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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) COMMENTS ON TRACK 1 MICROGRID AND RESILIENCY STRATEGIES STAFF PROPOSAL

ANNA VALDBERG
ROBIN Z. MEIDHOF

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-6054
E-mail: Robin.Meidhof@sce.com
E-mail: Anna.Valdberg@sce.com

Dated: **January 30, 2020**

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I.
INTRODUCTION

Pursuant to the January 21, 2020 Administrative Law Judge Ruling Requesting Comments on Track 1 Microgrid and Resiliency Strategies and Staff's Proposal (Track 1 Ruling) issued in the above captioned proceeding, Southern California Edison Company (SCE) provides its responses to the questions raised about the recommendations contained in the Staff Proposal. On January 22, 2020, the Bioenergy Association of California (BAC) requested an extension of seven days for parties to file comments in response to the Track 1 Ruling. On January 24, 2020, ALJ Rizzo denied that request.

Given the expedited nature of Track 1, SCE respectfully requests that the Commission consider designating as an interim or pilot solution any approved proposals, where appropriate, to be revisited after a certain number of months (e.g., 24) or in a later track of this proceeding or any subsequent proceeding. Designating a proposal as a pilot or an interim solution, accompanied by a plan to revisit the proposal using the more traditional stakeholder process and timelines, accomplishes the goal of facilitating immediate action to address the 2020 wildfire

season. It also allows for further thoughtful engagement on the issues with the added benefit of real data, results, and lessons learned. These time-limited pilot proposals should be made only to facilitate PSPS resilience for Investor Owned Utilities (IOU) customers and the grid. In addition, given the expedited comment period to respond to the Staff Proposal, SCE's responses below reflect the best information SCE has available at this time. As SCE gains experience through this proceeding and other related efforts, SCE may modify its positions or make additional arguments to those discussed herein.

II.

SCE RESPONSES TO QUESTIONS

3.1. Prioritizing Interconnection Applications to Deliver Resiliency Services at Key Sites and Locations

All Interconnection Proposals:

SCE supports Staff's Guiding Principles for Interconnection Proposals and is committed to working with the Commission and all stakeholders to: (1) reduce the amount of time required to interconnect distributed energy resources (DERs) that support resiliency in areas impacted by public safety power shutoffs; (2) maintain the safety and reliability of the electric grid; and (3) ensure just and reasonable rates for participating and non-participating customers.[1] Below, SCE provides its responses to the questions posed in the Track 1 Ruling to the best of its ability at this time.

1. **Please indicate support of or opposition to the adoption of each proposal and justify the rationale. For the proposals that include implementation options, please indicate which options should be supported or opposed and why.**

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

SCE supports Staff's recommended Option #1 of their Interconnection Proposal 1, and should the Commission adopt this Proposal, SCE will commit to working with stakeholders to develop template-based application generating facilities designs (Template Based Single Line

[1] *See* Staff Proposal, Section 3.1.2 at p. 7.

Diagrams). Although Staff recommends Option #1 only, SCE's initial evaluation suggests that a combination of Option #1 and Option #2 would likely be most effective. In this process, the IOUs would first informally consult with key stakeholders to develop acceptable template designs and later, share those designs with stakeholders via a technical meeting described in Option #2, to solicit feedback and finalize the templates. This process will ensure that IOUs can develop these templates quickly while allowing for a broader set of stakeholders to provide input, thus minimizing, or potentially eliminating, stakeholder protests when IOUs submit an Advice Letter for the Commission to approve the inclusion of the agreed upon template-based designs as part of the Interconnection Request form.

SCE understands Staff's comment on the complexity of working groups, however, SCE believes the majority of these designs should not generate significant controversy leading to a prolonged working group process. SCE agrees with Staff's rationale in not recommending Option #3.

By utilizing Commission approved template-based designs, developers and customers will need to abide by the selected template design for their project. Once a developer/customer selects a specific template-based design, SCE will consider that design as approved and the developer or customer, in turn, will be required to comply with the terms of the Commission-approved interconnection agreement. SCE notes that, to make the process functional, should an IOU discover that a developer/customer has not complied with the interconnection agreement or approved template-based design, an IOU would need to reserve all legal rights to address this breach. Therefore, SCE may seek to revise the current language in approved Interconnection Agreements or to add language to a pre-approved template design form to ensure that legal roles, responsibilities, and liabilities are sufficiently addressed.

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

SCE is generally supportive of Staff's proposal on expedited utility sign-off for installed projects. SCE however has reservations regarding the application of the three options identified by staff.

With respect to Option #1, SCE agrees with adding additional technical information to SCE's NEM Handbook, as applicable, that can provide information on when a field inspection may be required. However, SCE notes that projects have different characteristics and need to be evaluated on a project-by-project basis to determine if field inspection is required. For certain types of equipment, such as verification of adequate means of disconnection (e.g., usage of a Visible-Lockable-Disconnect), SCE has very successfully relied on methods outlined in Option #3. However, for other verification requirements (such as verification of relaying/control settings and the demonstration of the performance of these relays or controls), a field verification would be required, so that SCE can verify that these systems have been programmed correctly and that these systems operate as intended. In order to operate the electric grid in a safe and reliable manner, it is essential for SCE to be able to verify that these systems perform as intended. While Energy Division (ED) Staff recommends Option #2, SCE does not support this option because local jurisdiction inspectors do not inspect system elements for utility safety requirements. For example, utility requirements for generator disconnects require a "Visible Open Disconnect" (per Rule 21 Section H.1.d), which a local inspector may or may not verify. Another example is that a local inspector may inspect the grounding of relaying equipment, but they will not inspect the relay for settings that comply with the appropriate utility Rule 21 requirements, as that is the responsibility of the utility. Since utility inspections and local jurisdiction inspections seek to achieve different objectives, they are not necessarily duplicative of one another and should both be maintained. SCE supports coordinating, to the extent IOUs can, with local jurisdiction inspectors to align their inspections and utility inspection dates to avoid or reduce potential delays.

SCE supports Option #3, but with modification. SCE already makes use of photos, equipment technical information, and other information such as plot plans provided within the interconnection application process, to determine that the equipment installed meets SCE requirements. SCE supports continuing this practice but should not be required to accept photos, technical information and other information in lieu of a field inspection. SCE does not support

increasing the complexity of a process that has already shown to be effective for SCE. Therefore, SCE does not support the addition of attestations or the need to coordinate with local jurisdictions to enforce utility inspection requirements. As indicated in comments on Option #2, SCE and local inspectors may or may not be verifying the same electrical characteristics and the need to coordinate with a third party (a local inspector) may actually increase the time for verification.

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

SCE notes that Interconnection Proposal #3 does not apply to NEM projects, which are processed in a matter of days and are not queued. Non-NEM Rule 21 projects are queued, however, so Proposal #3 would not necessarily benefit small (generally smaller than 10 kW) non-export projects that are capable of passing the Fast Track Initial Review without requiring upgrades. These <10 kW non-export projects are also processed relatively quickly (30 or fewer business days) and thus a prioritization scheme would have little benefit. Proposal #3 primarily applies to larger non-export projects or exporting projects that do not pass Initial Review or Supplemental Review and therefore require Detailed Study. These are the exact projects that, because of their complexity and potential impacts to the Distribution System, are less likely to be quickly interconnected in the first place and must go through review to ensure grid safety and reliability.

SCE is strongly opposed to the concept of "queue-jumping" (Option #1) or "priority grouping" (Option #2) of interconnection requests. SCE's opposition stems from the long-established fundamental principles and standards of non-discrimination that are applied across wholesale and retail energy systems. Criteria that favors a certain group of interconnection requests over others is *per se* discriminatory to the non-favored group. Queue jumping would lead to certain delay for non-prioritized projects, a potential restudy for those projects subjecting applicants to additional study costs, and potentially additional construction costs if the interconnection would require SCE to upgrade its distribution facilities to safely and reliably

support the interconnection when, based on a fair queue, another project would have triggered those upgrades.

Creating a "priority" queue holds potential unintended consequences (as noted in the Staff Proposal) for interconnection requests, including FERC-jurisdictional projects that are not selected to be in the "priority" group. An equitable and efficient interconnection process maintains the non-discriminating queuing protocols currently in place.

The Staff Proposal accurately describes some of these unintended consequences, including wasted study effort, delays, and cost impacts. The Staff Proposal also mentions the additional uncertainty that such a priority queue would create. Reducing uncertainty for interconnection customers is one of the primary benefits of the interconnection reforms made to Rule 21 in recent years. Allowing a "criteria-based priority" proposal to move forward would undo much progress made in recent years in reducing uncertainty in the interconnection process.

SCE understands the Commission's goal of mitigating PSPS and other reliability events by creating an environment whereby DERs and microgrids are deployed to improve grid and/or customer resiliency. Time certainly is of the essence for DERs and/or microgrids to be placed in service prior to the 2020 wildfire season. SCE believes that other techniques could be implemented rather than the concept of "queue jumping" or "priority grouping." SCE agrees that some aspects of the interconnection process could be improved with increased staff and investment in IT (Option #3) but does not support a specific mandate requiring IOUs to implement such changes. SCE has already been investing heavily in IT, especially in developing its new online interconnection portal, the Grid Interconnection Processing Tool (GIPT).[2] Increases in staffing can be supported with sufficient lead time, but IT and staffing alone are not the only root cause of delays beyond tariff timelines. SCE's response to Question 20 below

[2] On December 30, 2019, a member of the Commission's Interconnection Discussion Forum provided informal comments related to microgrid interconnection issues via email to the Service List of R.19-09-009. The email stated, "We applaud SCE for releasing its new partially automated interconnection tool (GIPT) earlier than expected… We also hope that GIPT can be a model for the other IOUs to adopt or at least emulate in some manner."

discusses several steps that interconnection customers can do independently to move projects more quickly and efficiently through the interconnection process. Adding IOU staff and IT resources will not solve all aspects of customers' concerns on the time required to process interconnection request. Incorporating streamlining measures such as use of pre-approved single-line diagrams is a prime example of efforts that improve both customer and IOU processes.

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

SCE agrees with Staff and does not currently support or recommend Proposal #4 and, therefore, does not provide any further commentary on this proposal in the following questions. SCE does, however, reserve the right to provide further comment on Proposal #4 in its Reply Comments after viewing intervenors' filings.

2. **Are changes to any rate schedules or electric rules needed to implement any of the proposals? If so, which ones, and how do they need to be changed? Please propose specific language.**

If Interconnection Proposal #1 (Use Pre-approved Designs in Application Process) is adopted, SCE will need to modify its Commission-approved interconnection applications and related tariffs[3] by submitting an Advice Letter to include the pre-approved designs.

At this time, SCE does not believe any rate schedules or electric rules need to be modified to implement Interconnection Proposal #2 (Expedite Utility Sign-Off on Installed Projects). That is, SCE can update its NEM Handbook, as applicable, without updates to rate schedules or tariffs.

At this time, SCE does not believe any rate schedules need to be modified to implement Staff's Interconnection Proposal #3 (Accelerate Interconnections for Key Locations, Customers, and/or Facilities). However, the implementation of any prioritization scheme would require a stakeholder process and amendments to Rule 21, followed by IOUs filing Advice Letters to implement the new procedures. Additionally, to the extent that the Commission orders

[3] While the question specifically asked for changes to rate schedules or electric rules, the Commission-approved interconnection applications associated with Rule 21 and NEM are considered part of the tariff.

modifications to its rules that conflict with SCE's FERC jurisdictional tariffs, SCE would be barred from implementing those portions that contradict FERC rules.

3. **Is CPUC action required in order to implement any of the proposals? If so, what action would be most appropriate?**

With respect to Staff Interconnection Proposal #1, if the Commission adopts SCE's recommendation to combine Options #1 and #2, Commission action may be required to support the formation of a stakeholder working meeting. SCE does not anticipate that this would require more than two working meetings that the Commission would need to coordinate. Action from the Commission will also be needed to determine how the diagrams should be submitted to the Commission for approval and to expeditiously approve IOU Advice Letters to implement the agreed-on template designs.

With respect to Staff Interconnection Proposal #2, at this time, SCE does not believe Commission action is needed to implement this proposal.

