilities under Rule 2.

Rationale: This would ensure that these types of devices are explicitly covered under Rule 2. This would allow customers to seek these types of microgrid arrangements with their utilities without the need for the utility to seek a deviation from Rule 2 from the CPUC.

Option 2: Require Southern California Edison (SCE) to amend their respective version of Rule 2 to not specify any examples of added/special facilities.

Rationale: Staff understands that Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E) do not currently cite the added/special facilities section of Rule 2 as a barrier to microgrid development. Their view is that by not specifying what qualifies as an added facility (beyond the broad definition), there is no need to ask for a deviation from Rule 2 to install and operate microgrid control devices per customer request. SCE however, received (by CPUC resolution[3]) a deviation from Rule 2, Subsection H allowing them to install microgrid control equipment. The resolution notes that "[t]his decision has no effect on future projects which will still require [CPUC] approval to deviate from Rule 2, Subsection H." Requiring SCE to rewrite the Rule 2 tariff with a less specific approach to equipment types should prevent the requirement of a CPUC resolution to build and operate these types of microgrids. PG&E and SDG&E would also be required to provide an explanation as to why their current versions of Rule 2 do not prohibit the construction of these types of microgrids.

Option 3: Maintain the status quo, i.e. do not require the IOUs to make amendments to their respective versions of Rule 2.

Rationale: None of the IOUs raised any concerns about using added/special facilities to build and/or control microgrids behind the customer meter. The IOU's also use these agreements to recoup infrastructure and operation costs, preventing a cost shift to the broader rate base. Projects of this type are relatively rare and require extensive customer interface with the IOUs to develop. Therefore, there is little resistance to these types of projects. Staff can monitor this situation as experience with microgrids continue to develop over time.

[2] Resolution E-4840 June 15, 2017 – Authorizing Southern California Edison to develop and implement a microgrid demonstration project with the United States Department of Defense at the United States Army National Training Center, Fort Irwin, California

[3] Ibid.

Recommendation

Staff recommends Option 2. Microgrids of this type are rare and tend to be capital intensive, however requiring SCE to take a less prescriptive approach to these types of microgrids would reduce administrative barriers to broader deployment. Additionally, requiring PG&E and SDG&E to enumerate why their current versions of Rule 2 do not prohibit these types of microgrids would eliminate any regulatory ambiguities surrounding their construction. Finally, Staff will ensure that any modification of the Rule 2 tariff aligns with proposals and outcomes put forth as part of the Transportation Electrification Framework[4] developed in the Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.[5]

[4] Draft Transportation Electrification Framework – CPUC Staff, Feb. 3, 2020, CPUC Staff
[5] R.18-12-006 Docket

Proposal 2: Direct Utilities to Revise Rule 18/19 to Allow Microgrids to Serve Critical Customers on Adjacent Parcels

Table 1 Attributes of microgrids expected to benefit from Proposal 2

Name of Attribute	Attribute
Size and Type of Generation and Storage and Fuel	Within statutory limitations of P.U.C. 8371(d): • Applicable for all MWs and all types of technology • Applicable for all types of fuel
Location of Assets	• Customer Sited
Ownership of Assets	• Customer Owned • Third Party Owned
Real Property	• Type II: 1-2 contiguous parcels not crossing street
Operational Responsibilities	• Split operation
Relationship to Grid	• Grid-tied
Market Orientation	• Customer-Facing
Islanding Duration	• Indefinite
Greenhouse Gas and Criteria Air Pollutant Emissions	• Renewable • Hybrid
Asset Portability	• Stationary

Summary of Barrier

Each IOU has an electric rule governing the supply of electricity to separate premises and the use of electricity by others.[6] Generally, if electricity is delivered by the utilities to a premise, the rules prohibit that premise from supplying the electricity to a different premise.[7] Per PG&E Electric Rule No. 18 and SDG&E Rule No. 19, the electricity may not be supplied through the same meter even if the separate premises are owned by the same customer. SCE Electric Rule No. 18 does not have a specific clause for separate premises owned by the same customer.

The electric rule could be perceived as a barrier by microgrid developers who wish to maximize the use and benefit of their microgrid by supplying power to adjacent premises in the event of grid outages, either owned by them or someone else. For illustrative purposes, a solar PV and battery system may be used at premise A to shave peak load demand and export excess generation back to the utility grid and engaged in island mode in the event of a grid outage. Adjacent to premise A, premise B does not have its own microgrid system. In this example, premise A is prohibited from supplying electricity to

[6] PG&E is Electric Rule No. 18 Supply to Separate Premises and Submetering of Electric Energy. SCE is Electric Rule No. 18 Supply to Separate Premises and Use by Others. SDG&E is Electric Rule No. 19 Supply to Separate Premises and Resale.

[7] Specifically, SCE is Section C, PG&E is Section B, and SDG&E is Section A.

adjacent premise B during grid outages. This rule is primarily a barrier for microgrids where islandable assets would be located on two contiguous parcels of land.

The purpose of the underlying rule is to ensure the safety and reliability of the electricity supplied from the distribution grid to the customers, and to protect customers who may have no or limited choices about who provides their electricity. Currently, there is no method for the utilities to monitor the flow of electricity after it reaches the assets behind the utility meter. This lack of visibility poses potential safety, reliability, and operational concerns. Additionally, in the illustrative example above, the utility will also be unable to ensure the sale of electricity only occurs during emergency outages. Finally, if a customer becomes dependent on the microgrid provider for electricity, the customer may be vulnerable to overcharging.

Critical facilities are defined as those facilities included in the list the large investor owned utilities are required to develop and maintain pursuant to D.19-05-042, Appendix A, p. A4-A5.

Proposals

Option 1: Allow critical facilities owned by municipal corporations to be exempt from Electric Rule No. 18/19. Subject to the limits of P.U.C 218[8], allow premises to supply the electricity to an adjacent premise to conduct emergency and/or critical operations during a grid outage. The municipal corporation and/or the adjoining premises or customer is required to install a device, subject to the utilities' review and approval, that prohibits parallel operation of the service line between the premises during normal operation.

The proposal does not require entities to become an electric cooperative.

Rationale:

- Option keeps the integrity of not selling power from premise to premise. The transfer of electricity is restricted to only during grid outages and for critical facilities.
- Option is technically feasible and financially feasible.
- Option does not trigger cost shifting as the equipment will be paid for by the customer. One may argue that there may be a utility administrative costs to ensuring that the electricity is not being transferred during normal operations. But these costs may be nominal due to the limited number of projects (i.e. adjacent municipal critical facilities) and the fact that municipal facilities are unlikely to purposely operate during normal operations.
- Option limits protects the customer from overcharging, because during normal operations, the customer would continue to receive electricity from the regulated utility during normal operations.
- Option does not require an electric cooperative status because the electricity supply is only allowable during grid outages and not during blue sky conditions.

[8] P.U.C 218 requires any entity who wishes to sell power to more than two contiguous parcels or across a street to become an electrical corporation, which by way of P.U.C 216, is defined as a "public utility."

Option 2: Like Option 1, allow critical facilities owned by municipal corporations to be exempt from Electric Rule 18/19. However, set a subscription limit of 10 microgrid projects within the three IOU's territory. Once the capacity is reached, the CPUC and IOUs will revisit the exemption to determine if exemption should continue and/or if there are any modifications needed based on observing the exempt projects.

Rationale:

- In addition to the rationales provided in Option 1. Option 2 allows for a review of the exemption and potential modifications to improve this proposal.
- The subscription limit will be capped at a fixed number of projects rather than at fixed number of Mega Watts (MW)s is to ensure the data will not be skewed if one or more projects has a relatively high number of installed MW.

Option 3: Maintain status quo. No changes to the Electric Rules 18/19.

Rationale:

- If there are two adjacent premises that would like to supply from one to another during grid outages, the premises can be configured to be either master metered or in front of the utility meter during the microgrid project planning stages.
- Option maintains the safety and reliability of the electric grid because the IOUs would not need to monitor if the supply of energy is also occurring during normal operations.

Recommendation

Staff recommends Option 2. Option 2 enables municipal critical facilities who wish to maximize the use and benefit of their microgrid by supplying power to adjacent premises in the event of grid outage. By setting a subscription limit, the Commission and IOUs will have the opportunity to revisit this exemption to closely review the exempt projects and data to identify any unintended issues.

Utilities will file a Tier 2 Advice Letter to implement changes to Rule 18/19.

Proposal 3: Direct Utilities to Develop a Microgrid Rate Schedule

Table 3-1 Attributes of microgrids expected to benefit from Proposal 3

Name of Attribute	Attribute
Size and Type of Generation and Storage Assets	Within statutory limitations of P.U.C. 8371(d): • Applicable for all MWs and all types of technology • Applicable for all types of fuel
Location of Assets	• Customer-sited
Ownership of Asset	• Customer-owned • Third party owned
Real Property	• Type I: Single parcel
Operational Responsibilities	• Unitary operation
Relationship to Grid	• Grid-tied
Market Orientation	• Customer-facing
Islanding Duration	• Long Duration • Indefinite
Greenhouse Gas and Criteria Air Pollutant Emissions	• All
Asset Portability	• Stationary

Summary of Barrier

The proposal and proposal options presented here address three different types of barriers, one regulatory, and two financial. Each barrier is described below.

Rate Complexity (regulatory barrier): Some microgrid stakeholders have indicated that the multitude of individual rate options under which different distributed energy technologies that interconnect under Rule 21 can take service are confusing. For example, there are separate Net Energy Metering options for systems that involve solar generation alone, solar and storage together, fuel cells alone, or a combination of those technologies. The complexity of these rate options, it has been suggested, may itself represent a barrier to sales of microgrid projects that combine multiple generation and/or storage resources because of the difficulty and lack of certainty in determining which rate options are available and most advantageous to the customer. By extension, this abundance of individual technology-specific rates may pose a regulatory barrier to the commercialization of microgrids.

High Initial Costs (financial barrier): A different barrier that microgrids may face is high initial costs relative to other solutions that provide a competitive set of services. This is particularly likely to be true for microgrids that generate low to no criteria air pollutant or greenhouse gas emissions.[9] To the extent

[9] See the section "Financial Barrier: High Project Costs" in the companion document, Microgrids and Resiliency Concept Paper, for additional discussion of this barrier.

that such high initial costs depress investment in microgrids to a level lower than what might be in the public interest, they could represent a financial barrier to microgrid commercialization.

High Operating Costs (financial barrier): Microgrid stakeholders have suggested that certain utility-imposed cost responsibility surcharges increase the ongoing operating costs of microgrids. These cost responsibility charges include nonbypassable charges, departing load charges, and standby charges.[10] As with initial costs, to the extent that high operating costs depress investment in microgrids below what is socially optimal, such costs could represent a financial barrier to the commercialization of microgrids.

Staff emphasizes that the costs associated with constructing and operating a microgrid represent a financial barrier to microgrid commercialization, not a regulatory one.

Proposals

This proposal involves directing the utilities to develop a single rate schedule to enable installation of combinations of component technologies that individually and collectively meet Rule 21 interconnection requirements and together comprise a microgrid. This proposal would facilitate the commercialization of customer-sited, customer-facing microgrids.

Staff offers several options for implementing this proposal, which are summarized in Table 3-2 below. Option 1 includes granting exemptions to one or more cost responsibility surcharges according to a set of criteria presented in Table 3-2 and 3-3. The exemption from cost responsibility surcharges is intended to address the financial barriers presented above, not the regulatory barrier.

Options 2 and 3 include different ways of limiting the eligibility for the rate schedule to minimize the possibility of unintended adverse consequences. Option 4 is like Option 1, but without including any additional cost responsibility surcharge exemptions. Option 5 involves further study of the rate schedule via a working group process. Each of these options is explained in more detail below. Following a description of each proposal, Staff presents a separate rationale specifically for the idea of offering exemptions to cost responsibility surcharges.

Table 3-2 Summary of options for implementing Proposal 3

Proposal 3 Option #	Proposed Action	Export Allowed	Net Energy Metering (NEM) Eligibility	Enrollment Cap	Proposed Additional Exemption from Cost Responsibility Surcharges
1	New Rate Schedule	Yes	NEM eligible	No restrictions	Per criteria in Table 3.3
2	New Rate Schedule	No	Not NEM eligible	No restrictions	
3	New Rate Schedule	Yes	NEM eligible	1,200 MW statewide	

[10] See the section "Financial Barrier: Nonbypassable, Departing Load and Standby Charges" in the companion document, Microgrids and Resiliency Concept Paper, for a detailed discussion of these charges.

4	New Rate Schedule	Yes	NEM eligible	No restrictions	None
5	Study via Working Group	TBD via working group report			

Table 3-3 Proposed criteria for determining cost responsibility surcharge exemptions

Criteria	Proposed Additional Exemption from Cost Responsibility Surcharges		
	Departing Load Charges	**Standby Reservation Charges**	**Nonbypassable Charges***
New or Incremental Load	Yes	No	No
Long Duration or Indefinite Islanding	No	Yes	No
New or Incremental Load and Long Duration or Indefinite Islanding	Yes	Yes	No
Long Duration or Indefinite Islanding for Critical Facilities	Yes	Yes	Yes
All Others	No	No	No

* Staff notes that exempting microgrid customers from nonbypassable charges shifts these costs to other customers. Since these charges are used to fund programs like California Alternate Rates for Energy (CARE), which provides discounts for low income customers, and energy efficiency, this could allow microgrid customers to avoid paying for their fair share of those programs.

Table 3-4 Definitions for use in determining microgrid eligibility for cost responsibility surcharge exemptions

Term	Definition
New or Incremental load	Load that had not been served by an IOU on or before January 1, 2021.
Long Duration or Indefinite Islanding	Must be able to self-generate power to serve critical loads for at least 96 hours when utility service is unavailable.
Critical Facilities	Those facilities included in the list the large investor owned utilities are required to develop and maintain pursuant to D.19-05-042, Appendix A, p. A4-A5

Option 1: Within 30 days of CPUC order, the three major large investor owned utilities would be required to file an Advice Letter to create a separate rate schedule for customer-sited, customer-facing microgrids composed of technologies that individually and collectively meet the requirements of Rule 21. The tariff would consolidate component technologies into a single rate schedule. Individual projects would also be required to meet the following eligibility requirements:

- Must be less than or equal to ten megawatts capacity

- Must meet technology requirements of P.U.C. 8371(d)

The rate schedule would exempt a customer-sited, customer-facing microgrid from one or more cost responsibility surcharges according to the criteria in Table 3-3 using the definitions in Table 3-4. Staff notes that exempting microgrid customers from nonbypassable charges shifts these costs to other customers. Since these charges are used to fund programs like California Alternate Rates for Energy (CARE), which provides discounts for low income customers, and energy efficiency, this could allow microgrid customers to avoid paying for their fair share of those programs.

The rate schedule would be subject to CPUC re-evaluation after five years. The utilities would be mandated to file an annual report to track the quantity of microgrids that take service under this new rate schedule.

Option 2: Identical to Option 1, except that customers would be not be allowed to elect service under NEM nor to export power.

Option 3: Identical to Option 1, except that enrollment in this rate schedule would be limited to a maximum of 1,200 MW statewide, to be allocated to each large electrical corporation according to 2019 load share. If the 1,200 MW limit is achieved before the five-year period is completed, the Commission can re-evaluate this limit.

Option 4: Identical to Option 1, except that no additional exemptions for cost responsibility surcharges would be granted.

Option 5: This option would task a microgrids working group to study and recommend prudent and reasonable cost responsibility surcharges in conjunction with a new microgrids rate schedule for customer-sited, customer-facing, microgrids.

The microgrid rate schedule would include a two-year phase-in or transition period beginning January 1, 2021 during which the customer-owned behind the meter microgrid remains interconnected with the IOU and pays the extant charges. During the transition period, the microgrids working group would be charged to evaluate and redefine applicable nonbypassable charges, standby charges, and departing load charges that should be charged to ensure bundled customer indifference and to ensure that departing load paid their fair share.

The analysis would include assessing the probability that high levels of non-variable and storage supported distribution generation could become unavailable at times other than systemic grid failures. The working group would define the terms and conditions applicable after the transition period, regarding interconnection, departing load charges, standby charges, nonbypassable charges, and permanent islanding. Projects that qualify for this rate schedule installed after January 1, 2021 would be enabled to transfer service into the new rate schedule upon CPUC approval of the rate schedule.

Rationale for Exempting Projects from Cost Responsibility Surcharges

Stakeholders to this R.19-09-009 Rulemaking have advocated for reducing or eliminating standby charges and departing load charges from behind the meter customer owned microgrids.[11] The CPUC has consistently required departing customers pay their fair share of utility infrastructure costs incurred on their behalf prior to departure. At the same time, there is CPUC precedent to adjust, at least temporarily, cost responsibility surcharges to provide economic incentives to encourage the installation of customer generation that is considered to be in the public interest.

D.03-04-030 found that, based on the policy preferences articulated by the Legislature (and expressed in statutory language) and in prior CPUC decisions, the Commission had sufficient policy basis to believe that customer generation confers a positive public benefit (California Public Utilities Commission 2003). In that case, the CPUC applied cost responsibility surcharge components differently to different categories of customer generation.

Specifically, D.03-04-030 defined different exceptions or exemptions from Department of Water Resources bond charges, Department of Water Resources power charges, SCE historic procurement charge, and Competition Transition Cost for the following three categories of customer generation systems, and provided a three-year period after which the Commission would re-evaluate them to consider technological advances or economies of scale in customer generation production and sale:

1. Clean systems with a capacity of under 1 MW (including-net metered systems)
2. Systems with a capacity of more than 1 MW that also meet the criteria established in P.U.C Section 353.2 ("ultra-clean and low-emission distributed generation")
3. All other types of customer generation

As the net energy metering program evolved with experience, the program was later refined resulting in a realignment mandating payment of certain previously exempted nonbypassable charges. CPUC Decision D.16-01-044 confirmed that for purposes of the NEM successor tariff, the relevant nonbypassable charges were defined as: Public Purpose Program Charge; Nuclear Decommissioning Charge; Competition Transition Charge; and Department of Water Resources bond charges (California Public Utilities Commission 2016). D.16-01-044 also stated that independent of the NEM successor tariff or any other rate schedule, the customers of community choice aggregators, as well as direct access customers, also pay the Power Charge Indifference Adjustment.

The Commission asserted that nonbypassable charges support important programs that are used by and benefit all ratepayers, including NEM successor tariff customers. The Decision re-aligned requirements such that NEM successor customers must pay NEM successor tariff nonbypassable charges on each kWh of electricity they consume from the grid in each metered interval. Those actions assured cost recovery whereby all customers pay in a fair, transparent way. It realigned how customers not on NEM are treated by mandating payment of nonbypassable charges on the full amount of electricity the NEM successor tariff customer receives from the grid, as with other customers.

This latest Decision found that by continuing net energy metering with NEM successor tariff customers paying reasonable charges for interconnection and paying nonbypassable charges for all

[11] See the section "Financial Barrier: Nonbypassable, Departing Load and Standby Charges" in the companion document, Microgrids and Resiliency Concept Paper, for a detailed discussion of these charges.

electricity consumed from the grid, as well as being on an applicable TOU rate, would likely allow customer-sited renewable distributed generation to continue to grow sustainably.

For present-day residential customers using solar generation, existing residential rate schedules provide a solar generation facilities exemption whereby these residential customers may be exempted from standby charges assuming that they comply with the special conditions expressed in the rate schedule (e.g., PG&E Schedule E-1, sheet 5, Special Conditions, section 10, authorized by D.20-05-013, AL 5831-E). These exemptions are conditioned based on capacities to serve load less than 1 MW, restrictions from sale of power or making more than an incidental export of power or assuming the customer has not elected service under the Net Energy Metering tariffs. These residential customers were not exempted from the Department of Water Resources bond charges and Competition Transition Charges.

Similarly, distributed energy resources exemptions are available to residential customers adhering to certain time-of-use provisions of the same rate schedule and are exempted from applicable standby reservation charges. These exemptions had been authorized via P.U.C Sections 353.1 and 353.3 (Article 3.5 added by Stats. 2001, 1st Ex. Sess.) which expressly enabled installations over a two-year period (operational between May 1, 2001 and June 1, 2003) as motivated by the California energy crisis of 2000-2001, and increased installations of distributed energy resources subject to certain criteria including:

- Being located within a single facility;
- Sizing no larger than five megawatts in aggregate capacity;
- Serving onsite loads or over-the-fence transactions allowed under P.U.C. Sections 216 and 218;
- Powering by any fuel other than diesel; and
- Complying with emission standards and guidance adopted by the State Air Resources Board pursuant to Sections 41514.9 and 41514.10 of the Health and Safety Code.

Recommendation

Staff recommends Option 4.

Rationale:

- Options 1 thru 3 are based on elements within existing tariffs that already allow exemption from standby charges for customer generation that physically disconnects from the IOU's grid and it could similarly be extended to apply to behind the meter microgrids.
    - For example, generators that are solely used for backup purposes when large investor owned utility electric service is unavailable are not subject to the standby rule.
    - Relatedly, D.03-04-030 states that customer responsibility surcharges adopted in D.03-04-030 would not apply to new customer load or incremental load of an existing customer where the load is being met through a direct transaction with customer generation and the transaction does not otherwise require the use of transmission or distribution facilities owned by the utility.

- Options 1 thru 3 have the potential to reduce costs, thereby encouraging customers to build microgrid projects. These options may enable economic viability and provide financial incentives for projects providing resilience services for critical facilities that provide public benefits. By imposing a timeframe after which the Commission would evaluate results of the program and determine financial viability of microgrids, the rate schedule would be adopted on a piloted five-year duration.
- Option 1 offers the greatest financial support to the widest range of microgrid configurations but poses the greatest risk of unintended adverse consequences. The most likely adverse consequence would be an inequitable shifting of costs associated with microgrid development from non-participating to participating customers.
- Option 2 limits the risks posed by Option 1 by concentrating the benefits associated with exemptions to cost responsibility surcharges on simpler and easier to implement microgrids that are designed solely to provide backup power.
- Option 3 broadens the range of microgrids that would benefit from the proposed rate schedule compared to Option 2, and limits the risks posed by Option 1 by instead instituting an overall enrollment cap.
- Option 4 eliminates the risk of cost shifting by not instituting any exemptions to cost responsibility surcharges.
- Option 5 provides parties and stakeholders time to deliberate upon fair cost allocations that follow the legislative intentions of avoiding cost shifting and preserving bundled customer indifference from new market development.
- Overall, Option 4 represents the best combination of addressing the regulatory barrier of complex rate schedules while avoiding the risk of inappropriate and unfair cost shifting.

Proposal 4: Direct Utilities to Develop a Microgrid Pilot Program

Table 4. Attributes of microgrids expected to benefit from Proposal 4

Name of Attribute	**Attribute**
Size and Type of Generation and Storage and Fuel	Within statutory limitations of P.U.C. 8371(d): • Applicable for all MWs and all types of technology • Applicable for all types of fuel
Location of Assets	• All types
Ownership of Assets	• All types
Real Property	• All types
Operational Responsibilities	• All types
Relationship to Grid	• All types
Market Orientation	• All types
Islanding Duration	• Long Duration • Indefinite
Greenhouse Gas and Criteria Air Pollutant Emissions	• Renewable (may include existing fossil resources)
Asset Portability	• Stationary

Summary of Barrier

Like Proposal 3, this proposal addresses financial barriers to microgrid commercialization. Please see the description of the financial barriers above, and the section on financial barriers to microgrids in the companion paper "Microgrids and Resiliency Staff Concept Paper" for more information.

Proposals

To mitigate project costs and alleviate upfront project costs, this proposal requires the IOUs to develop an incentive program to fund clean energy community microgrids that support the critical needs of vulnerable populations most likely to be impacted by grid outages. This includes but not limited to:

- Develop a program delivery plan which will describe but not limited to the following elements: program guidelines, project eligibility and scoring criterion, and program implementation process.
- Establish program criteria eligibility to ensure that incentives are dispersed accordingly with the emphasis listed in this proposal.
- Review project proposals and distribute incentives to eligible projects.

The program would meet the following objectives and goals:

- Increase electricity reliability for critical public facilities in communities that 1) are at higher risk of electrical outages in the next five-years and 2) have a lower historical level of electric reliability.
- Prioritizes serving communities with higher proportions of communities with low-income residents, access and functional needs residents and electricity dependents.
- Enable communities with lower ability to fund development of backup generation to maintain critical community services during grid outages. Critical facilities are defined as those facilities included in the list the large investor owned utilities are required to develop and maintain pursuant to D.19-05-042, Appendix A, p. A4-A5.

Project Criteria

- Ability to reach commercial operations by January 31, 2022.
- Cost cap per project $15 million.
- Ability to demonstrate that it meets the program objectives and goals previously listed.
- Criteria air pollutant and greenhouse gas emissions cannot be worse than the equivalent grid power.
- Project must allow for islanding of all critical loads for at least 96 hours.

Community Criteria

- Proportion of low-income residents, as measured by California Alternate Rates for Energy and Family Electric Rate Assistance Program participation or eligibility.
- Top 25% score using CalEnviroScreen 3.0 criteria.
- Proportion of people with "Access and Functional Needs", as defined by D.19-05-042.
- Proportion of customers on medical baseline or electricity-depend Medicare patients, if microgrid will serve them.

Technology performance criteria:

- Must be able to maintain supported loads without interruption during outage.
- Must be electrically isolated from the larger grid during islanded operation (locally sited generation and storage resources).
- Must be able to seamlessly reconnect with grid power when outage is over.
- Must be able to support multiple loads and meters. Although back up for a single-meter service is not the target, single-meter service may be eligible.
- Eligible technology costs should include generation technology and/or storage technology, microgrid controllers, customer outreach, community costs, reconfiguration of electric service equipment on customer side of meters (for example to isolate and serve certain loads) and/or on utility side of meter.

By June 1, 2022 or six months after the commercial operation date of the last project, CPUC will hire, or direct the IOUs to hire, a third-party contractor to conduct a cost-effectiveness analysis to review the program. The review will include an analysis of the participants' bill savings and avoided costs, the extent to which the program has supported commercialization, and the extent to which the program has supported resiliency. Afterwards, Staff will make a recommendation regarding the status of the program for CPUC consideration.

The key program elements are listed below:

a. Load Serving Entities

Option 1: PG&E, SDG&E, and SCE will administer this program to all customers within their respective territory.

Option 2: A competitive process will be used to select a program administrator who will administer this program to all customers within the IOU's territories.

b. Funding Source

Option 1: The projects will be funded by the ratepayers from the same county the project is located in. The cost recovery accounting treatment for the program incentives will be designed to come directly from the participant's county ratepayers.

Option 2: The projects respective funding source will not be limited from a specific region, but instead will be allocated to all distribution customers of the jurisdictional electric utility.

c. Project Eligibility

Option 1: The program administrators will develop a scoring prioritization system that demonstrates their eligibility as listed in the overview. Priority will be given to the highest scoring proposals.

Option 2: The funding will be dispersed on a "first come, first served" basis to projects that are able to demonstrate their eligibility as listed in the overview.

d. Project Subscription Limit

Option 1: The program will be paused when the when the project subscription reaches 15 projects.

Option 2: There will not be a limit to the number of projects if the project is able to demonstrates its' ability to meet the commercial operation date by January 1, 2022.

e. Utility Infrastructure Eligibility

Option 1: In addition to the eligible technology costs described above. Customers within SCE and SDG&E territory will also have access to a one-time matching funds payment to offset some portion of the utility infrastructure upgrade costs associated with implementing the islanding function of the microgrid.

Option 2: Other than the eligible technology costs described above, no utility infrastructure upgrade costs associated with implementing the islanding function of the microgrid will be eligible.

Recommendation

Staff recommends a. Option 1, b. Option 1, c. Option 2, d. Option 1, and e. Option 1. The rationale for Staff's recommendation is provided in the section below. Utilities will file a Tier 1 Advice Letter to implement this program.

Rationale:

CPUC Energy Division Staff recommends the adoption of these options the following reasons:

- Load Serving Entities – PG&E, SDG&E, and SCE will administer this program to all customers within their respective territory. This proposal is an extension the IOUs microgrid community engagement efforts and requirement to provide local government microgrid data that were each ordered by D.20-06-017.

  Additionally, this program is meant to be a pilot program to provide funding for projects that can meet the commercial operation date of January 31, 2022. The IOUs will also be able to rapidly implement the program whereas a competitive solicitation for a third-party administrator will increase the program lead time. Therefore, we proposed for the IOUs to administer the program.

- Funding Source – Option 1 avoids the cost shifting from one county to another.

- Project Eligibility – The program will be on a first come, first served basis to promote a greater number of program participants with projects that are able to meet the commercial operation date by January 1, 2022. Local government projects often have greater lead times compared to a private partnership project due to factors such as stakeholder planning process and public requests for offers. The alternative of a scoring prioritization system would increase the overall project timelines and hinder ability of projects to reach a commercial operation date of January 1, 2022.

- Project Subscription Limit – One of the program elements is to conduct an analysis to review the cost-effectiveness analysis and benefits of the program before determining the continuation of the program. 15 projects will be sufficient to inform the study. Additionally, this may also encourage potential participants to apply and complete the project early.

- Utility Infrastructure Eligibility – In addition to the immediate project costs, special facilities cost is also financial barrier. Access to a one-time matching funds to offset some portion of the utility infrastructure upgrade costs may help with this. Consistent with current practice, SCE and SDG&E will continue to own and operate all existing and future distribution facilities, service facilities, and interconnection facilities, including any upgrades to those facilities necessary to enable the microgrid. Customers within PG&E territory will not be eligible under this proposal as utility infrastructure upgrade incentives are already offered via the PG&E's Community Microgrids Engagement Program.

Proposal 5: Direct Utilities to Conduct Pilot Studies of Low-Cost, Reliable Electrical Isolation Methods

Table 5 Attributes of microgrids expected to benefit from Proposal 5

Name of Attribute	Attribute
Size and Type of Generation and Storage and Fuel	Within statutory limitations of P.U.C. 8371(d): • Applicable for all MWs and all types of technology • Applicable for all types of fuel
Location of Assets	• Customer Sited
Ownership of Assets	• Customer Owned
Real Property	• Single Parcel
Operational Responsibilities	• Unitary
Relationship to Grid	• All
Market Orientation	• Customer-Facing
Islanding Duration	• All
Greenhouse Gas and Criteria Air Pollutant Emissions	• All
Asset Portability	• Stationary

Summary of Barrier

To safely provide backup power from distributed generation or storage to customer loads during a grid outage, the loads and the distributed generation providing the backup power must be electrically isolated from the grid for the duration of the outage. This electrical isolation allows formation of an intentional island and minimizes the possibility of backfeeding electricity from the distributed generation or storage onto the macrogrid during the outage, which would be a significant safety concern.