With respect to Staff Interconnection Proposal #3, Commission action would be required to include any prioritization scheme, and the rules, regulations, and procedures surrounding the scheme would need to be added to Rule 21 so that all parties are aware of the updated prioritization scheme. IOUs would then be required to file Advice Letters to implement the new procedures. Any prioritization scheme that affects projects seeking interconnection under SCE's Wholesale Distribution Access Tariff (WDAT) or the CAISO Interconnection Procedures may need to be harmonized amongst all of the interconnection tariffs (Rule 21, WDAT, and CAISO), thus corresponding filings to the Federal Energy Regulatory Commission (FERC) may be required to fully implement this proposal.

4. **For proposals that require CPUC action, what standards are appropriate for CPUC to use to determine whether the action is justified?**

In determining whether these proposals are justified, the Commission needs to consider the customer impact, cost and benefit of implementing the proposals versus other alternatives, and technical feasibility of the proposal, including addressing and resolving the challenges

identified in SCE's response. In addition, the Commission needs to consider whether changes to the interconnection processes that affect projects seeking interconnection under SCE's WDAT would require filing with the FERC.

Regarding Proposal #1 to create a working group meeting to discuss template-based designs, the Commission should use similar standards used in their coordination of the technical meetings for the Smart Inverter Working Group (SIWG). However, unlike the SIWG meetings that continue for months, SCE does not expect these working group meetings to require more than two sessions. In fact, given the representation of the SIWG, the Commission may find it appropriate to assign this action item to that working team if meetings can be expedited.

5. **Should CPUC consider cost recovery for any of these proposals in this proceeding? For example, should CPUC consider cost recovery for additional IOU technical resources to support the intake, prioritizing, technical support, and processing of interconnection applications? Please discuss**.

If any of the proposals are implemented and result in SCE incurring incremental costs (including changes needed to the interconnection portals to handle new application and procedural requirements), then SCE should be granted cost recovery for those costs. As stated in SCE's January 21, 2010 Resiliency Proposal and Response to Administrative Law Judge's Ruling in this proceeding, the Commission has already authorized SCE to record costs associated with any relevant microgrid proposals in SCE's existing Wildfire Mitigation Plan Memorandum Account (WMPMA), as those costs will be associated with programs and activities set forth in SCE's forthcoming 2020 Wildfire Mitigation Plan (and can be reviewed for reasonableness in Track 3 of SCE's pending 2021 GRC as contemplated by the Scoping Memorandum in that proceeding). Alternatively, the Commission could authorize the establishment of a new memorandum account to track incremental microgrid-related costs and address cost recovery of those costs when it is appropriate to do so.

6. **Are any changes to statute required to implement any of the proposals? If so, please state the Public Utilities Code section and propose language.**

For Staff's Interconnection Proposals #1, #2, and #3, SCE does not believe there is a need to change any statutes.

7. **For each proposal,**
   a. **Estimate the time required to implement the proposal; and**

Interconnection Proposal #1 – Implementation requirements

To implement Proposal #1, the IOUs will first have to agree with industry on the acceptable design templates. To achieve this, SCE proposed a combination of Option #1 and Option #2 allowing SCE, other IOUs, and some key stakeholders (such as Tesla, Stem, Enphase, etc.) to first mutually establish acceptable design templates. This collaboration should take up to three weeks. SCE has already developed and provided design templates to the Commission's Interconnection Discussion Forum and has received positive feedback on such designs which may allow for quick agreement.

Having achieved consensus with key stakeholders, the agreed-on template designs would then be presented at Commission sponsored working meetings as outlined in Option #2. A maximum of two working meetings in the span of three weeks would be needed to achieve the goal of developing template designs.

One key to success will be guidance from the Commission. SCE strongly believes in adopting an 80:20 guideline, by which the template designs are acceptable for 80% or more of potential interconnected projects. Without Commission guidance, stakeholders may want to expand to more template designs than may be necessary, which will significantly extend the time required to develop, achieve consensus, and implement the use of template designs, achieving the opposite affect intended by this proposal. Therefore, if Commission guidance is provided to use the 80:20 approach, where template-based designs would be used for at minimum 80% of the projects and the remaining 20% will continue to be evaluated through the current process, SCE believes that a total of six weeks would be needed to agree on template designs.

Second, with agreed upon template designs, SCE would have to submit an Advice Letter for the Commission to approve updating the NEM and Rule 21 Interconnection forms. This may take up to four weeks plus time for Commission review and approval of the Advice Letter.

Finally, SCE interconnection portals for NEM and Rule 21 will need to be updated or an interim alternative communication method developed. This may take from four to six weeks.

In total, SCE estimates that it may take between 14 and 16 weeks to fully implement the proposal, under the assumption that the Commission adopts the 80:20 approach described above.

Interconnection Proposal #2 – Implementation requirements

As indicated in SCE's response to question #1, SCE supports, with modification, Option #3 and has already been successfully implementing the critical elements (use of photos, equipment technical specification, etc.) to approve interconnection projects without an SCE field inspection. SCE also supports adding additional language to SCE's NEM Handbook, as applicable, in support of Option #1.

Therefore, if no additional requirements are imposed and implementation of this proposal is limited to what SCE supports as indicated in the response to question #1, then only the update to SCE's NEM Handbook is needed to comply with Option #1, which SCE approximates will take between four to seven weeks.

Interconnection Proposal #3 – Implementation requirements

Any adoption of any form of prioritization scheme (Option #1 or #2) should require a stakeholder process to determine the relevant rules, regulations, and procedures to amend Rule 21. For Option #3 (increasing staffing and/or IT), staffing increases would require resource planning, hiring, and training of new staff, while continued development of IT resources would require scoping, procuring, coding, testing, and other development efforts to enhance interconnection tools. Based on recent Rule 21 stakeholder efforts such as Working Groups 2 and 3 under the ongoing Rule 21 OIR, such an effort could take up to a year to fully implement. As explained further below, acquiring additional staff and training them will require several

months for each of those activities. Further development of interconnection tools will also require several months depending on scope.

b. Estimate the IOU staff hours required to implement the proposal.

SCE notes that the responses to this question are based on high-level estimates rather than detailed analysis which could not be completed given the compressed timeframe for response.

Proposal #1 –SCE staff hours estimate

SCE development of proposed template designs: SCE has already developed and introduced into the Commission Interconnection Discussion Forum the templates that SCE believes are sufficient to address greater than 80% of the interconnection applications (80:20 approach). Thus, no additional hours are needed for this element.

Industry collaboration on template designs: The number of hours for industry collaboration (for Option #1 and Option #2 as proposed by SCE) may be a range of 50 to 70 SCE staff hours over the span of six weeks.

Development of Advice Letters: The number of hours ranges from 30 to 40 SCE staff hours over a span of up to four weeks.

Preparation of Interconnection Tools: The number of hours ranges from 75 to 100 SCE staff hours over a span of up to four to six weeks for interconnection staff development, plus a currently unknown amount of IT staff development hours depending on the scope of development.

In total, the IOU estimated hours to implement Option #1 is 155 to 210 hours over a period of 10 to 16 weeks.

Proposal #2 –SCE staff hours estimate

As indicated above, if no additional requirements are imposed and implementation of this proposal is limited to what SCE supports as indicated in the response to Question #1, then only an update to SCE's NEM Handbook is needed to comply with Option #1. SCE approximates this will take up to 80 SCE staff hours over four to seven weeks.

Proposal #3 – SCE staff hours estimate

Development of Prioritization Scheme: Though SCE advises against the development of a prioritization scheme, SCE participation in a stakeholder process to develop the rules, regulations, and procedures around any possible prioritization scheme is estimated to include at least 5 stakeholder meetings at two hours each, with four SCE staff hours of preparation or reaction time to each, totaling 30 hours per person/contributor over a span of one to two months. With the assumption of the need for a case manager and several contributors, the hour requirements could rise to more.

Development of Advice Letters; The number of hours ranges from 30 to 40 SCE staff hours over a span of up to four weeks.

Further Development of Interconnection Tools: The number of hours ranges from 75 to 100 SCE staff hours over a period of six months of interconnection staff development, plus a currently unknown amount of IT staff development hours depending on the scope of development.

Staffing Increases: Resource planning, job posting, interviewing and hiring, and training new staff would require at least 80 SCE staff hours over six months. New staff would require four weeks of intensive training to become effective, with on-the-job training to take an additional six months to become fully productive.

8. **For each proposal,**
   a. **Estimate how much the proposal would reduce the amount of time required for interconnection;**

Proposal #1

Interconnection Proposal #1 to use pre-approved designs in the application process will reduce time required by interconnection customers to prepare interconnection applications as well as reduce the time required by IOUs to deem an interconnection complete.

Rule 21 allows 10 business days from application receipt to deeming the application complete. Applications that are complete from inception can reduce this duration to a few business days. This timeframe can become significantly extended if there are many rounds of

deficiencies in the application that need to be cured by the interconnection customer prior to deeming the application complete. As a missing or incomplete single-line-diagram (SLD) is often one of these deficiencies, the use of pre-approved and standard SLDs would eliminate the deficiency churn (for that item) and potentially shave several business days off of the overall timeline.

Proposal #2

Interconnection Proposal #2 to expedite utility sign-off on installed projects may reduce interconnection time by eliminating the need to schedule and coordinate a site visit, which typically can take up to 10 business days.

Proposal #3

Interconnection Proposal #3 to accelerate interconnections for key locations, customers and/or facilities may reduce interconnection timelines for certain applications. NEM projects are processed quickly and are not queued. Small (<10kW) non-NEM non-export Rule 21 Fast Track eligible projects, meaning those that can pass Initial Review without requiring upgrades, are processed relatively quickly and a prioritization scheme would likely have little benefit. This is because it will likely take the same amount of time to perform an Initial Review for a priority-listed project as a non-priority listed project.

Where the time savings for priority-listed projects over non-priority listed projects could occur is in larger non-exporting (>10 kW) and exporting Rule 21 projects that do not pass Initial Review and Supplemental Review and are therefore required to go through the Detailed Study process. Being able to skip to the front of the line might shave off a few months in the Detailed Study process for a few fortunate projects, and any savings in that phase might lead to a few months saved in the overall timeline to in-service date. However, any incremental timeline adjustments to detailed design/engineering, construction, and equipment procurement would negatively impact other customers with projects in the queue and may, as noted above, not be implementable where they conflict with FERC regulations.

b. State the population of project types (e.g., net energy metering (NEM) solar > 30 kilowatt [kW], NEM-paired storage > 10 kW) that would benefit from this streamlining.

Interconnection Proposal #1 to use pre-approved designs, accounting for SCE's proposed limitations as identified in the response to Question #1, includes the following types of interconnection projects.

- NEM solar ≤ 30kW. Based on 2019 historical data, this accounts for 99% of the NEM solar-only projects
- NEM solar ≤ 30kW with paired storage (≤ 10kW). Based on 2019 historical data, this accounts for 98.5% of the NEM solar - coupled with storage projects.
- Rule 21 Non-export (<10kW). Based on 2019 historical data, this accounts for 34.2% of the Rule 21 storage-only projects. SCE notes that this is based on a small set of data (149 projects). If Rule 21 non-export storage is used at the residential level, the percent population would be equivalent to NEM paired with storage.

Interconnection Proposal #2 to expedite utility sign-off on installed projects, accounting for SCE's proposed limitations as identified in the response to Question #1, may benefit the following types of interconnection projects.

- NEM solar only, NEM solar-paired storage or small Rule 21 non-export storage for which SCE does not uses a self-contained meter panel. These type of generating facilities would be greater than 30kW (> 30kW). Based on 2019 Interconnection Request data for SCE, the population of this size project for NEM Solar only, NEM Solar – paired storage, and Rule 21 non-export storage project was approximately 1%

Interconnection Proposal #3 to accelerate interconnections for key locations, customers and/or facilities may potentially benefit from the prioritization scheme in Option #1 or Option #2. However, to reiterate what SCE stated in response to Question 8(a), non-NEM non-export interconnection requests smaller than 10 kW, that are eligible for Fast Track and pass Initial Review without requiring upgrades, would not benefit timewise from priority queueing versus non-priority projects. Projects that may benefit include non-export projects greater than 10 kW and exporting projects that fail Initial Review and Supplemental Review and thus require the Detailed Study process. However, these projects would only benefit at the expense of discriminating against non-priority projects and customers.

9. **Should any of the proposals be modified before being adopted and/or implemented? If so, please describe and justify any changes.**

With respect to Staff Interconnection Proposal #1, and as indicated in SCE's response to Question #1, SCE recommends that a combination of Options #1 and #2 be used. SCE does not fully understand what it means to "informally consult with industry" in Option #1 and cautions that if only a small set of key stakeholders are used to represent "industry," then stakeholders who may not have been consulted may protest SCE's Advice Letter and delay the implementation of the proposal. Therefore, SCE urges the Commission to adopt SCE's suggestion to create a working group meeting to discuss template-based designs, as noted in response to Question #4, which is a standard Commission practice that promotes stakeholder inclusion and transparency. This process also increases the probability that SCE's Advice Letter would be approved without any protests, or at least provides Commission staff with insight into the basis for any such protest.

With respect to Staff Interconnection Proposal #2, this proposal should be modified as follows:

a) IOUs should be required to add additional technical information to their respective NEM Handbooks to provide information on when a field inspection may be required

b) IOUs should make use of photos, equipment, technical information, and information provided as part of the interconnection such as plot plans, to determine that the equipment installed has met requirements. When the information provided does not demonstrate compliance, IOUs shall continue to perform field inspections. This should be limited to verification of equipment type such as the verification of compliance to Rule 21 visible open disconnect requirements, but this should not be used for verification of equipment performance and configuration requirements such as the verification of relay settings and its response to systems conditions, which shall continue to be evaluated via field inspections as determined by the IOU.

With respect to Staff Interconnection Proposal #3, SCE reiterates that it does not support Options #1 and #2. With respect to Option #3, SCE appreciates the Commission's understanding that additional staffing and/or IT resources are likely needed to expedite a variety of processes. Unfortunately, the Staff-proposed approach will not likely support SCE's ability to expedite interconnection processes beyond what it can do by making internal staffing adjustments, due to

the time it takes to hire and train the new employees and implement IT infrastructure. Please see SCE's responses to Question #23 for additional details.

10. **Are there other options for each proposal that have not been listed? If so, please elaborate on the option(s) that should be considered. Include as much detail as possible.**

With respect to Staff Proposal #1, SCE believes that modifications based on SCE's response to Question #9 will adequately improve the proposal.

With respect to Staff Proposal #2, SCE believes that modifications based on SCE's response to Question #9 will adequately improve the proposal.

SCE does not suggest any additional options under Proposal #3.

<u>Interconnection Proposal 1</u>:

11. **Are the three listed system types - (1) Rule 21 non-export storage, (2) NEM + Paired storage (Alternate Current [AC] Coupled and Direct Current [DC] coupled), and (3) NEM Solar - the most appropriate system types to consider in this proposal? Please justify the response. Beyond these three system types, should the utilities develop standardized single line diagrams for additional technologies or system types? If so, which technologies or system types should be prioritized and why?**

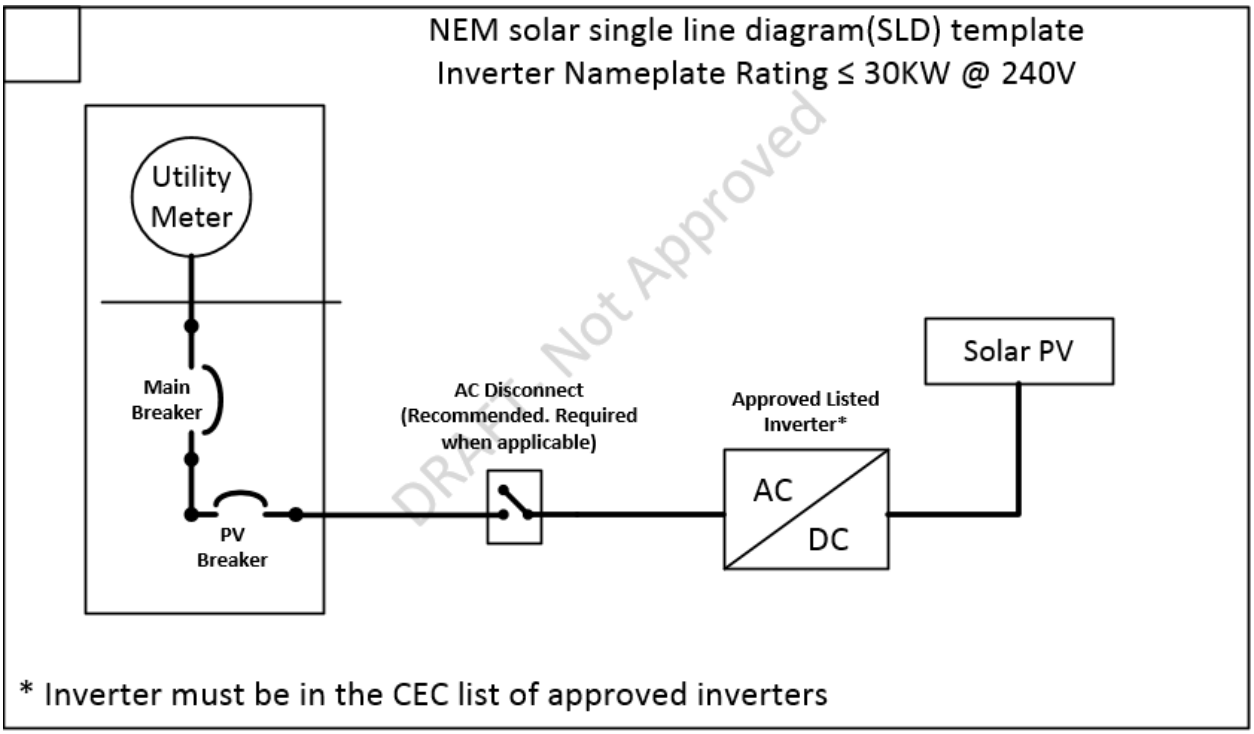
Yes, SCE believes that these three categories of projects, with the limitations proposed by SCE, will cover the vast majority of project population (>90% based on 2019 interconnection requests). Therefore, SCE does not believe that the utilities should be required to develop standardized single line diagrams for additional technologies given that those types of projects may only yield marginal benefits and at this point, the utilities and DER stakeholders should focus on the implementation of these three types of systems. Moreover, SCE intends to focus any efforts with respect to technologies and processes to those specific to near-term deployments in areas projected to be impacted by Public Safety Power Shutoffs, which is consistent with the scope of Track 1 of the proceeding.

12. **For each of the three system types described - (1) Rule 21 non-export storage, (2) NEM + Paired storage (AC Coupled and DC coupled), and (3) NEM Solar) - should a size limitation be placed on projects utilizing pre-approved single line diagrams? If so, what should it be and why?**

Yes, size limitation should be imposed on template design. The size limit and justification of the limit is as follows:

- NEM solar only – Inverter nameplate ≤ 30kW at 240V services.

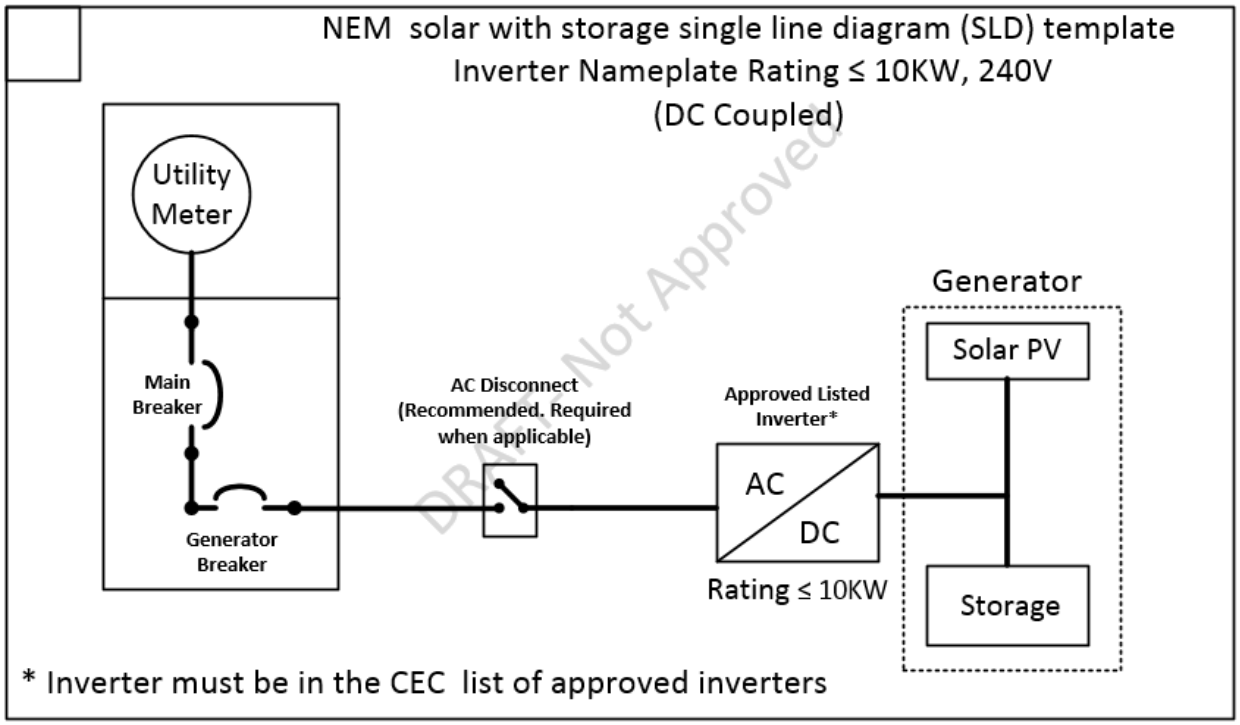
This limitation allows projects to be interconnected without an SCE requirement to install a visible, lockable open disconnect.

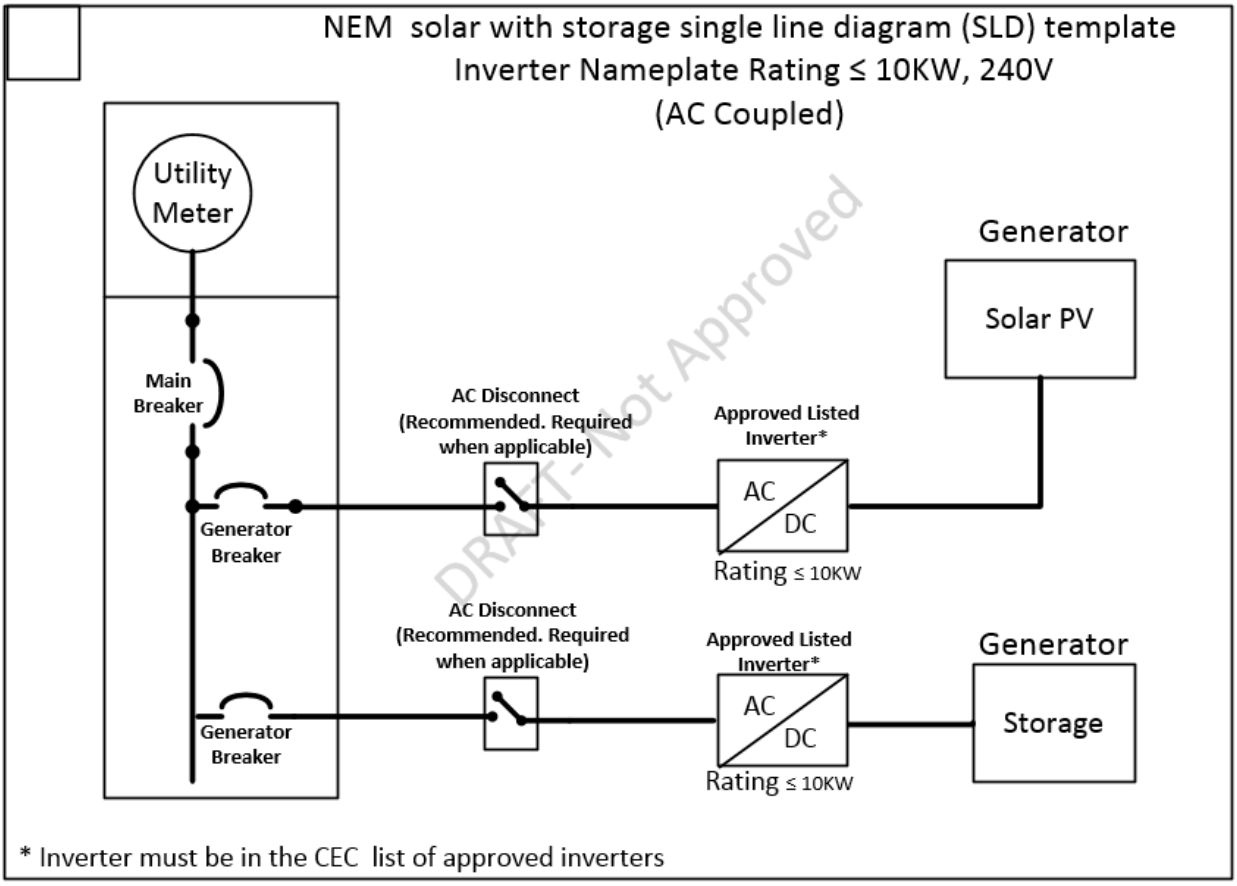


DRAFT Not Approved

- NEM Solar + Storage (240V) – Solar Inverter Nameplate ≤ 30kW with Storage Inverter Nameplate ≤ 10kW with no limit on the storage kWh capacity (AC or DC coupled).