Electrical isolation can be provided by multiple types of equipment. A transfer switch, typically found in installations with a conventional generator, allows switching of load between two sources (e.g., utility power and backup power). An island-capable smart inverter interconnected under Rule 21 requirements, for use with a battery energy storage system with or without additional generation (e.g., photovoltaic system, fuel cell), allows operation in parallel with the grid during normal conditions and islanded operation during outages. These are only two examples of equipment that can provide electrical isolation, but most options are relatively expensive and can require extensive reconfiguration of existing electrical service panels to meet applicable codes and standards. While many photovoltaic and battery energy storage systems are being installed that utilize the smart inverter approach, the cost may be a significant barrier for several applications.

Many of the existing solar photo voltaic (PV) systems in California were installed with non-smart inverters (e.g., grid interactive inverters) that disable the inverter alternating current (AC) output during a grid outage to prevent backfeed of electricity onto the grid. This functionality is called anti-islanding because it prevents the formation of an island and does not allow the solar PV system to provide power to loads during the outage. It is possible to add battery storage to an existing solar PV system to provide resiliency to desired loads; however, many people find it to be cost prohibitive.

Electric vehicles with on-board inverters could discharge AC power to provide resiliency to desired loads; however, a means of isolating these loads from the electric grid would be necessary to prevent backfeed. Vehicle-to-building and vehicle-to-home are emerging use cases but likely have the same concerns about the cost of isolating equipment.[12]

In Track 1 of this proceeding, Energy Division Staff considered, but did not recommend adoption of, a proposal to allow the use of smart meters for electrical isolation.[13] The proposal received support from multiple parties.[14] PG&E recommended future pilot scale assessment of utilizing the smart meter to isolate electrical loads to expedite development of microgrids in its January 30, 2020, comments.[15] In its June 11, 2020, final decision for Track 1, the CPUC did not adopt the proposal but determined further attention to the approach was warranted in a later track of the proceeding.[16]

Proposals

Require the IOUs to develop a pilot program to evaluate the safety and reliability of utilizing low-cost methods to provide electrical isolation for backup power applications and to identify and propose solutions for any implementation and deployment issues. This includes but is not limited to:

- Development of a program delivery plan describing but not limited to the following elements: program guidelines, project eligibility and scoring criterion, and program implementation process.
- Identification of products, prototypes, or concepts that can materially reduce the cost of providing electrical isolation for purposes of intentional islanding at a single customer's premise.
- Establish evaluation criteria to assess the safety and reliability of these products, prototypes, or concepts when installed and operated to provide electrical isolation to a single customer's premise.

[12] Providing AC power from electric vehicle batteries to loads for purposes of resiliency (Vehicle-to-building and vehicle-to-home) is distinct from providing AC power from electric vehicle batteries to the macrogrid (vehicle-to-grid). The purpose of vehicle-to-grid is to deliver power to the grid, so the stipulation of electrical isolation is not applicable.
[13] See Interconnection Proposal 4 in Administrative Law Judge's Ruling Requesting Comments on Track 1 Microgrid and Resiliency Strategies Staff Proposal, January 21, 2020.
[14] Decision 20-06-017 June 11, 2020 - Decision Adopting Short-Term Actions to Accelerate Microgrid Deployment and Related Resiliency Solutions, p. 23.
[15] Pacific Gas and Electric Company's (U 39 E) Response to the January 21, 2020, ALJ Ruling and Staff Proposal, p. 12.
[16] Decision 20-06-017 June 11, 2020 - Decision Adopting Short-Term Actions to Accelerate Microgrid Deployment and Related Resiliency Solutions, p. 32.

- If safety and reliability criteria are met, establish technical and performance specifications that a product would be required to meet to allow for approval by the large IOU to install and operate the product at a single customer's premise.
- If safety and reliability criteria are met, recommendations for any changes or variances to large IOU Electrical Rules necessary to allow for approval by the large IOU to install and operate the product at a single customer's premise.

The program would meet the following objectives and goals:

- Determine the feasibility of utilizing low-cost methods to safely and reliably provide electrical isolation at a single customer's premise.
- Reduce the costs of providing electrical isolation to safely and reliably allow intentional islanding so that backup power may be provided at a single customer's premises during grid outages, such as Public Safety Power Shutoffs (PSPS).

Technology performance criteria:

- Be low-cost relative to an island-capable inverter or a transfer switch. Low-cost includes avoiding installation labor or any reconfiguration of existing electrical equipment that would be required using other approaches to provide electrical isolation.
- Meet all necessary safety requirements, including the ability to obtain Underwriters Laboratory listing when applicable.
- Meet any pre-deployment safety testing and acceptance criteria established by the IOUs.

Pilot program funding:

- Actual incurred costs, maximum of $1 million per IOU, would be funded by ratepayers from customer classes, likely residential and small commercial, that would be able to utilize these approaches to electrical isolation for backup power projects.

Option 1: Direct utilities to focus on a pilot program on using the integral remote disconnect switch in most smart meters to provide low-cost electrical isolation at a single customer premise for behind the meter backup power applications.[17]

When only backup power capabilities are desired and generation or storage equipment cannot be connected in parallel with the macrogrid, an electrical isolation approach that does not require interconnection under Rule 21 is possible.[18] Much of the advanced metering infrastructure (a.k.a. smart meter) installed in California IOU territories has an integral remote connect/disconnect switch. When this switch is in the open position, the customer's service entrance equipment and all downstream

[17] While this option focuses on a single premise, it may be possible to utilize the remote disconnect switch in smart meters to enable in-front-of-meter microgrids intended to serve multiple nearby critical facilities (e.g., "main street microgrids). By opening the remote disconnect switch of all non-critical facilities on a mid-feeder line segment, provision of electricity would be limited to critical facilities, reducing the amount of load necessary for a microgrid to supply. Safety and reliability findings from the proposed option may be able to inform the feasibility of more broadly using, in microgrids, the smart meter remote disconnect switch. Utilizing this concept for in-front-of-meter microgrids may be further considered in a future track of the proceeding.

[18] One such example is a make-before-break transfer switch.

equipment, devices, and loads will be electrically isolated from the macrogrid. When this switch is in the open position, backfeed to the macrogrid from the customer's premises will not be possible. If generation or storage resources are only electrically connected to the premises' electrical service when this switch is open and could not be connected in parallel with the macrogrid, interconnection approval under Rule 21 for the generation and storage resources is not required. This would allow a greater degree of freedom for an end-customer to provide and configure their own sources of backup power. Under this approach, these sources of backup power would only be able to provide electricity to the customer's premise during macrogrid outages. During the December 16, 2019, interconnection discussion forum, one concept for utilizing the remote disconnect switch in smart meters as a low-cost means of providing grid isolation was presented.[19]

Additional technology performance criteria for Option 1:

- Avoid the need for interconnection approval under Rule 21 to further reduce backup power project complexity and cost.
- Only allow electrical continuity between backup power devices and the premises' electrical service during macrogrid outages. Electrical continuity between backup power devices and the premises' electrical service is not allowed when utility power is present on the line side of the smart meter.
- Upon restoration of power from the macrogrid, immediately break electrical continuity between any backup power devices and the premises' electrical service.

Rationale: Providing a lower cost means of electrical isolation would reduce the cost of a basic resiliency project such as backup power for Public Safety Power Shutoff events. By eliminating the ability to connect backup power equipment in parallel with the macrogrid, interconnection under Rule 21 is not necessary, providing further simplification and cost reduction. When combined with a grid-forming source such as an electric vehicle capable of discharging AC power, this approach to electrical isolation may enable a pathway for use of existing, non-islandable solar PV systems for resiliency purposes during times when the solar PV system would normally be producing electricity.

Option 2: Direct the utilities to develop a pilot program that includes using the integral remote disconnect switch in most smart meters as well as other approaches to provide disconnection of a premises' entire electrical service to provide electrical isolation during macrogrid outages.

In addition to the approaches to providing electrical isolation described in Option 1, other approaches that do not rely on the integral remote disconnect in smart meters could allow for generation (e.g., solar PV systems) to be connected in parallel to the macrogrid during normal conditions but would provide disconnection of a premises' entire electrical service during outages so that backup power (e.g., battery energy storage systems) could be provided to the premises' loads. When the premises' entire electrical service is isolated during outages, whole premise backup power can be provided and the costs of reconfiguring existing electrical equipment (e.g., relocation of branch circuits to a backup power panel) can be eliminated or substantially reduced. These approaches would require interconnection approval

[19] Using Existing Smart Meters for Improved PSPS Resiliency, 33 North Energy and CESA, December 16, 2019.

under Rule 21 and may rely on a combination of equipment acting together to ensure only intentional islanding is allowed and backfeeding of electricity the macrogrid during outages is prevented.

Rationale: Option 2 is inclusive of Option 1 and expands the proposed pilot program to include additional approaches to disconnecting an entire premises' electrical service that do not rely on the integral remote disconnect switch in smart meters. These additional approaches can reduce the installation cost of backup power systems when there is generation, such as a solar PV system, connected in parallel with the macrogrid and could reduce the installation costs of adding battery storage to existing solar PV systems.

Recommendation

Staff recommends Option 2 to evaluate the feasibility of using lower cost means to provide electrical isolation safely and reliably for backup power projects. Option 2 includes a broader set of technology options in the proposed pilot program that can provide increased flexibility for end-customers to provide and configure their own sources of backup power or to reduce the costs of incorporating battery energy storage systems for backup power with new or existing solar PV systems.

3. Secondary Proposals

Public Utilities Code 8371(a)

Public Utilities Code 8371(a) directs the CPUC to "Develop microgrid service standards necessary to meet state and local permitting requirements." Staff proposes that this requirement has been fulfilled by actions already taken in D.20-06-017 to establish template single line diagrams for interconnection. The discussion below provides background on service standards and permitting, the rationale for Staff's proposal, and additional activities that could further reduce permitting-related barriers to microgrid commercialization.

Background

Staff understands microgrid service standards as standards that define the quality of service that should be expected from a microgrid. P.U.C. 8371(a) specifically refers to service standards in the context of "state and local permitting." Staff proposes that the primary aspect of microgrid service quality that pertains to state and local permitting is safety.

Previously, in D.20-06-017, Ordering Paragraph 1, the CPUC ordered the utilities to develop template single line diagrams for the purpose of simplifying and streamlining interconnection of common project types, including projects that would be considered customer-sited, customer-facing microgrids, such as solar and storage projects. In requiring the use of template single line diagrams for interconnection, the CPUC has promulgated a standard that can be used by state and local permitting authorities for the purpose of reviewing permits related to microgrid project installations. Template single line diagrams simplify the representation of the electrical configuration of microgrid projects, which enables permitting authorities to focus their attention more rapidly and effectively on safety-related considerations. Therefore, by requiring IOUs to develop template single-line diagrams in D. , CPUC has fulfilled the requirement of P.U.C. 8371(a).

In the Staff Concept Paper, Staff also notes several other activities that are underway or could be undertaken to further reduce permitting-related barriers to microgrid commercialization. Some of these activities fit more naturally within the authority of other agencies, and/or require significant time and effort to complete. Staff does not recommend any of the CPUC-jurisdictional activities at this time, because the effort required is not commensurate with the expected benefits for microgrid commercialization relative to other activities.

Proposals for Further Reducing Permitting Related Barriers to Microgrid Commercialization

- Energy Storage Guidebook (underway): California Energy Commission has awarded a contract for the development guidebook similar to the Solar Permitting Guidebook that will assist local governments with permitting customer-sited, customer-facing battery storage projects. Since storage is a key challenge in microgrid permitting, this guidebook should help reduce the permitting challenges associated with microgrid projects as well.

- Permitting Gap Analysis: Coordinate with other state agencies and CPUC proceedings to evaluate gaps and streamline permitting for both behind-the-meter and in-front-of-meter battery energy storage systems

- Require IOUs to Develop Battery Safety Best Practices Guide: Require the IOUs to clarify "prudent electrical practices" as they pertain to battery energy storage systems using existing codes and standards.

- Expand CPUC Oversight of Utility Battery Storage Systems: Expand CPUC oversight of safety compliance of IOU owned or procured battery energy storage systems and integrate safety related quality assurance and quality control requirements into the IOU contracting and procurement process.

- New Rulemaking on General Order 131-D: Open a Rulemaking to revise General Order 131-D to explicitly define whether hybrid distributed energy resources including battery energy storage integrated with generators would be considered additions to electric generating capacity and whether General Order 131-D applies to distributed energy resources interconnected within substations.

- Revise Zoning and Streamline California Environmental Quality Act (CEQA) Treatment of Microgrids: Rebalance the perceived advantage that General Order 131-D grants large investor owned utilities for distributed generation microgrids installed on utility owned property by recommending to Office of Planning and Research to standardize zoning ordinances and streamline CEQA and other permit requirements for installation of in front of the meter utility scale microgrids.

Public Utilities Code 8371(c)

Public Utilities Code 8371(c) directs the CPUC to "Develop guidelines that determine what impact studies are required for microgrids to connect to the electrical corporation grid." Staff proposes that, at a minimum, the same impact studies that are required for other distributed energy resources are also required for microgrids. The discussion below provides a background on interconnection, the rationale for Staff's proposal for meeting the requirement of P.U.C. 8371(c). At the end of this section Staff lists additional proposals for enhancing understanding of the impact studies needed for the interconnection of microgrids.

Background

Interconnection is the physical connection of a generator in parallel to the electric grid. The administrative process and the technical requirements for interconnection, operation, and metering of the generator are specified in a tariff. The purpose of an interconnection tariff is to allow a generator access to the grid while maintaining the safety and reliability of the grid. The interconnection process has frequently been cited as a barrier to the development of distributed generation, including microgrids, because for some projects it can be complex, lengthy, and costly. One of three tariffs will be applicable for distributed generation requesting interconnection with a large IOU electric grid (see below for a description of each tariff). All three tariffs use filters (a.k.a. screens) to determine if an interconnection request can be processed under an expedited fast track review or if detailed study is required. Costs of any necessary upgrades to the electric grid are borne by the entity requesting interconnection except for NEM generators. California statute requires that the cost of system upgrades for NEM generators are recovered by the IOUs through rates.

Rule 21 is a CPUC jurisdictional tariff, implemented by an IOU, for interconnections to the distribution grid. It applies to NEM generators, qualifying facilities that sell all their generation to the utility under the Public Utility Regulatory Policy Act, and generators that do not export to the grid because all generation is consumed on-site. The CPUC has made numerous updates to Rule 21 to accommodate new technologies and to improve the transparency, consistency, and speed of its processes. Most recently, the Track 1 decision of this proceeding required the IOUs to develop template single line diagrams to simply the interconnection request process for some projects and to allow use of photographs, videos, or virtual inspections in lieu of field inspections, where grid safety and reliability are not compromised, to shorten the approval process of completed installations.[20] In the CPUC's separate interconnection proceeding, which includes four formal working groups, additional updates to Rule 21 are being considered.[21]

The Wholesale Distribution Access Tariff or Wholesale Distribution Tariff is a Federal Energy Regulatory Commission jurisdictional tariff, implemented by an IOU, for interconnections at the distribution grid where the generator sells all its generation into the California Independent System Operator's (CAISO) wholesale market.

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[20] Decision 20-06-017 June 11, 2020 - Decision Adopting Short-Term Actions to Accelerate Microgrid Deployment and Related Resiliency Solutions.
[21] R.17-07-007 Interconnection Rulemaking.

The CAISO tariff is a Federal Energy Regulatory Commission jurisdictional tariff, implemented by the CAISO, for interconnections at the transmission grid where the generator sells all its generation into the wholesale market or to an IOU.

Most interconnection requests in California are under Rule 21 and most of those requests are for relatively straightforward projects. PG&E indicated that in the last three years, 95% of its Rule 21 applications, accounting for 38.6% of installed capacity, were for project types that qualify for fast track review.[22] These small, mostly residential projects, have benefitted from improvements to Rule 21 and are generally approved in a timely manner. Larger capacity projects under Rule 21 usually require detailed study, which is a slower, more costly, and more opaque process. These projects are more complex, have a more unique design, and are more likely to trigger system upgrades. Microgrids, which often have a mix of local generation and storage, may be more likely to require detailed study. If a project is electrically independent of the transmission system and of all other projects requesting interconnection to the distribution grid and that have not yet been studied, then the project qualifies for the independent study process. If a project is electrically dependent on other projects requesting interconnection to the distribution grid and that have not yet been studied, then the project will be part of the distribution group study process.

The detailed interconnection studies utilize power flow, short circuit, and stability analyses to identify any necessary equipment at the interconnection, any necessary upgrades to the distribution system, or any necessary upgrades to the transmission system to prevent thermal overloads and out of range voltages, and to address short circuit, stability, and reliability issues that could result from the generator. While these studies are necessary to maintain grid safety and reliability, Energy Division Staff is committed to working toward improved transparency, consistency, and speed of the interconnection process.

Microgrids are comprised of the same types of distributed generation, storage, and loads that can otherwise be interconnected to or served from the macrogrid. The unique feature of a microgrid is the ability to operate in island mode and continue providing electricity to loads within the microgrid during grid outages. The existing interconnection study processes are intended to be capable of evaluating any type of generation or storage that may be interconnected with the macrogrid. Microgrids may be more complex due to the inclusion of multiple types of generation or storage, but the existing interconnection study processes can accommodate the generation and storage technologies utilized in microgrids just as they can accommodate these technologies when interconnected with the macrogrid in absence of a microgrid.

Proposals for Enhancing Understanding of Microgrid Interconnection Studies

Option 1: Utilize the microgrids working group to support development of any additional streamlining or improvements to Rule 21 and to ensure that they are applicable to microgrids. Coordinate with Energy Division Staff to ensure issues relevant for microgrids, such as the processes for interconnection applications that involve increases in load (e.g., battery storage, electric vehicle supply

[22] Pacific Gas and Electric Company's (U 39 E) Response to the January 21, 2020, ALJ Ruling and Staff Proposal, January 30, 2020, pp. 18-19.

equipment) or interconnection applications that include multiple generation technologies, are considered for improvement within the interconnection proceeding.

Rationale: The CPUC's R.17-07-007 interconnection rulemaking is generally the appropriate venue for considering significant modifications to Rule 21. Resiliency and microgrids Staff can take an active role in that proceeding to ensure microgrids are adequately considered when changes are being made to Rule 21.

Option 2: Utilize the microgrids working group to identify attributes or characteristics of microgrids, such as microgrid controllers, that are not adequately addressed by Rule 21 requirements and create a workplan to consider these issues.

Rationale: The microgrid controller will play an important role in the interconnection of microgrids because it is "the brain" of the microgrid. Rule 21 should consider inclusion of minimum technical specifications and performance requirements for microgrid controllers so microgrid developers can readily identify and incorporate compliant equipment early in their design process. See additional discussion in the technical barriers section 7.3 of the Staff concept paper.

Option 3: Utilize the microgrids working group to coordinate with IOUs and the CAISO to ensure microgrid attributes and characteristics are adequately addressed by the Wholesale Distribution Access Tariff/Wholesale Distribution Tariff and the CAISO tariff and to transfer any applicable improvements made to Rule 21 to facilitate the application process for microgrids.

Rationale: The CPUC does not have jurisdiction over the Wholesale Distribution Access Tariff/ Wholesale Distribution Tariff or the CAISO tariff but can work with the large IOUs and CAISO to address any microgrid issues, such as considering minimum technical specifications and performance requirements for inclusion in the tariffs.

Recommendation

Based on Staff analysis to date, there are no additional categories of interconnection studies necessary to maintain grid reliability and safety for the interconnection of microgrids with local generation and storage resources. The power flow, short circuit, and stability analyses in the existing interconnection processes (Rule 21, Wholesale Distribution Access Tariff/ Wholesale Distribution Tariff, CAISO tariff) are sufficient to identify any necessary equipment or upgrades for the interconnection of behind-the-meter microgrids. For interconnection of in-front-of-meter microgrids, which utilize a portion of a utility's distribution system during island mode, it will be necessary to augment the existing interconnection studies to adequately identify any necessary equipment or upgrades. For in-front-of-meter microgrids, the augmented studies need to account for substantially different operating conditions during the microgrid's grid-connected and island modes of operation (e.g., lower power flows and lower available fault duty during island mode).

Staff recommends options 1, 2, and 3 as a reasonable approach to integrating any necessary changes to interconnection tariffs that will improve the application process for microgrids. Because microgrids are one of many types of projects that must use the interconnection process, it is important to maintain as much consistency and technology neutrality as possible within the interconnection tariffs. The best way to achieve this is by including microgrid issues in those existing venues.

Public Utilities Code 8371(e)

Public Utilities Code 8371(e) directs the CPUC to "Form a working group to codify standards and protocols needed to meet California electrical corporation and Independent System Operator microgrid requirements." The discussion below provides a brief background and a proposal for fulfilling this requirement.

Background

Staff is not aware of any specific microgrid requirements currently imposed by either electrical corporations or the California Independent System Operator. Such requirements may, however, be created in the future. Moreover, as evidenced by the proposals in this document and the accompanying Microgrids Staff Concept Paper, there are a multitude of policy and technical issues that would benefit from discussion within a working group.

Proposal for Establishing a Microgrids Working Group

Therefore, Staff proposes to establish a Microgrids Working Group to further explore issues related to electrical corporation and CAISO microgrid requirements, as well as other issues relevant to the further development of microgrid policy. Staff proposes the following steps to launch the working group:

1. Develop a draft charter covering objectives, deliverables, ground rules for participation and governance, meeting frequency, and meeting format.
2. Convene kickoff meeting to confirm charter and identify priority issues.
3. Develop a schedule and milestones for addressing each issue.

There are several options for facilitating a working group:

Option 1: Direct utilities to hire a third-party facilitator for the working group, similar to the approach used to support the Interconnection rulemaking.

Option 2: Energy Division Staff will facilitate the working group, similar to the approach used for the Modeling Advisory Group that has supported the CPUC's Integrated Resource Planning process.

Option 3: Direct stakeholders to convene their own working groups, similar to the approach used for the second phase of the Power Charge Indifference Adjustment proceeding.

Recommendation: Staff recommends starting with Option 2. After forming a Staff-led working group, should specific topics be well suited to one of the other options, those could be then be pursued as appropriate.

Public Utilities Code 8371(f)

Public Utilities Code § 8371(f) directs the CPUC, in consultation with the California Energy Commission and the CAISO to, "Develop a standard for direct current metering in the commission's Electric Rule 21 to streamline the interconnection process and lower interconnection costs for direct current microgrid applications." Staff proposes that alternative pathways are now available to fulfill the purpose of this requirement and that the public interest is best served through use of the alternative pathway and by monitoring DC metering standards development activities already underway. The discussion below provides background information and the rationale for Staff's proposed approach to fulfilling the requirement of P.U.C. 8371(f).

Background

Certain configurations of distributed energy resources containing storage devices and NEM-eligible generators may be required to measure the direct current (DC) output of the NEM-eligible generator to protect the integrity of NEM. DC revenue-grade electric utility meters are generally not available and there are no national standards for their accuracy or repeatability.

Electric power is the rate of transfer of electrical energy. Power is measured in watts, with 1 watt equal to 1 joule of energy per second. Systems for transferring power are either AC or direct current. AC systems are characterized by quantities, such as voltage and current, that vary periodically in magnitude and direction over time, typically in a sinusoidal waveform. DC systems are characterized by quantities that are constant in magnitude and direction over time. Examples of AC and DC waveforms are shown in the figure below.

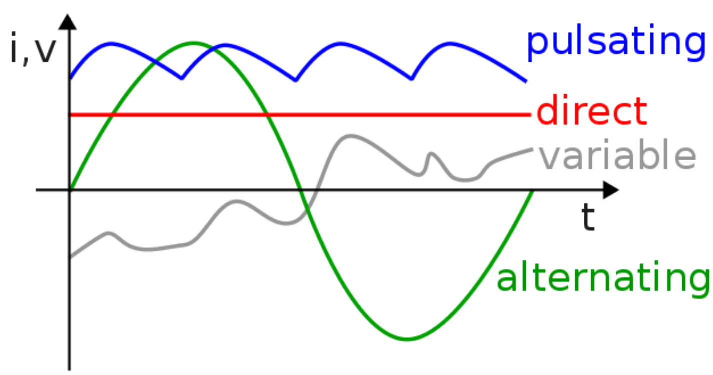

Figure 1 Zureks - Own Work, Public Domainz
https://commons.wikimedia.org/w/index.php?curid=6578453

While a growing amount of end-use electricity loads use DC power (e.g., electronics, light-emitting diode lighting), nearly all the transfer of power within electric utility systems and within buildings is AC. DC may be used to transfer high voltage power over long distances, such as the Pacific DC Intertie connecting the Pacific Northwest and Los Angeles. AC power is produced from rotating machines that convert mechanical energy into electrical energy. DC power can be produced from rotating machines but is now common as the output of distributed energy resources, such as solar PV systems, battery energy storage systems (BESS), and fuel cells. Electric vehicle powertrains and battery systems operate on DC power. AC power can be converted to DC power with a rectifier and DC power can be converted to AC power with an inverter.

Metering equipment for measuring electrical quantities such as voltage, current, and power is readily available for both AC and DC but varies widely in its purpose, usage, accuracy, and cost. Highly accurate, relatively low-cost AC watthour meters for measuring electric power flow over time through a circuit, are ubiquitous in electric utility systems because they are necessary for determining the amount of electricity consumed by a customer for purposes of billing. Accuracy and repeatability of revenue-grade AC watthour meters has long been regulated by public utility commissions, first for electromechanical meters and now for solid-state meters. Examples are shown below.

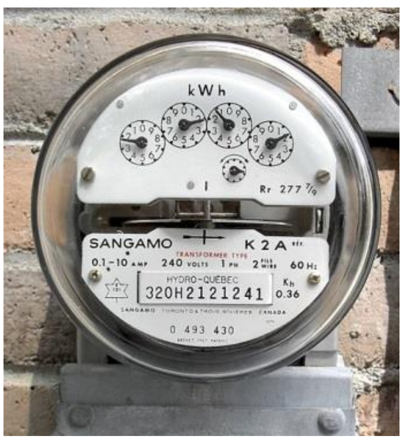

Figure 2 Example of Electromechanical Electric Utility Meter

Kristoferb at English Wikipedia / CC BY-SA (https://creativecommons.org/licenses/by-sa/3.0)

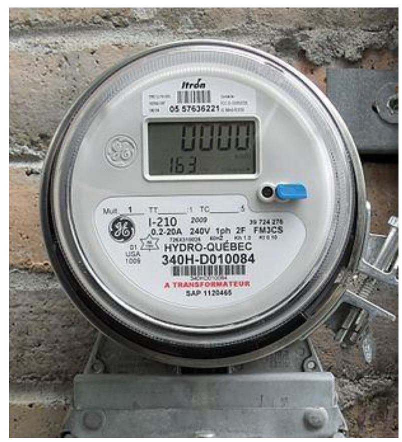

Figure 3 Example of Solid-State Electric Utility Meter

Kristoferb at English Wikipedia / CC BY-SA (https://creativecommons.org/licenses/by-sa/3.0)

In the U.S., voluntary national standards such as the American National Standards Institute (ANSI) standards ANSI C12.1, "American National Standard for Electric Meters – Code for Electricity Metering," and ANSI C12.20, "American National Standard for Electric Meters for Electricity Meters – 0.1, 0.2 and 0.5 Accuracy Classes" may be referenced in these regulations. Because utility power is exceptionally rarely transferred to the end customer in DC, revenue-grade DC watthour meters are not commonly available and there are no corresponding national standards governing their characteristics.

With increasing penetrations of solar PV systems and BESS, there is growing interest and need for standardized, accurate, cost-competitive DC metering, particularly for measurement of power. Modern inverters for these systems almost always include AC power metering, and often DC power metering, but it is rarely revenue-grade and repeatability and accuracy do not conform to any standards. NEM is a tariff providing credit for eligible customer generation that is exported to the utility grid rather than self-consumed. In distributed energy systems that combine generation and BESS, the BESS may be either AC-coupled or DC-coupled. In an AC-coupled configuration, the generator (e.g., solar PV) and the BESS each have their own inverter. The AC output of the solar PV can be measured with a Net Generator Output Meter and the measurements from the meter and the utility grid meter can be used to ensure only electricity generated by the PV system is compensated under NEM. In a DC-coupled configuration, the generator (e.g., solar PV) and the BESS share a single bidirectional inverter. Because the AC output from the inverter could include grid electricity that had been used to charge the BESS, there is no point in the distributed energy resources system where measuring AC power can be used to measure only electricity generated by the PV system. There are pros and cons for each configuration, but two significant advantages of DC-coupled systems are lower costs due to one inverter rather than two and increased efficiency due to fewer AC-DC and DC-AC conversions. Examples of these configurations are shown below.