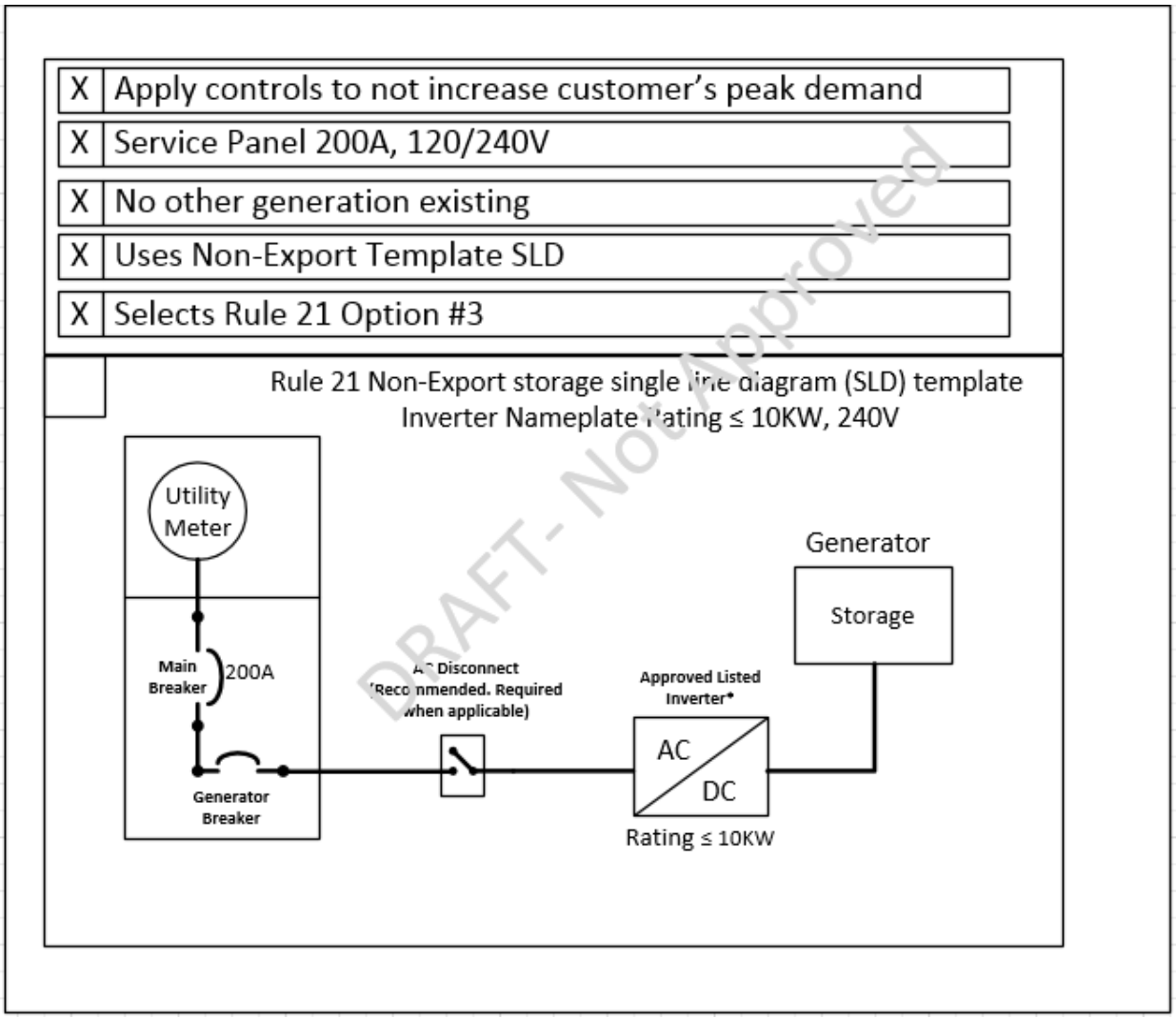
This will allow for projects to be interconnected without the need to install a visible lockable disconnect and without the need to install relaying, metering, or control systems and thus extensively expending the interconnection process.


NEM solar with storage single line diagram (SLD) template
Inverter Nameplate Rating ≤ 10KW, 240V
(DC Coupled)
Utility Meter
Main Breaker
Generator Breaker
AC Disconnect (Recommended. Required when applicable)
Approved Listed Inverter*
AC
DC
Rating ≤ 10KW
Generator
Solar PV
Storage
* Inverter must be in the CEC list of approved inverters
DRAFT - Not Approved


NEM solar with storage single line diagram (SLD) template
Inverter Nameplate Rating ≤ 10KW, 240V
(AC Coupled)
Utility Meter
Main Breaker
Generator Breaker
AC Disconnect (Recommended. Required when applicable)
Approved Listed Inverter*
AC
DC
Rating ≤ 10KW
Generator
Solar PV
Generator Breaker
AC Disconnect (Recommended. Required when applicable)
Approved Listed Inverter*
AC
DC
Rating ≤ 10KW
Generator
Storage
* Inverter must be in the CEC list of approved inverters
DRAFT - Not Approved

- Rule 21 non-export – Storage (240V) with inverter Nameplate ≤ 10kW inverter nameplate with no limit on the storage kWh capacity.

With this limit and the typical customer panel service rating of 120/240V-200A, residential customers will be able to utilize Rule 21 non-export Option #3 which does not require the installation of relays, control systems, or metering. In addition, SCE would not require the installation of a visible lockable disconnect.



In SCE's view, the size limitation would allow for the ability to expedite the interconnection process by significantly simplifying SCE's technical review of these types of applications. These limitations would cover over 95% of SCE's NEM, NEM+Storage, and Rule 21-Storage interconnection requests.

13. **Which implementation option would be most effective and efficient for developing template single line diagrams? Please justify the response.**

As noted in SCE's response to question #1, the combination of Options #1 and #2 would be the most effective. Using a combination of these two options will take advantage of working with stakeholders (Option #1) to first develop a set of template designs, and will also provide a transparent means to obtain input from stakeholders (Option #2). This process increases transparency and reduces the probability of stakeholder protests when IOUs submit Advice Letters to the Commission for approval.

14. **What is required in the template-based interconnection application process to ensure that developers are using IOU-approved equipment to avoid delays in the review process or after a project has been built?**

When customers select to use a template-based design, SCE operates under the expectation that the customer will abide by the terms of the contract and will construct, operate and maintain the generating facility according to the contract. While SCE reserves its right to perform field verification before or after the project has achieved permission to operate, SCE does not anticipate using field verification to ensure that customers are building their projects in accordance with the selected approved single line diagram.

Interconnection Proposal 2:

15. **Under what circumstances should field inspections be required? What system installations and settings need to be verified by field inspections?**

SCE interprets "field inspections" in this instance, to be those conducted by SCE personnel. Consistent with the Commission-approved Tariff Rule 21, SCE shall always have the right to perform inspections on equipment and systems in order to ensure safe grid interconnection.[4] This right, however, should not be exercised without reason. To this end, field inspections should be performed based on the following conditions:

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[4] Rule 21, Section D.5 states "Distribution Provider shall have the right to review the design of a Producer's Generating and Interconnection Facilities and to inspect a Producer's Generating and/or Interconnection Facilities prior to the commencement of Parallel Operation with Distribution Provider's Distribution or Transmission System. Distribution Provider may require a Producer to make modifications as necessary to comply with the requirements of this Rule. Distribution Provider's

a. When customer-provided information such as photos, plot plans, equipment documentation is not sufficient to verify compliance with requirements.

b. When specific traditional protection functions are required for interconnection.

c. When operational performance requirements are required for a safe interconnection.

d. At any time, when using typical engineering practices, deemed it necessary to ensure grid safety.

16. How should compliance be evaluated for Option 2?

SCE does not support Option #2 because of the reasons specified in SCE's response to Question #1.

17. Are there any circumstances that a field inspection should still be conducted by the IOUs even if it is duplicative of the local authority inspection?

SCE field inspections and local authority field inspections are not duplicative as these inspections do not verify the same requirements. The field inspection performed by the local authority inspector is focused on verification of the electrical system against the National Electrical Code (NEC) requirements (e.g., grounding, wiring, and protection) while SCE field inspection focuses on elements that ensure compliance with SCE interconnection requirements (e.g., adequate work clearances and open visible disconnection). Both field inspections are critical to ensuring that systems meet local code safety requirements as well as interconnection safety requirements.

18. How should IOUs coordinate the division of site inspection responsibilities with local jurisdictions? Should final agreements on these responsibilities be reached, how should they be formalized (e.g., signing of memoranda of understanding)?

SCE urges the Commission to not introduce the requirement to coordinate with the local jurisdiction inspector for several reasons. First, as outlined in SCE's response to question #1,

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review and authorization for Parallel Operation shall not be construed as confirming or endorsing Producer's design or as warranting the Generating Facilities' and/or Interconnection Facilities' safety, durability or reliability. Distribution Provider shall not, by reason of such review or lack of review, be responsible for the strength, adequacy, or capacity of such equipment." Rule 21, Section D.6 further states that "A Producer's Generating Facility and/or Interconnection Facilities shall be reasonably accessible to Distribution Provider personnel as necessary for Distribution Provider to perform its duties and exercise its rights under its tariffs approved by the Commission, and under any Generator Interconnection Agreement between Distribution Provider and Producer."

each inspection is very specific. The local authority field inspector mostly inspects aspects of compliance against the NEC code while the SCE field inspection covers aspects of operational compliance, as discussed in SCE's response to Question #17. Second, there are hundreds of local authority jurisdictions with each likely having its own requirement. In SCE's view, to reach consensus on division of responsibilities for hundreds of local authorities would be neither feasible nor necessary. Finally, having to determine consensus with hundreds of local authority field inspectors would delay the implementation of this proposal.

Interconnection Proposal 3:

19. **Should either Option 1 or Option 2 of Interconnection Proposal 3 be adopted, what criteria should be used to determine which key locations, facilities, and/or customers are prioritized in the interconnection process? When discussing, please refer to the following four sets of criteria previously published by the Commission for similar purposes. If there is preference for modification or an alternative to these four sets of criteria, please explain and justify the recommendation.**

Please refer to SCE's response to Question #1 regarding the project types most likely to benefit from either Option #1 or Option #2 as these options are not likely to provide timeline benefits to NEM and small non-exporting non-NEM projects. SCE is strongly opposed to the concepts of "queue-jumping" (Option #1) or "priority grouping" (Option #2) of interconnection requests. SCE's opposition stems from the long-established fundamental principles and standards of non-discrimination that are applied across wholesale and retail energy systems. Criteria that favors a certain group of interconnection requests over others is *per se* discriminatory to the non-favored group.

If priority projects are required to enter the queue ahead of non-priority projects that have already had the interconnection studies performed, the non-priority projects might have to undergo costly and time-consuming restudies. If these restudies result in unfavorable outcomes, meaning the non-priority projects had upgrades shifted to them (a very possible outcome), the discrimination against the non-priority projects would be highly visible. Creating a "priority" queue may result in unintended consequences (as noted in the Staff Proposal) for interconnection requests that are not selected to be in the "priority" group, including FERC-jurisdictional

projects. Equitable and efficient interconnection process requires maintaining the queuing protocols currently in place.

The Staff Proposal accurately describes some of these unintended consequences, including wasted study effort, delays, and cost impacts. The Staff Proposal also mentions the additional uncertainty that such a priority queue would create. Reducing uncertainty for interconnection customers is one of the primary benefits of the interconnection reforms made to Rule 21 in recent years. Allowing a "criteria-based priority" proposal to move forward would undo progress made in regard to reducing uncertainty.