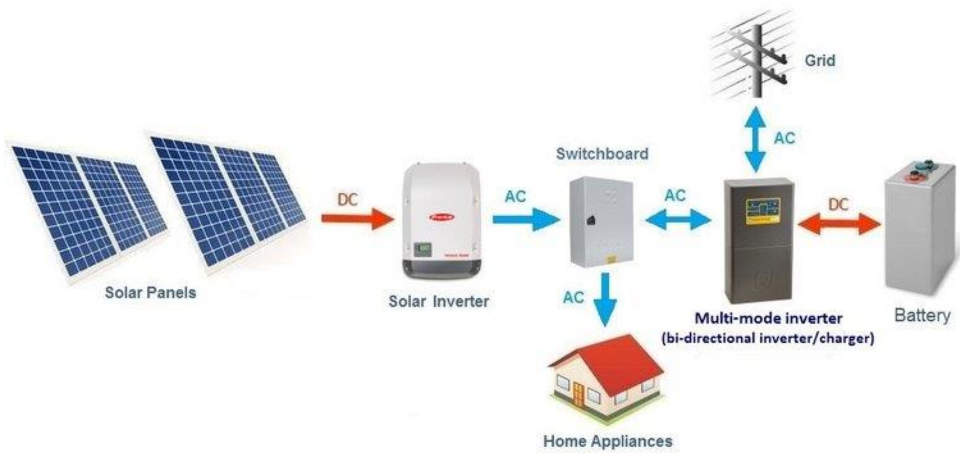

Figure 4 Example of AC-coupled DER System

https://www.cleanenergyreviews.info/blog/ac-coupling-vs-dc-coupling-solar-battery-storage

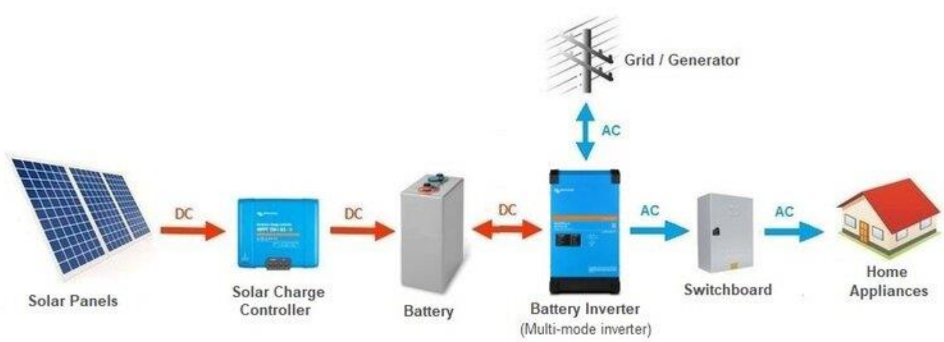

Figure 5 Example of DC-Coupled DER System

https://blog.fluenceenergy.com/energy-storage-ac-dc-coupled-solar

In its May 15, 2014, D.14-15-033,[23] the CPUC ruled that in order to protect the integrity of NEM, large NEM paired storage generating facilities (i.e., storage devices larger than 10 kilowatt) must install either: 1) a non-export relay on the storage device(s); 2) an interval meter for the NEM-eligible generation, meter the load, and meter total energy flows at the point of common coupling; or 3) an interval meter directly to the NEM-eligible generator(s). A combination of 1) and 2) could be used to interconnect AC-coupled NEM paired storage systems and a combination of 1) and 3) could be used to interconnect DC-coupled NEM paired storage systems. However, the lack of readily available, affordable DC revenue-grade electric utility metering rendered option 3 theoretical. Although the CPUC recognized that certain large generating facilities with a single inverter and NEM-paired storage devices (i.e., DC-coupled) could not accommodate the metering requirements, it did not approve an alternate metering configuration.[24]

In its January 31, 2019, D.19-01-030,[25] the CPUC approved use of certified power control-based options for ensuring NEM credit accrues only to NEM-eligible generation in large solar plus storage systems.[26] This decision provided a viable pathway for the interconnection of DC-coupled large NEM paired storage and solar PV generating facilities while avoiding the need for DC metering equipment and non-export relays. In its March 28, 2019, D.19-03-013, the CPUC ordered the IOUs to "support development of direct current metering standards by participating in the EMerge Alliance initiative or equivalent as utility resources allow."[27] Because export of electricity to the grid will be AC for the foreseeable future and because solar PV is the most commonly paired resource with BESS, D.19-01-030 lessened the imperative to develop revenue-grade DC metering equipment. The decision did not address the use of power control-based options for other NEM-eligible, inverter-based generating types such as certain approved fuel cell technologies.

Microgrids may incorporate DC-coupled generators and DC loads, typically to reduce capital costs and increase efficiency by avoiding unnecessary conversions between AC and DC. Electric vehicle supply equipment for DC fast charging, where the battery of the electric vehicle is directly connected to a high-power DC source for rapid charging, is an example application. There is an increasing interest in DC power distribution within buildings, mainly for improved efficiencies (Vossos 2019). More widely available, lower cost revenue-grade DC metering may have enabling benefits for microgrids with DC resources and DC loads; however, measurement of the DC electricity consumption or generation from those resources and loads would rarely or never be under the jurisdiction of the CPUC unless it was for preserving NEM integrity.

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[23] Decision 14-05-033 May 15, 2014 - Decision Regarding Net Energy Metering Interconnection Eligibility for Storage Devices Paired with Net Energy Metering Generation Facilities.
[24] Ibid, p. 21.
[25] Decision 19-01-030 January 31, 2019 - Decision Granting Petition for Modification of Decision 14-05-033 Regarding Storage Devices Paired with Net Energy Metering Generating Facilities.
[26] An example is a power control system (PCS) that prevents electricity from being imported from the grid to charge the BESS, ensuring that the BESS is only charged from the NEM-eligible generator.
[27] Decision 19-03-013 March 28, 2019 - Decision Adopting Proposals from March 15, 2018 Working Group One Report, Ordering Paragraph 4.

Proposals for Development of DC Metering Standards

Option 1: Approve use of power control-based options with all NEM-eligible, inverter-based generators that are DC-coupled with electrical storage for purposes of ensuring NEM integrity.

Rationale: Power control-based options for limiting or prohibiting electricity import or export to ensure NEM integrity are implemented through the inverter's firmware and should be equally functional and reliable for all NEM-eligible, inverter-based generators, not just solar PV. Approving use of power control-based options for these additional NEM-eligible, inverter-based generators may improve the interconnection process for installing battery storage along with one of these generator types.

Option 2: Require IOUs to report on DC metering development activities undertaken pursuant to D.19-03-013. Determine if active participation by CPUC Staff or IOU Staff should be required in one of the existing standards development processes for revenue-grade DC metering: Emerge Alliance Revenue Grade DC Metering Standard (EMerge Alliance), National Electrical Manufacturers Association DC Energy Accuracy (ANSI Standards Action 2019), or IEC 62053-41 Electricity Metering Equipment (DC) (International Electrotechnical Commission) .

Rationale: Development of standards for revenue-grade DC metering may result in lower cost metering that could enable further utilization of DC resources and loads in microgrids resulting in higher efficiencies and lower losses between generation and load.

Recommendation

Staff recommends both options 1 and 2. Option 1 provides near term compliance pathways for most DC-coupled distributed energy resource configurations that require maintaining NEM integrity. Option 2 provides a longer-term approach to further enabling use of DC to DC configurations in microgrids.

4. Program Evaluation

Staff recommends that any activities undertaken pursuant to this Staff proposal, including changes to electric rules, new rate schedules, incentive programs, or pilot studies, be independently reviewed and evaluated by a neutral third party. Such a review should include, but not be limited to:

- costs and benefits to customers who directly participate in a microgrid;
- costs and benefits to other customers;
- progress towards achieving the objectives of SB 1339, including microgrid commercialization;
- extent of incremental contribution to achieving related state and CPUC policy goals and objectives;
- effectiveness of appropriate coordination with related programs and policies, such as the Self Generation Incentive Program;
- impact of activities on resiliency;
- whether any temporary activities, programs, or rate schedules should be extended.

To achieve this program review, Staff recommends that the CPUC conduct a competitive solicitation for a program evaluator through the state contracting process overseen by Department of General Services. Upon CPUC authorization, Energy Division Staff will develop a budget change proposal for reimbursable funds to be used for program evaluation. Staff proposes a budget of $1M for program evaluation.

5. Acronyms

AC	Alternating Current
ANSI	American National Standards Institute
BESS	Battery energy storage systems
CAISO	California Independent System Operator
CEQA	California Environmental Quality Act
CPUC	California Public Utilities Commission
D.	Decision
DC	Direct Current
IOU	Investor-Owned Utilities
kW	Kilowatt
MW	Megawatt
NEM	Net Energy Metering
PG&E	Pacific Gas and Electric
P.U.C	Public Utilities Code
PV	Photovoltaic
SB	Senate Bill
SCE	Southern California Edison
SDGE	San Diego Gas and Electric

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END ATTACHMENT 1

ATTACHMENT 2

Microgrids and Resiliency Staff Concept Paper

California Public Utilities Commission Energy Division

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

July 22, 2020

Prepared by:

This Staff Proposal was developed by the Resiliency and Microgrids team which at time of publication includes: Julian Enis, Forest Kaser, Rosanne Ratkiewich, Patrick Saxton, Joyce Steingass, Daniel Tutt and Jessica Tse.

Acknowledgements:

The authors would like to thank the stakeholders who provided comments and met with us. Additionally, the authors would like to Andrew Salazar who also contributed to the development of this report but is no longer part of the Resiliency and Microgrids team. Additionally, the authors would like to thank the stakeholders who provided comments and met with us.

This Staff proposal reflects a collaborative effort involving many Staff across multiple agencies and informed by stakeholder participation. Such efforts and engagements have been essential to the formation of content and recommendations contained within.

Table of Contents

1. Executive Summary

In this document, the California Public Utilities Commission's (CPUC) Energy Division Staff presents recommendations for actions to facilitate the commercialization of microgrids.

The purpose of this document is to:

- Establish a conceptual foundation for accompanying Staff proposals for facilitating the commercialization of microgrids pursuant to Senate Bill (SB) 1339 and ongoing work related to the development of policies related to resiliency and microgrids.
- Propose working definitions for the following key concepts: microgrids, resiliency, and commercialization.
- Describe the essential attributes and value propositions of microgrids.
- Identify potential barriers to the commercialization of microgrids and propose methods for addressing them.

This document is intended to complement a separate companion document, titled "Staff Proposal for Facilitating the Commercialization of Microgrids Pursuant to SB 1339", which articulates specific proposals for facilitating the commercialization of microgrids pursuant to SB 1339. Staff anticipates that the specific proposals for implementing SB 1339 described in the companion document will be addressed in the short term, while the conceptual issues and additional proposals articulated in this document will be addressed over a longer period of time.

2. Introduction

2.1 Background

SB 1339, enacted in 2018, directs the CPUC to undertake activities to further develop policies related to microgrids.[1] On September 12, 2019, the CPUC initiated Rulemaking (R.) 19-09-009 to develop a framework for facilitating the commercialization of microgrids pursuant to SB 1339 and improving the resiliency of the electrical system.

On December 20, 2019, the CPUC issued a scoping memo which divided the proceeding into three tracks. Track 1 of the proceeding encompasses the CPUC'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. 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 commercialization 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, the formation of working groups to codify standards and protocols.

This document is intended to complement a separate companion document, titled "Staff Proposal for Facilitating the Commercialization of Microgrids Pursuant to SB 1339". This proposal is part of the Track 2 of the proceeding, and makes recommendations addressing Track 2 issues that:

- Direct Utilities to Revise Rule 2 To Explicitly Allow IOUs to Install Microgrids as Special Facilities
- Direct Utilities to Revise Rule 18/19 to Allow Microgrids to Serve Critical Customers on Adjacent Parcels
- Direct Utilities to Develop a Microgrid Rate Schedule
- Direct Utilities to Develop a Microgrid Pilot Program
- Direct Utilities to Conduct Pilot Studies of Low-Cost, Reliable Electrical Isolation Methods

To develop this proposal, CPUC Energy Division Staff conducted research and completed numerous meetings with a wide variety of stakeholders on microgrid topics, including definitional issues, deployment barriers, interactions with other policy goals, and potential solutions.

Additionally, in partnership the California Energy Commission, Staff applied lessons learned from Electric Program Investment Charge program. Specifically, the program's projects and data contributed to the development of ideas in this concept paper and the Staff proposal.

[1] SB 1339 is also known as Public Utilities Code 8371. See Appendix 9.3 for a complete copy.

2.2 Document Overview

This document is organized into seven chapters and several appendixes:

- **Chapter 1** presents an executive summary of the proposals Staff recommends for implementation.

- **Chapter 2** provides information on the legislative, procedural background and statutory requirements that gave rise to the Staff proposal.

- **Chapter 3** proposes a set of guiding principles for developing the analysis and recommendations of the Staff proposal.

- **Chapter 4** explains various definitions of key terms and provides guidance on how the terms are used within the Staff proposal.

- **Chapter 5** discusses the attributes of a microgrid to provide additional, more granular standardized vocabulary for characterizing microgrid types beyond the conceptual definition articulated in the previous chapter.

- **Chapter 6** identifies the types of value different propositions microgrids could potentially provide and their relationship to other state laws and policy goals and existing CPUC policies and programs.

- **Chapter 7** presents details of various categories of barriers and solutions to achieve the commercialization of microgrids for Track II of R. 19-09-009. The standard structure for this chapter begins with a description of the barrier, various proposals, and Staff recommendation. However, some subsections deviate from this standard structure when the proposals address multiple barriers.

- **Chapter 8** includes the Bibliography which contains external resources cited within the Staff proposal. Internal resources citations are cited in the footnotes.

- **Chapter 9** includes the appendices. **Appendix 9.1** contains definitions. This section contains common concepts that may have different meanings to various readers and therefore establishes a baseline of understanding between readers on how these terms are being used within this document. **Appendix 9.2** contains an acronym key of commonly used terms throughout the document. **Appendix 9.3** contains the full text of Public Utilities Code 8371. **Appendix 9.4** contains the full text of Public Utilities Code 218. **Appendix 9.5** describes the statutory requirements of Public Utilities Code 8371 and how the CPUC have met and exceed those requirements so far.

3. Guiding Principles

The guiding principles listed below are intended to establish a basis for reviewing and evaluating proposed actions for facilitating microgrid commercialization. The principles also serve as criteria for evaluating one proposed action against another. The order of these principles does not indicate priority.

1. The action protects public interests served by existing rules, policies, and regulations.

2. The action is feasible from a technical, financial, and market perspective.

3. The action avoids shifting costs between ratepayers.

4. The action aligns with but avoids duplicating all applicable and related CPUC policies, such as, but not limited to:

    - Ensuring just and reasonable rates for participating and non-participating customers;
    - Maintaining the safety and reliability of the electric grid, both physical and cyber security;
    - Advancing equity in its programs and policies in Environmental Justice and Social Justice Action Plan;
    - Ensuring jurisdictional electric utilities are prepared for emergencies and disasters pursuant to General Order 166;
    - Supporting deployment of distributed energy resources as described in the DER Action Plan;
    - Meeting the demand for energy services using the loading order first set forth in the CPUC's 2003 Energy Action Plan, and subsequently reiterated in multiple forums (including Decision (D.) 07-12-052). The priorities, or loading orders is as follows: energy efficiency, demand response, renewable power, distributed generation, and clean and efficient fossil-fired generation.
    - Deploying distributed energy resources in locations where they provide the greatest benefits pursuant to the Distribution Investment Deferral Framework and AB 327;
    - Implementing the set of multi-use application rules, per D. 18-01-003, to guide utilities on how to promote the ability of storage resources to realize their full economic value when they are cable of providing multiple benefits and services to the electricity system;
    - Implementing the Resolution Electric Safety and Reliability Branch's ESRB-8 and D.20-05-051, which, among other things, ordered utilities to engage local communities in developing de-energization programs;
    - Reducing the impacts of public safety power shutoffs on critical facilities, vulnerable customers, and disadvantaged communities in high fire threat districts via the Self Generation Incentive Program's equity and resiliency policies instituted by D.19-09-027 and D.20-01-021;

- Ensuring the safe and reliable operation of the grid in real-time by providing sufficient resources to the California Independent System Operator (CAISO) when and where needed, per Public Utilities Code (PUC) Code 380 and the Resource Adequacy program.

5. The action supports the State of California's goals and policies, such as, but not limited to:

- The California Global Warming Solutions Act (Nunez 2006) - requires California to reduce its greenhouse gas emissions from all sources throughout the state.
- Clean Energy and Pollution Reduction Act (De Leon, Senate Bill 350 Clean Energy and Pollution Reduction Act of 2015 2015) – established clean energy, clean air and greenhouse gas reduction goals, including reducing greenhouse gas to 40% below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050. The Act increases the use of renewable generation, doubles targets for energy efficiency and encourages transportation electrification.
- California Renewables Portfolio Standard Program (De Leon 2018) – requires all utilities in the state to source half of their electricity sales from clean, renewable resources such as wind, solar, geothermal, and biopower, by 2030.
- The 100 Percent Clean Energy Act of 2018 (De Leon 2018) – requires the CPUC to plan for 100 percent of total retail sales of electricity in California to come from eligible renewable energy resources and zero-carbon resources by December 31, 2045.
- The Natural and Working Lands Climate Solutions Act (Wolk 2016) – identifies the protection and management of natural and working lands as a key strategy towards meeting this ambitious greenhouse gas reduction goal. Specifically, SB 1386 directs state agencies to consider the carbon sequestration potential of natural and working lands when revising, adopting, or establishing policies, regulations, expenditures, or grant criteria relating to their protection and management.
- Energy Storage System Procurement Targets (Skinner 2010) – encourages California to incorporate energy storage into the electricity grid.

4. Definitions

The purpose of this section is to define a common set of vocabulary and concepts to establish a baseline of understanding for later discussion of attributes, values, barriers and potential policy proposals.

Microgrid

Pursuant to SB 1339, the statutory definition of a microgrid is:

> *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 and 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.*

This statutory definition notwithstanding, Staff recognizes that different stakeholders use the word "microgrid" to refer to different things with similar elements and characteristics. For example, many practitioners may be familiar with the United States Department of Energy's definition of microgrid, which is similar to California's statutory definition (Ton and Smith 2012). The Department of Energy defines microgrids as "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode." Staff notes that the Department of Energy's definition implicitly excludes systems that are designed to never operate in parallel with a larger grid, e.g. fully islanded systems such as a backup generator behind a transfer switch, or a remote grid that does not interconnect to another system. In contrast, the many small, remote electrical systems that provide power to communities across the state of Alaska, are commonly referred to as microgrids.

Another common difference in usage relates roughly to the number of buildings involved. To some, a microgrid inherently implies multiple buildings, all electrically interconnected with each other either behind a single utility meter (such as a university campus) or using the utility's distribution system (such as the San Diego Gas and Electric microgrid serving the community of Borrego Springs). Others use the word microgrid to refer to a single building that has its own generation and/or storage resources, such as a fire station with solar PV system and battery storage.

Acknowledging the ambiguity in the term microgrid, the Institute of Electrical and Electronics Engineers (IEEE) avoids using the term altogether, referring instead to all intentional island systems that could serve as local electric power systems as "demand response island systems" (2011).

Researchers at Lawrence Berkeley National Lab have proposed a different approach, adopting metric nomenclature to distinguish between different scales of microgrids. According to this approach, larger, multi-facility systems, especially those that use utility infrastructure, are "milligrids." Medium-sized systems that belong to single customer are "microgrids." Smaller networks for distributing lower voltage power for networked communications systems are "nanogrids" (Marnay 2011).

While the exact definitions may differ, Staff proposes that two core characteristics drawn from these various usages provide a practical basis for consideration of microgrid policy at CPUC: 1) a relatively small size; 2) the ability to serve loads, as a system, independent of a larger electrical grid. For the purposes of this proposal, unless otherwise specified, Staff will use the term "microgrid" inclusively to refer to systems that have these two core characteristics. Staff believes this approach is consistent with the statutory definition, while having the advantage of being simpler and more accessible.

To reduce ambiguity with respect to how big a microgrid can be while still satisfying the condition of being "relatively small", Staff proposes to use thresholds established by United States Census Bureau and Office of Management and Budget for classifying populated areas (Health Resources & Services Administration - Defining Rural Population n.d.). The Census Bureau defines an Urbanized Area as having more than 50,000 people. The Office of Management of Budget distinguishes "micropolitan" counties from "metropolitan" counties based on whether they contain an urban core of at least 50,000 people. Accordingly, Staff proposes that microgrids be defined as serving less than 50,000 residential customers (each individual in a dwelling unit would count separately toward this total). According to this proposal, an electrical system that serves 50,000 people or more would simply be a grid, rather than a microgrid.

Microgrids, using the sense of the term described above, include a wide range of system types. Not all microgrids, however, face the same types of barriers to commercialization (and some types may currently face few to none). As a result, in describing specific barriers, and proposals for overcoming those barriers, Staff endeavor, where possible, to denote the specific types of microgrid to which the barrier or policy in question applies. This description may include but not be limited to the type of ownership, targeted customers, and electrical configuration. Additional attributes of microgrids that can be used to identify specific types of microgrids are described in the next chapter.

It should be noted that while this Staff Concept Paper does use an inclusive definition, Staff distinguish the concept of virtual power plants from microgrids. Virtual power plants and microgrids have certain similarities: they both aggregate and optimize multiple distributed energy resources and can be controlled as a unit. A key difference, however, is that virtual power plants involve resources in disparate locations that each separately interconnect with the larger grid and would not normally be expected to be electrically connected to each other during islanded operation. Because the elements of a virtual power plant do not inherently affect each other, they do not constitute a system. Thus, the concept of virtual power plants is excluded from this Staff Concept Paper.

Resiliency

Resiliency is a concept that is often invoked in discussions about microgrids but lacks a clear, specific, and widely shared meaning. Many see resiliency as a valuable attribute that microgrids may be better positioned to deliver than the traditional grid. On that basis, properly valuing resiliency has been suggested as an approach to facilitate the commercialization of microgrids pursuant to the requirements of SB 1339. Without a clear definition of what resiliency is, however, it is difficult to develop policies to account for the ability of microgrids or other resources to deliver it.

The idea of resiliency is germane to a wide variety of industries and circumstances beyond energy, but even within energy policy, it is understood in different ways. Staff notes that the term has recently been defined and/or used in at least four open CPUC proceedings:

- Distributed Resources Planning and Integrated Distributed Energy Resources: In a report dated August 1, 2016 and filed in R.14-10-003[2] the Competitive Solicitation Framework Working Group identified resiliency as one of the services that distributed energy resources could potentially provide to the distribution grid. In brief, resiliency was defined as a service similar to reliability, with the additional requirement that this service also provides power to islanded end use customers when central power is not supplied and reduces duration of outages.
- Self Generation Incentive Program: In D. 19-09-027[3] and subsequent related decisions, the term "resiliency" is not explicitly defined, but implicitly refers to the ability to provide electricity to a customer who would otherwise lack it due to a public safety power shutoff, similar to the definition proposed by the Competitive Solicitation Framework Working Group.
- Climate Adaptation: D.19-10-054[4] includes extensive discussion of the definition of resilience. Finding of Fact 17 holds that "Resilience is the achieved outcome of an adaptation strategy." Finding of Fact 18 states that "Resilient means able to withstand extreme and incremental events and the ability of utility systems to recover when a disruption occurs."
- Transportation Electrification: An Energy Division Staff Proposal introduced via ruling into R.18-12-006[5] on February 3, 2020 states that "we use resilience to mean the ability and availability of EVs to provide and receive energy services during a wider grid outage."

Resiliency versus Reliability: One key area of ambiguity in defining resiliency for the purpose of developing microgrid policy lies in how it relates to the more widely used concept of power system reliability. Below are two examples of how resiliency has been characterized by two credible authorities that highlight how differences in emphasis can create confusion about what resiliency fundamentally means:

- "Resiliency is not the same as reliability." (National Academy of Sciences, Engineering and Medicine 2017)
- "Resilience… is unquestionably an element of reliability." (Cheryl LaFleur, then Federal Energy Regulatory Commission Commissioner, 2018)

Staff proposes that power system reliability and resiliency may be reconciled by recognizing resiliency as a subset or special case of reliability. In other words, all resiliency measures contribute

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[2] Rulemaking 14-10-003 October 2, 2014 - Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning and Evaluation of Integrated Distributed Energy Resources.
[3] Decision 19-09-027 September 12, 2019 – Decision Establishing a Self-Generation Incentive Program Equity Resiliency Budget, Modifying Existing Equity Budget Incentives, Approving Carry-over of Accumulated Unspent Funds, and Approving $10 Million to Support the San Joaquin Valley Disadvantaged Community Pilot Projects.
[4] Decision 19-10-054 October 24, 2019 - Strategies and Guidance for Climate Change Adaptation
[5] Rulemaking 18-12-006 December 13, 2018 - Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.

to reliability, but not all reliability measures necessarily contribute to resiliency. Furthermore, a pragmatic way to distinguish resiliency from reliability, at a conceptual level, is to treat resiliency as specifically addressing response to large scale disruptive events.

For example, under this approach, preventative replacement of a single aging distribution service transformer would be considered a reliability measure because the causal event posing the risk (aging of that particular transformer) is small in scope. In contrast, relocating a substation to avoid flood risk that is exacerbated by climate change would be considered a resiliency measure, because the underlying disruption of climate change is one that acts at a large scale. Similarly, actions to mitigate the scope of public safety power shutoffs would be considered resiliency actions because the risk of the underlying disruptive event being mitigated, fire, is large in geographic scale in California.

By this definition of resiliency, certain well-establishing reliability planning and procurement practices could reasonably be considered resiliency measures. For example, certain transmission reliability standards promulgated by the North American Electric Reliability Corporation are designed to ensure that the bulk transmission system can withstand large-scale contingency events, such as the loss of one, or two, major transmission lines. Similarly, the local resource adequacy requirement is designed to ensure that sufficient generation is available in transmission-constrained areas to respond to major contingencies. Establishing a common understanding of resiliency thus facilitates side-by-side comparison of different measures for achieving it.

Resilience Trapezoid: While a standard, high-level understanding of resiliency can aid in the evaluation of the ability of microgrids to provide it relative to other solutions, additional granularity in categorizing types of resiliency solutions would be even more beneficial. One way to provide additional granularity would be to follow the approach proposed by researchers studying the transmission system in the United Kingdom in response to high wind events. Panteli, et. al. (Panteli, et al. 2017) developed a framework for more formally analyzing the response of any function to a disruptive event by dividing actions into phases which can be summarized as: preparation, resistance to disruption, adaptation, and recovery. Resistance to disruption can also be grouped with adaptation as part of the phase that immediately follows the disturbance.

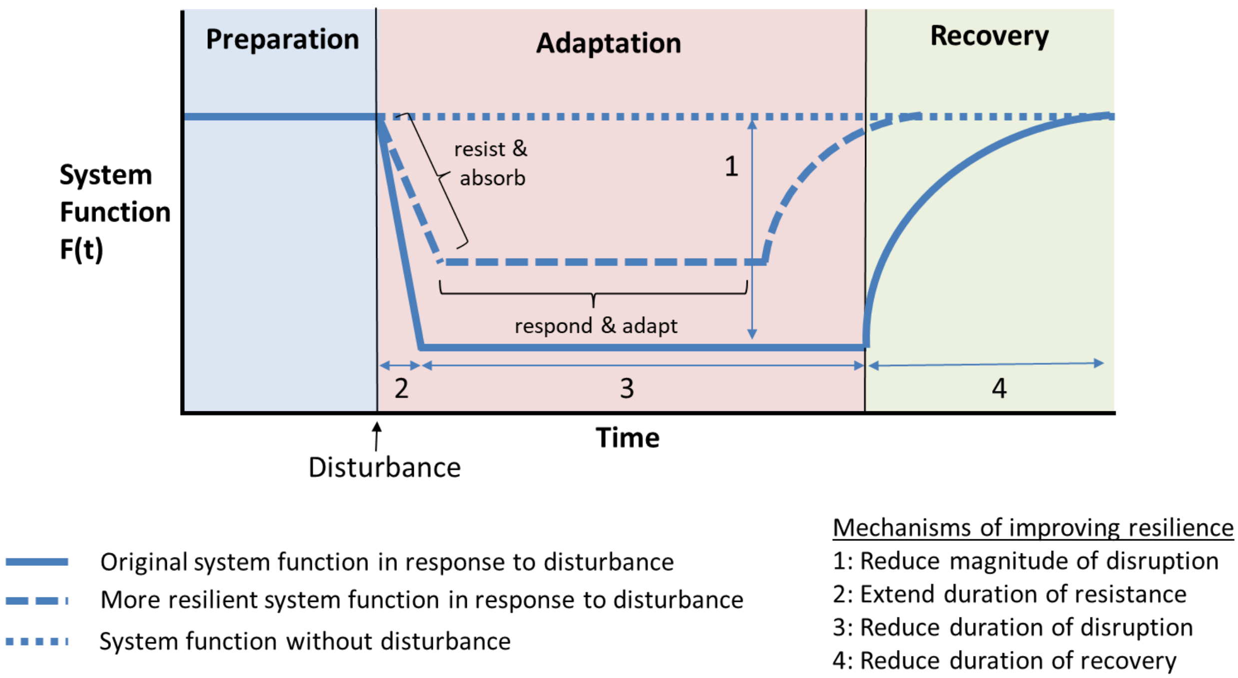

Figure 1 Resilience Trapezoid (adapted from T. Ding, Y. Lin, G. Li, et al. (2017); T. Ding, Y. Lin, Z. Bie, et al. (2017))

Charting the function of the system over time as it moves through those phases produces what the researchers call a "resilience trapezoid," as shown in Figure 1. Using this framework, a mitigation measure is any activity that shrinks any of the dimensions of the trapezoid relative to the normal functioning of the system. Combining this framework with the definition above, Staff proposes the following working definition:

Resiliency refers to the ability to mitigate the impact of a large, disruptive event by any one or more of the following mechanisms:

1. Reducing the magnitude of disruption;
2. Extending the duration of resistance;
3. Reducing the duration of disruption;
4. Reducing the duration of recovery.

Staff notes that while the resilience trapezoid was originally developed to study an aspect of electricity system function, the phases of response within this model can be used to study other functions dependent on or impacted by electricity system disruption and overlaid to discover relationships between system function responses. Some of these associated functions might be (but are not limited to): economic well-being, societal continuity, air quality, or health.

Staff further notes that different microgrids, or other resiliency measures, may protect against different types of disruptions. For example, a microgrid that relies on a generator within a tsunami risk zone may offer protection against a transmission outage that is part of a public safety power shutoff, but not against an outage caused by tsunami.

These considerations imply that a measure that is proposed to have a resiliency benefit should be explicitly specified by referring to each of the following characteristics:

1. The system functions that are supported by the measure.
2. The type of disruptive events that are being protected against.
3. The aspects of resiliency that are affected by the measure:
    - magnitude of disruption;
    - duration of resistance;
    - duration of disruption; and/or
    - duration of recovery.
4. The amount by which each aspect of resiliency is expected to improve as a result of the measure.

In order to develop analysis that is as specific and fair as possible, Staff endeavor, where possible, to use this working definition as a guide for discussing potential values, barriers, and policies related to the ability of microgrids to provide resiliency.

Commercialization

SB 1339 directs the CPUC to take specified actions to facilitate the commercialization of microgrids for distribution customers of large electrical corporations. There are several interpretations of "commercialization." The following is a discussion of some definitions of the concept, why commercialization is important, and how the definition might be used to define goals in the regulatory framework. With a common understanding of how the term is being used in this proceeding, metrics can be designed to assess the effectiveness of policy adopted to fulfill the statue.