SCE understands the Commission's goal of mitigating impacts from PSPS and other reliability events by creating an environment whereby DERs and microgrids are deployed to improve grid and/or customer resiliency. Time certainly is of the essence for DERs and/or microgrids to be placed in service prior to the 2020 wildfire season.

SCE believes that other techniques could be implemented rather than the concept of "queue jumping" or "priority grouping." Should the Commission still choose to adopt one of these options, SCE provides the following comments on the aforementioned sets of criteria.

a. "Assigned Commissioner's Scoping Memo and Ruling for Track 1" issued on December 20, 2019, in R.19-09-009 ("key sites and locations");

Basing a prioritization on specifics is better than doing so based on generalities. Thus, SCE would prefer the use of unambiguous types of customer sites or facilities; such as, medical baseline customers, police/fire/Emergency Medical Services (EMS) facilities, schools, water, senior care facilities, or Disadvantaged Communities (DACs) that are well established and verifiable and within Tier 2 or Tier 3 High Fire Risk Areas (HFRAs). SCE prefers these over ambiguous characteristics such as "critical facilities" or "hard to reach customers," which are difficult to define.

b. D.19-05-042, Appendix A at A4 and Appendix C at C2 (definition of "critical facilities");

Same answer as 19(a).

c. D.19-09-027, Conclusions of Law (COL) 5-7, Attachment A at A1 (definition of customers with "critical resiliency needs" for purposes of incentive eligibility under the Self-Generation Incentive Program); and

Same answer as 19(a).

d. Decision adopting Self-Generation Incentive Program revisions pursuant to SB 700 and other program changes (January 16, 2020); (mailed on December 11, 2019 in R.12-11-05, COL 17 modification to definition of customers with "critical resiliency needs").

In addition to the same concerns discussed in SCE's response to 19(a), SCE supported the December 11, 2019 Proposed Decision on SB 700 in R.12-11-005, but did raise concerns around its definitional change to Resiliency as meaning an Self Generation Incentive Program (SGIP) applicant that has experienced at least two PSPS events prior to application.[5] In Opening Comments on the PD, SCE explained that, "given the number of accounts that could potentially be impacted by a PSPS event, the tracking of two events per service account would become unwieldy. To decrease the administrative burden of tracking so many customer service accounts, SCE recommends that the language of the decision be updated to "whose ~~electricity~~ **electrical circuit** was shut off during two or more discrete PSPS events prior to the date of application for SGIP incentives." Decision 20-01-021 was effective January 16, 2020 without incorporating this recommendation by SCE.[6]

20. Should either Option 1 or Option 2 of Interconnection Proposal 3 be adopted, what implementation challenges would likely need to be overcome? For each identified challenge, please suggest one or more possible paths forward.

Echoing SCE's previous responses, SCE is strongly opposed to the concept of "queue-jumping" or "priority grouping" of interconnection requests. SCE is also concerned with any prioritization scheme that may contradict FERC rules and regulation and may, in the final analysis, not be implementable.

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[5] *See* SCE's Opening Comments on Commissioner Rechtschaffen's Proposed Decision, filed January 3, 2020, p. 3.

[6] *See* D. 20-01-021, Ordering Paragraph 21, at p. 102.

SCE expects that where the prioritization scheme could be more effective (but also lead to more inequity) would be for projects that are required to go through the Detailed Study process. Among the challenges for implementing such a scheme would include the following:

a) How to determine which projects fall into the priority categories and whether those priority categories could change over time.

b) How to communicate with non-priority projects that other projects are moving forward in the queue and their projects will be delayed.

c) Engineers/planners would have to maintain two queue lists. These lists are required to determine which projects trigger any required upgrades. SCE is concerned about multiple priority projects on the same circuit, how those would be evaluated versus one another, and whether a mini cluster study approach would be needed.

d) Placing projects in a priority queue does not change the "lumpy" aspect of system upgrades. There still may be priority customers that are charged for large upgrades that later-queued projects might benefit from (this aspect does not change if the prioritization/queuing scheme is changed).

e) The Commission would need to institute a requirement that a study cannot be performed in both the priority and non-priority queues. Once on the priority list and in receipt of a study, the project cannot be allowed to switch to the other queue list (if a "negative result", such as triggering a large upgrade, occurs).

f) Determining when the transition period begins, or where to draw the timeline to implement the new scheme.

g) IOUs would be required to essentially "reserve" latent/available capacity for high-priority projects. This comes into play if later-queued non-priority projects are seeking to interconnect to the same system or circuit as priority projects. Non-priority projects in the same system could more likely trigger upgrades (depending on amount of latent/available capacity). Determining what requirements should be placed on these reservations of latent capacity will be a significant challenge.

21. Should either Option 1 or Option 2 of Interconnection Proposal 3 be adopted, please estimate the number of new, resiliency-focused projects that would enter the queue. What impact would this influx have on projects that are queued but not prioritized according to the criteria established in this proceeding? State the estimated impact in terms of delays (X days or X months) per project.

Creating a prioritization construct would likely not, in and of itself, lead to any volume increase or decrease. The prioritization would only apply to certain qualifying projects and address the time spent in the process. Increases or decreases in the volume of interconnection

requests are largely tied to procurement solicitations or new (or expanded) customer programs implemented by IOUs and other Load Serving Entities (LSEs). An example of this is the recent increase in the SGIP Equity Resiliency budget outlined in D.19-09-027.

SCE has the infrastructure in place to handle a large influx of NEM and NEM-paired storage interconnection requests, which are adeptly managed through the Powerclerk Interconnect system. However, if SCE receives a large influx of non-NEM battery storage projects via its GIPT or manual systems, processing such an influx would be more taxing to SCE's systems and workforce. SCE routinely receives thousands of NEM projects per month and these projects have been adequately streamlined into an "assembly line" process that can handle this level of volume. Non-NEM projects have much more variety and complexity to them, and the complexity requires substantially more interaction with SCE resources to intake, manage, technically evaluate, negotiate, design/engineer, construct, and so forth. Where the NEM interconnection process resembles an assembly line, the non-NEM interconnection processes take a custom approach. Nevertheless, SCE would seek to meet its commitments and Rule 21 timelines as required by the tariff, taking an "all hands on deck" approach to the influx, and being very communicative to customers and the Commission if, despite its best efforts, timelines will be negatively impacted.

Under such a scenario (an influx of thousands of non-NEM battery storage requests), any prioritization construct would add further complexity to already-strained resources and processes. It is entirely possible that non-prioritized projects would be on the receiving end of negative impacts such as restudies and delays to finalize studies for the priority projects, which could cause delays spanning up to months at a time in certain instances.

22. **Should Option 3 be adopted, how should the IOUs be required to demonstrate compliance? For example, should each utility be required to demonstrate that they are using their full budget, as allocated in their General Rate Case, for staffing? Should the IOUs be required to open memo accounts in order to track interconnection staffing and related costs?**

SCE agrees that some aspects of the interconnection process could be improved with increased staff and investment in IT (Option #3). SCE has already been investing heavily in IT as it has been developing its online interconnection portal, GIPT. Increases in staffing can be supported with sufficient lead time, but IT and staffing alone are not the only root cause of delays beyond tariff timelines. IOUs should be allowed to take any reasonable measures to manage their workflow and business as they see best, including allocating resources to prioritize interconnections in PSPS impacted areas.

If any of the proposals are implemented and result in SCE incurring incremental costs, then SCE should be granted cost recovery for them. Accordingly, the Commission should authorize the establishment of a memorandum account to track incremental costs and address cost recovery when it is appropriate to do so.

23. **The following questions on Interconnection Proposal 3, Option 3 are directed to the IOUs.**

    a. **On average, how much time is required, from date of job posting to start date, to hire new staff for the teams that evaluate and process interconnection applications?**

On average, it takes three to six months (though sometimes much longer) for SCE to post a job, screen and select candidates, conduct interviews, select new hires, and onboard new hires in the categories below (intake analysts, interconnection advisors, contract managers). Training these resources is described in part c) below.

    b. **Briefly describe the skills and knowledge needed to safely and efficiently process and evaluate interconnection applications. If various roles require different skillsets, please specify (1) the skills required for each role, and (2) the typical duties performed by staff in that role**.

SCE provides information concerning four main roles: intake analyst, interconnection advisor, distribution engineer, and contract manager.

Intake analysts:

Responsibilities and Skills:

- Managing the flow of interconnection requests through SCE's intake portals and manual processes, working with interconnection customers to solve deficiencies in interconnection requests of all types, getting the interconnection request to a "deemed complete" state.

- Taking charge of adding the interconnection request to internal databases and processing the receipt of checks and wire transfers for application fees and study deposits through SCE accounting and in compliance with SOX and other requirements.

- Answering queries in the interconnection email Q&A inbox, the Q&A phone number, and answers data requests.

- Key skills include: computer skills, particularly Microsoft Office Suite, including Access; attention to detail; managing electronic data and occasional paper flows, knowledge of interconnection procedures and specific interconnection request requirements such as generation/storage facility technical data, site control/exclusivity, single-line diagrams, SOX requirements, etc.

- Typically requires a Bachelor of Science (B.S.) degree and at least two years of experience.

Interconnection advisors:

Responsibilities and Skills:

- Managing the interconnection process from receipt of interconnection requests through execution of the interconnection agreements (and related agreements) and handoff to Contract Management.

- Working closely with intake analysts and interconnection customers to resolve deficiencies in the interconnection request.

- Working closely with distribution engineers on technical evaluations and studies, including Initial Review, Supplemental Review (if required), and Detailed Study Process (if required).

- SCE interconnection advisors are expected to manage a portfolio of interconnection requests at the same time, in all of the tariff types (Rule 21, Wholesale Distribution Access Tariff (WDAT) and California Independent System Operator (CAISO)).

    - Senior interconnection advisors also work on policy and regulatory matters, process improvement, and other special projects.

- Key skills include: project management skills, computer skills, intimate knowledge of interconnection procedures, contract management skills, customer service skills, time management skills.

- Technical knowledge of the distribution and transmission system is required.

- Typically requires B.S. degree, prefers Master's in Business Administration (MBA)/Juris Doctor (JD) and at least five years of experience for advisors and seven years of experience for senior advisors.

Distribution engineers:

Responsibilities and Skills:

- Review the interconnection application to verify that the application contains all the technical information that would be needed to perform the technical evaluations.

- Evaluating, once application has been deemed complete, the project accounting for the type of project (NEM, Storage, Non-export) and the options which have been selected (such as non-export option 1, 2…6, export, etc.).

- In the evaluation, the distribution engineer would evaluate the project against the applicable Rule 21 fast track screens (Rule 21 section G) and determine if detailed studies are necessary.

- When required, the engineer would perform the necessary detailed studies to determine if and what system upgrades and mitigations are required in order to interconnect the project to the grid.

- Further, the engineer evaluates the equipment and design of the project to ensure that the project meets SCE's requirements for interconnection, isolation, and protection.

- When necessary, the engineer will perform a field inspection to verify that the systems and equipment meet the requirement of the operation option selected by the customer, as well as to verify important interconnection system parameters.

- Key skills include: The engineering skills that are necessary to evaluate that generation projects meet technical, safety and performance requirements include but are not limited to the following;

    - Ability to perform technical calculations to evaluate the applicable Rule 21 technical screens.

    - Ability to utilize SCE power flow tools to perform an engineering evaluation.

    - Ability to determine adequate mitigation requirements in accordance to SCE engineering standards.

- Ability to apply and interpret technical standards to evaluate generation project specifications.
- Ability to use engineering knowledge to determine and mitigate atypical system configuration.

- Typically requires: Minimum requirements are a B.S. in Engineering, with Power option as preferred. Entry level engineers are typical within SCE, with hands-on training provided by experienced SCE engineers using SCE classroom and field training.

Contract managers:

Responsibilities and Skills:

- After handoff of executed contracts from interconnection advisors, manages the contract milestones through detailed design/engineering, construction, in-service/permission to operate, and final accounting/true-up.
- Work closely with interconnection advisors, interconnection customers, engineering, construction personnel, and accounting system.
- Maintain contracts database. Contract managers are expected to be familiar with all of the tariff types (R21, WDAT and CAISO).
- Key skills include: project management skills, computer skills, knowledge of interconnection procedures and agreements, negotiation skills to work on amendments of agreements, customer service skills, and time management skills.
- Technical knowledge of the distribution and transmission system is required.
- Typically requires a B.S. degree and at least five years of experience.

c. On average, how long does it take, from employee start date, for a new employee to gain the skills described in response to question 5(b)?