According to United States Department of Energy, "Commercialization is the process by which technologies and innovations developed in the lab make their way to market" (United States Department of Energy n.d.). According the University of Pittsburgh, "Commercialization is the process by which a new product or service is introduced into the general market. Commercialization is broken into phases, from the initial introduction of the product through its mass production and adoption." (University of Pittsburgh, Innovation Institute n.d.) From this, the stages of commercialization can be understood to be:

1. Research and development and technology innovation;
2. Market testing and pilot projects;
3. Early commercialization (early adoption); and
4. Scalable or mass production and adoption by market.

Adapting these concepts to microgrids poses the question of whether the concept of commercialization involves the specific technology involved in the configuration of microgrids or the microgrid itself. Staff proposes that this proceeding concern itself with the commercialization of "the microgrid" as the product being introduced into the marketplace. Staff is not working to address the commercialization of, for example, microgrid controllers, or storage solutions but microgrid "systems" as a whole, defined earlier in this paper. This allows for an agnostic approach to the specifics behind microgrid design, ownership, and business model.

The effectiveness of a strategic set of interventions designed to reduce market barriers that allows for market penetration of microgrids could be determined by a portfolio of outcomes such as improved market share, penetration or saturation in relation to the size of the market overall (market change after interventions within a timeline over market baseline without intervention). Other metrics that could be included in the portfolio could be based on a function of regulatory interventions that demonstrate what effect the interventions are having. Examples of this type of measurement could be consumer awareness, contractor training, number of microgrid interconnections approved, number of alliances formed, number or frequency of microgrids installed in which sectors, reduction in microgrid costs, or capital availability. After the metrics are determined, a strategy for tracking and collecting data on those metrics could be determined as well as who will be responsible for those metrics.

5. Microgrid Attributes

The purpose of this section is to provide additional, more granular standardized vocabulary for characterizing microgrid types beyond the conceptual definition articulated in the previous chapter. This standardized vocabulary is intended to clarify which types of microgrids are at stake in the discussion of barriers and analyzed proposed solutions that follow in the next chapter. Specifically, this section identifies the most significant attributes of microgrids.

The basic physical components of a microgrid are typically one or more sources of generation, one or more loads, and a device to maintain an appropriate balance between the generation and load, typically referred to as a microgrid controller. Depending on the type of microgrid, additional equipment may include conductors, transformers, protection devices, and a control network. Despite these common elements, Staff recognizes that, using the inclusive definition described in the preceding chapter, microgrid classification is not straightforward given the many number of ways that different microgrid attributes may be combined. For example, a microgrid may be 100% renewable or 100% fossil-based or may be any combination of those characteristics. Establishing appropriate microgrid policies, therefore, requires clear identification of the type of microgrid involved. To that end, this section provides high-level descriptions of the most significant microgrid attributes. In discussing values, barriers, and proposals associated with microgrids elsewhere in this document and in the companion paper, Staff endeavors to clarify the specific types of microgrids that are involved.

The table below summarizes the primary attributes and terminology proposed for specifying microgrid types for the purpose of microgrid policy development. Descriptions of each attribute and descriptor follow. Staff recognizes that additional attributes may be relevant for consideration of specific policy or technical matters.

Table 1 Attributes and Descriptors

Name of Attribute	Descriptors for Specifying Attributes
Size and Type of Generation and Storage and Fuel	• [X] MW [X] technology (e.g., solar PV, wind turbine, solid oxide fuel cell, reciprocating engine, etc.) • [X] MW/ [X] MWh [X] technology energy storage system (e.g., lithium ion battery, vanadium redox flow battery, load leveler, etc.) • [X] fuel (e.g., diesel, biodiesel, natural gas, renewable natural gas, biomethane, hydrogen)
Location of Assets	• Customer Sited • Utility Sited
Ownership of Assets	• Customer Owned • Utility Owned • Third Party Owned
Real Property	• Type I: Single parcel • Type II: 1-2 contiguous parcels not crossing street • Type III: > 2 contiguous parcels, not crossing street • Type IV: assets cross street
Operational Responsibilities	• Unitary operation • Split operation
Relationship to Grid	• Grid-tied • Independent
Market Orientation	• Customer-Facing • Grid-Facing
Islanding Duration	• Long Duration • Short Duration • Indefinite
Greenhouse Gas and Criteria Air Pollutant Emissions	• Fossil Fuel • Renewable • Hybrid
Asset Portability	• Stationary • Portable

5.1 Size and Type of Generation and Storage Assets

Among the most fundamental attributes of a microgrid are the size and underlying technology of the generation and storage assets. Generation resources are often identified by their physical mechanism of operation, fuel type, and capacity. Examples of generation resources that have been or could be used in microgrids include reciprocating engines, microturbines, solar photovoltaic panels, fuel cells, and wind turbines. Whether or not the generation source is inverter based has implications for the protective systems needed to ensure customer and worker safety. For example, inverter-based generators do not generate as much fault current as non-inverter generators.

Microgrids may rely on an array of fuel sources. Examples of fuels include diesel, biodiesel, natural gas, renewable natural gas, hydrogen, solar insolation, and wind. Generation technologies come in a wide range of sizes. Typical commercially available sizes vary by technology. In some cases, generators can only operate within a defined range of power output, and efficiency of operation varies with output according to the generator's characteristic power curve. Some generators also have limits with regards to how quickly they can ramp up or down in response to changes in load, frequency, and/or voltage.

Microgrids usually include energy storage of some type to help maintain the balance between load and supply, capture generated energy in excess of demand, and/or to maintain generators within their required power parameters. Examples of storage include diesel storage tanks, battery energy storage systems, and flywheels. For microgrids using natural gas, the natural gas transmission system can act as a form of storage.

5.2 Location of Assets

Depending on the point where a microgrid is interconnected between the utility's system and the customer's equipment, a microgrid may be referred to as a "behind-the-meter" system or an "in-front-of-the-meter" system.

A behind-the-meter microgrid is one in which the assets on the customer's side of the meter are energized during islanded operation. The system's generated electricity is typically intended to be used on the same premise but could flow power back to the grid at certain times during non-islanded operation. In contrast, an in-front-of-the-meter microgrid is when the generation facilities that provides electricity to the load are positioned in front of the meter.

Staff notes that while using the meter to distinguish between these two types of microgrids is a common practice, it can create some confusion for certain configurations. For example, it is possible for the customer to own assets in front of the meter, and even to own the meter itself. A more precise way of distinguishing between microgrids that are located on a customer's property, and microgrids that involve significant utility infrastructure is to refer to the point of interconnection.

A "customer-sited microgrid" is one in which the assets that are energized during islanded operation are all on the customer's side of the point of interconnection, which could be either in front of or behind the meter. In contrast, a "utility-sited microgrid" would entail one or more assets located on the utility's side of the point of interconnection being energized during islanded operation. Note that a customer-sited microgrid could be interconnected under either a retail or a wholesale tariff, which can affect whether or not generation assets in the microgrid can be counted towards supply-side procurement obligations. That distinction is covered under the section on interactions with the transmission and distribution system below.

5.3 Ownership of Assets

A microgrid system is composed of many pieces of equipment such as, but not limited to generation, storage, controller, conductors, meters, transformers, and protection devices. There are variations on how different assets may be owned, but the primary ownership models are customer owned, utility owned, and third-party owned.

Customer owned microgrids provide power directly to the owner. With customer owned microgrids, owners are responsible for the upfront capital costs from design to construction. After the microgrid is installed, owners are also responsible for continuous system operation and maintenance. The owners also have complete control of their system and receive the direct benefits of the system. In addition to resilience and reliability, the system may be programmed to reduce bill costs through energy efficiency load management. Additionally, the owners may also directly benefit from the revenue stream generated by selling energy and services back to the grid.

Utility owned microgrids are directly owned by a utility. Under this type of ownership model, the microgrid serves as an extension of the utility's existing distribution system. Depending on the generation source, the utilities could use microgrids to satisfy a part of their renewable energy mandates. Additionally, since utilities may own the distribution assets a microgrid uses, the utilities may be able to understand where a microgrid system may best be located, such as through the Distribution Investment Deferral Framework, a process for the utilities to identify opportunities for distributed energy resources to defer or avoid distribution infrastructure projects. If the utility can successfully coordinate with local government, utility owned projects may also align with local government site priorities.

Third-party or mixed ownership is another possible ownership model. Ownership within a third-party model may also vary. In some models, end users may have a power purchase agreement with a third part contract. The end users could include individuals, multiple owners, or utilities. In these models, the investors may cover upfront capital costs, from design to construction to operations, in exchange for the revenue streams associated with selling energy to the grid when the system is not in island mode. The end user receives the right to purchase power from the on-site distributed energy resources through a power purchase agreement and is not responsible for the operation and maintenance of the system. Additionally, third-party ownership may even have numerous entities owning various pieces of the system, such as separate owners for the generation, storage, and the connecting infrastructure. Third-party ownership can eliminate the need for the end users to contribute upfront costs on their own which creates an opportunity for customers who previously would not have considered a microgrid due to financial barriers.

Staff notes that the term "customer microgrid" could be ambiguous, depending on whether the reference is to the location of the assets, the ownership of the assets, or the type of interconnection agreement. For example, consider the case of a customer who contracts with a third party using a power purchase agreement model to develop a microgrid that is designed primarily to serve load only on the customer's property behind the point of interconnection under a net energy metering rate schedule. Such a microgrid could be considered "customer microgrid" from the point of view of asset location, but a "third party microgrid" from the point of view of asset ownership. For that reason, the term "customer-sited microgrid" is preferred for denoting microgrids in which the assets are located on the customer's side of the point of interconnection.

5.4 Operational Responsibilities

As described in the previous section, microgrid systems are composed of many pieces of equipment (e.g. controller, generation, storage, protection equipment, etc.) that could be owned by different entities. Additionally, the equipment may also have its own operational and maintenance implications.

The responsibility for operating the various assets depends on the owners and beneficiaries of the microgrid who can choose to assign the responsibility in different ways. For example, the entity operating an asset may not necessarily be the owners of the asset. Additionally, an entity's responsibility may vary depending on the specific site conditions such as whether the microgrid is under normal grid connected or islanded operations. For example, operational responsibility for a generation resource could shift from the resource owner to the utility during an outage event.

There is no common terminology for referring to different types of operational responsibility models. At a basic level, Staff proposes to distinguish between "unitary operation" microgrids where a single entity has responsibility for all aspects of operation and "split operation" microgrids, where operational responsibilities are shared among two or more entities.

5.5 Real Property

An important attribute from a regulatory perspective that is related to asset location, asset ownership, and operational responsibilities is the nature of how the land on which the assets are located is owned. Public Utilities Code 218[6] and Electric Rule 18/19[7] impose slightly different requirements related to the distribution of electricity beyond the scope of a single parcel. By definition, these requirements are not relevant to utility-sited, utility-owned microgrids. To afford a more nuanced analysis of the idea of multi-parcel customer-sited microgrids that are not utility owned, Staff proposes four categories:

- I: Microgrids whose islanding assets are confined to a single parcel
- II: Microgrids whose islanding assets are located on one parcel or two contiguous parcels and do not cross a street or public right of way
- III: Microgrids whose islanding assets are located on more than two contiguous parcels and do not cross a street or public right of way

[6] P.U.C 218 requires any entity who wishes to sell power to more than two contiguous parcels or across a street to become an electrical corporation, which by way of P.U.C 216, is defined as a "public utility."
[7] Rule 18/19 are electric rules governing the supply of electricity to separate premises and the use of electricity by others. Generally, if electricity is delivered by the utilities to a premise, the rules prohibit that premise to supply the electricity to a different premise.

- IV: Microgrids whose islanding assets are located on any number of parcels and cross a street or public right of way

Using these categories for purposes of exposition, Staff's understanding is that P.U.C 218 currently requires that utilities own at least the cross-parcel conductors for Category III and IV microgrids. In contrast, Rule 18/19 would typically limit Category II microgrids to utility ownership and operation, but case-by-case deviations are possible (see, for example, Port of Long Beach microgrid).

5.6 Relationship to Larger Grid

Microgrids may operate as separate electricity systems without interacting with a larger grid. These types of systems typically but not exclusively operate in remote areas and are sometimes called "remote grids." For example, such microgrids are abundant in remote areas of Alaska. Staff proposes to use the term "independent microgrid" to refer to a microgrid that never runs in parallel with a larger grid. This encompasses the idea of a remote grid as well as a microgrid that involves a voluntary choice not to interconnect with the larger grid.

In contrast, Staff proposes to term a microgrid that is physically connected to and capable of running in parallel with a larger grid a "grid-tied microgrid."

5.7 Market Orientation

Grid-tied microgrids can all interact with the larger grid but the extent and nature of the interaction may differ based on the interconnection agreement, which reflects the market orientation of the microgrid resources, or system configuration, which reflects how the microgrid components interact with each other.

The primary way in which grid-tied microgrids differ in how they interact with the broader macrogrid relates to whether they are interconnected under a retail or a wholesale tariff. Staff proposes to use the term "grid-facing" to refer to microgrids interconnected under a wholesale tariff and "customer-facing" to refer to microgrids interconnected under a retail tariff.

Generally, microgrids that operate under a retail agreement are designed to serve local loads and have access to retail tariffs and tariff riders, such as net energy metering. In contrast, microgrids that operate under a wholesale agreement are more likely to be designed primarily to serve loads or provide services outside of the electrical boundary of microgrid itself. Under current rules and policies, such microgrids tend have greater ability to participate in wholesale markets.

A related, but slightly different way in which grid-tied microgrids may differ in how they interact with the broader grid relates to how they are configured to operate. A microgrid may be designed to largely operate independently while retaining the ability to flow energy as needed to and from the central grid. These systems act as a single aggregated asset and interact with the larger grid through a single interface. Under this approach the separate resource within a microgrid are aggregated as a single resource when bidding into the wholesale power market rather than each resource in a microgrid having to compete separately. The elements within a microgrid of this type may be more likely to be optimized for serving local load and minimizing local costs. This type of microgrid would most likely be interconnected under a retail tariff as a customer-facing microgrid.

In contrast, a microgrid could instead be configured such that generation and/or storage elements normally interact with the larger grid on their own. Under this approach, the microgrid would only function as an integrated unit in island mode. Such a microgrid would likely be designed primarily to serve the bulk power market (grid-facing) while offering backup power under emergency conditions.

Given the likely congruence between microgrids that are always operating in an integrated manner with customer-facing microgrids and the congruence between microgrids that only operate in an integrated manner during a wider grid outage with grid-facing microgrids, Staff does not propose separate terminology to capture this specific distinction at this time.

5.8 Islanding Duration

A microgrid's ability to island is a continuous variable and not a discrete one. In other words, a microgrid's islanding duration could be any number of hours. For the purposes of this description, the duration is categorized into long duration, short duration and indefinite islanding.

- Long Duration - The duration of a microgrid's ability to island depends on generation capacity, fuel availability (including solar insolation), storage capacity (including fuel storage), load, and load management.

  A microgrid may have several sources of generation, some of which may be intermittent such as solar energy and some may be able to run continuously such as fuel cells (as long as it has a continuously natural gas or hydrogen fuel supply), each impacting islanding duration.

  In addition to the amount of generation, storage, and access to a continuous fuel supply, load management is also key to islanding duration. Intermittent sources may be programmed to provide energy for longer islanding durations. Depending on the system's programming, if power is temporarily interrupted, battery systems can be used to provide instant power to the microgrid for a limited duration to bridge an outage until another generation source can serve the load. If no other backup generation exists, the battery system may be only able to last until storage capacity is exhausted (typically a few hours). However, battery systems may be programmed to maximize the longevity of the operation duration by providing energy to critical loads and recharging to balance generation and electric demand.

  The length of time that would qualify a microgrid as a long duration microgrid is heavily dependent on the type of disruption the microgrid is intended to help mitigate, or the type of benefit it is designed to create. For example, a grid-facing microgrid that provides at least four hours of islanding duration could potentially be used to meet resource adequacy obligations but may fall short of meeting the need to provide power during a multi-day public safety power shutoff event.

- Short Duration - Conversely, there are microgrids with short duration islanding ability that only provide backup generation for a few hours or less at a time. Depending on how it is programmed, it may be designed to reduce peak energy usage and customer billing costs by leveraging on-site resources for optimal efficiency. At the same time, it may also be available to act as a resource for the broader grid, offering energy and demand response in return for revenue.

- Indefinite Islanding - Microgrids with indefinite islanding capability operate independently of the utility grid. These microgrids are more common where the central grid is unavailable or does not exist, such as those operating in remote areas such as in mountainous terrain or on a literal island. For example, with a population of approximately 4,000, Catalina Island is located 22 miles off the coast of Southern California and is completely cut off from the mainland with no access to outside power lines. Indefinitely islanding microgrids are the same as independent microgrids. Microgrids that can be operated as islands for indefinite period of time may also be installed where the utility grid is available, but the customer prefers not to take utility service.

5.9 Greenhouse Gas and Criteria Air Pollutant Emissions

The greenhouse gas and criteria air pollutant emissions intensity of microgrids vary depending on the type of technology and the type of fuel used.

Below are various types of microgrid fuel and technology configurations.

- Fossil Fuel Microgrids - Historically, most microgrids have generated power using fossil fuel combined heat and power and/or backup diesel generators which emit criteria air pollutants and greenhouse gases during operation. Two factors affect the overall contribution of fossil fuel generators to overall pollution during operation: emission intensity and run time. The emissions intensities of different fossil fuel sources vary based on the chemical composition of the fuel, generation technologies, and conditions of operation. Run time is strongly influenced by the intended use of the microgrid, particularly whether it is intended primarily to provide backup power during emergencies or to provide ongoing services to the customer or the grid.

- Renewable Fuel Microgrids – Microgrids may also be entirely based on renewable energy generation using, for example, solar, wind, or bioenergy resources. Solar and wind resources are typically not associated with local criteria pollutant emissions during operation. Bioenergy resources vary in their emissions intensity. Biologically derived diesel fuel, for example, would be expected to have a higher criteria pollutant emissions intensity than biologically derived methane fuel. As with fossil fuels, chemical fuel composition, generation technologies, and conditions of operation, and run time based on intended use will all affect emissions intensity during operation.

- Hybrid Microgrids - A microgrid may also consist of multiple generation resources that combine fossil and renewable resources and fuels. For example, a microgrid can be made up of a hybrid of solar PV, battery and diesel generators. The solar PV may be used during the day allowing the diesel generators to be turned off. Then in the event of an outage, the microgrid can be programmed so that the diesel fuel is used only when the battery and solar is unable to support load, therefore extending the duration of islanding.

Most microgrids today still include at least some non-renewable generation. As illustrated by the table below, even for microgrids that have received Electric Program Investment Charge Program to support the renewable aspects of the project, it is common to incorporate existing non-renewable generation.

Table 2 Selected Electric Program Investment Charge Grant Microgrid Projects and their Renewable and Fossils Resources

Project	Renewable Generation and Storage (kW)	Fossil Resources Present
Blue Lake Rancheria	920	Diesel Generator
City of Fremont Fire Stations[8]	125	Diesel Generator
Honda Distribution Center, Chino*	286	Diesel Generator**
Laguna Wastewater Treatment Plant[9]	2,226	CHP Gas Engines
Las Positas College[10]	700	Diesel Generator
Richmond Kaiser Medical Center[11]	500	Diesel Generator
Robert Mondavi Institute, UC Davis*	220+	None reported

**EPIC final project report still in progress*
***Diesel generator likely removed*

5.10 Asset Portability

Typically, microgrids are permanent assets that are intended to remain on the premise indefinitely. Permanent systems may be able to provide continuous resilience and reliability to facilities compared to facilities without such systems or when temporary systems may not be set up in time before an outage.

[8] Final Project Report: California Energy Commission Final Project Report: Solar Emergency Microgrids for Fremont Fire Stations, September 2019
[9] Final Project Report: California Energy Commission Final Project Report: Constructing a Microgrid for a Wastewater Treatment Facility, December 2019
[10] Final Project Report: California Energy Comission Final Project Report: Making a Microgrid From Legacy Systems, July 2019
[11] Final Project Report: California Energy Comission Final Project Report: A Novel, Renewable Energy Microgrid for a California Healthcare Facility, April 2019

Microgrids may also be mobile where the generation and storage systems are temporarily sited. Temporary systems may be a good option in locations where permanent generation units could not be interconnected to the central grid due to technical and/or other challenges. Temporary systems may also be deployed relatively quickly where they may be used as a critical near-term bridge solution. Relative to permanent solutions which have long site and construction lead times, temporary microgrids may provide islanding capabilities when other solutions are not immediately feasible.

6. Microgrid Value Propositions

The purpose of this section is to identify the types of value different microgrids could potentially provide and their relationship to other state laws and policy goals and existing CPUC policies and programs. The descriptions do not include an evaluation of how effective, or not, microgrids are at delivering that type of value, either on an absolute basis or relative to other types of measures. The relative costs and cost effectiveness of a given microgrid at delivering a particular value depends on the specific attributes of the microgrid and factual context in which a microgrid project is being considered. Staff offer some general considerations regarding comparing microgrids with alternative measures at the end of the section.

6.1 Backup Power

With the challenges posed by both unplanned outages and planned power shut offs used by utilities to mitigate the risk of wildfires, microgrids can offer value as a backup power solution. Microgrids provide facilities with the ability to disconnect from the traditional grid during power outages and maintain operations. While backup power during outages is not a new concept, low-emissions microgrids may provide additional value due to their ability to operate in parallel during non-outage conditions, and to mix multiple generation sources to extend traditional backup power duration or capacity.

The importance of backup power is recognized in several state and CPUC policies. Therefore, policies that facilitate the commercialization of microgrids uphold and support the underlying goals and values of those other policies.

- <u>Office of Statewide Health Planning and Development Backup Requirements for Hospitals</u> (Healthcare Facility Attributes 2020) (Bliss 2019) – The Office of Statewide Health Planning and Department is the state agency that regulates hospital safety and is responsible for creating and enforcing standards to protect healthcare workers and patients alike. The most relevant standard created by the agency was emergency power standards. In California, hospitals must be able to separate electrically from the utility grid during power emergencies and maintain all essential operations for up to 96 continuous hours using onsite generation.

- <u>CPUC Rulemaking Regarding Emergency Disaster Relief Program (R. 18-03-011)</u> – In March 2020, President Batjer issued proposals for maintaining resilient and dependable communications networks during catastrophic events that will better aid emergency responders and ensure the public's ability to reliably communicate and receive critical information. This included proposals to require 72 hours of backup power immediately following a power outage, to share critical infrastructure location information with emergency responders, and to develop uniform protocols for responding to disasters. Backup power includes but is not limited to central offices, network nodes, remote terminals, and wire centers. These proposals are currently under consideration by the CPUC.

- CPUC General Order 166 – General Order 166 are standards to ensure that electric utilities are prepared for emergencies and disasters in order to minimize damage and inconvenience to the public which may result from electric system failures or hazards posed by damage to the electric distribution facilities. While back up power is not explicitly stated in General Order 166, backup power may be a component of the utility's emergency response plan (Standard 1) and contribute to responding to major outages in a timely manner (Standard 5).

- California Building Code (California Building Code 2016 - Chapter 27 Electrical 2016) – Modern building codes and standards acknowledge the vulnerability of electrical power supplied by utilities, and therefore require that most buildings have at least some emergency power to supply select loads during power outages. The level of emergency power required by building codes does not allow critical facilities to operate indefinitely during power outages. For many buildings, the code only requires enough electricity to power equipment for occupants to safely leave the building.

  Per the California Building Codes, the emergency power systems must load transfer upon loss of power within 10 seconds and standby systems must perform load transfer upon loss of power within 60 seconds. The load duration is a minimum of two hours without being refueled or recharged. Additionally, the regulations require electricity for exit-related functions such as but not limited to emergency alarm systems, exit signs, smoke control systems, gas detection systems and emergency responder radio coverage systems.

- Federal Emergency Management Agency's Emergency Power Systems for Critical Facilities: Best Practices (Emergency Power Systems for Critical Faciilities: A Best Practices Approach to Improving Reliability 2014) – Recognizing the importance of emergency power in keeping critical facilities operational during and after a major natural disaster, the Federal Emergency Management Agency published a best practices white paper for emergency power systems for critical facilities. The white paper provides mitigation strategies and describes code requirements intended to minimize emergency power vulnerabilities.

- National Fire Protection Association: NFPA 110 Standard for Emergency and Standby Power Systems – The NFPA is a non-profit organization that develops and provides recommended industry practices to reduce risk of economic losses from fire. NPFA 110 recommends 96 hours of onsite fuel storage for generators used for life-safety protection and in high seismicity areas for critical facilities to address the risk of widespread damage to infrastructure that may occur after an earthquake.

- Federal Emergency Management Agency FEMA 543, Design Guide for Improving Critical Facility Safety from Flooding and High Winds – Providing Protection to People and Buildings (FEMA, 2007), and Guidelines for Design and Construction of Healthcare Facilities (FGI, 2014) also recommend that generators be able to run 96 hours without refueling.

- President's National Infrastructure Advisory Council: Surviving a Catastrophic Power Outage How to Strengthen the Capabilities of the Nation (December 2018) –The National Infrastructure Advisory Council recommended that the Department of Homeland Security oversee initiatives of several federal agencies to strengthen ability for the national power infrastructure to survive a catastrophic power outage. In contrast to a longterm power outage which is defined as 72 hours or more, this paper defined a catastrophic power outage to be long duration, lasting several weeks to months due to physical infrastructure damage. Recommendations included but were not limited to: develop design criteria and/or standards for critical infrastructure hardening, backup power, blackstart capabilities, fuel supply requirements, back-up communications requirements (including a standardized mobile command center design), food and water considerations, and other requirements that communities and businesses can build to. And, to expand the National Institute of Standards and Technology Community Resilience Program to include the catastrophic power outage federal design basis criteria.

6.2 Grid Services

As commonly understood, grid services are elements that are necessary to deliver electricity to customers and ensure system reliability. Grid services involve maintaining the reliability and stability of the grid as they respond to the inherent variability and uncertainty of electricity supply and demand. A microgrid can act as a single controllable load with respect to the broader grid and can utilize its local generation or storage to provide grid services. A microgrid can manage local load by helping to address power quality and reliability, potential capacity, and voltage issues on a small but critical scale.

Bulk system level services (California ISO: Glossary of Terms and Acroynms 2015) (Annual Report on Market Issues and Performanes 2008)

- Energy – the kilowatt-hours required to operate loads.
- Capacity – the maximum capability to supply and deliver a given level of power required to serve consumer demand at any point in time.
- Regulation Up – Regulation reserve provided by a resource under CAISO energy management system control that can increase its actual operating level Energy production or decrease its Energy consumption in response to a direct electronic signal from the CAISO to maintain standard frequency in accordance with established Reliability Criteria.
- Regulation Down – Regulation reserve provided by a resource under CAISO energy management system control that can decrease its actual operating level Energy production or increase its Energy consumption in response to a direct electronic signal from the CAISO to maintain standard frequency in accordance with established Reliability Criteria.
- Spinning Reserves – Reserved capacity provided by generating resources that are running (i.e., "spinning") with additional capacity that is capable of ramping over a specified range within 10 minutes and running for at least two hours. The CAISO needs Spinning Reserve to maintain system frequency stability during emergency operating conditions and unanticipated variations in load.

- Non-Spinning Reserves – Generally, reserved capacity provided by generating resources that are available but not running. These generating resources must be capable of being synchronized to the grid and ramping to a specified level within 10 minutes, and then be able to run for at least two hours. Curtailable demand can also supply Non-Spinning Reserve if it is telemetered and capable of receiving dispatch instructions and performing accordingly within 10 minutes. The CAISO needs Non-Spinning Reserve to maintain system frequency stability during emergency conditions.

Distribution system level services previously defined by the CPUC include[12]

- Distribution Capacity Services – are load-modifying or supply services that distributed energy resources provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure.
- Voltage Support Services – are substation and/or feeder-level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems.
- Reliability (back-tie) – services are load-modifying or supply services that provide a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations.
- Resiliency (microgrid) – similar to reliability services, with additional requirement that this service will also provide power to islanded end use customers when central power is not supplied and could reduce the duration of outages.

Microgrids may provide bulk and distribution system level grid services which aligns with the state and CPUC policies and programs listed below. The importance of grid services is recognized in the state and CPUC policies below. Therefore, policies that facilitate the commercialization of microgrids uphold and support the underlying goals and values of those other policies.

Bulk system level related policies and programs

Generally, the CPUC represents the interests of California's electric public utility consumers at the federal and regional level with efforts related to transmission and wholesale market policies. Key CPUC activities that supports its mission in the transmission and wholesale market are:

- Advocating for "just and reasonable" transmission rates,
- Engaging in transmission planning and policy initiatives and proceedings, and
- Ensuring the state's electric reliability.

Specifically, this includes but not limited to:

[12] Competitive Solicitation Framework Working Group Final Report, August 1, 2016. Adopted by CPUC D.16-12-036, Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot, COL 2 at 74.

- Western Regional Coordination – CPUC Staff devotes effort to monitoring and participating in western transmission planning and related energy policy activities, particularly those associated with the Western Electricity Coordinating Council and its Transmission Expansion Planning Policy Committee, but also those of other organizations, including the Western Governors' Association-affiliated Committee on Regional Electric Power Cooperation.

- Energy Storage and Distributed Energy Resources Initiative – Facilitated by CAISO, this initiative is a stakeholder initiative to enable wholesale market level participation of energy storage and distributed energy resources interconnected to the distribution grid.

- Demand Response – Currently, demand response programs are administered by California's three regulated investor-owned utilities. Independent commercial entities known as 'aggregators' or 'Demand Response Providers' may also approach customers to offer demand response services. Residential, commercial, agricultural, and industrial customers can all participate in demand response programs and receive incentives for doing so.

Distribution system level related policies and programs

- Distribution Investment Deferral Framework[13] – is a CPUC-directed planning framework for identifying, evaluating, and selecting opportunities for distributed energy resources to displace, defer or avoid traditional distribution investments and produce net ratepayer benefits. Deployed distributed energy resources will alleviate infrastructure strain and may allow distribution upgrades to be deferred. In other words, the Distribution Investment Deferral Framework is a non-wires alternative program for the distribution grid. If there is increasing load, meaning circuit and substation upgrades may not need to occur in the near term, which can save enough money to make DER alternatives cost effective. In the long term, traditional upgrades may still be needed, but the application of time-value-of-money concepts to the cost-cap calculation along with value stacking (e.g., resource adequacy) can make near-term DER installations cost effective.

- Competitive Solicitation Framework – provides a solicitation process for accepting third-party bids for distributed energy resources installations. It is currently used by the Distribution Investment Deferral Framework.[14] The solicitation process was also applied to several pilots to test the deferral of traditional distribution infrastructure using distributed energy resources.[15] Distributed energy resources tariffs, once developed, may increase the number of grid upgrade deferrals. Distributed energy resources tariffs are being investigated for application to the Distribution Investment Deferral Framework.

[13] D.18-02-004 Decision on Track 3 Policy Issues, Sub-Track (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process)
[14] Administrative Law Judge's Ruling on the Application of the Competitive Solicitation Framework for Distribution Investment Deferrals in the Distribution Resources Planning Proceeding. R.14-08-013. November 19, 2018.
[15] D. 16-12-036 Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot

- Distributed Energy Resources (DER) Tariffs – is a topic that was included in the scope Integrated Distributed Energy Resources proceeding (R.14-10-003) in part to fulfill the requirements of Public Utilities Code 769(b)(2), which calls for the identification of tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources.

- Distributed Energy Resources Action Plan – is a roadmap for decision-makers, Staff, and stakeholders to guide development and implementation of policy related to distributed energy resources.[16]

6.3 Greenhouse Gas and Criteria Pollutant Emissions Reductions

While there is no requirement for microgrids to be composed solely of renewable energy generation, (and currently many microgrids depend at some level on some form of fossil fuel or hybrid fuel) the legislation directing this proceeding does include language that prohibits the development of a tariff for "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."[17] This is also consistent with CPUC policy to prohibit fossil fueled resources (e.g., diesel back up generation) from participating in demand response programs.[18]

The aggregated clean distributed energy resources that are incorporated into microgrids could contribute toward meeting state policy goals of reducing greenhouse gases and, if the assets are located on the utility's side of the point of interconnection, meeting the state renewable portfolio standard goals (most recently revised in SB 100).

Microgrids could also help absorb the load associated with electrification of buildings and transportation. This further supports state policy regarding greenhouse gas reductions (noted in SB 350, Section 3, and California Building Code, 2016) as well as local codes and standards encouraging electrification.

Microgrids could be designed to utilize nearby greenhouse gas emitting sources such as landfills, agricultural waste or human wastewater systems, turning those sources with high global warming potential (methane) into a gas with lower global warming potential (carbon dioxide). This technology can contribute to the achievement of state clean energy and greenhouse gas reduction goals.

6.4 Resource Adequacy

California's Resource Adequacy program is designed to ensure that sufficient resources are available to be dispatched by CAISO when needed to the extent the microgrids include generation or storage

16 CPUC Webpage on Distributed Energy Resource Action Plan.
17 CA Health & Safety Code § 41514.1 (through 2012 Leg Sess)
18 D. 16-90-056 created the policy that prohibits the use of certain fossil fuels from being used to create Demand Response load reductions. The Decision was implemented by Resolutions E-4838 and E-4906.

resources that meet program eligibility rules, microgrids could also help satisfy resource adequacy obligations.

If the microgrid as a whole, or components of the microgrid, are non-dispatchable, the Resource Adequacy framework would treat them as embedded in the load forecast so that if they reduce peak loads, load serving entities that control them will receive lower resource adequacy requirements. Non-dispatchable resources do not directly reduce load serving entities' resource adequacy obligations.

If the microgrid as a whole, or a constituent part of the microgrid, acts as a behind-the-meter storage doing demand response, it can be counted towards meeting resource adequacy obligations to the extent it can be dispatched to offset load at peak hours.

6.5 Energy Efficiency, Demand Management, and Distributed Energy Resources

To the extent that the development of microgrids drives the implementation of energy efficiency measures, microgrids support the achievement of energy efficiency policies and goals. Since 2005, the CPUC has established energy efficiency goals based on legislative requirements established by SB 1037, which modified P.U.C. 454.5 and added P.UC. 454.55, 454.56, and 1002.3.

Energy efficient equipment and design can lower the amount of power required to operate a microgrid, thereby lowering capital costs for generation and storage resources. Alternatively, lower loads due to energy efficiency can extend the islanding duration of the microgrid. Thus, microgrids inherently favor implementing energy efficiency measures. Opportunities for efficiency measures include efficiency of generating sources, efficiency of storage medium, efficiency of usage (load), and efficiency between modes (inverters, line losses, etc.).

Additionally, the microgrid controller, which at a minimum operates the generation and storage resources to serve loads, may also include the capability of managing loads. This load management function can make energy available to the larger grid system if the microgrid is participating in a demand response program, consistent with the loading order of the larger grid.

Since microgrids combine distributed generation and distributed storage, they also support State and CPUC policies that encourage development of distributed energy resources more generally. The State of California, by way of a wide range of policies including the Self Generation Incentive Program in 2001 implemented by the CPUC, has supported the deployment of distributed energy resources, defined as "distribution-connected distributed generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies."[19] The Distributed Energy Resources Action Plan, endorsed by the CPUC at the November 10, 2016 Voting Meeting, describes a vision that supports state policy directives related to "rates and affordability, climate change, environmental sustainability, economic prosperity and coordination with other governmental

[19] California's Distributed Energy Resources Action Plan: Aligning Vision and Action (September 29, 2016).

entities."[20] The loading order was adopted in the 2003 Energy Action Plan prepared by the energy agencies.[21] The loading order consists of decreasing electricity demand by increasing energy efficiency and demand response, and meeting new generation needs first with renewable and distributed generation resources, and second with clean fossil-fueled generation.

Additionally, the microgrid controller, which at a minimum operates the generation and storage resources to serve loads, may also include the capability of managing loads. This load management function can make energy available to the larger grid system if the microgrid is participating in a demand response program, consistent with the loading order of the larger grid. The loading order consists of decreasing electricity demand by increasing energy efficiency and demand response, and meeting new generation needs first with renewable and distributed generation resources, and second with clean fossil-fueled generation. The loading order was adopted in the 2003 Energy Action Plan prepared by the energy agencies.[22]

6.6 Customer Choice

Microgrids support a variety of State and CPUC policies that seek to give customers more choices about how they meet their energy needs. The allowance of Direct Access generation, the provision for Community Choice Aggregators to independently procure generation for customers as an alternative to that procured by Investor Owned Utilities (IOUs), and the development of the Self Generation Incentive Program and Net Energy Metering that incentivizes customer-sited renewable resources are all examples of mechanisms designed to provide customers with more choice. Microgrids are one more option for customers to choose a difference source of energy, inherently combining generation and energy storage. Additionally, microgrids provide customers a choice on how to achieve resiliency as well.

6.7 Land Use

Widespread development of microgrids as distributed energy resources that generate energy close to loads could help reduce the scale of new supply-side generation needed to meet state greenhouse gases and renewable energy goals. Generation projects, especially large renewable projects, are often constructed far away from the end-user and sometimes require new transmission lines. Generation projects and transmission lines may impact natural or working lands. Microgrids that reduce the total statewide need for large generation projects can thus help preserve greenfield, habitat or agricultural lands. Managing natural and working lands is an official part of state greenhouse gas reduction

[20] Ibid.
[21] Enery Action Plan 2003.

strategy.[23] SB 1386[24] identifies the protection and management of natural and working lands. By reducing pressure on natural and working lands, microgrids (and distributed energy resources in general) support that state policy.

As the land use component of California's greenhouse gas emission reduction strategy, SB 375 encourages housing development near transit resources to reduce the greenhouse gas and criteria air pollutant emissions associated with car commuting. The goal of increasing housing density close to transit and the goal of serving loads locally in order to reduce pressure on natural and working lands may sometimes conflict. For example, the more load is located on a specific area of land due to increased housing density, the larger the area required to serve that load with solar PV generation.

Identifying enough compatible land to serve the local load with renewable resources can be difficult. The Huntington Beach Advanced Energy Community project is one example of how challenging it is to meet all energy needs locally. (Commission 2019) Increasing electrification of energy end uses, including transportation, space and water heating, as well as the need to serve existing high intensity commercial and industrial loads all contribute to the challenge.

Microgrids can be designed to utilize brownfields (previously dveloped land with the possible presence of contaminants), developed spaces such as parking lots or public gathering areas, or the rooftops of multifamily housing.

6.8 Resiliency

As discussed in the definition of resiliency, the ability of microgrids to provide resiliency can be characterized using the following parameters:

1. The system functions that are supported.
2. The type of disruptive events that are being protected against.
3. The aspects of resiliency that are affected:
    a) magnitude of disruption;
    b) duration of disruption;
    c) duration of adaptation; and/or
    d) duration of recovery.
4. The amount by which each aspect of resiliency is expected to improve.

Recognizing that microgrids can potentially support the resiliency of more than one type of system function, this section will first discuss the primary system function and then address additional system functions.

The primary system function for which microgrids can provide resiliency is electrical power for the load that is included within the microgrid's electrical boundary. The type of disruptive events that

[23] Senate Bill 375, Steinberg. California's Sustainable Communities and Climate Protection Act of 2008. Accessed June 30, 2020 from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200720080SB375.

[24] Senate Bill 1386, Wolk. Resource conservation: working and natural lands. Accessed July 14, 2020 from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1386

microgrids can protect against would include public safety power shutoffs, or any other wider grid outage. The ability of a specific microgrid to protect against a specific type of disruption would have to be examined on a case-by-case basis.

The aspect of resiliency that is most affected by microgrids is the magnitude of disruption. By supplying electricity during a grid outage, the system function within the microgrid can be restored to its normal level, or some significant fraction of its normal level. A microgrid may also be able to reduce the duration of adaptation (microgrid switches on rapidly in event of power failure) and the duration of recovery (lines that stay energized may not need same level of inspection prior to reenergization).

The amount by which microgrids can improve each aspect of resiliency is highly dependent on the specific details about the specific microgrid and the disruptive event. Depending on the event and the design of the system, resilient microgrid systems can deliver:

- 100% load for an unlimited time (Highest value of resiliency)
- Less than 100% load for an unlimited time (Medium high value of resiliency)
- Less than 100% load for a limited time (Lower value of resiliency)

The "limited time" period represents the system duration level before needing to import any fuels. "Less than 100% load" indicates a need for a load curtailment plan that prioritizes loads. The determination and prioritization of what is included in each tiered category of load to be powered for what duration of time will vary from microgrid to microgrid depending on local needs (Clean Coalition n.d.).

An example of such a prioritization schedule is below:

- Tier 1 - Critical load, for example 10-15% of total load: Life-sustaining or crucial to keep operational during a grid outage
- Tier 2 - Priority load, for example 15-20% of total load: Important but not crucial to keep operational during an outage
- Tier 3 - Discretionary load, for example 65-75% of total load: Remainder of the total load

In addition to electrical power, microgrids may be able to support the function of other systems that depend on electricity. Microgrids installed at the single customer level provide power to that customer, whether a residence, hospital, fire station, emergency community care center or grocery store. While serving that customer directly, the functionality that remains operable could also offer value to those in the surrounding community. Continuity of functionality at the customer level could decrease the level of disruption experienced by the whole community.

For example, microgrid power supply to a large customer such as a university campus or tribal center can provide resources such as charging stations for the surrounding community. The broader community benefit can be also be more indirect. A microgrid that provides power for medical devices or refrigeration for medications it helps those customers directly but also decreases pressure on the emergency response and health care systems. If a food bank can maintain power, they can continue to provide food to those in need, who in turn will be in a better position to help support their families and communities. When fewer people are struggling to meet their basic needs, more people and resources are available to contribute to recovery from disruption.

The total resiliency value of a microgrid is therefore not necessarily limited to just the function of providing power to the load within the microgrid boundary. It can also include the value of the individuals in the surrounding community continuing to have access to food water, medical help, safe shelter, transportation, as well as social connection and support.

The measurement of both the direct value of having power during a wider grid outage and the indirect values associated with maintaining other societal functions is not straightforward. Refer to the Barriers and Proposals chapter for more information on ideas for addressing that challenge.

6.9 High Level Comparison of Microgrids to Other Measures

Distributed energy resources such as renewable or clean energy generation or storage can be deployed without being part of a microgrid. Greenhouse gas reductions can be achieved without microgrids. It may be possible to reduce the scope of deenergization events by covering, undergrounding, replacing, rerouting, sectionalizing, or otherwise modifying transmission and distribution infrastructure without deploying microgrids. Energy efficiency measures can be deployed outside of a microgrid. Backup power can be provided by traditional fossil fuel generators.

For each value described above, it may be that other solutions are more effective or economical than microgrids at delivering it. Alternatively, in certain circumstances, microgrids may be more desirable. For example, for remote communities where developing, maintaining, and/or replacing long transmission or distribution lines is more costly, microgrids may be a superior option.

Staff notes, however, that microgrids may be better suited than other solutions to deliver combinations of these values. From reducing greenhouse gas emissions, to reducing transmission line losses; from minimizing impacts on natural and working lands to mitigating the impact of PSPS events; from increasing resiliency to providing grid services, microgrids can concurrently serve these functions. In other words, microgrids may be most competitive with other solutions when the full range of relevant values and State and CPUC policy goals are considered simultaneously rather than one by one.

7. Barriers and Solutions

The purpose of this section is to identify and describe real and perceived barriers to the commercialization of microgrids and identify and describe possible solutions and recommendations for next steps to overcome those barriers. This section is organized into four categories of barriers: regulatory, financial, technical, and other. Each category has the same structure which includes barriers, proposals, and Staff recommendations. In some instances, sets of related barriers may be grouped together for clarity and brevity.

Note that the proposals put forward in response to each barrier are Staff opinions and represent current thinking on the topic. Accordingly, they by no means constitute a comprehensive list of possible solutions for overcoming a given barrier and Staff are not advocating for one position over another.

7.1 Regulatory Barriers

Regulatory Barrier 1: Lack of Application Process for Utility-Scale Microgrids

There are established processes that allow customers wishing to install customer-sited microgrids to satisfy utility requirements for interconnection. Specifically, customers can use either Rule 21 or Wholesale Distribution Access Tariff, depending on the system configuration and the goals of the project. Depending on the utility, Rule 2 may allow utilities to build and operate such a microgrid on their behalf.

In contrast, community members (and their designated representatives in local or tribal governments) who would like to engage a utility to develop a utility-scale microgrid to benefit their community currently lack a transparent, uniform process for doing so. While D.20-06-017 establishes a set of requirements intended to make such engagement easier, more collaborative, and more effective, it stops short of establishing a standardized set of rights and responsibilities for the customers and utility, or a detailed application process. The absence of standard rules of engagement creates regulatory uncertainty that could impede commercialization of utility-scale microgrids.

Proposal

Require utilities to develop a new Electric Rule that would govern the development of utility-scale microgrids by utilities on behalf of customer applicants. This Rule would include, at a minimum, the following elements:

- rights and responsibilities of the customers that would be part of the microgrid, as well as those of the utility;
- process for accepting and reviewing applications;

- studies required to ensure safety and reliability and any fees or charges for conducting the studies;
- schedule of costs for developing, constructing, operating and maintaining the microgrid.

Staff offers three process options for implementing this proposal:

Option 1: Require the utilities to propose a new rule in this proceeding. The final adoption will be through a decision and ongoing modifications will be implemented through Advice Letters.

Option 2:

- Require interested parties to form a working group to develop the requirements for the new Rule
- Take comments in R.1909009 on the requirements proposed by the working group and areas of non-consensus
- Provide guidance to utilities on how to proceed based on record in R.1909009.

Option 3: Postpone consideration of this proposal to a later track of this proceeding to allow time to evaluate the outcome of the actions directed by D.20-06-017.

Recommendation

Staff recommends Option 2. This proposal offers a promising way to directly fulfill the requirement of PUC 8371(b), which requires CPUC to reduce barriers to microgrid deployment without shifting costs. Since this Rule would include a mechanism to transparently allocate any costs associated with developing, constructing, operating, and maintaining the microgrid directly to the beneficiaries, cost shifting would be prevented. Forming a working group to further elaborate on the requirement would strike an appropriate balance between the urgency implied by SB 1339's statutory deadline of December 1, 2020 and the need to develop an approach that is fair, safe, and effective. The first option would risk moving too quickly and sacrificing the quality of the of the Rule. The third option would cause inappropriate delays.

Regulatory Barrier 2: PUC 218

Description of the Barrier: Public Utilities Code (PUC) 218[25], commonly referred to as the "over-the-fence" rule, essentially requires any entity who wishes to sell power to more than two contiguous parcels or across a street to become an electrical corporation, which by way of PUC 216[26], is defined as a "public utility." If an entity becomes an electric corporation, it is a public utility subject to CPUC regulations, including customer service, public safety, rate regulation and reporting. There is a cost to set up and respond to PUC proceedings as an electrical corporation respondent subject to regulation. The cost and regulatory requirements can be prohibitive, serving as a barrier to microgrid

[25] CA Pub Util Code § 218
[26] CA Pub Util Code § 216

development. As can be seen in the examples that follow, this barrier applies primarily to microgrids in which the assets that are energized during islanded operation are on both sides of the point of interconnection. It does not apply to microgrids where the assets are entirely on the customer's side of the point of interconnection.

As an example, a property owner might have several buildings that have low electrical use, but high capacity to host microgrid resources that if maximized, could provide electricity for homes and businesses within a neighborhood location with enough power to operate even if a grid outage ensues. Another example might be a low-income neighborhood prone to power outages that would like to contract with a third-party to install, finance and operate a microgrid to increase neighborhood resiliency. A third example might be a city that wants to connect several city-owned buildings that are separated by public streets with a microgrid to enhance its resiliency in the event of a grid disruption. Throughout California, projects like this could contribute to the achievement of the state's clean energy and emissions reductions while also providing resiliency solutions through islanded microgrids.

PUC 218 currently prohibits such property owners to sell its excess electricity to more than two contiguous neighbors or that crosses a public street without becoming an electrical utility.

Historical Context: The definition of an electrical corporation was set in 1951 as part of the regulatory consensus of the time that determined electricity was a necessity and therefore required oversight to address the problem of unaccountable power and control over infrastructure and services rendered to the public. Regulation was to assure reasonable rates for quality (safe and reliable), equal and fair access to a necessity considered to be a foundational commodity (Constitution of the State of California, Volume 1, Chapter 764, Division 1, Regulation of Public Utilities, Part 1 Public Utilities, Chapter 1 General Provisions and Definitions, 216-218, p. 2029).[27]

In 1984, at the same time Senate Bill 1773 provided an exemption for cogenerators from the electrical corporation definition, it also added an additional eligibility requirement for the exemption. An "electrical corporation" was previously defined to be "every corporation or person owning, controlling, operating, or managing any electric plant for compensation within this state, except where electricity is generated on or distributed by the producer through private property solely for its own use or the use of its tenants and not for sale or transmission to others".[28] SB 1773 added the prohibition of any entity other than an electrical corporation (as defined) from distributing electricity generated at one property to more than two neighboring immediately adjacent properties and further prevents those properties from sharing electricity if "there is an intervening public street constituting the boundary between the real property on which the electricity is generated and the immediately adjacent properties where the electricity would also be used."[29]

[27] Constitution of the State of California, Volume 1, Chapter 764, Division 1, Regulation of Public Utilities, Part 1 Public Utilities, Chapter 1 General Provisions and Definitions, 216-218, p. 2029. Accessed June 17, 2020 from clerk.assembly.ca.gov/sites/clerk.assembly.ca.gov/files/archive/Statutes/1951/51Vol1_Chapters.pdf#page=2)
[28] CA Pub Util Code § 218(a)
[29] CA Pub Util Code § 218(b)(2)

Subsequent exemptions added such as the "independent solar energy producer", are also subject to sharing with no more than two immediate neighbors that are not across a public street. The effect of this additional language was a limitation on the development of competitive distributed generation.

Application of Law in a Changing Environment: PUC 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 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.)

In the current market and regulatory environment there is a concern that microgrid development is only affordable to those with substantial economic means. Universal access to power means making reliable and affordable electricity available to all. As more and more end uses electrify, electricity becomes even more a necessity. Most of the time connection to the grid guarantees this universal access. Recent Public Safety Power Shutoff events have demonstrated that as a percentage of income lost due to economic disruption, low-income and disadvantaged communities are more highly impacted by disruptive energy events.[30] Providing universal access to reliable power may necessitate the deployment of microgrids, especially for customers who are highly impacted by disruptions for which alternative solutions pose significant technical, political, or financial challenges.

This raises important questions, such as:

- how to ensure reliable service for customers served by the microgrid;
- do customers have the option to opt out of a microgrid project that may increase costs on their utility bills;
- is there any protection for "customers" of microgrids to ensure they are not paying excessive costs for the microgrid services;
- do third-party operated microgrids increase wildfire ignition risks;
- who is liable for any damage caused by the electric distribution system when a third-party is operating the microgrid?

[30] As an example, a refrigerator full of food for a family of four, costing $500 represents a higher percentage of a low income family's monthly income than a high income family's monthly income. Reference the PSPS hearings where woman was telling about 25% of her salary went to pay for the food in her fridge that she lost.

Micro-utilities: Microgrids could potentially fall under the category of "electric micro-utilities" as defined under Public Utilities Code Section 2780-2780.1.[31] Legislative analysis indicates this category was declared as acknowledgement of the burdens of the "public utility" categorization for entities serving under 2000 customers. Only one organization, Mountain Utility, (based in Kirkwood, California) has utilized this category.[32] Under this categorization, the CPUC could consider some or all the legal, administrative, regulatory, and operational costs burdensome to the limited resources of the micro-utility. This is not to say the micro-utility would bear no responsibility for the kinds of considerations elicited by those legal, administrative, and operational costs. But under this consideration, the CPUC could articulate a set of boundaries within which they are subject to rate setting, non-discriminatory delivery of services to all who desire service as well as those that wish to opt out, and safety and reliability oversight as well as a minimalistic reporting scheme designed with the smaller scope and considerations of an entity serving fewer than 2,000 customers. The CPUC can still determine exemption status as respondents on a categorical or case-by-case basis or ease the participation requirements in critical areas of analysis. For example, in lieu of the full process of Renewables Portfolio Standard, integrated resource planning and resource adequacy analysis, planning and consideration, a microgrid considered as an electric micro-utility could instead be required to report on measures that fulfilled the intent of those programs such as: renewable resources, fair practices rate-setting, integration between resources and interfacing with the larger grid, and resource adequacy to anticipate and fulfill microgrid participants contractual and anticipated usage and generation capacities.

Electric Cooperatives: Community microgrids (microgrids that provide energy resources for more than one property owner, not necessarily contiguous) could form an electrical cooperative.

Within Section 2868 of Chapter 9 of Part 2[33]:

"The following definitions shall apply for purposes of this article:

(a) "Electric utility" means an electrical corporation as defined in Section 218, a local publicly owned electric utility as defined in Section 9604, or an electrical cooperative as defined in Section 2776."[2]

Within Section 2776[34]:

"As used in this chapter, the term "electrical cooperative" means any private corporation or association organized for the purposes of transmitting or distributing electricity exclusively to its stockholders or members at cost."[3]

According to this language it could be interpreted that an established electrical cooperative (as defined in Section 2776) could be formed as the organizing structure defined by Section 2868 as an "electric utility" operating the microgrid as long as it transmits or distributes electricity exclusively to the microgrid participants at cost. Oversight of fair treatment between customers, assurances of

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[31] CA Pub Util Code § 2780-2780.1
https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=1.&title=&part=2.&chapter=5.5.&article=

[32] At the time the bill was passed (2004), Mountain Utility was owned by Kirkwood Ski Area which represented approximately 70% of the utility's load, but also served some residents and businesses in the area. Mountain Utility was eventually purchased by Kirkwood Meadows Public Utility District in 2011.

[33] CA Pub Util Code § 2868 (2017)

[34] CA Pub Util Code § 2776 (through 2012 Leg Sess)

safety standards and reliability of electricity would be in the jurisdiction of the electrical cooperative and thus out of the scope of jurisdiction of the Commission. The Commission would not have authority to establish rates of the electrical cooperative, but the legislation states the rates established to those served by the cooperative is to be "at cost."[35]

PUC Section 8387[36]details various safety mechanisms electrical cooperatives must undergo for wildfire safety, including the holding of a public meeting to present their wildfire mitigation plan that they will submit to the California Wildfire Safety Advisory Board on July 1st every year, among other things.

PUC Section 454.52[37] discusses how the Commission has authority over electrical cooperatives for the purposes of this section, which discusses the filing of an Integrated Resource Plan, if "the electrical cooperative has an annual electrical demand exceeding 700 gigawatthours, as determined based on a three-year average commencing with January 1, 2013."[38] Additionally, PUC Section 454.52 discusses greenouse gas reduction targets, Resource Adequacy and Renewable Portfolio Standard requirements.

Proposals

Option 1: The CPUC could adopt a set of regulatory rules to further guide the development of Electric Micro-Utilities as they could pertain to microgrids.

The CPUC could set tiered levels of customers under 2,000 customers that would need to meet levels of legal, administrative, regulatory, and operational requirements in alignment with those levels. For example, while a microgrid with 10 or less participants would be subject to the similar stringent safety standards, a microgrid of that level might be required to undergo less arduous reporting. The next level of microgrid might be on the order of 10-100 participants with a higher level of reporting, while the next level of participants on the order of 100-2000 participants would have the highest level of reporting in this category.

Additionally, the CPUC could set consumer protection measures similar to those already established in the landlord/tenant example whereby energy passing through the master meter to the tenants can't be sold at a higher rate than was paid to the interconnected load serving entity (investor owned utility, community choice aggregation, local public utility).

Option 2: The CPUC could recommend the legislature consider amending the PUC 218 to create an additional entity defined as a microgrid. If an entity meets the definition of a microgrid, it would then be allowed to distribute power across property and lines and roads even if those properties are not adjacent. The amendment could require microgrids to meet certain requirements that ensure safety and reliability to the microgrid participants as well as the larger grid (if interconnected), and certain requirements that ensure alignment with state policy goals such as greenhouse gas emission reductions, renewable energy, and resource adequacy.

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[35] CA Pub Util Code § 2777 (2019)
[36] CA Pub Util Code § 8387 (2016)
[37] CA Pub Util Code § 454.52
[38] Ibid.

Option 3: Community microgrids (microgrids that provide energy resources for more than one property owner, not necessarily contiguous) could form an electrical cooperative. Staff notes that this proposal for addressing the perceived barrier that PUC 218 poses to microgrid development may not require changes to existing statute or CPUC rules or policies.

Regulatory Barrier 3: CEQA Exemption Issues

Under the California Constitution[39], a city or county or other public body may not regulate matters over which the Legislature grants regulatory power to the CPUC. The CPUC has exclusive jurisdiction to regulate electric facilities of investor owned utilities. In addition to CEQA, CPUC General Order (GO) 131-D[40] governs the construction of electric transmission and substation facilities by investor-owned utilities (California Public Utilities Commission 1995). It imposes requirements for a permit to construct or certificate of public convenience and necessity under specific circumstances with the purpose of ensuring compliance with applicable requirements of CEQA. It provides public notice and a process for the public interest to be heard by the CPUC in land use/siting issues related to electric transmission/power line/distribution facilities. Because CPUC has not modified GO 131-D since 1995 its applicability, definitions, and categorical exemptions may warrant updating to address gaps or perceived barriers to microgrids.

Land use issues may pose a barrier depending on jurisdiction, installing battery energy storage or other microgrid components may trigger CEQA analysis. GO 131-D specifies that certain construction of electric distribution facilities would not require a permit to construct nor a certificate of public convenience and necessity when it occurs on existing utility-owned property or within the boundary of a utility-owned substation.

Conversely, the same project sponsored by a third-party project applicant sited in public or private property not owned by a utility may require land acquisition and a conditional use permit issued by the local city or county jurisdiction. The permitting process may significantly expand project timelines depending on whether the facilities constitute a "project" within the meaning of CEQA, initial study results in eligibility for a categorical exemption, . Similarly, when an investor owned utility does not own sufficient land to site a utility-scale microgrid or proposes construction on greenfield land, the land use issues may pose a barrier by expanding the project cost and extending the schedule.

In adopting renewable energy resources to meet target greenhouse gas emissions by 2045, the Office of Planning and Research has worked with local jurisdictions to enhance or streamline permitting processes with recommendations that Office of Planning and Research published within its Solar Permitting Guidebook. CPUC Staff understands that the Solar Permitting Guidebook explains

[39] CA Constitution Article XII § 8 (2018)
[40] General Order 131-D, "Rules Relating To The Planning and Construction of Electric Generation, Transmission, Power, Distribution Line Facilities and Substations Located in California." Effective September 10, 1995, D.95-08-038.

requirements for solar photovoltaic installations by describing key steps in permitting processes and providing recommendations and best practices for improving local permitting timelines.

By comparison to the microgrids situation, where community microgrids or in front of the meter utility scale battery storage installations are anticipated, it would be advantageous to have some of the same work products that Office of Planning and Research accomplished for solar installations available to local jurisdictions to streamline microgrid projects. For example, templates, model ordinances regarding zoning, streamlined permitting processes. The Office of Planning and Research is also engaged with the California Energy Commission in initiatives mandated by implementation of Assembly Bill 2154. Those initiatives, however, are limited to exploring the streamlining possible for enabling behind the meter battery energy storage for installations smaller than one megawatt.

Another potential perceived barrier to utility microgrids may be the regulatory interpretation of GO 131-D regarding the definition of "additional generating capacity" and whether it would apply to battery energy storage integrated with generators or to distributed generation energy resources. Utilities installing additional generating capacity greater than 50 megawatts could trigger the need for environmental review or require a certificate of public convenience and necessity involving more extensive time, effort, and expense.

Proposals

Option 1: Open a Rulemaking to revise GO 131-D to explicitly define whether hybrid distributed energy resources including battery energy storage integrated with generators would be considered additions to electric generating capacity and whether GO 131-D applies to distributed energy resources interconnected within substations.

Rationale: Revising GO 131-D to clarify that applicability to utility scale microgrids installed by investor owned utilities or procured by investor owned utilities from third party developers could address whether distributed generation resources such as battery energy storage systems are considered increases to electric generating capacity or substitutes for electric generating capacity that do not require CPUC permitting.