For intake analysts, interconnection advisors, and contract managers, basic skills can be gained in three to four weeks of intensive training, plus on-the-job experience and mentoring for at least six months to achieve adequate productivity. Full productivity, however, takes approximately one year in the position, and longer for more complex work. These are mostly "learn on the job" roles. Mentoring is provided by the employee's manager and from others on the team with experience.

In regard to engineering skills, these skills grow over time and in coordination and consultation with more experienced engineers via on-the-job training. To support engineering

knowledge growth, SCE distribution and planning engineers undergo a rigorous engineering program that is coordinated with day-to-day engineering activities. This training program provides engineers the knowledge and skills that are foundational to their engineering growth and career development.

What is relevant in this question is the complexity of generation projects that are to be evaluated. For very complex projects which are generally in the multi-MW size, it is necessary to have engineers with many years of experience to evaluate or support the evaluation of such projects. However, for the types of projects as proposed by the Commission in Interconnection Proposal #1 and Proposal #2 (Solar NEM, Solar + Storage, and Rule 21 non-export storage), and with modifications by SCE, the level of engineering knowledge needed to evaluate these types of projects is lower, such that six to 12 months would be adequate for engineers to achieve the necessary knowledge to evaluate these types of projects. However, if SCE's modifications are not adopted, then engineers will need to acquire a much higher level of engineering knowledge, which is typically obtained with three to six years of engineering experience.

It is for this reason that SCE urges the Commission to adopt SCE's modifications, as they will allow for an expedited technical review without the need to utilize SCE's most experienced engineers (except for consultation purposes).

d. Describe how staff knowledge and experience corresponds to complexity of interconnection applications that are assigned (e.g., does junior/less-experience staff get assigned to fast track applications? Do all staff handle all types of requests?). What are typical timelines for gaining the knowledge required to process more advanced cases?

For intake analysts, interconnection advisors, and contract managers, these staff work on all types of requests, but there is some specialization for certain types of requests beyond the typical Rule 21 project. Specialization can include by tariff, region, or customer concentration, and can also be for more unique contracts such as Qualified Facilities (QF) conversions, Affected Systems, and WDAT Load. The average time in position for SCE's intake analysts is currently two years. The average time in position for interconnection advisors is currently five

years. The average time in position for senior advisors is greater than 10 years. As mentioned in the previous response, it takes approximately one year in the position to achieve full productivity for intake analysts, interconnection advisors, and contract managers, with more time in the position needed for more complex work.

SCE currently employs a dedicated team of engineers responsible for evaluating the types of projects being proposed by the Commission (Solar NEM, Solar + Storage, and Rule 21 non-export storage), which are limited based on SCE's size limitation. These engineers have the equivalent level of engineering knowledge and thus handle all of these project types. Where more complex projects (such as non-NEM exporting projects, or projects using controls/relaying schemes) need to be evaluated, those projects are typically handled or supervised by engineers with three to six years of experience or more).

e. If other proposed Interconnection Proposals were adopted (e.g., template-based applications), would it be possible to reduce the time needed to train new staff to safely and efficiently process interconnection applications? Please identify the proposals and estimate the reductions to training time that they would allow.

Standardization would favorably impact the ability to process more requests with the same resources. As stated previously, SCE supports efforts to standardize single-line diagrams and other "template-style" approaches to high volumes of requests. SCE's GIPT was designed for bulk uploads of requests. One way to effectively handle an influx of a large volume of non-NEM interconnection requests would be to standardize and turn SCE's current custom approach into more of an "assembly line."

The time estimated to train new resources mentioned in question 23(d), which is three to four weeks, already includes in an assumption that the types of interconnection requests that these new-hires would be working on would be as standardized as possible. Certainly, the more standardized the applications, the better for a group of inexperienced resources to process, but there would be no distinct saving of training time above what is already being estimated at three to four weeks. For engineering resources, as indicated in question 23(c), the utilization of templates does significantly reduce the level of training needed in comparison to training for all

types of complex generation projects. Thus, while obtaining the adequate on-job training for engineers to gain the knowledge to independently support complex generation projects may take several years, training engineers to evaluate these types of template-based projects would be six to12 months depending on the new-hire's previous experience.

3.2. Modifying Existing Tariffs to Maximize Resiliency Benefits

SCE supports Staff's Guiding Principles for Tariff Proposals[7] and is committed to work with the Commission and all stakeholders to: (1) reduce tariff barriers for distributed energy resource use cases that support resilience; (2) maintain the integrity of existing tariffs that are intended to reward production of on-site renewable energy; (3) maintain the safety and reliability of the electric grid; (4) ensure just and reasonable rates for participating and non-participating customers; and (5) provide flexibility to customers to improve their own resiliency. Below, SCE provides its responses to the questions posed in the Track 1 Ruling to the best of its ability at this time.

3.2.1. Storage Charging Proposals

1. **Please indicate support of or opposition to the adoption of either proposal and justify the position. Please also indicate which proposal warrants most support and justify the response.**

SCE agrees with Staff and does not support Proposal 1: to allow both export and import during a pre-PSPS window. While Proposal 1, to allow both export and import during the pre-PSPS window, may appear to be desirable, it can compromise the safety and reliability of the grid due to export power impacts, such as voltage, thermal, or system protection issues, which were not studied during the engineering technical evaluation. Thus, SCE does not support Proposal 1 to allow both export and import during a pre-PSPS window.

In general, SCE agrees with Staff and supports the concept of Proposal 2: to allow the temporary transition to non-export mode during a pre-PSPS window, though SCE notes significant concerns with implementing the proposal in 2020. SCE agrees with the Staff's

[7] *See* Staff Proposal, Section 3.2.3 at p. 15.

Proposal 2 for the same reasons outlined in the Staff Proposal. Specifically, Proposal 2 will best maintain NEM integrity because NEM-Paired Storage Systems will be allowed to charge from the grid in advance of PSPS events, but will not be allowed to export to the grid. Additionally, certain NEM-Paired Storage Systems are already allowed to charge from the grid as long as the storage systems do not export to the grid[8]. However, SCE will need to evaluate, investigate and mitigate any safety concerns, such as potential circuit equipment overload which may occur if a large number of storage projects charge from the grid at the same time prior to the PSPS event. Currently, SCE relies on the "no charging from the grid" requirement (associated with most NEM-Paired Storage Systems) to ensure SCE's grid does not experience any safety issues that may be caused by storage charging. This is because when the storage system does not charge from the grid, grid equipment, such as transformers and service drops, would not carry the charging load and thus should not experience any overload directly linked to storage charging. However, if the "no charging from the grid" requirement is lifted, then SCE's electrical equipment, such as transformers and service drops, may see increase in demand for which these systems may or may not be capable of supporting, leading to possible safety concerns such as equipment overload conditions. The impacts of this type of modification have not been evaluated as part of the interconnection process.

Before the adoption of either proposal, there are significant challenges that must be addressed. The first challenge that must be addressed is the updating of the Underwriters Laboratory (UL) Power Control Systems (PCS) as this standard was specifically developed for the purpose of maintaining NEM integrity. To this end, the UL PCS standard has very rigid requirements for allowing changes to the Power Control Systems. In order to implement either proposal, UL and stakeholders would need to update the UL PCS standard to account for this new use case. However, updating the UL Power Control Systems to allow customers to change

[8] Schedule NEM-ST defines NEM-Paired Storage Systems as a Generating Facility that includes a Renewable Generator and an Integrated or Directly connected energy storage devices. Directly connected energy storage devices are not required to be charged exclusively from the Renewable Generator and may also be charged from the grid.

operational modes will compromise the ability to maintain NEM integrity during non-PSPS periods if changing modes of operation is not restricted as currently required in the UL PCS standard. Further, the utilization of Power Control Systems is in its infancy and has not been sufficiently used to make a determination on how it can be applied to either proposal. At this time, SCE is unsure of the timeframe needed to determine how the utilization of UL Power Control Systems can be applied to either proposal. Therefore, while supportive of this proposal, SCE notes that deployment of this proposal may be challenging in 2020 due to required changes to Power Control Systems that are not in SCE's control (such as updating the UL PCS standard, manufacturing of controls, and certification).

To help mitigate this risk, SCE proposes to set certain grid charging restrictions including when energy storage can be charged from the grid prior to a PSPS event. Such conditions may include instructing customers in the identified PSPS areas to begin charging their energy storage in advance of PSPS forecasted events (e.g. two days before PSPS events or upon SCE notifying customers of possible PSPS events). These restrictions include a) charging from host customer renewable resources (e.g., solar) when available, b) when host renewable resources are not available, then customers should begin charging outside of the customer's peak hours (such as at night), c) limiting charge level of each individual project (such as 25% charging) to allow a larger number of customers to charge and share grid capabilities The two day-ahead instruction timing coincides with the time for SCE to notify customers of possible PSPS events.

In addition, SCE proposes that customers who select to operate under this option restrict their energy storage charging such that the storage charging will not increase the host customers' peak demand when charging the energy storage systems. This would require customers to charge from the grid during their non-peak usage time (such as night, when loading is low). However, it should be noted that the current charging control standards (UL PCS) do not account for this requirement and therefore additional changes to the standards need to be investigated.

The current protocols to communicate these changes in operating modes and additional restrictions have not been fully vetted (as part of the UL PCS standards development) or tested in the real world to ensure that the grid can operate safely and reliably.

2. **Are changes to any rate schedules or electric rules needed to implement any of the proposals? If so, which ones, and how do they need to be changed? Please propose specific language.**

Before considering any modifications to the NEM tariffs (or any other tariffs associated with energy storage) to implement Proposal 2, the challenges associated with doing so, which are discussed above and will be discussed in more detail below (see responses to questions 6-8), need to be addressed and resolved. At a minimum, the tariffs would need to include (1) clarification that the adopted proposal will be implemented as a time-limited pilot and will apply only to customers located in the identified PSPS areas, (2) grid charging restrictions, and (3) emphasis on maintaining the integrity of NEM and customer penalties if NEM rules are violated. It is also possible, depending on the proposed tariff modifications, that parties will need to assure that such modifications do not violate any applicable FERC rules and regulations. SCE is unable within the timeframe allotted for this filing to propose specific tariff language. Should the Commission issue a decision on either of Staff's Proposals, SCE commits to offer proposed tariff modifications pursuant to the Commission's General Order 96-B and submit an Advice Letter with proposed modifications to the affected tariffs.

3. **Is CPUC action required in order to implement either proposal? If so, what action would be most appropriate?**

The conditions and requirements that allowed energy storage to participate in NEM were adopted in D.14-05-033, Decision Regarding Net Energy Metering Interconnection Eligibility for Storage Devices Paired with Net Energy Metering Generation Facilities.[9] Accordingly, the Commission will need to issue a decision to further modify certain NEM-paired storage

[9] Subsequent Commission decisions modified certain conditions and requirements including D.16-04-020, D.18-02-008, and D.19-01-030.

requirements adopted in its prior decisions. Furthermore, the Commission would need to direct SCE to modify its NEM tariffs and other affected tariffs in order to implement Proposal 2.

4. **If CPUC action is required, what standards are appropriate for CPUC to use to determine whether the adoption of either proposal is justified?**

In adopting Proposal 2, the Commission needs to consider the customer impact, cost and benefit of implementing the proposal, and technical feasibility of the proposal, including addressing and resolving the challenges identified in SCE's response. SCE urges the Commission to ensure that NEM integrity is maintained.

5. **It has been noted that either proposal would only impact large NEM-paired storage systems (>10 kW) that have opted to meet the NEM metering requirements by installing equipment that prevents grid charging of the storage device. Given this limitation, please describe the value of this proposal's adoption.**

NEM-paired storage projects >10 kW, as indicated by the question, require that a metering, relaying, or UL power control system be used to ensure NEM integrity. Among SCE's 2019 data for all NEM-Paired storage projects, this type of project (NEM-paired storage >10kW) represented only 1.5% of the NEM-paired storage project population. Therefore, SCE only sees incremental value in focusing on NEM-paired storage >10 kW projects. As previously indicated, SCE proposed that the immediate need is to focus on the NEM-paired storage ≤10 kW (and other types as indicated by SCE) which captures over 98% of the project population.