Option 2: Maintain the status quo by addressing regulatory interpretations regarding applicability of GO 131-D related to additional generating capacity on a case-by-case basis. As situations arise, the respective legal divisions of the utility and the CPUC can meet and confer so that Staff can provide recommendations on rule applicability. Recently, an investor owned utility seeking to install a substation scale microgrid requested the CPUC Staff's first impressions to determine whether a synchronous generator coupled or integrated with battery energy storage would trigger the GO 131-D threshold of 50 megawatts electric generating capacity. The question centered on whether the battery should count as incremental capacity. In another situation, Staff posed the question whether battery energy storage that replaces or substitutes for additional electric generating capacity would trigger a CEQA review of a proposed utility scale battery energy storage project. In both cases, the respective legal divisions of the CPUC and the utility met and conferred to determine whether they could resolve rule applicability, which in those examples, they succeeded.

Rationale: Revising a CPUC General Order is a major undertaking which could require 18 to 24 months. Performing legal analysis to interpret GO 131-D as needs arise may be a shorter cost-effective option compared to a rulemaking.

Option 3: Rebalance the perceived advantage that GO 131-D grants investor owned utilities for distributed generation microgrids installed on utility owned property by recommending to Office of Planning and Research to standardize zoning ordinances and streamline CEQA and other permit requirements for installation of in front of the meter utility scale microgrids. Recommend to Office of Planning and Research to facilitate workshops with local jurisdictions as they did for PV installations to address potential for CEQA exemptions and standardized language to adopt for model zoning ordinances in State of California that would streamline permitting processes for community microgrids and in front of the meter utility scale battery energy storage.

Rationale: Clarifying zoning ordinances by providing recommended standardized zoning ordinance language and addressing which categorical exemptions may facilitate installation of utility-scale microgrids could build consistent, streamlined processes.

Regulatory Barrier 4: Distribution and Transmission System Data Access

Local government agencies seeking to build In Front of the Meter resilience solutions need access to Investor Owned Utility distribution and transmission system data to craft area appropriate resilience solutions, such as microgrids. Stakeholders acknowledge the need to work with the Investor Owned Utilities to build these solutions safely, however they have in the past complained about a perceived lack of transparency by the Investor Owned Utilities regarding rules surrounding sharing sensitive data. Stakeholders believe that their interactions with the Investor Owned Utilities will be more productive if there is more data in hand to work with before engaging to build resilience solutions. Staff has identified two main barriers to accessing utility data: 1) Confidentiality, Cybersecurity, and Critical Electric Infrastructure Information rules; and 2) Data Centralization.

Regulatory Barrier 5: Confidentiality, Cybersecurity, and Critical Energy/Electric Infrastructure Information

Confidentiality, Cybersecurity, and Critical Energy/Electric Infrastructure Information rules present a clear barrier to the development of microgrids and resilience solutions that require the use of Investor Owned Utilities infrastructure because the Investor Owned Utilities have in the past invoked some of these rules to restrict access to data they deem sensitive. Doing so has limited the development of non- Investor Owned Utilities owned and developed community scale microgrids and has restricted access to infrastructure data local government entities could use to craft area-appropriate resilience solutions.

The Investor Owned Utilities' confidentiality rules are put in place to prevent unauthorized access to customer information (such as a customer's name, address, and meter location). The 15/15 rule (adopted in D.97-10-031) is the confidentiality rule most often invoked when restricting access to customer data. This rule requires that datasets representing load cannot be released publicly if there are less than 15 commercial and industrial customers or 100 residential customers represented, or one customer makes up more than 15% of the total load recorded. Invocation of this rule has led to heavy data redactions in the Distributed Resource Planning portals (specifically the Integrated Capacity Analysis and Distribution Investment Deferral Framework maps[41]). This rule limits the portals' usefulness as tools in planning resilience solutions. On the other hand, the Investor Owned Utilities cannot release individual customer meter data without the customer's express written consent, pursuant to several statutes and CPUC decisions (see Attachment B of R.08-12-009 for a list of these statutes and decisions[42] as well as the Energy Data Access Decision (D.14-05-016[43]) which established the Energy Data Access Committee and laid out customer privacy rules for data aggregation purposes). Electronic provision of this data is currently available to demand response providers through the "click-through" process established by D.16-06-008[44] (later modified by D.17-06-005)[45] where customers can allow providers access to meter data by using their electronic account sign in and agreeing to certain terms. Currently, the "click-through" authorization is only available to Demand Response providers in Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) territory. But in Pacific Gas and Electric (PG&E)'s territory, both Demand Response providers and Distributed Energy Resource providers are authorized to use the "click-through" process to obtain customer load data. Currently, the expansion of "click-through" access to Distributed Energy Resource providers in SCE and SDG&E territories is being addressed by CPUC in the consolidated proceeding A.18-11-015 et al.,[46] where recently both a scoping memo was filed and case management hearings were held. Individually sourcing meter data from customers requires each customer to opt in and would take a long time to gather and process the data for use in a microgrid solution. These rules represent a barrier because granular circuit load data is essential to the design process for microgrids.

Cybersecurity rules are put in place to prevent unauthorized access to Investor Owned Utility computing infrastructure and transmission and distribution system control infrastructure. Setting up new portals or use of existing distribution resource planning portals puts the onus of protecting confidential customer information on the Investor Owned Utilities and end users and requires

[41] PG&E's ICA/DIDF/PVRAM maps can be found here; SCE's DRP External Portal (DRPEP) can be found here; and SDG&E's ICA map can be found here.
[42] Decision 11-07-056 July 28, 2011 – Decision Adopting Rules to Protect the Privacy and Security of the Electric Usage Data of the Customers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company, Attachment B
[43] D.14-05-016 June 5, 2014 – Decision Adopting Rules to provide access to Energy Usage and Usage-Related Data While Protecting Privacy of Personal Data
[44] Decision 16-06-008 June 9, 2016 – Decision Addressing Budgets for Day-Ahead, Real-Time, and Ancillary Services During the Intermediate Implementation Step of Third-Party Demand Response Direct Participation
[45] Decision 17-06-005 June 15, 2017 – Decision Addressing Pacific Gas and Electric Company's Petition for Modification of Decision 16-06-008
[46] A.18-11-015 Docket – Application of Pacific Gas and Electric Company for Approval of Its Proposals and Cost Recovery for Improvements to the Click-Through Authorization Process Pursuant to Ordering Paragraph 29 of Resolution E-4868. (U39E) (Note: Though the title of this proceeding refers only to PG&E, the three applications separately filed by PG&E, SCE, and SDG&E were consolidated by ALJ Ruling on December 5, 2019.

additional information technology resources to execute safely. However, clear standards that govern cybersecurity of distribution level data do not exist. Currently, the Federal Energy Regulatory Commission has adopted the North American Electric Reliability Council's Critical Infrastructure Protection cybersecurity reliability standards for the bulk electric system infrastructure (e.g. transmission and generation assets covered by North American Electric Reliability standards, generally > 100 kV) (NERC n.d.). However, these standards only includes a narrow subset of grid assets and are compliance based, which severely limits their usefulness when trying to extrapolate them to the distribution level, as is outlined in Safety and Enforcement Division's white paper on physical security[47] as well as the joint Energy Division/Policy and Planning Division white paper on cybersecurity[48]. Rather, CPUC oversight is reliant on a maturity model to assess the strength of Investor Owned Utility systems (which are also independently tested and audited by third parties) because often the writing of standards lags far behind the reality of the environment. Providing data to local governments and their contracted developers will require certification that data will be used reasonably by these end users, and that these end users will provide a reasonable level of security commensurate with cybersecurity and confidentiality best practices (the County of San Diego enacted standards as such (Cybersecurity Resources n.d.), and the National Pipeline Mapping System portal also follows best practice by requiring user agreement to an nondisclosure agreement on sign in (PHMSA n.d.)).

Critical Energy/Electric Infrastructure Information rules were developed by North American Electric Reliability Corporation and enforced by the Federal Energy Regulatory Commission to restrict access to data that if revealed, would present a clear and present threat to security of the electrical system (FERC n.d.). Currently, there is not a broad understanding as to what data can legally be classified as Critical Energy/Electric Infrastructure Information under these rules, and the Investor Owned Utilities have variously used Critical Energy/Electric Infrastructure Information as a pretense for not sharing infrastructure data that local governments need to craft area appropriate resilience solutions (see SDG&E response to questions on the Track 1 Staff Proposal[49] where SDG&E claimed that Critical Energy/Electric Infrastructure Information rules prevented them from sharing a broad range of distribution and transmission data that was being requested by parties). Generally, it is understood that if the physical location of the infrastructure is known then it cannot be classified as Critical Energy/Electric Infrastructure Information due to that information being public knowledge. However, there is no current listing of exactly what distribution infrastructure can be classified as Critical Energy/Electric Infrastructure Information, which creates ambiguity about what data the Investor Owned Utilities can and cannot withhold due to these restrictions.

Regulatory Barrier 6: Data Centralization

Currently, there is no one place where local governments and developers can get the grid infrastructure information and data required to independently develop in-front-of-meter resilience

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[47] SED Staff White Paper Feb. 2015 – Regulation of Physical Security for the Electric Distribution System
[48] Grid Planning and Reliability Policy Paper September 19, 2012 – Cybersecurity and the Evolving Role of State Regulation: How it Impacts the California Public Utilities Commission
[49] R.19-09-009 January 30, 2020 – Response of San Diego Gas and Electric Company (U 902-E) to Questions on Staff Proposal

solutions. This makes gathering and working with the data difficult and requires extensive interface with the Investor Owned Utilities which can be a lengthy process. Thus, the benefits of having resiliency solutions in place are not being realized in the face of de-energizations or other grid events. Currently the main sources of grid data are the Distributed Resource Planning maps (Integrated Capacity Analysis and Distribution Investment Deferral Framework). However, the Integrated Capacity Analysis and Distribution Investment Deferral Framework maps were originally intended to ease development of behind-the-meter solar and storage solutions and are not necessarily as useful for in-front-of-the-meter microgrid development. Additionally, PG&E has a newly developed Public Safety Power Shutoff portal coming online in 2020 that will include circuit level data about outages and historical impact reports which will be made available to local governments for emergency planning purposes (PG&E n.d.). The data portals also suffer from some issues, including data redactions per the 15/15 rule, lack of granularity in customer load data, and contain some dubious data, and do not address historical outages that could be used to better target resilience solutions. Additionally, maps posted on PG&E's new Public Safety Power Shutoff portal are only intended to address historical de-energization events for emergency planning purposes and show circuit level data of the events. The electric grid is potentially moving into an era where it may be owned and maintained by multiple entities, including local and tribal governments. While this is not the case at present, access to centralized customer load data will provide a platform for exploring more distributed non-utility electrical grid ownership, operation, and expansion. This barrier will be important to address because it will empower these entities to make productive and informed and safety-conscious investment decisions when crafting area appropriate resilience solutions.

Proposals

Option 1: Coordinate with the demand response team and any associated proceedings to leverage the expansion of "click-through" process access to distributed energy resources providers across Investor Owned Utilities' service territories.

Rationale: The click-through process is already established to procure confidential customer load data that is essential to the development of microgrids. Using this system would require developers to sign up as distributed energy resources providers but would allow them to gain access to customer data based only on customer consent without having to interface with the Investor Owned Utilities. This system is already in place for PG&E but would require both SCE and SDG&E to expand system capabilities to accommodate this addition, as is being proposed in A.18-11-015.[50] Staff will coordinate internally with the demand response team to further evaluate the usefulness of this process in procuring load data for microgrid development.

Option 2: Coordinate with the Distributed Resource Planning and Public Safety Power Shutoff proceedings to expand access to customer load and Investor Owned Utility infrastructure data

[50] A.18-11-015 Docket – Application of Pacific Gas and Electric Company for Approval of Its Proposals and Cost Recovery for Improvements to the Click-Through Authorization Process Pursuant to Ordering Paragraph 29 of Resolution E-4868. (U39E) (Note: Though the title of this proceeding refers only to PG&E, the three applications separately filed by PG&E, SCE, and SDG&E were consolidated by ALJ Ruling on December 5, 2019.

through the existing Integrated Capacity Analysis, Distribution Investment Deferral Framework, and Public Safety Power Shutoff portals.

Rationale: Since existing portals already have built-in cybersecurity measures, it would be prudent to use these resources to begin hosting the data required. Additionally, the Distributed Resource Planning proceeding has made significant inroads into data provision. Combining efforts to expand the data available through one of these portals would prevent duplication of effort and would help achieve greater data centralization. Additionally, the Distributed Resource Planning proceeding has addressed some Critical Energy/Electric Infrastructure information concerns in data provision through the Integrated Capacity Analysis, Distribution Investment Deferral Framework and Photovoltaic Renewable Action Mechaninism portals which can be leveraged to provide broader data access. However, in the R.19-09-009 Track 1 decision (D.20-06-017[51]) recommended, but did not require, the Investor Owned Utilities use existing Distributed Resource Planning portals to meet compliance requirements laid out. Additionally, the IOUs asked for and received a sixty (60) day extension to the advice letter filing deadline for this requirement, so at this time these advice letters have not been received. Staff will evaluate the Advice Letters once received and will then recommend an appropriate course of action based on the proposals laid out therein.

Option 3: Further expand the data portal required by Track 1 of this proceeding

Rationale: This would require working with the Investor Owned Utilities to expand data access through the portals they were required to stand up in Track 1 of this proceeding (as laid out in D.20-06-017[52]). The Investor Owned Utilites were required to file advice letters detailing how their portals will be made available to local governments and how the portals will present the data required; these compliance steps are still pending and will require analysis to determine how the portals will be set up and how feasible adding required data will be. Further conversations will need to be conducted with stakeholders and the Investor Owned Utilites to clarify what data is needed, and what data the CPUC can compel the Investor Owned Utilities to share. This will require extensive coordination with the Distributed Resource Planning team, CPUC's Safety and Enforcement Division, and CPUC legal counsel to ensure that all concerns confidentiality, cybersecurity, and critical energy/electric infrastructure concerns are addressed.

Option 4: Coordinate with the Energy Data Access Committee groups to address these issues in subsequent Energy Data Access Committee meetings

Rationale: There was no broad consensus on what data could be shared through a portal in Track 1 of this proceeding, and thus bringing together a broad range of stakeholders representing the Investor Owned Utilities, local and tribal governments, community based organizations, and microgrid developers would help to determine what data is actually required to build microgrids, what data can be reasonably provided without confidentiality or critical energy/electric infrastructure issues, and what cybersecurity issues need to be addressed. The existing Energy Data Access Committee is a perfect venue to raise these concerns because it brings together the necessary stakeholders and has overlap with these issues. This would require close coordination with CPUC

[51] D.20-06-017 June 17, 2020 – Decision Adopting Short Term Actions to Accelerate Microgrid Deployment and Related Resiliency Solutions
[52] Ibid.

Staff that are responsible for these meetings and will require Staff to work with stakeholder to develop content to bring to these meetings. This option would require a timeline which may stretch into Track 3 and should also be coordinated with Integration Capacity Analysis and Locational Net Benefit Analysis working groups to address potential overlaps.

Option 5: Develop a definitive list of distribution infrastructure data that can be shared without critical energy/electric infrastructure concerns

Rationale: The Investor Owned Utilities often use Critical Energy/Electric Infrastructure Information as a pretense to not share data they deem sensitive or may threaten their franchise. This option would require a thorough legal analysis of the North American Electric Reliability Corporation/Federal Energy Regulatory Commission rule to create a definitive list of distribution infrastructure data that cannot be withheld on the grounds that it qualifies as critical energy/electric infrastructure. This list can be used to bolster any requirements for data portals and to hold the Investor Owned Utilities accountable for sharing useful infrastructure data.

Regulatory Barrier 7: Lack of Standardized Metrics for Measuring Resiliency and Resiliency Value[53]

Determining an approach to quantifying resilience value is critical for investment decision making, rate-making and emergency planning as we address the vulnerability and changing nature of our energy system.

Why is it important to quantify resilience? Who might use this information?

"Measuring real improvements is dependent, in part, on understanding baselines for various indicator categories; using measures can help communities see improvements in their resilience over time, better gauge and measure their investments, understand tradeoffs among community priorities, and assist decision makers in establishing incentives for increasing resilience" (National Research Council 2015).

Utilities and regulators can use the information to make decisions on infrastructure investments and balance costs between ratepayers. Local governments need to develop the most efficient, cost-effective and resilient emergency mitigation plans. Developers and private customers need to be able to understand how their priorities, designs and decision making will affect their project.

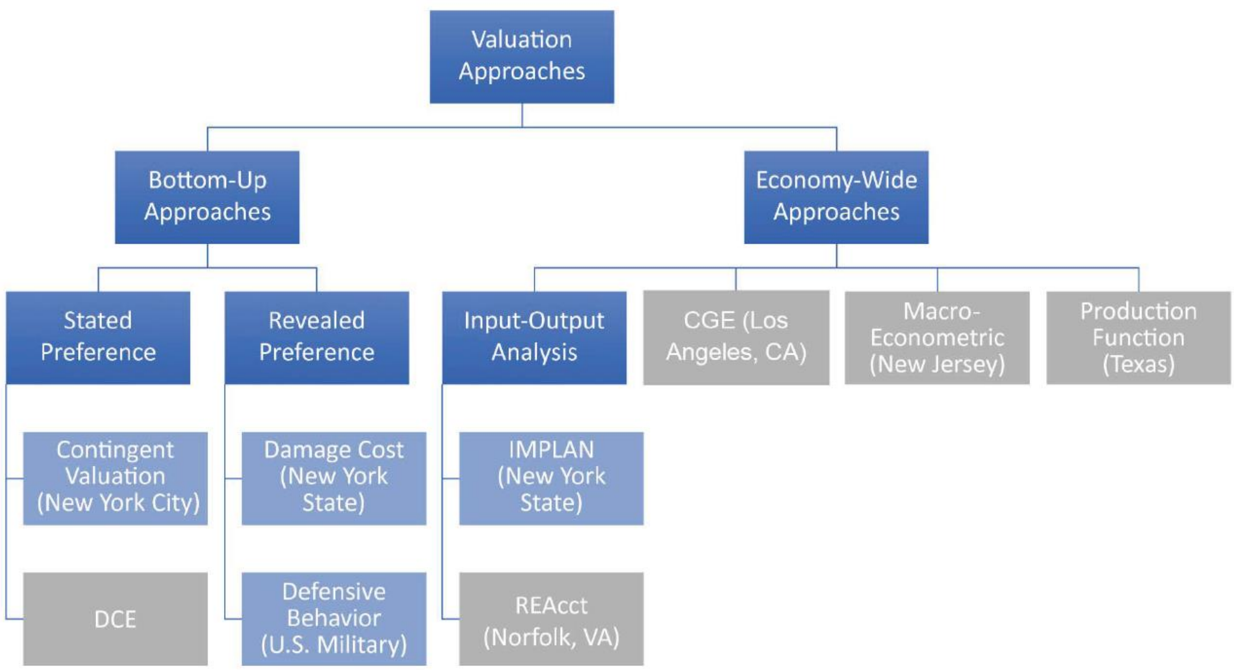
The National Association of Regulatory Utility Commissioners convened a study on analytical practices used by regulators around the country. It determined that while there were various tools available to capture different perspectives of resilience value, there was "no one single valuation methodology that captured all the regulatory concerns regarding the resiliency value of distributed energy resources" (National Association of Regulatory Utility Commissioners: 2019). The various methods included in the report are listed in outline format below, and the chart in Figure 2 shows

[53] Lack of Standardized Metrics for Measuring Resiliency and Resiliency Value could also be a financial barrier.

where some of the methods are currently being used. A brief description of different approaches to resiliency valuation follows the chart.

1. Bottom-Up approach
    1. Stated Preference method
        1. Contingent Valuation - Interruption Cost Estimate Calculator.
        2. Accepted and used standard calculation for estimating interruption (or societal) costs to customers
    2. Revealed Preference method
        1. Damage Cost - FEMA Benefit Cost Analysis Tool
        2. Defensive Behavior - Generator Cost
2. Economy-wide approach
    1. Input-out-model – IMPLAN, REAcct
    2. Computational General Equilibrium
    3. Macro-econometric
    4. Production Function

Figure 2 Methods used to calculate the value of avoided power interruptions and the value of resilient DER in different locations in the United States *(National Association of Regulatory Utility Commissioners: 2019)*



<u>Description of different approaches to resiliency valuation</u>

- The "Bottom-up Approach" looks at more granular effects from the individual or consumer perspective.
- The "Economy-wide" approach represents a more top-down generalized view, looking at economic impact as a whole.

- "Resiliency value based on disruption (Contingent Valuation)" attempts to capture what is the price that consumers are willing to pay to keep their power on, or restore power in the aftermath of a disruption? Grid reliability has a much lower value when the supply of electricity has been so steady that its presence is taken for granted. The value of resiliency goes dramatically up while in the midst of such disruption.
- "Resiliency value based on cost of outage (Damage Cost Method)" assesses damage impacts of an outage.
- "Resiliency value based on cost of equipment (Defensive Behavior Method)" looks at the value of resiliency as reflected in how much consumers might be willing to pay for systems that are within their control to keep the lights on. Post Public Safety Power Shutoffs, generator sales in Northern California hit an all-time high. It's expected that battery sales will experience an uptick in sales as well (Shao 2019). These are assets that might not be prioritized by the average consumer had they not just experienced several days without power.

As an example of how resiliency value can be calculated at a high level, Michael Wara at the Stanford Woods Institute for the Environment used the Interruption Cost Estimate Calculator (The Interruption Cost Estimate Calculator n.d.) to estimate that a 48-hr 2018 PSPS event cost residential and small commercial and industrial customers a combined $2.5 Billion. Without C&I customers, residential customer impact alone is $65 million (CNBC 2019). The economic impact of residential outages in 2020 may be significantly different given the number of people now working from home due to COVID-19 shelter-in-place orders if they are in place at the time.

As mentioned in the resiliency definition section, Panteli, et.al. defined a resilience trapezoid in an effort to model and quantify resilience as a response to disruption (Panteli, et al. 2017). Panteli's original modeling assists in quantifying operating and infrastructure resiliency as it reflects a transmission system during high wind events in the United Kingdom. Calculations in this model reflect power service levels (Wh) and time (the point of time in the timeline, or duration measured in time. The calculations do not include factoring in any type of energy storage.

Resilience here is the quantity of baseload that can be met at a specific timeframe before, during, and after an unplanned and uncontrollable disturbance event. The model does not reflect economic, environment, social or health considerations. These additional considerations would add robust dimension to the basic operations/infrastructure model. However, it provides a framework for understanding what the phases and variables are to consider. The model can be adapted to study other system functions that are disrupted by the same event and overlaid to determine the relationships between systems. The overall goal is to raise the bottom of the trapezoid.

In an effort to create a system of metrics used to understand resiliency value that does take into consideration the constellation of systems impacted by electrical outages as it relates to distributed energy resources, microgrids and the broader effort to modernize the grid, Commonwealth Edison Company in Illinois has, with the involvement of a stakeholder Working Group, developed a comprehensive set of 58 metrics relevant to microgrid deployment and grid modernization efforts in the context of disruptions of any kind (Illinois Commerce Commission 2018). The metrics fall into four categories:

- Energy System Resilience and Performance
- Community and Social Resilience
- Critical Infrastructure Resilience
- Economic Resilience

With these 58 metrics they hope to capture a measurable valuation of resiliency that includes some of the more elusive areas of consideration such as community resilience, social continuity, and short and long term economic and environmental impact.

Proposals

Option 1. Develop a set of metrics for measuring and evaluating microgrid resiliency performance that take into account five areas of concern:

1. Which loads are backed up and how much load (Tier 1, 2, 3)? Metric: kW
2. Duration of backup – with no other inputs? Metric: time in hrs
3. What level of notification/advanced notice is needed for backup at specified load/duration? Metric: (0-1hr, 1-4hr. 4-12hrs, 12-24 hrs, 24-48hrs)
4. What level of crossover is available (intermittent down time before specified backup is available)? Metric (time in secs, min)
5. How clean is it? Metric: GHG and particulates in PPM

Tiers can be defined as follows:

- **Tier 1** = Critical load, which sustains basic life, safety or emergency response needs crucial to keep operational during a grid outage. Indefinite energy resilience for critical load is worth highest value.
- **Tier 2** = Priority or supporting loads that maintain important but not critical functional or operational needs. Important but not absolutely crucial to keep operational during an outage.
- **Tier 3** = Discretionary load is the remainder of the total load.

Each concern has a metric with ranges that correlate to a resilience level for that concern. Factors are assigned to each range and are used to determine level of resiliency. Factors can be used individually or aggregated for an overall "resilience level."

The method can be applied to a variety of procurement approaches, such as tariffs, investment decisions, or cost-benefit analyses that inform program goals. For example, the CPUC could establish standard values for each type and level of resiliency for the purpose of compensation via a rate schedule or standard contract offer, e.g. 2 hours' worth of backup is worth "Z" amount of cost. Alternatively, each community can decide that level X of Y type of resiliency is worth Z investment. This method would enable individual customers or communities to make informed decisions about the amount and type of resiliency that they prefer and the price they are willing to pay for it.

Option 2: Work with the CEC's EPIC program to develop and track a set of metrics with existing or newly solicited projects. The metrics set could be based on the metric set developed by the Commonwealth of Edison Company in Illinois or could be developed independently. The metric set would be developed and used to gain more understanding of effective resiliency measurement and valuation metrics and methodologies that can be replicated, scaled and standardized, as well as gain an understanding of how funded or prospective microgrid projects perform.

Option 3: Develop a "Resiliency Investment Framework" to define expectations and rules for how utilities should plan and implement investments in resiliency. This framework could be one approach to continuing the work of facilitating the commercialization of microgrids while also serving as a vehicle for operationalizing the concept of resiliency in utility planning and investment decisions. The framework would addressing both how resiliency should be measured and how it should be valued. The framework could utilize one or more of the valuation approaches discussed in the Options 1 and 2 in this section and more fully integrate these approaches with other CPUC planning and procurement processes.

7.2 Permitting Barriers

Microgrids rely on energy storage to serve interconnected loads and smooth out intermittencies in renewable energy production. Analysis of the current landscape for Battery Energy Storage Systems reveals that there are currently several gaps in how they are permitted statewide which present barriers to microgrid development. In general, Staff assessed the gaps in permitting by splitting systems into categories based on system ownership/operation and system type. The system ownership/operation categories were: Private ownership/operation, 3rd party ownership/operation, and Investor Owned Utility ownership/operation. The system types were: Behind-the-meter, small-scale in front of the meter, and utility-scale in front of the meter. The issue faced by Staff in analyzing the gaps in this area is that creating regulation to fill these gaps could have the undesirable effect of creating new barriers to microgrid development; however stakeholder safety as always is the top priority and these barriers were assessed for both.

The overarching gap across all system types that presents a barrier to microgrid development is inconsistency of battery energy storage systems permitting across Authorities Having Jurisdiction. As it stands, inspection and permitting of these systems is left up to each individual Authority Having Jurisdiction, who must assess systems for fire code and building code compliance. Though there is extensive and widespread experience with solar photovoltaic system permitting, batteries are uncharted territory for most Authorities Having Jurisdiction because of previously low system adoption rates and steep learning curves. This will be discussed as a barrier to microgrid development in more detail below.

Utility-scale Investor Owned Utility owned/operated, and 3rd party owned/operated in-front-of-meter systems are a specific area where gaps exist in current regulation and where jurisdiction is unclear. Gaps for systems of this type include not having clarification on what utilities deem to be "prudent electrical practices" when constructing these installations, lack of clarity onsite inspection jurisdiction over systems installed inside of the substation fence, lack of safety related quality assurance/control in utility procurement and contracting processes, lack of CPUC oversight of safety compliance for utility installations, and lack of coordination across state agencies to evaluate gaps and streamline permitting for large scale installations. These gaps will also be discussed as a barrier to microgrid development in more detail below.

Analysis of privately owned and 3rd party owned behind-the-meter and in-front-of-the-meter small scale Battery Energy Storage Systems showed that two major gaps in current codes, standards, and regulation are that Rule 21 mandates: 1) no battery energy storage systems safety standards for behind-the-meter installation, and 2) that there needs to be clarity on the scope of the California Energy Commission's Energy Storage Guidebook as required by California Assembly Bill 546, which is limited to behind-the-meter customer-sited installations.

The gaps illustrated above are all issues with battery energy storage systems installation, however Staff feels that the barriers shown below are overarching issues that need to be addressed so that these gaps can be closed.

Permitting Barrier 1: Lack of consistency across AHJs in permitting Battery Energy Storage Systems

Inspection and permitting of battery installations is overseen by individual Authorities Having Jurisdiction, and to date there has been no concerted effort to standardize inspections state-wide. This has led to longer project timelines and uncertain outcomes for developers trying to build battery energy storage systems as they must navigate different land use and zoning codes by jurisdiction. Additionally, existing CPUC regulations providing exclusive jurisdiction for Battery Energy Storage System installations inside substation fences has allowed Investor Owned Utilities, in most cases, to build battery energy storage systems without significant Authority Having Jurisdiction or CPUC permitting. This is perceived to be unfair to 3rd party developers because Investor Owned Utilities have a significant advantage for those situations wherein an Investor Owned Utility does not deal with lengthy and uncertain Authority Having Jurisdiction permitting for new installations. Additionally, CPUC oversight in this area is currently confined to reviewing Investor Owned Utility contracts for battery energy storage systems, and then a safety inspection within five (5) years of the beginning of operation, which means that there is lower visibility into the engineering, procurement, and safety of these installations.

This inconsistency presents a large barrier to microgrid development (particularly for in-front-of-the-meter installations) because it can add significantly to project timelines and can increase costs for developers and end users while also giving an unfair advantage to Investor Owned Utilities in building in-front-of-the-meter Battery Energy Storage Systems. Previous efforts by the Office of Planning and Research in streamlining cogeneration and solar photovoltaic system permitting could be used as models for addressing some of the issues this barrier presents and clarifying roles and responsibilities.

Permitting Barrier 2: Lack of Consistent, Clear Battery Safety Standards

Currently, there are no clear mentions of Battery Energy Storage System safety/certification standards in the codes and regulations governing installation of these systems. California is currently in the process of adopting the 2021 Fire Code which will have a section specifically addressing battery energy storage systems safety that will closely mirror the National Fire Protection Association 855 standard (NFPA n.d.).