6. **Parties have stated that, under the existing Underwriters Laboratory Power Control System Certification Requirement Decision, power controls system settings can be changed by the manufacturer or system developer/installer and that this change can be accomplished, in many cases, remotely. Please describe the process by which these settings would be adjusted ahead of a PSPS event and reset following the conclusion of the event. Please include answers to each of the following sub-questions in response.**

    a. **Which party or parties have the capability to adjust power control system settings?**

The Power selection modes have several options as described in section 204.3 of the UL Power Control System Standard Certification Requirement Decision. SCE suggests that due to the complexity of the various options and given the infancy of this standard (no project has used

this standard successfully), it may be more appropriate to consult with UL personnel to determine what implementation procedures are available for this option.

b. How should that party be informed of upcoming PSPS events?

SCE will leverage its current PSPS notification process to inform parties of upcoming PSPS events. When customers are on a circuit that is in scope for potential de-energization, SCE notifies these customers (in their preferred method of contact – e-mail, text, phone call) 48 hours in advance of the period of concern and again 24 hours before the period, whenever possible. Because SCE's PSPS decision making is based on circuit-by-circuit forecasts, and not large geographic areas, SCE believes it is more efficient to notify customers and let them contact their aggregator, when necessary. Customers must also understand that sometimes PSPS events occur on short notice (< 4 hours' notice) or without notice if unforeseen weather conditions occur. In these situations, customers would not have adequate time to charge their battery prior to the PSPS event.

c. What geographical information about the upcoming PSPS event would be necessary for this party to determine which systems were eligible for adjusted power control system settings?

As stated above, SCE does not believe it is feasible to communicate high-level information to aggregators because not all circuits or customers in a given area will be in scope for a PSPS event. SCE is open to proposals from aggregators on how to accomplish this communication but is currently unaware of such a mechanism.

d. Should customers be given the opportunity to opt in or out of settings changes? If so, how should this process be handled?

Yes. Customers should inform the entity responsible for implementing changes that they would like to opt out, if so.

e. Following the conclusion of the PSPS event, how quickly could power control system settings be returned to their defaults? How quickly should the settings be required to return to their defaults?

Power control settings could be returned to their defaults within 24 hours, unless new PSPS events are projected to return within the seven day weather forecast.

f. Following the conclusion of the PSPS event, would it be necessary for the utility to verify that the power control system settings had been reset to their default? Please justify and describe how this verification could be accomplished.

If verification is deemed necessary, SCE should be able to exercise its access and inspection rights pursuant to Rule 21 to verify that the power control system setting had been reset to its default.[10] Current communication protocols do not allow SCE to directly verify the status of a customer's power control system. Currently, the vendor and customer have access to this information and SCE's validation process would need to be implemented on a retroactive basis.

g. If settings were found, at a later date, to have been allowed to remain in a configuration that allowed systems to violate NEM integrity, which party should be held responsible?

Based on the UL power control standard (as currently in place), violating NEM integrity may only be done intentionally. That is, even if the NEM-paired storage is changed to "charge from the grid mode," the UL power control systems will still maintain NEM integrity as it will not allow the storage systems to "discharge to the grid." Therefore, SCE does not see this as an issue unless the customer or entity controlling the storage is constantly altering modes to violate NEM integrity (such as changing modes to charge from grid at night and changing modes to discharge to grid in the day). If a party is found to have violated NEM integrity, that entity in the contractual agreement with SCE should be held responsible. Furthermore, if the customer or entity controlling the energy storage configuration violates NEM integrity, it may compromise NEM-related billing.

[10] *See* fn. 2 above re: Rule 21, Sections D.5 and D.6.

7. **If either proposal were adopted, should NEM metering requirements be adjusted such that power control system settings may be adjusted immediately after the announcement of an upcoming PSPS event is made? Alternately, should power control system setting adjustments be allowed only a specific number of hours ahead of the planned PSPS event? If one supports the latter option, what number of hours is appropriate and why?**

Given the expedited timeframe of these comments, SCE has not had an opportunity to develop a fully vetted proposal. However, SCE would prefer that power control system settings be adjusted immediately after announcement of an upcoming PSPS event. SCE would prefer that customers have a broader window to charge their energy storage systems, which allows for more varied charging and reduces the likelihood of overloading SCE's system. Ideally, this charging time would be two days ahead of an expected PSPS event.

To the extent programs like SGIP require cycling of energy storage systems, SCE would coordinate to ensure this cycling requirement be waived during PSPS events.

8. **If either proposal were adopted, what risk, if any, could the increased load caused by the synchronized charging of multiple energy storage systems pose to the safety and reliability of the grid? For any risks identified, please address the following additional questions:**

Synchronized charging of multiple energy storage systems does pose a safety and reliability risk to the electric grid. This risk may be reduced by requiring that storage charging occurs in the following methods:

- When a renewable resource is available, it should be used as priority to charge the storage.
- When charging from the grid, the energy storage charging should not increase host customer's existing peak demand. For example, if the peak demand was 5 kW prior to the installation of the energy storage, then the charging of the energy storage should not increase the customer's peak demand beyond the original 5 kW, thus requiring the storage to charge during the customer's off-peak periods.
- Energy charging should be restricted to a given limit (such as 25% of maximum charging value). This would allow for constant charging of a large population of storage projects with lower risk of grid overloads.
- Limit the amount of energy storage projects on distribution circuits assuming maximum synchronized charging and circuit peak conditions.

To mitigate this impact, SCE proposes to set a limit on when customers can charge their energy storage (e.g., customers in the PSPS area can begin charging their energy storage two days before a potential PSPS event, during off-peak periods).

a. Has this risk been sufficiently assessed as part of the interconnection study process? Why or why not?

No, the interconnection study only addresses the discharging of the storage and does not address the charging portion. This is because in the interconnection study, customers have agreed that when charging from the grid, storage charging will not increase the host customer's peak demand. When operated in this manner, SCE's service transformers and service drops will not experience increased peak demand and thus are not evaluated in the study process. Further synchronized charging has not been evaluated as part of the interconnection study.

b. What options should be considered in order to mitigate this risk?

Some options to reduce the risk of synchronized charging overloading the grid include those listed above in response to Question #8.

c. If left unmitigated, what is the worst-case scenario that could result?

The worst-case scenario would involve the distribution circuits and substation being loaded beyond their ratings, which can lead to significant safety and reliability issues. As an example, circuit equipment and conductor which is rated to support a given level of loading can be loaded in excess of its ratings, causing conductor and equipment overload and potentially excessive area voltage depression below acceptable PUC Rule 2 limits, which can lead to equipment failure and safety issues.

9. Adjustments to NEM metering requirements could interact with other standards, tariffs, and incentive programs. Please identify any such interactions and note any penalties customers might face as a result of grid charging.

SCE is still evaluating its tariffs to determine how a change to NEM metering requirements could affect its tariffs and incentive programs. SCE respectfully reserves the right to provide further comment on this question after reviewing Comments from intervenors.

10. **What other implementation issues will need to be addressed if either proposal is adopted? For each issue identified, please describe a possible path forward.**

The following implementation process issues should be discussed and addressed prior to the implementation of Proposal #2 (allowing temporary transition to non-export during PSPS).

As indicated in SCE's response to Question #1, the standard for power control systems is not capable of working in the way outlined in the Staff's Proposal. Thus, the first issue that would have to be addressed is to update the UL power control system standard such that it can be used to support the proposed use case while still maintaining its original intent to maintain NEM integrity.

SCE notes that UL power control systems have not been used for this purpose and thus industry would have to manufacture control equipment with these updated standard requirements. Since SCE has not seen much activity on the usage of these control systems, this type of system may not be readily available for utilization.

See also SCE's responses to Questions 6 through 8 above for issues that need to be addressed if either proposal is adopted.

11. **Should either proposal be expanded to all pre-planned outage events (including non-PSPS events) in order to maximize resiliency impacts?**

Neither proposal should be expanded beyond PSPS to include all pre-planned outage events (*e.g.*, scheduled maintenance). To do so would extend beyond the scope of Track 1 of this proceeding. Any such expansion should be fully addressed in the context of the appropriate proceeding or working group to ensure the development of consistent and cohesive policy. For purposes of this pilot, SCE does not believe that expanding Proposal 2 to include applications outside of PSPS events is appropriate. SCE is willing to revisit this in the future.

12. **Should either proposal be adjusted to mandate that grid charging only be allowed during hours when grid power is largely produced by renewable generation? Please discuss.**

No. NEM and SGIP customers already have the obligation to be on Time-Of-Use (TOU) rates that require their operation of energy storage systems in a manner consistent with

California's energy and environmental objectives. Currently, these rates are the only "signals" the customers receive to operate in accordance with the intent of the programs they participate in (both NEM and SGIP).

In addition, although communication standards are rapidly evolving and will allow installers and utilities to provide grid resiliency and environmental signals to optimize the operation of those systems, at this time such standards are still in infancy and wide adoption of such communications are not in place yet.

13. **Should this proposal be modified in any other way before being adopted and/or implemented? If so, please describe and justify any changes.**

Yes, the staff proposal should be modified as follows:

- Investigate the capabilities of the UL power control systems. As indicated in the response to Question #1, SCE's understanding of the UL power control system standard is that it is not capable of performing as proposed by Staff Proposal #2. Thus, a required change to the proposal would be to first investigate the capabilities of the UL power control system standard and update the standard as required to meet the needs of the resiliency use case while still maintaining the NEM integrity use case (original intent) during non-PSPS time periods.

- Institute SCE's comments on Question #8.b to mitigate the safety impacts that may be caused by synchronized charging.

14. **Are there other options for each proposal that have not been listed? If so, please elaborate on the option(s) that should be considered. Include as much detail as possible.**

No, Staff has identified the correct issues and needed mitigations for the utilization of the UL power control system. SCE has no further comments.

3.2.2. Storage Capacity Limit Proposals

1. **Please indicate support of or opposition to the adoption of either proposal, and discuss the position taken.**

SCE supports Staff's Proposal 1 to modify the NEM tariff to remove storage sizing limits and to require islanding ability for energy storage systems larger than 10 kW to the extent the proposal can be implemented without presenting any safety, operational, or technical constraints

(i.e. overloading circuits during pre-PSPS window). SCE also supports Proposal 1 to the extent that the special carve-out specific to NEM-paired storage is limited for purposes of Track 1 of this proceeding to customers located in key locations subject to PSPS.

For the same reasons provided by Staff, SCE does not support Staff's Proposal 2.[11]

2. **Are changes to any rate schedules or electric rules needed to implement any of the proposals? If so, which ones, and how do they need to be changed? Please propose specific language.**

Before considering any modifications to the NEM tariffs (or any other tariffs associated with energy storage) to implement Proposal 1, any safety, operational, or technical constraints need to be addressed and resolved first. At a minimum, the tariffs would need to include (1) clarification that the adopted proposal will be implemented only as a time-limited pilot (i.e. 24 months) and will apply to customers located in the identified PSPS areas, and (2) emphasis on maintaining the integrity of NEM and customer penalties if NEM rules are violated. At this time, SCE prefers not to propose any specific tariff language but once the Commission issues a decision on the Staff Proposal, SCE will put forward its proposed tariff modifications pursuant to the Commission's General Order 96-B and submit a compliance Advice Letter with proposed modifications to the affected tariffs.

3. **Is CPUC action required in order to implement any of the proposals? If so, what action would be most appropriate?**

The conditions and requirements that allowed energy storage to participate in NEM were adopted in D.14-05-033, *Decision Regarding Net Energy Metering Interconnection Eligibility for Storage Devices Paired with Net Energy Metering Generation Facilities*. Accordingly, the Commission will need to issue a decision to override and further modify certain NEM-paired

[11] *See* Staff Proposal at p. 19 where it states: "…since the augmentation of these existing rules is intended to facilitate the provision of resiliency benefits to customers in a grid outage event, staff finds it appears reasonable to require the utilities to require the interconnecting customer to demonstrate that their system is designed to operate independently of the grid in an outage event, so that the intended resiliency benefits of the addition of the storage may be realized."

storage requirements adopted in prior its decisions. Furthermore, the Commission would need to direct SCE to modify its NEM tariffs and other affected tariffs in order to implement Proposal 1.

4. **If CPUC action is required, what standards are appropriate for CPUC to use to determine whether the adoption of either proposal is justified?**

In adopting Proposal 1, the Commission needs to consider the customer impact, cost and benefit of implementing the proposal, and technical feasibility of the proposal, including addressing and resolving the challenges identified in SCE's response. More importantly, the Commission needs to ensure that the NEM integrity is maintained.