Permitting Barrier 3: Lack of System Configuration Templates for Permitting

There are currently no existing templates for different system configurations to ensure speedy permitting of systems by Authorities Having Jurisdiction. Having templates would help to streamline the permitting process for both in-front-of-the-meter and behind-the-meter battery energy storage systems by reducing administrative burden for authorities having jurisdiction and would allow end users to see benefits of battery energy storage systems installation quicker through standardization of system types across installations. The adopted decision from Track 1 of R.19-09-009 (D.20-06-017[54]) requires the Investor Owned Utilities to create single line diagrams for Net Energy Metered paired storage systems for smaller systems. Additionally, per the requirements of Assembly Bill 546, the California Energy Commission is developing a guidebook of best practices for permitting of behind the meter Battery Energy Storage Systems for Authorities Having Jurisdiction (CEC n.d.). This effort will feed into ongoing efforts to integrate battery energy storage systems permitting into the Solar Automated Permit Processing platform application in collaboration with The Solar Foundation and the National Renewable Energy Laboratory. However, these efforts are limited in scope and are still firmly in the future.

Permitting Barrier 4: : Limited Pre-approved Equipment List

The current pre-approved equipment list is administered as a part of the California Energy Commission's Solar Equipment List (CEC n.d.). The list is current as of January 21, 2020; however, it is extremely limited. This presents a barrier to all types of microgrids because not having a reference list of batteries to use slows down the permitting process by requiring additional engineering analysis. This prevents end users from being able to reap the resilience benefits of having a battery system and creates more administrative burden for Authorities Having Jurisdiction. Currently, the California Energy Commission is developing this list, but this effort will take time and the status of the project is currently unknown.

Proposals

Option 1: Expand CPUC oversight of safety compliance of Investor Owned Utility owned or procured Battery Energy Storage Systems, and integrate safety related quality assurance and quality control requirements into the Investor Owned Utility contracting and procurement process

Rationale: This would require CPUC to review and accept pro forma contracts to verify that battery energy storage systems safety is adequately addressed in Investor Owned Utilities' procurement documents and contracts for engineering procurement contracts and power purchase agreements. The Investor Owned Utilities would submit periodic compliance filings via advice letter regarding battery performance and safety, as well as submit systems to CPUC inspections to verify safety and

[54] D.20-06-017 June 17, 2020 – Decision Adopting Short-Term Actions to Accelerate Microgrid Deployment and Related Resiliency Solutions

operation and maintenance programs are compliant with Authority Having Jurisdiction standards. Furthermore, CPUC should emphasize that local Authorities Having Jurisdiction performing fire code inspections are allowed and encouraged to require battery energy storage systems installers to contract with third parties to perform inspections to verify compliance. From the CPUC perspective, this would require creating a standard of review for compliance filings. Review of these contracts by CPUC Staff, however, would not attempt to verify adequacy of safety plans, rather it would verify that the proper Authority Having Jurisdiction had performed the analysis and/or inspection and had signed off on submitted plans.

Also, since Investor Owned Utility owned and operated battery energy storage systems falls under CPUC jurisdiction, there should be requirements imposed on the contracting and procurement process as a check on the Investor Owned Utilities' ability to self-certify these installations. CPUC should periodically examine the request for offers process and the standard technical specifications to verify that the Investor Owned Utility is sufficiently controlling the design, installation, and operations and maintenance of these systems. Additionally, CPUC should require the Investor Owned Utilities to adopt standards that ensure battery energy storage systems installations are designed, tested, certified, listed, procured, and installed using qualified processes, procedures, equipment, and personnel.

Option 2: Coordinate with other state agencies and CPUC proceedings to evaluate gaps and streamline permitting for both behind-the-meter and in-front-of-meter battery energy storage systems

Rationale: Permitting and Authority Having Jurisdiction consistency issues will require close coordination with the California Energy Commission and the California Governor's Office of Planning and Research to clarify jurisdiction and to further illuminate gaps in regulation for Battery Energy Storage Systems.

Option 3: Require the Investor Owned Utilities to clarify "prudent electrical practices" as they pertain to battery energy storage systems using existing codes and standards

Rationale: Since the current definition of "prudent electrical practices" is still very open to interpretation, this would require the utilities to create a specific definition for this phrase that includes references to codes, standards, and regulations. This way Investor Owned Utilities' electrical practices can be more stringently held to standards developed by independent test labs.

7.3 Financial Barriers

Financial Barrier 1: High Project Costs

Microgrids, especially in-front-of-the-meter projects, are very capital- and engineering-intensive, leading to high initial costs. Distributed energy resources (renewables such as solar, fuel cell, and wind, fossil generators such as diesel and natural gas generators and cogeneration units, and storage assets such as batteries and flywheels) and microgrid control equipment are all expensive resources. Engineering costs are also high because designing and commissioning the resources and controllers takes time and understanding of operating conditions. Finally, because of the mix of generation and storage resources, lengthier inspection and permitting processes are incurred because of multiple required inspections creating longer permitting timelines.

High initial costs can discourage microgrid development, especially those that involve cleaner generation sources, if solutions with lower initial costs for delivering similar services exist. This presents an equity issue because lower income customers and communities that may benefit the most from a clean energy microgrid maybe least able to afford it. This is a problem for all microgrid types, either behind the meter or in front of the meter, but is most acute for larger and more complex projects.

Financial Barrier 2: Availabilty of Financing

Upfront capital expenditures of microgrid systems present cost barriers. Large utilities have the cash flow available to pay for the project assets until the cost is absorbed by their business revenue, often with the microgrid costs included in the General Rate Case proposal. Other kinds of project owners typically must pursue other options to overcome this type of financial barrier. Cost responsibility varies depending on type of ownership.

In any of the financed cases, investors, banks, or utilities willing to put up the upfront cash for a microgrid project look for low risk/high potential for success in such a project. Thus, they want to see high probability of the project successfully navigating project installation, approval, interconnection, and operability. Ideally the project can take advantage of revenue streams available to it that help the project "pay for itself". These revenue streams might come from charging for the energy used by microgrid participants but might also include payments from the connected larger grid as valuation of services the microgrid provides to the larger grid.

Often, short term contracts, current regulations, policies or interconnection procedures have presented significant enough potential barriers as to represent a high risk for investors, banks, private- or third-parties, such that either financing is not approved, or costs associated with the afore-mentioned barriers increase the necessary financing to a level that is not cost-beneficial, sustainable or desirable.

Identifying these potential barriers that have represented an increase risk for investors and proposing solutions to overcome those barriers is part of this proceeding. The goal is to reduce the risk of viable projects that provide benefits to the community and the grid, such that the risk factor is reduced, and financing options become more available.

The following table suggests types of financing available to types of ownership. Discussion of the financing options follows the table.

Table 3 Types of microgrid ownership

Type of Ownership	Financing Options Available
Private ownership	Cash, bank loan
Municipal ownership	Cash, bank loan
Community District Facility (CDF)	Bond Issuance (Mello-Roos), On Bill Financing
3rd Party	Debt to Equity, OBF
Investor Owned Utility	Cash, General Rate Case
Local Publicly Owned Utility	Cash, On Bill Financing
Cooperative/Community	CDF/Bond/ On Bill Financing

1) Cash – Funds are taken out of budgeted monies

2) Bank loan – Funds are obtained through traditional bank financing with repayment determined by loan contract.

3) On Bill Financing – Utility or community choice aggregation agrees to advance capital expenditure with agreement to repay over a determined period of time, administered as a part of the energy bill.

4) Bond Issuance – Formation of a Community District Facility that then issues bonds to raise capital for the project. Repayment of the project is by way of On Bill Financing bill administration services to microgrid participants via either partnering directly with the utility or via a community choice aggregation. Utility or community choice aggregation partnership can be via a Power Purchase Agreement with the CDF.

5) Debt to Equity – A third party entity/investor can provide upfront capital costs of the project in lieu of the owner, then provide financing to the owner(s) of the project (which might be any of the named types of owner above) that is distributed over the microgrid participants based on energy use. Administration of billing could be directly from the third-party entity or via a partnership agreement with a community choice aggregation or Utility.

6) General Rate Case – The utility proposes the project, put the projects out for bid through the Request for Proposal process, moves through the selection process based on least-cost-best-fit criteria, and submits a request to the PUC for approval of the project indicating whether the utility will be seeking cost recovery through the General Rate Case process or via some other CPUC approved cost-recovery mechanism.

In any of the financed cases, investors, banks, or utilities willing to put up the upfront cash for a microgrid project look for low risk/high potential for success in such a project. Thus, they want to see high probability of the project successfully navigating project installation, approval, interconnection and operability. Ideally the project can take advantage of revenue streams available to it that help the project "pay for itself". These revenue streams might come from charging for the energy used by microgrid participants but might also include payments from the connected larger grid as valuation of services the microgrid provides to the larger grid.

Often, current regulations, policies or interconnection procedures have presented significant enough potential barriers as to represent a high risk for investors, banks, private- or third-parties, such that either financing is not approved, or costs associated with the afore-mentioned barriers increase the necessary financing to a level that is not cost-beneficial, sustainable or desirable.

Identifying these potential barriers that have represented an increase risk for investors and proposing solutions to overcome those barriers is part of this proceeding. The goal is to reduce the risk of viable projects that provide benefits to the community and the grid, such that the risk factor is reduced, and financing options become more available.

Financial Barrier 3: Cost of Ownership in Special Facilities Agreement

In each IOU's version of electric Rule 2, there is a section that describes added/special facilities.[55] These are defined by the IOUs as equipment which is in addition to or a substitute for standard equipment required to interconnect to the IOU's system. This definition includes standard equipment such as transformers and poles but can also include behind the meter assets (SCE's Rule 2, Section H specifically names load control devices and meters). This section also specifies a monthly ownership charge that the IOUs levy on the customer requesting these facilities to be built. This charge allows the IOUs to recover the asset cost (which covers replacement of the asset) and cover operations and maintenance expenses incurred by construction of the asset directly from the customers that required it. This prevents a cost shift onto other ratepayers for an interconnection that may not provide services to the broader grid.

High ownership costs present a barrier to microgrids because if the IOUs deem that added/special facilities are required for a microgrid to interconnect, it can add significantly to the overall project cost which will likely be passed on the end user. From interacting with parties who have developed microgrids where Rule 2 came into play, it is also clear that there can be uncertainty surrounding what equipment will be required by the IOUs which adds cost to projects. Additionally, PG&E's cost of ownership charges are levied in perpetuity for the assets in question (SCE and SDG&E both have this as an option, but also allow for the charge to be levied only over the life of the asset). These issues can disincentivize microgrids as a potential resilience measure for given areas and will prevent customers from reaping the benefits a microgrid can provide because of the uncertainty surrounding the true cost of the project.

Financial Barrier 4: Wholesale and Distribution Market Access

A commonly cited financial barrier to distributed energy resources, including microgrids and their constituent resources, is the inability to access revenues associated with providing distribution and wholesale services. There are many different factors associated with this overarching problem, and many venues in which challenges and opportunities for overcoming this barrier have been and are currently being discussed, debated and litigated. Some of these are discussed under the section on

[55] PG&E is Section I, Special Facilities; SCE is Section H, Added Facilities; SDG&E is Section I, Special Facilities and Maintenance (PG&E Rule 2, SCE Rule 2, and SDG&E Rule 2)

microgrid value propositions earlier in this document (see, for example, grid services and resource adequacy topics).

In very broad terms, for some services, markets are currently in operation, but distributed energy resources may not be able to fully participate in them in the same way that supply-side resources can for certain reasons (e.g., markets operated by the California Independent System Operator, or the Resource Adequancy market). For other services, some market activity exists, but the market processes and structures are nascent and under development (e.g., market for capacity deferral identified through the Distribution Invesment Deferral Process). For other services, the service itself or need for the service may be poorly defined and/or no specific organized markets yet exist (e.g., dynamic voltage support, resiliency).

Financial Barrier 5: Non-bypassable, Departing Load and Standby Charges

Non-bypassable charges, departing load charges, and standby charges are often grouped together. In the vernacular, "departing load charges" and "non-bypassable charges" are often used interchangeably. The nomenclatures do refer to specific charges which are differentiated from one another.

Departing Load Charges: Departing load charges are intended to avoid cost shifting of customers who leave the utility service in favor of a different electricity provider. In the case of microgrids, this would be represented by distributed energy resources located within the microgrid, which would deliver energy to the microgrid participants. Depending on the size and configuration of the microgrid, the system may connect to the larger grid system to exchange a variety of services.

PG&E refers to its "Customer Generation Departing Load Non-bypassable Charge" in PG&E's Electric Schedule E-DCG Sheet 1. In this Schedule E-DCG the utility's Departing Customer Generation policies including exemptions are described.[56] A "departing load" is a load that is departing from taking service from the utility and instead taking service from another source (for example, an energy service provider). The utility has purchased energy on the customer's behalf via long term contracts. The Power Charge Indifference Adjustment is one way that the costs incurred by the utility on behalf of departing loads are recovered. The Power Charge Indifference Adjustment is not applied to NEM-eligible generation sources.

Nonbypassable Charges: A "nonbypassable charge" is a charge that no matter the customer's choice of provider, all customers (bundled and departing load) are charged with paying to recover fixed charges or program costs of the electrical system with which the customer is connected. In PG&E's Electric Schedule S,[57] these charges are broken out as part of the Reservation Charge Rate and part of the Total Energy Rates.

[56] PG&E's Electric Schedule E-DCG Sheet 1 – Departing Customer Generation CG (Advice 4743-E-A, effective December 20, 2015.
[57] PG&E's Electric Schedule S – Standby Service (Advice Decision 5661-E-B, effective May 1, 2020.

Charges considered to be nonbypassable charges associated with Departing Customer Generation are:

1. The Department of Water Resources Bond Charge
2. Power Charge Indifference Adjustment
3. Ongoing Competition Transition Charge
4. Nuclear Decommissioning Charge
5. Regulatory Asset Charge
6. Public Purpose Program Charge
7. Energy Cost Recovery Amount (superseded and replaced the Resource Adequacy)

Some of these charges are referred to as "Cost Responsibility Surcharges". As background to these charges, in 1995 the purpose behind the CPUC approval of restructuring the electric industry was "to provide customers with competitive choices as to their generation resources, the idea being that effective competition will produce efficiencies in operation and lower rates."[58] In recognition that this introduced retail competition could result in stranded costs for the utilities, the CPUC established "a non-bypassable charge called the competition transition charge for all retail customers of the utility, whether they continue to take bundled service from their current utility or pursue other options."[59] The CPUC authorized this recovery of such stranded costs with an objective of the utilities collecting such costs "in a manner that is competitively neutral, is fair to various classes of ratepayers, and does not increase rates."[60]

The Department of Water Resources and the Power Charge Indifference Adjustment resulted from statutes enacted after the 2000-01 energy crisis. To prohibit cost-shifting, these charges are required of all end-use customers to pay their fair share of costs incurred on their behalf. Costs incurred include long term procurement contracts established on behalf of customer anticipated demand.

Customers or customer groups are granted an exemption or exception to either or both the Competition Transition Charge and DWR depending on whether the IOU or Department of Water Resources incurred the costs in the pertinent category to serve that customer or customer group.

Standby Charges: "Standby Service" is charged to customers to pay for the utilities expenses that it incurs to provide electricity and capacity on a standby basis. This applies to customers whose electricity supplies come from facilities other than the utility, in the event that generation source fails or is not available. The utilities have an obligation to be the "last resort". In order to be able to available as a last resort resource, it incurs expenses (procurement, resource adequacy, transmission and distribution capacity) to be able to quickly provide such service. "Standby Service" is service paid for by customers whose load is regularly and completely provided by facilities not owned by PG&E or "who at times take auxiliary service from… another public utility", or "who require PG&E to provide reserve capacity and stand ready at all times to supply electricity on an irregular or noncontinuous basis".

[58] 1995 Cal. PUC Lexis 1034; 64 CPUC2d 1; 166 P.U.R.4th 1, Decision 95-12-063; Rulemaking 94-04-031; Investigation 94-04-032, December 20, 1995, p. 6.
[59] Ibid., p. 20.
[60] Ibid., p. 20.

For customers who operate non-utility generating capacity, the Reservation Capacity[61] is no greater "than the customer's hourly peak demand established during the most recent 12 months of actual customer operation;" or "for customers with electric loads that exceed the capability of their non-utility generation" such that they require "regular provision of supplemental power service through" PG&E facilities the Reservation Capacity is determined by considering the capacity of the non-utility generating units and any load-shaving that could occur in the event of the non-utility generator capacity outages. "Supplemental Standby Service (Backup Requirements) apply to Schedule E-19 and E-20 customers whose nonutility source of generation does not regularly supply" all the customers' needs. In this case, "back-up requirements are the portion of the customer's maximum demand and energy usage in any billing month caused by the nonoperation of the customer's alternative source of power".

Also listed on PG&E Electric Schedule S as part of its Energy Rate are "New System Generation Charge", "California Climate Credit", "Transmission", "Transmission Rate Adjustment" and "Reliability Services". The latter three of these charges make up the Federal Energy Regulatory Commission jurisdictional balancing account charge set by Federal Energy Regulatory Commission retail services. "Transmission" and "Reliability Services" appear under both "Reservation Charges" and "Energy Rate by Components" depending on whether they are part of the reserved energy or the energy used via Schedule S.

Standby charges represent the largest of the three types of charges. "Standby charges have… been increasing at a much faster rate than demand charges in commercial rate schedules, a rate class that would potentially capture a significant portion of the microgrid market in California. From November 2014 to November 2019, PG&E standby total reservation charges have increased 133% from $3.33/kW to $7.75/kW. In contrast, over this same period, summer and winter demand charges for A-10 TOU have increased 44% from $13.40/kW to $19.25/kW and 82% from $6.68/kW to $12.17/kW, respectively. For E-19 over this same five-year period, maximum monthly demand charges have increased 59% from $10.24/kW to $16.27/kW.[62] [63]

Components of a microgrid that are NEM-eligible are exempted from standby charges as well as Power Charge Indifference Adjustment charges.

<u>Barriers to Microgrid Development:</u> Party comments have sometimes referred to departing load or standby charges as barriers or hurdles to microgrid development.[64] Staff does not agree with this characterization that these charges reflect regulatory barriers rather. Instead, Staff views the

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[61] PG&E's Electric Schedule S – Standby Service (Advice Decision 5661-E-B, effective May 1, 2020; Sheet No. 40251-E Revised Cal. P.U.C. Sheet No.40251-E; Cancelling Revised Cal. P.U.C. Sheet No.28241-E, Advice Letter 5076-E, Decision 17-04-039, Filed May 26, 2017.

[62] Reply Comments of EtaGen in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, pp. 5-6.

[63] https://www.pge.com/tariffs/electric.shtml

[64] Opening Comments of CalSSA in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 6; Opening Comments of MRC in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 1; Reply Comments of NFCRC in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, pp. 4-5.

underlying barrier as a financial one that arises from the underlying initial and operating costs of microgrid projects.

Depending on the way it is set up and operated, microgrids represent load that could be served all or some of the time by its own resources therefore representing a "departing load" for those microgrid participants that were originally receiving power from the larger grid. It has been argued that by providing their own power (direct access), the microgrid participants are shifting cost responsibility for these charges that are supposed to be carried by all who benefit from the services and reliability provided by the larger grid.[65] Others object on the basis that these were set up because of significant efforts and broader policy objectives.[66]

In terms of the application of standby charges, it can be further argued that microgrid participants, especially microgrids largely reliant on variable renewable resources use the grid as power reliability when and if their renewable energy is not sufficient to meet their needs. In response, microgrid developers/owners have argued if a system is designed to island sufficiently to provide power when the grid is not available (e.g. PSPS events), the larger grid is not a source of reliable power. The microgrid is the source of resiliency in that scenario.[67] "Microgrids should not be evaluated in a worst-case scenario engineering review. It is highly unlikely that all of a microgrid's resources (load, generation, and storage) will be unavailable at a single time such that it must meet full internal load during peak system conditions with grid imports."[68]

In blue sky conditions, the microgrid as a set of distributed energy resources can potentially offer services back to the grid, such as storing surplus generation, participating in demand resource programs, participating in wholesale markets, and providing ancillary services such as voltage and frequency regulation, depending on the scale and assets of the microgrid resources.

For these reasons, and to encourage the adoption of microgrids, stakeholders have suggested that policy around NBC, departing load and standby charges as they apply to microgrids be examined

[65]Reply Comments of CUE in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 4; Opening Comments of UCAN in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 3; Opening Comments of Port of Long Beach in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 6.

[66] Reply Comments of SCE in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 11.

[67] Opening Comments of The California Hydrogen Business Council in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 3; Opening Comments of MRC in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, pp. 5-6; Reply Comments of EtaGen in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, pp. 5-6; Reply Comments of Bloom in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 7;

[68] Opening Comments of MRC in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, pp. 5-6

and consider reduction, restructuring or exemption from some or all of these.[69] Staff is recommending proposals associated with these charges in its Staff Proposal paper.

Financial Proposal 1: Operations Islanded Grid Services Agreement

This proposal seeks to create a set of standardized tariffs which includes rules, rates, and defines the cost structure allocation between the utility and the various stakeholders within a microgrid.

This tariff proposal would enable customer-owned microgrids. It would be technology agnostic. This tariff should include rules, charges, and requirements for interconnection, including timelines the timelines the stakeholder must meet.

Option 1: Develop a standardized operational roles and responsibilities agreement. The agreement establishes roles, responsibilities, and operational requirements for the microgrid under blue sky conditions and island mode.

Option 2: Develop a standardized infrastructure cost recovery agreement. The agreement defines how the distribution costs to install and operate the microgrid will be recovered. The customer requested distribution upgrade will not be socialized beyond the requesting customer.

Option 3: Develop a grid services agreement. The agreement defines how the microgrid infrastructure funders and the generation owners will be compensated for the microgrid development.

Option 4: Develop an energy agreement that describes how the generation provider will be compensated for the energy supplied during island mode.

Recommendation

Staff recommends maintain status quo and does not recommend any of the options listed above. At the time of this proposal, the Redwood Coast Airport Microgrid team is developing a set of experimental tariffs that includes the set of standardized agreements listed above. Staff recommends actively monitoring the project and deliverables.

[69] Opening Comments of Shell Energy in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 6; Opening Comments of CalSSA in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 6; Opening Comments of The California Hydrogen Business Council in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 3, 5; Opening Comments of The Microgrid Resources Coalition in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 1, 5-6; Reply Comments of EtaGen in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 5-6; Reply Comments of Bloom, in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 4, 7; Reply Comments of NFCRC in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, p. 4-5.

Financial Proposal 2: Distribution Support Services Request for Proposals

Option 1: Allow microgrids to enter into Distribution Services Support Agreements with the utilities that formalizes the localized distribution services and provides a market pathway to uphold these advanced services.

Discussion: While microgrids' primary driver of adoption is often its resiliency, microgrids have value as multi-faceted solution packages. For those within the microgrid boundaries, microgrids provide electrical generation and storage services as well as resiliency services in the event of a larger grid outage by continuing to supply power to those within the microgrid boundaries. However, a microgrid can also provide customizable services to its interconnecting utility during "blue sky" conditions that can meet localized needs. As utilities increase their development of sectionalized circuits, microgrids, serving as distributed energy resources located within these sectionalized circuits can provide energy, capacity, and ancillary services to support localized substation or sectional needs. The flexibility of microgrids and their configuration therein, allow microgrids to: (1) provide reactive power voltage support acting like a dynamic shock absorber, (2) ramp down onsite generation or ramp up imports to absorb excess power; (3) export power, ramping down microgrid needs to go into export stance; and (4) aid in restoration, so when the substation comes on, the microgrid is already up and synchronous. In certain circuits this could represent significant value.

Formalizing these services into a contractable agreement offers a framework for formal partnership between microgrid operators and the utilities providing assurance and accountability to both utility and microgrid project. It increases the transparency of resources within microgrids that can be made available to the utility as a balancing mechanism in their role as distribution system operator. A contractable agreement provides acknowledged valuation of microgrid benefits that can be provided to the larger grid, while also providing the microgrid systems operators with system function and optimization guidelines. The acknowledged valuation in the form of an assured revenue stream by way of the contract can be used to access capital markets for investment.

Jurisdiction: The CPUC, CAISO

Type of action required: The CPUC would need to issue a Decision. Additionally, CPUC would need to provide review and approval of utility and microgrid owner/operators contract agreements.

- <u>Sub-Option 1:</u> Maintain status quo. Third party microgrid project owners and operators have the ability to enter into partnership agreements with the utilities (e.g. Redwood Coast Airport Microgrid project). Financial compensation for services as noted above would have to be agreed upon on a case-by-case basis with the utilities. Additionally, such services may be wrapped into a microgrid tariff rate schedule addressed elsewhere in this document.

- <u>Sub-Option 2:</u> Develop a pilot program initiated and developed by utilities, the plan of which would be approved by the CPUC by Advice Letter. The pilot program for each utility would be developed within specific sectionalized circuits and microgrid project to study benefits and issues arising out of contractual agreements.

Option 2: Allow private developers to make unsolicited proposals to resolve energy transmission and distribution system issues identified in state and regional energy planning processes through microgrid development proposals. This proposal could permit but not require unsolicited projects to be bid out before they are awarded, at the discretion of the CPUC. The CPUC would either directly approve or provide policy guidance on when a supplier would be permitted to proceed with a non-competitive procurement based on the Integration Capacity Analysis, Distribution Investment Deferral Framework and Solar Photovoltaic and Renewable Auction Mechanism maps. Factors such as the quality of the proposal and the urgency of the need would be considered by the CPUC. Such proposals could be competitively bid or directly approved by the CPUC if just and reasonable.

Discussion: According to party comments[70] the request for proposal process currently implemented via utility driven protocols is often too restrictive and limited in scope, technology or timing to allow for robust third-party development options to be considered. The proposal makes more visible provisions for third-party microgrid developers to offer project solutions in response to utility identified grid needs. As subject matter experts of microgrid technology, custom configuration design and operations, third party microgrid developers may be able to provide more innovative, cost-effective, timely solutions that can potentially provide more specific procurement that solves specific local problems resulting in more reliable, resilient energy service at competitive, and potentially substantially lower cost to ratepayers.

Jurisdiction: Mixed. CPUC oversees the distribution system, but CAISO oversees the transmission system.

Type of Action required: Decision

- Option 1: Maintain status quo. The current request for proposal, request for information process allows utilities to issue bids for projects that answer to needs identified in their respective capacity and resource planning processes.
- Option 2: The CPUC issues an order compelling the utilities to allow developers to make unsolicited proposals to resolve energy transmission and distribution system issues identified in state and regional energy planning processes.

Financial Proposal 3: Microgrid-Specific Rate Design

This proposal would task a microgrids working group to develop and recommend a new rate design for CPUC approval. The specific rate design whould incorporate dynamic hourly prices that better approach cost recovery for the real time cost. For example, the microgrids working group would take into consideration the following elements: a) flat base energy rate; b) CAISO day ahead energy price; and establish additional price signals for c) recovering the cost to provide the distribution circuit peak capacity and d) adding capacity price signals to the hours when system loads are at their highest. These dynamic hourly prices would allow recovering the cost of generation capacity to serve customers during peak load periods. A rate proposal such as this may incentivize demand for additional microgrids. Key questions that this rate proposal would need to address include:

[70] Opening Comments of The Microgrid Resources Coalition in Response to the Commission's Request for Comments on the Preliminary Scope of Rulemaking 19-09-009, October 21, 2019, pp.10-11.

- Customer classification;
- Project size limitation;
- Eligible technologies to interconnect;
- Allowable fees and charges that a utility may request;
- Net energy metering billing credits for exported electricity;
- Metering requirements;
- Load aggregation;
- Billing, and
- Configurations and metering.

7.4 Technical Barriers

Technical Barrier 1: Maintaining Stability within a Microgrid During Island Mode

A microgrid may transition to island mode due to abnormal conditions on the macrogrid or at the will of the microgrid operator. When the microgrid transitions to island mode, the disconnection from the macrogrid must be accomplished in an orderly fashion that doesn't contribute to or result in abnormal conditions on the macrogrid. Some parameters for how and when distributed energy resources can connect or disconnect from the electric grid are already defined, such as those in Rule 21 for smart inverters. These existing requirements provide a starting point for defining similar parameters for how and when microgrids can connect and disconnect from the macrogrid. The microgrid controller should be able to implement an orderly transition to island mode regardless of the complexity of the microgrid or the types of distributed energy resources within the microgrid.

Once the microgrid is in island mode it is electrically independent of the macrogrid and must rely on its own resources, controls, and protection schemes in order to maintain operational stability. Analogous to the macrogrid, the microgrid in island mode must be able to continuously balance supply and load. Voltages and frequency within the island must stay within acceptable operating ranges in order to maintain stability. It is necessary for the microgrid to have a grid-forming resource to act as the reference for voltage and frequency. The grid-forming resource can be a rotating machine or certain inverter-based equipment. Local generation and storage must be able to provide necessary real and reactive power to any instantaneous change in load, such as a motor or pump starting.

Reserve margins, such as an incremental amount of battery storage, can help to achieve the necessary supply resources. If a microgrid in island mode experiences a fault, it must have a protection scheme that clears the fault prior to the supply resources tripping offline. The controls and protection schemes necessary to accomplish these tasks are a critical focus of the microgrid's design process and will vary significantly depending on the characteristics and desired performance of an individual microgrid.

Low-inertia microgrids (e.g., those without rotational machine generation) are likely to require additional consideration during the design process to ensure stable operation in island mode. For a behind-the-meter microgrid, this design process will be the responsibility of the project developer. For an in-front-of-meter microgrid, this design process must necessarily be coordinated with utility to ensure the microgrid's controls and protection schemes in island mode are compatible with the existing controls and protection schemes on the portion of the utility's distribution grid that will be part of the island.

Proposals

Option 1: Initially require the same functionality and communication capabilities for microgrid controllers, or a combination of the controller and other equipment (e.g., inverter, gateway), as those required in Rule 21 for smart inverters. Determine if any future updates to IEEE Standard 1547:

IEEE Standards for Interconnection and Interoperability of Distributed Energy are necessary to augment these functionalities and requirements.

Rationale: If microgrid controllers meet, at a minimum, the existing operational parameters for smart inverters, it is likely transition to island mode can be achieved without contributing to or resulting in abnormal conditions on the macrogrid. Any future interconnection requirements determined to be applicable to other types of distributed energy resources should be evaluated for applicability to microgrids to ensure consistency of requirements.

Option 2: Conduct additional research on what, if any, additional requirements for microgrid controllers may be necessary to adequately define parameters for how and when a behind-the-meter microgrid transitions to island mode when there are no abnormal conditions on the macrogrid (e.g. choice of the microgrid operator). Determine if IEEE Standard 2030.7-2017 for the Specification of Microgrid Controllers should be required for interconnection of behind-the-meter microgrids.

Rationale: Because microgrids can be disconnected from the macrogrid at will, irrespective of macrogrid operational characteristics, it may be necessary to further define the criteria for making this type of transition to island mode.

Option 3: Conduct additional research to identify best design practices for the stable operation of behind-the-meter microgrids once in island mode.

Rationale: Behind-the-meter microgrids must be designed for stable operation in island mode. Because the design is the domain of the microgrid developer, there are no formal CPUC or utility requirements for how stable operation is achieved.

Option 4: Build upon lessons learned and transferable information from in-front-of-meter microgrids (e.g., Borrego Springs, Redwood Coast Airport, EPIC projects) to characterize parameters and inform development of consistent requirements for orderly transition of in-front-of-meter microgrid to island mode and stable operation once in island mode. Determine if IEEE Standard 2030.7-2017 for the Specification of Microgrid Controllers should be required for interconnection of in-front-of-meter microgrids.

Rationale: In-front-of-meter microgrids in island mode utilize a portion of the utility distribution grid. It is necessary to develop requirements for how and when islanding of the in-front-of-meter microgrid is achieved and how stability on the islanded portion of the utility distribution grid will be achieved. Because in-front-of-meter microgrids remain relatively unique, the best available information will come from demonstration projects.

Technical Barrier 2: Lack of Load Visibility to Distribution System Operators

Whenever behind the meter distribution generation serves load that is also behind the meter, the load is masked from the distribution system operator. The distribution system operator only has visibility of the net load, that which is being served through the distribution system. If the distribution generation is intermittent (e.g., photovoltaic system), the net load served by the distribution system operator will vary with the output of the photovoltaic system. The change in net load can occur quickly, such as when clouds pass over a PV system. At higher levels of distributed generation, the lack of load visibility has the potential to create operational challenges as the changes in net load and generation could result in voltage and frequency variations. Smart inverter functionality required by Rule 21 can be used to maintain acceptable voltage and frequency ranges and provide additional operational adjustments. Smart inverters are also required to have minimum communication capabilities that meet the IEEE 2030.5 standard for the Smart Energy Profile Application Protocol. As smart grid investments such as advanced distribution management systems and distributed energy resource management systems, the controls for managing large numbers of communications capable distributed energy and storage resources will evolve and the load visibility issue will be partially mitigated.

Microgrids and their ability to serve internal loads using local generation and storage resources will also result in a lack of gross load visibility to the distribution system operator. If loads within the microgrid are sufficiently large, similar operational challenges on the distribution grid could occur when transferring load from the electric grid to the microgrid or vice versa. A sudden, large, unplanned load transfer could result in abnormal operating conditions on the macrogrid.

With high enough penetration of distributed generation, including that within microgrids, load visibility problems may occur on the transmission and sub-transmission systems making it more difficult to continuously balance supply with demand.

Proposals

Option 1: Initially require the same functionality and communication capabilities for microgrid controllers, or a combination of the controller and other equipment (e.g., inverter, gateway), as those required in Rule 21 for smart inverters. Determine if any future updates to IEEE Standard 1547: IEEE Standards for Interconnection and Interoperability of Distributed Energy are necessary to augment these functionalities and requirements.

Rationale: If a combination of the microgrid controller and the local generation and storage within the microgrid, has the same functionality and communications capabilities as smart inverters, then solutions to improve distribution system operational control will also be applicable to microgrids. Any future interconnection requirements determined to be applicable to other types of distributed energy resources should be evaluated for applicability to microgrids to ensure consistency of requirements.

Option 2: Coordinate with Energy Division Staff to ensure microgrid use cases are sufficiently addressed in the Common Smart Inverter Profile and any other work areas related to advanced distribution management systems and distributed energy resource management systems. Determine if IEEE Standard 2030.7-2017 for the Specification of Microgrid Controllers should be required for interconnection of behind-the-meter microgrids.

Rationale: Microgrid uses cases should be considered contemporaneously with other use cases when smart grid investments are made to ensure interoperability and compatibility.

Option 3: Collaborate with the CAISO to identify and respond to any concerns related to load visibility at the transmission level.

Rationale: Load visibility and associated issues can be identified and addressed in the working group that will be formed as required by P.U.C. § 8371(e).

Technical Barrier 3: Protecting Workers and Customers

A ubiquitous safety feature of utility system design is the use of overcurrent protection relays. Depending on the specific type of relay, it may operate on both the magnitude of the fault current and the duration of the fault. The existing interconnection processes in Rule 21, Wholesale Distribution Access Tariff, and the CAISO tariff have significant requirements to ensure the safe interconnection and operation of equipment to protect workers and customers. For some distributed generation interconnection applications, this can include detailed study of short circuit duty, fault detection sensitivity, and relay coordination to validate, and modify if necessary, the existing grid protection scheme. Because many microgrid configurations would result in only relatively low levels of fault current during abnormal conditions, there may be additional scenarios that are not adequately addressed in these existing processes for validating the grid protection scheme.

When microgrids are connected in parallel to the utility grid during normal operations, it is likely that the existing processes to assess safe interconnection and operation are adequate because of the knowledge and experience gained from other parallel connected distributed generation resources. A large behind-the-meter microgrid may require its own coordination and protection studies for operation of the microgrid in island mode, but these studies would be the responsibility of the project developer because power flow during island mode will not occur on utility-owned equipment. In-front-of-meter microgrids operating in island mode are likely to require new processes to assess safe interconnection and operation because power flow will occur on utility owned equipment where the protection scheme is designed for the higher levels of fault current that would occur absent the in-front-of-meter microgrid.

Proposals

Option 1: Conduct additional research on what, if any, additional processes may be necessary to assess safe interconnection and operation of behind-the-meter microgrids. Determine if any future updates to IEEE Standard 1547: IEEE Standards for Interconnection and Interoperability of Distributed Energy are necessary to augment these functionalities and requirements.

Rationale: Potential changes to existing interconnection processes to improve safety for workers and customers should be developed based on information gathered from individuals and groups with the most direct experience and knowledge on interconnection issues. Any future interconnection requirements determined to be applicable to other types of distributed energy resources should be evaluated for applicability to microgrids to ensure consistency of requirements.

Option 2: Build upon lessons learned and transferable information from in-front-of-meter microgrids (e.g., Borrego Springs, Redwood Coast Airport, Electric Program Investment Charge projects) to inform development of consistent requirements to assess safe interconnection and operation of in-front-of-meter microgrids.

Rationale: In-front-of-meter microgrids in island mode may result in substantially different power flows over portions of the utility distribution system than the power flows during normal operations. This likely necessitates development of new processes for assessing safe interconnection and operation of in-front-of-meter. Because in-front-of-meter microgrids remain relatively unique, the best available information will come from demonstration projects.

Technical Barrier 4: Potential impacts of microgrids on broader grid stability

When a microgrid's local generation and storage resources are operating in parallel with the macrogrid, there is a potential for electrical disturbances within the microgrid to impact the stable operation of the macrogrid. This is generally true for distributed energy resources connected in parallel with the electrical grid whether they are part of a microgrid or not. Existing interconnection requirements address these concerns by defining operating parameters, such as voltage and frequency, which must be maintained within acceptable ranges for allowing parallel operation of distributed energy resources. Microgrid controls and protection schemes must ensure that a fault or transient event within the microgrid does not cause an impact on the macrogrid. It is possible that a disturbance external to the microgrid (e.g., transient event on macrogrid) could be the trigger of abnormal conditions within the microgrid. Regardless of the source, if a disruption internal to a microgrid operating in grid connected mode is not able to be resolved quickly enough to avoid impacts on the macrorgrid, it must disconnect from the macrogrid.

Transitioning a microgrid to and from island mode increases the potential for an event that disrupts stable operation of the macrogrid. From the perspective of the macrogrid, abrupt addition or loss of the microgrid's load or supply can lead to instability on the macrogrid. The connection or disconnection of the microgrid to the macrogrid must be done in a controlled and expected manner. Prior to a microgrid transitioning from island mode to grid connected mode, the microgrid controller must synchronize the voltage, frequency, and phase angle within the microgrid to the macrogrid. Conceptually these issues are not significantly different for behind-the-meter and in-front-of meter microgrids but may require additional detail and complexity for in-front-of-meter microgrids because they utilize a portion of the utility's distribution system. Existing interconnection processes address similar issues for other types of distributed energy resources and may adequately address these issues for microgrids.

Proposals

Option 1: Initially require the same functionality and communication capabilities for microgrid controllers, or a combination of the controller and other equipment (e.g., inverter, gateway), as those required in Rule 21 for smart inverters. Determine if any future updates to IEEE Standard 1547: IEEE Standards for Interconnection and Interoperability of Distributed Energy are necessary to augment these functionalities and requirements.

Rationale: If microgrid controllers meet, at a minimum, the existing operational parameters for smart inverters, it is likely that stable operation during grid-connected mode and transition to island mode can be achieved without contributing to or resulting in abnormal conditions on the macrogrid. Any future interconnection requirements determined to be applicable to other types of distributed energy resources should be evaluated for applicability to microgrids to ensure consistency of requirements.

Option 2: Conduct additional research on what, if any, additional requirements for microgrid controllers may be necessary to adequately define parameters for ensuring microgrids operating in grid-connected mode and transitions of a microgrid to and from island mode do not result in impacts on macrogrid stability. Determine if IEEE Standard 2030.7-2017 for the Specification of Microgrid Controllers should be required for interconnection of microgrids.

Rationale: It may be necessary to further define requirements for microgrid controllers to ensure impacts to stability of the macrogrid are avoided. If additional requirements are needed, they should be developed based on information gathered from individuals and groups with the most direct experience and knowledge on these issues.

7.5 Other Barriers

Other Barrier 1: Electric Vehicles

The California Air Resources Board's most recent greenhouse gas emission inventory finds that the transportation sector accounts for 41% of California's greenhouse gas emissions, by far the largest of any economic sector (California Air Resources Board). Accordingly, electrification of transportation is a main objective in California's efforts to reduce greenhouse gas emissions and local air pollution (Office of Governor Edmund G. Brown Jr. 2018). Development of sufficient electric vehicle supply equipment is one of the necessary conditions for achieving widespread transportation electrification.

The CPUC has developed policies and approved utility expenditures that support this objective.[71,72] Estimates of aggregate electric vehicle charging demand in California by 2025 approach 1,000 MW (Bedir 2018). Where and when this charging occurs will result in significant impacts on the electricity grid, requiring distribution system upgrades, changes to resource planning, and increased operational flexibility. Microgrids can help support widespread adoption of electric vehicles by utilizing a combination of their local generation and energy storage resources and their ability to control the amount and timing of load served by the electricity grid. This load control can reduce the need for distribution system upgrades in some cases. Local energy storage resources within a microgrid can provide a source of electric vehicle charging during grid outages, helping to maintain transportation availability. During grid outages, the batteries of electric vehicles could be discharged to provide power to loads within the microgrid.

Electric vehicles and their integration with the utility system are primarily being addressed in other CPUC proceedings, such as the Development of Rates and Infrastructure for Vehicle Electrification OIR R.18-12-006.[73] Electric vehicles are generally a use case for microgrids rather than an explicit barrier to microgrids. Energy Division Staff will coordinate on electric vehicle policy to ensure fair and reasonable treatment of electric vehicles and related infrastructure when part of a microgrid.

Other Barrier 2: Electric Vehicles Integration – Controlled Load

Electric vehicle supply equipment within a microgrid can be supplied with power from the electricity grid or from within the microgrid. The microgrid controller can operate the electric vehicle supply equipment as demand responsive or dispatchable load by combining local generation and storage resources within the microgrid and information such as grid operating characteristics, pricing signals, or programmatic criteria in order to manage the charging load shape. The microgrid controller can optimize charging levels and sources to reduce impact of the charging load on the grid, to minimize charging costs, to minimize the greenhouse gas footprint of the charging load, or other desired metrics. Control of the electric vehicle supply equipment in this manner may be called managed

[71] Draft Transportation Electrification Framework, Energy Division staff proposal, California Public Utilities Commission, February 3, 2020.
[72] Transportation Electrification Activities Pursuant to Senate Bill 350, CPUC.
[73] Open proceedings on zero-emission vehicles, CPUC.

charging or V1G.[74] V1G does not require that the electric vehicle supply equipment meet interconnection requirements (e.g., Rule 21) because all electricity flows toward the load and no electricity is exported to the grid.

When control of the electric vehicle supply equipment is based on static information (e.g., time-of-use pricing or programmatic criteria), the charging load may be demand responsive and traditional demand side management strategies can be employed. When control of the electric vehicle supply equipment is based on dynamic information (e.g. real-time grid operating characteristics), a minimum of one-way communication from either a utility or an aggregator to the microgrid controller is necessary to support near real-time dispatchable load control. As utility distribution system management, distributed energy resource management, and data acquisition systems evolve, the use case of managed electric vehicle charging through load control, including electric vehicle supply equipment within a microgrid, must be considered and minimum technological and operational rules defined. To site electric vehicle charging in locations that would not trigger distribution system upgrades or where managed electric vehicle charging would help defer those upgrades, microgrid project hosts, owners, and developers need transparent information about the utility distribution system.

Proposals

Option 1: Coordinate with other CPUC proceedings, other state agencies, and the Vehicle Grid Integration working group established in R.18-12-006 to ensure that evolving strategies, technologies, and rules for distribution system management, including communication requirements, support the use case of V1G within a microgrid (Gridworks). Ensure that V1G within a microgrid is allowed in and supported by any applicable programs or tariffs.

Rationale: V1G within a microgrid should be on a "level playing field" with V1G directly connected to the utility grid. Ensuring that V1G within a microgrid is adequately defined and addressed in other CPUC proceedings will enable broader adoption of EVs by reducing the impact to the grid of large EV charging loads and by establishing clear requirements for development of microgrids that are able to provide this capability.

Option 2: Coordinate with the CPUC's Integration Capacity Analysis mapping efforts (Integration Capacity Analysis Working Group 2018) and efforts at other state agencies, such as the California Energy Commission's assessment of electric vehicle charging infrastructure (California Energy Commission) as directed by AB 2127 (Ting, 2018), to ensure adequate information about utility distribution systems is available to assist in siting of microgrids in locations that can avoid or reduce distribution system upgrades triggered by large EV charging loads.

Rationale: The magnitude of the grid impact of large electric vehicles charging loads depends on the location and timing of the charging. These impacts can be reduced by siting microgrids with V1G capabilities in preferred locations on the distribution system.

[74] Managed charging includes switching charging on or off, delaying charging, and controlling the rate of charging. See Vehicle - Grid Integration, Energy Division, California Public Utilities Commission, March 2014, pp. 17-18.

Other Barrier 3: EV Integration - Vehicle-to-Grid

Charged batteries within electric vehicles can be a backup source of electricity exported to the electricity grid during normal operating conditions. Controlled discharge of the batteries in electric vehicles can provide support to the electricity grid when needed or when economically beneficial for the owner of the electric vehicle and is typically referred to as vehicle to grid (V2G). This managed discharge can be DC power flow from bidirectional EVSE (i.e., V2G-DC) or AC power flow directly from electric vehicles with onboard bidirectional inverters (i.e., V2G-AC). Microgrids can provide V2G-DC from EVSE or V2G-AC from electric vehicles within a microgrid in addition to V1G as previously discussed. V2G-DC requires bidirectional electric vehicle supply equipment, allowing electricity to flow to and from the EV batteries. Because electricity may be exported to the grid, the electric vehicle supply equipment must be interconnected under an applicable tariff. In IOU service territories the interconnection, including the electric vehicle supply equipment, must meet the requirements of Rule 2175 or the Federal Energy Regulatory Commission-jurisdictional wholesale distribution access tariff (SCE) (PG&E) (SDG&E) when interconnecting with the IOU's distribution grid or the California Independent System Operator Tariff when interconnecting with the transmission grid (CAISO 2016). V2G-AC requires that the onboard mobile inverter be approved under the applicable interconnection tariff. A minimum of one-way communication from either a utility or an aggregator to the microgrid controller is necessary to support V2G for grid support to indicate when and at what rate the battery power in the electric vehicles should be dispatched.

Proposals

Option 1: Coordinate with Energy Division Staff as the Rule 21 proceeding R.17.07.007 considers the V2G-DC recommendations in the Rule 21 Working Group 3 final report (Gridworks 2017). Ensure that any modifications to Rule 21 that enable or support V2G-DC are applicable to V2G-DC within a microgrid.

Rationale: The Rule 21 Working Group 3 reached consensus on multiple issues that clarify requirements for and enable interconnection of V2G-DC capable equipment. Ensuring any adopted modifications to Rule 21 that support V2G-DC are applicable to V2G-DC within microgrids supports broader adoption of EVs and establishes clear requirements for microgrids that are able to provide this capability.

Option 2: Coordinate with the V2G-AC interconnection subgroup, established in R.17-07-007 and R.18-12-006, efforts to establish interconnection requirements for mobile inverters.[76] Ensure that any recommendations for modifications to Rule 21 to support V2G-AC interconnections include V2G-AC within a microgrid.

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[75] Rule 21 Interconnection, CPUC.

[76] Joint Administrative Law Judges' Ruling Establishing Subgroup and Schedule to Develop Proposal on Mobile Inverter Technical Requirements for Rule 21 and Noticing Workshop, August 23, 2019.

Rationale: Establishing requirements for V2G-AC interconnections is a work in progress. Ensuring that V2G-AC within a microgrid is considered during this process will support broader adoption of EVs and establish clear requirements for microgrids that are able to provide this capability.

Option 3: Coordinate with other CPUC proceedings, other state agencies, and the Vehicle Grid Integration working group to ensure that evolving strategies, technologies, and rules for distribution system management, including communication requirements, support the use case of V2G within a microgrid. Ensure that V2G within a microgrid is allowed in and supported by any applicable programs or tariffs.

Rationale: V2G within a microgrid should be on a "level playing field" with V2G directly connected to the utility grid. Ensuring that V2G within a microgrid is adequately defined and addressed in other CPUC proceedings will enable broader adoption of electric vehicles by reducing the impact to the grid of large EV charging loads, providing support to the grid from electric vehicles, and by establishing clear requirements for development of microgrids that are able to provide this capability.

Option 4: Coordinate with the CPUC's Integration Capacity Analysis mapping efforts and efforts at other state agencies, such as the CEC's assessment of electric vehicle charging infrastructure as directed by AB 2127 (Ting, 2018), to ensure adequate information about utility distribution systems is available to assist in siting of microgrids in locations that can avoid or reduce distribution system upgrades triggered by large electric vehicle charging loads.

Rationale: The magnitude of the grid impact of large electric vehicle charging loads depends on the location and timing of the charging. These impacts can be reduced by siting microgrids with V2G capabilities in preferred locations on the distribution system.

Option 5: Coordinate with any future efforts to modify Wholesale Distribution Access Tariff or the CAISO Tariff to support V2G-DC or V2G-AC interconnections and to ensure that V2G interconnections with a microgrid are included.

Rationale: V2G interconnections are unlikely to occur exclusively under Rule 21 and any future efforts to develop V2G requirements in other tariffs should include V2G within a microgrid.

Other Barrier 4: EV Integration – Vehicle to Building During Power Failure/PSPS

During a grid outage or a Public Safety Power Shutoff, a microgrid will be isolated from the electricity grid, enter island mode, and local generation or storage will provide electricity to loads within the island. These local resources can be used to ensure that electric vehicle charging remains available during the outage. When isolated from the grid during island mode, it is also possible to provide resiliency to loads in the island by using charged EV batteries as a source of electricity. This form of resiliency is commonly referred to as vehicle-to-building (V2B) or vehicle-to-home (V2H). V2H is of particular interest for residential customers who own an electric vehicle and have experienced PSPS but do not have another source of resilient electricity (e.g., islandable battery storage). When V2B or V2H is capable of occurring when a microgrid is in grid connected mode or when it is within an in-front-of-meter microgrid, the same requirements as those for V2G-DC and V2G-AC will be applicable.[77] In a single-customer microgrid, where the entire island is behind one utility meter, where grid isolation is achieved by equipment independent of the EV or EVSE (e.g., break-before-make transfer switch), and where V2B or V2H is capable of occurring only during island mode, it is likely that some requirements such as Rule 21 interconnection will not be applicable.

Proposal

Option 1: Coordinate with Energy Division Staff to clearly delineate scenarios where approved Rule 21 interconnection is and is not required for V2B or V2H.

Rationale: When Rule 21 interconnection is necessary, the specific requirements should be the same as V2G-DC or V2G-AC. When grid isolation is achieved in a manner that does not require interconnection under Rule 21 and where V2B or V2H cannot occur in parallel with the electricity grid (i.e., can only occur in island mode), resiliency may be provided to loads within the island at lower costs and with less complexity and this allowance should be explicitly clear in Rule 21. Additionally, see Staff proposal 5.

Other Barrier 5: Cybersecurity

Cybersecurity of microgrid equipment that networks with Investor Owned Utilities' systems is a threat vector that bad actors could use to access the broader Investor Owned Utility's distribution control system. While this is a problem for only a subset of microgrids (in-front-of-the-meter solutions that use Investor Owned Utilities' infrastructure, most notably), it presents a large barrier to these types of systems because they need to conform to stringent technical specifications to be able to interface with the Investor Owned Utilities' systems to operate the microgrid while also conforming to security requirements imposed by the Investor Owned Utilities to protect their system. This can complicate the design of microgrid control systems and poses questions about the security and ownership of assets that can perform multiple tasks (e.g. controlling generation assets for wholesale market participation and controlling generation assets in islanded modes using the Investor Owned Utility's distribution infrastructure).

The Redwood Coast Airport Microgrid is currently using the idea of a "bright clear line" to deal with cybersecurity and interoperability standards. As a community choice aggregation, the Redwood Coast Energy Authority already uses the previously mentioned North American Electric Reliability Corporation critical infrastructure protection standards as a backbone of their systems and are audited by the CPUC and by PG&E for data security. The microgrid controllers used in their Redwood Coast Airport Microgrid project are clearly demarcated by their task. One controller is used to control the system in non-islanded condition to bid the capacity into the wholesale market, while a different controller is used to control the generating assets while in islanded condition using

[77] There may be configurations of equipment in an IFOM microgrid that would only allow V2B or V2H to occur during island mode. These potential configurations are not addressed in this section because they seem a less likely use case.

PG&E's infrastructure. This separation is crucial to the security of the system because it reduces possible points of ingress into the Investor Owned Utility's distribution control systems.

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9. Appendices

9.1 Definitions

Authority Having Jurisdiction – An organization, office, or individual responsible for enforcing the requirements of a code or standard, or for approving equipment, materials, an installation, or a procedure.

Battery Energy Storage System – A system consisting of electrical storage batteries, battery chargers, and any rectifiers, inverters, converters, and associated electrical equipment as required by a particular application.

Bundled Service Customers – Customers electing to continue to receive all of their electricity supply and delivery services from an investor owned utility.

Commercialization – Commercialization is the process by which a new product or service is introduced into the general market. Commercialization is broken into phases, from the initial introduction of the product through its mass production and adoption." (University of Pittsburgh, Innovation Institute n.d.)

Competition Transition Charge - A nonpassable charge on the bills of each customer of the distribution utility, including those who are served under contracts with non-utility suppliers, for recovery of the utility's transition costs arising from deregulation.

Cost Responsibility Surcharge – The mechanism by which the CPUC has allocated costs associated with past utility and Department of Water Resources commitments to Direct Access customers.

Departing load - That portion of the utility customer's electric load for which the customer discontinues or reduces its purchase of bundled or direct access service from the utility; purchases or consumes electricity supplied and delivered by "Customer Generation" to replace the utility or Direct Access (DA) purchases.

Macrogrid - An electrical system that serves 50,000 people or more would simply be a grid, rather than a microgrid (each individual in a dwelling unit would count separately toward this total). Also referred to as the "larger grid", the "wider grid" or sometimes just the "grid."

Microgrid – An electrical system serving less than 50,000 residential customers (each individual in a dwelling unit would count separately toward this total). The two core characteristics are: 1) relatively small size and 2) the ability serve loads, as a system, independent of a larger electrical grid.

Nonbypassable Charges – A "nonbypassable charge" is a component of the electric rate structure that no matter the customer's choice of provider, all customers (bundled and departing load) are charged with paying to recover fixed charges or program costs of the electrical system with which the customer is connected.

Resiliency – Resiliency refers to the ability to mitigate the impact of a large, disruptive event by any one or more of the following mechanisms:

1. Reducing the magnitude of disruption;
2. Reducing the duration of disruption;
3. Reducing the duration of adaptation; or
4. Reducing the duration of recovery.

Standby Service - "Standby Service" is charged to customers to pay for the utilities expense that it incurs to provide electricity and capacity on a standby basis. This applies to customers whose electricity supplies come from facilities other than the utility, in the event that generation source fails or is not available.

9.2 Acronyms

CAISO	California Independent System Operator
CEQA	California Environmental Quality Act
CPUC	California Public Utility's Commission
D.	Decision
GO	General Order
kW	Kilowatt
MW	Megawatt
PG&E	Pacific Gas and Electric
PUC	Public Utilities Code
R.	Rulemaking
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
V2B	vehicle-to-building
V2H	vehicle-to-home

9.3 Public Utilities Code 8371

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.

9.4 Public Utilities Code 218

DIVISION 1. REGULATION OF PUBLIC UTILITIES [201 - 3297]

(Division 1 enacted by Stats. 1951, Ch. 764.)

PART 1. PUBLIC UTILITIES ACT [201 - 2120]

(Part 1 enacted by Stats. 1951, Ch. 764.)

CHAPTER 1. General Provisions and Definitions [201 - 248]

(Chapter 1 enacted by Stats. 1951, Ch. 764.)

(a) "Electrical corporation" includes every corporation or person owning, controlling, operating, or managing any electric plant for compensation within this state, except where electricity is generated on or distributed by the producer through private property solely for its own use or the use of its tenants and not for sale or transmission to others.

(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.

(2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated or on real property immediately adjacent thereto, unless there is an intervening public street constituting the boundary between the real property on which the electricity is generated and the immediately adjacent property and one or more of the following applies:

(A) The real property on which the electricity is generated and the immediately adjacent real property is not under common ownership or control, or that common ownership or control was gained solely for purposes of sale of the electricity so generated and not for other business purposes.

(B) The useful thermal output of the facility generating the electricity is not used on the immediately adjacent property for petroleum production or refining.

(C) The electricity furnished to the immediately adjacent property is not utilized by a subsidiary or affiliate of the corporation or person generating the electricity.

(3) Sale or transmission to an electrical corporation or state or local public agency, but not for sale or transmission to others, unless the corporation or person is otherwise an electrical corporation.

(c) "Electrical corporation" does not include a corporation or person employing landfill gas technology for the generation of electricity for any one or more of the following purposes:

(1) Its own use or the use of not more than two of its tenants located on the real property on which the electricity is generated.

(2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated.

(3) Sale or transmission to an electrical corporation or state or local public agency.

(d) "Electrical corporation" does not include a corporation or person employing digester gas technology for the generation of electricity for any one or more of the following purposes:

(1) Its own use or the use of not more than two of its tenants located on the real property on which the electricity is generated.

(2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated.

(3) Sale or transmission to an electrical corporation or state or local public agency, if the sale or transmission of the electricity service to a retail customer is provided through the transmission system of the existing local publicly owned electric utility or electrical corporation of that retail customer.

(e) "Electrical corporation" does not include an independent solar energy producer, as defined in Article 3 (commencing with Section 2868) of Chapter 9 of Part 2.

(f) The amendments made to this section at the 1987 portion of the 1987–88 Regular Session of the Legislature do not apply to any corporation or person employing cogeneration technology or producing power from other than a conventional power source for the generation of electricity that physically produced electricity prior to January 1, 1989, and furnished that electricity to immediately adjacent real property for use thereon prior to January 1, 1989.

(Amended by Stats. 2008, Ch. 535, Sec. 1. Effective January 1, 2009.)

9.5 Statutory Requirements

Pursuant to Public Utilities Code (PUC) Code 8371, the CPUC shall take the following actions listed in the PUC Code Section below by December 1, 2020. This section summarizes how the Track 1 Decision 20-06-017 fulfills the statutory requirements, and how the proposals within this concept proposal may further accomplish the statutory requirements.

- Permitting Requirements 8371(a) - Develop microgrid service standards necessary to meet state and local permitting requirements.
  1. Track 1 Decision – Ordering Paragraph 1
  2. Track 2 Concept Paper – The following are additional proposals for further reducing permitting-related barriers: Energy Storage Guidebook, Permitting Gap Analysis, Battery Safety Best Practices Guide, CPUC oversight of utility battery storage systems, new rulemaking on GO-131-D, and revising the zoning and streamlining of CEQA treatment of microgrids.

- Barrier Reduction 8371(b) - Without shifting costs between ratepayers, develop methods to reduce barriers for microgrid deployment.
  1. Track 1 Decision – Ordering Paragraph 1 to 20.
  2. Track 2 Proposal – Proposals 1 to 5 and the secondary proposals.

- Impact Studies 8371(c) - Develop guidelines that determine what impact studies are required for microgrids to connect to the electrical corporation grid.
  1. Track 1 Decision – Not applicable.
  2. Track 2 Proposal – Proposals for enhancing understanding of microgrid interconnection studies.

- Rates and Tariffs 8371(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.
    1. Track 1 Decision – Not Applicable.
    2. Track 2 Proposal – Proposal for a new microgrids rate schedule and proposal for incentive pilot program

- Standards and Protocols 8371(e) - Form a working group to codify standards and protocols needed to meet California electrical corporation and Independent System Operator microgrid requirements.
    1. Track 1 Decision – Not applicable.
    2. Track 2 Proposal – Proposal for establishing a microgrids working group.

- Direct Current Meter Standards 8371(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.
    1. Track 1 Decision – Not applicable.
    2. Track 2 Proposal – Proposal for the development of DC metering standards

END ATTACHMENT 2