5. **The Self-Generation Incentive Program (SGIP) recently established a requirement that in order to receive an incentive intended for storage to provide resiliency benefits, the SGIP applicant must demonstrate that the system has been inspected and approved as able to operate independently from the grid in an outage by a local authority having jurisdiction (AHJ).[12] Specifically, the applicant must demonstrate that (1) an AHJ has approved plans showing that the system can operate independently from the grid, and (2) an AHJ has inspected the system after installation and has authorized operation. We seek comment on whether this same requirement should be required by the utility interconnection departments as part of the interconnection application for these systems, or whether there are other options for allowing the interconnection department to verify the that the system has been designed to operate independently from the grid in the event of a grid outage.**

SCE's responsibility is to ensure that when connected to the grid, the generating facility does not cause any safety or reliability issues to the grid or customers connected to the grid. SCE views that it is responsible for the safety of the grid, while the responsibility to ensure that the generating facility is capable of operating independently from the grid should fall on other parties. An option would be for an independent third-party California licensed engineer to verify the operation and submit a report of compliance to the utility or to the Commission.

6. **Does either proposal have any negative impacts on NEM or NEM-related tariffs with similar sizing restrictions?**

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[12] D.19-09-027 at 43, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M313/K975/313975481.PDF.

Negative impacts, if any, are minimized if the special carve-out specific to NEM-paired storage is limited to those customers who are located in the key locations subject to PSPS.

7. **Removing the sizing restriction will allow customers to partake in the short term (20 year) financial benefits of NEM, while allowing for storage larger than their highest consumption day of the year. In the long-run, will this encourage grid defections in a way which shifts grid costs to low-income customers?**

Possibly. However, this can be minimized if the special carve-out specific to NEM-paired storage is limited to customers located in key locations subject to PSPS. This would also be limited by adhering to NEM grid discharge prohibitions.

8. **Should either proposal be modified before being adopted and/or implemented? If so, please describe and justify any changes.**

SCE is still evaluating the impact of the Staff's proposals. SCE respectfully reserves the right to provide further comment on this question after completing its evaluation and reviewing Comments from intervenors.

9. **Are there other options for each proposal that have not been listed? If so, please elaborate on the option(s) that should be considered. Include as much detail as possible.**

No, Staff has identified the appropriate issues and developed proposals to mitigate them. SCE has no further comments at this time.

3.3. Ensuring Local Government Access to Distribution Infrastructure Data to Facilitate Development of Resiliency Projects

SCE supports Staff's Guiding Principles for Sharing Information with Local Government Agencies and is committed to work with the Commission and all stakeholders to: (1) foster collaborative problem solving by utilities, local agencies and state government; (2) facilitate the ability of local government agencies to protect the lives and health of their communities; (3) support equitable access to utility information across local government agencies; (4) and build upon existing emergency planning exercises already conducted pursuant to General Order 166.[13]

[13] *See* Staff Proposal, Section 3.3.2, at p. 22.

Below, SCE provides its responses to the questions posed in the Track 1 Ruling to the best of its ability at this time.

1. **Please indicate support of or opposition to the adoption of each proposal and justify the rationale. For the proposals that include implementation options, please indicate support of or opposition to each option and explain why.**

Proposal 1: Outreach and Communication

SCE agrees with the spirit of Proposal 1 and supports parts of it. SCE agrees with the need to coordinate with local governments and discusses its approach to doing so below. However, SCE opposes certain elements of the proposal that would add new additional requirements to the regular and extensive outreach and communication that SCE is already doing with local governments. Staff indicates that the Proposal would require the IOUs to:

> *a. Develop or ensure effective internal communication processes exist for managing interfaces with local government.*

SCE already coordinates closely with the local governments in the communities it serves and has designated representatives who interface regularly with local governments. SCE supports this recommendation and commits to continuously improve its outreach and engagement efforts with local governments.

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

SCE regularly informs and engages local governments in its service territory about utility electric transmission and distribution investment and operational plans, including planned projects that are intended to minimize the impacts of PSPS events. SCE tries to share as much information as possible or feasible about planned projects with local governments. While SCE generally supports this recommendation, SCE opposes the imposition of the following requirements for the identification of these projects because the information will vary from project to project and may not be available or known, and may evolve significantly as projects

and programs are developed from planning through implementation. These requirements may slow overall progress:

- Identify by County and provide geographic location.
- Describe scope, schedule, cost and number of customers impacted.
- Confirm potential for minimizing customer outages due to public safety power shutoff.

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

SCE meets regularly with local governments on its plans, projects, and issues, including but not limited to, the utility's electric transmission and distribution plans and projects, reliability/outages, and emergency preparedness plans. In addition, SCE provides local governments with annual reports containing information on reliability histories for circuits serving that specific jurisdiction as well as the utility's proposed reliability/capital improvements in that jurisdiction for the upcoming year.

SCE has conducted and will continue to implement in-person meetings to educate local government officials, tribal staff, and first responders, particularly those in HFRA, regarding SCE's Wildfire Mitigation Plan, including PSPS protocols and its potential impact on their community. These meetings are focused on education about the PSPS process. SCE will continue these meetings to further educate, enhance partnerships, and increase awareness. SCE also conducts community meetings across its service territory to educate local governments, stakeholders, and customers about its wildfire mitigation efforts and PSPS protocols.

While SCE already conducts regular and extensive outreach and communication with local governments in its service territory, SCE has strong concerns with and opposes this part of the Staff Proposal to mandate semi-annual workshops. In particular, given the outreach SCE already conducts, SCE does not believe it is necessary to have a requirement to conduct face-to-face workshops on a semi-annual frequency and to complete the first semi-annual round by April 30, 2020. In addition, SCE does not believe it is necessary to include a collaborative planning

session about enhancing grid resilience within the county in and across all local government agency jurisdictions that would be moderated by the county Office of Emergency Services Administrator and monitored, supported, and evaluated by Commission staff. Local jurisdictions across SCE's service territory have different needs and interests for information on SCE's wildfire mitigation plans and PSPS. Conducting semi-annual meetings with each local government agency in SCE's territory would be overly burdensome on all parties. SCE engages each local jurisdiction to understand their needs and prepares information to meet those needs. Therefore, there should not be a blanket requirement to meet with local governments in accordance to the characteristics and topics specified in the Staff Proposal.

Proposal 2: Resiliency Project Engagement Guide

SCE supports Proposal 2. SCE is capable of developing an Engagement Guide for local and tribal governments; the Guide would reference existing SCE processes for customer engagement, DER interconnection, and DER program deployment, and would leverage existing customer outreach methods that include flowcharts and best practice guidelines. SCE supports engaging with these communities on both microgrids and broader resiliency solutions to mitigate the impacts of PSPS events.

Proposal 3: Dedicated IOU Team for Local Government Projects

SCE supports Proposal 3. SCE has existing staff that could manage the intake of local and tribal government resilience projects; SCE has assigned Business Customer Service Representatives to serve as single points of contact for these entities.

Proposal 4: Developer Interconnection Training

SCE agrees with Staff in not recommending this proposal, and thus does not provide further comment on the specifics of Proposal 4.

Proposal 5: Separate Portal for Local Government

With respect to Proposal #5, SCE supports providing the necessary information in an alternative method to support local government needs. SCE is cognizant that some of the information in this proposal may be valuable to local governments, and thus SCE is willing to

work with stakeholders to determine what information they need as well as to determine methods that can be used to provide that information. Through regular meetings between SCE's designated representatives and local governments, SCE intends to partner with those communities to better understand the data that they need.

SCE does not support the complete set of new requirements in this proposal nor the development of a separate data portal as there are significant issues in determining what information can be shared (operational and customer information), what technology can be used (SCE would need to develop much more than what is currently in the Distribution Resource Plan External Portal (DRPEP)), and for what purpose. SCE does not believe that all these technical and non-technical issues can be resolved for a deployment of microgrids in 2020 and thus this item should be de-prioritized for future discussion.

2. **Are changes to any rate schedules or electric rules needed to implement any of the proposals? If so, which ones, and how do they need to be changed? Please propose specific language.**

At this time, SCE does not believe any changes to rate schedules or electric rules need to be implemented for any of the proposals.

3. **Is CPUC action required in order to implement any of the proposals? If so, what action would be most appropriate?**

At this time, SCE does not believe any Commission action is required to implement any of the proposals.

4. **For proposals that require CPUC action, what standards should be used to determine whether action is justified?**

N/A- see response to question #3.

5. **Should CPUC consider cost recovery for any of these proposals in this proceeding? For example, should CPUC consider cost recovery for additional IOU technical resources to support the intake, prioritizing, technical support, and processing of local government resilience projects? Please discuss.**

If any of the proposals are implemented and result in SCE incurring incremental costs, then SCE should be granted cost recovery for them. Accordingly, at the proper time, the

Commission should authorize the establishment of a memorandum account to track incremental costs with recovery to be addressed in a future proceeding.

6. **How long would it take to recruit, hire and train additional IOU resources to staff the dedicated IOU team for local government projects referenced in Proposal 3?**

Staffing and training of existing account management resources for a dedicated intake team for local government and tribal resiliency projects will entail multiple stages of planning and deployment. SCE anticipates these activities requiring approximately four to seven months. The preference is to train existing account management resources that are already familiar with these customer segments.

7. **What data from the list in Proposal 5 and Appendix 4.4 is essential for microgrid development? Please list the line numbers of data from the text of Proposal 5 as well as the line numbers of individual data points from Appendix 4.4 in response. Please indicate whether the response reflects the data that is needed for the development of a microgrid that is behind the customer meter or in front of the customer meter.**

SCE assumes that in front of the meter (IFOM) microgrids in this question refers to microgrids which would be connected on the primary voltage level generally less than 50kV.

Further, SCE notes that the data points in Appendix 4.4 support some of the technical aspects of IFOM microgrid development. However, there are many other challenges that need to be addressed beyond the technical elements in Appendix 4.4 that will first need to be addressed in order to enable the development of the IFOM microgrid applications. These additional challenges include but are not limited to:

- Operational control responsibilities
- Liabilities
- Microgrid component ownership
- DER compensation
- Communication and Cybersecurity.

SCE provides responses to each element in Appendix 4.4 as follows:

Substations				
Appendix 4.4 Line Number	**Behind the Meter (BTM) Microgrid**	**In Front of the Meter (IFOM) Microgrid**	**Not needed for Microgrid Applications**	**Additional Comments**
1		X		
2			X	Transmission information data is not necessary for IFOM or BTM microgrid applications, as transmission level can be evaluated using the Thevenin Equivalent Circuit model.
3		X		
4			X	The IFOM microgrid will not use the substation, thus rating would not provide any valuable information.
5		X		This would only be needed if the IFOM microgrid would carry the entire load of the substation, which may not be a likely condition.
6		X		This would only be needed if the IFOM microgrid would carry the entire load of the substation, which may not be a likely condition.
7			X	The IFOM microgrid will not use the substation, thus rating would not provide any valuable information.
8		X		
9		X		
10			X	Information not essential for microgrid development, such as high fire zones, have already been mapped which include areas affected by transmission lines.
11			X	Not needed for technical evaluation but may be needed to prioritize locations for microgrid development.
12			X	Not needed for technical evaluation but may be needed to prioritize locations for microgrid development.

Distribution Lines				
Appendix 4.4 Line Number	Behind the Meter Microgrid	In Front of the Meter Microgrid	Not needed for Microgrid Applications	Comments
13		X		
14			X	Transformer banks have the same origin as Substation Origin (line #13).
15		X		
16		X		
17		X		
18			X	Not needed for technical evaluation but may be needed to prioritize locations for microgrid development.
19			X	
20			X	
21		X		
22		X		
23		X		
24		X		
25			X	
26			X	The IFOM microgrid will not relay on existing distribution line protection schemes. Therefore, this is not relevant or needed for IFOM microgrid development.
27			X	SCE is unclear what a "wind polygon" is.
28		X		
29			X	Not needed for technical evaluation but may be needed to prioritize locations for microgrid development.
30		X		
31			X	What is important is the load profile and circuit information, rather than the number of customers and their locations.
32			X	It is unclear if this refers to existing distribution lines that would be converted to microgrid lines or if this refers to space needed for the construction of new microgrid lines. This type of evaluation would be conducted on various locations where a microgrid could be installed.
33			X	This type of evaluation would be conducted on various locations where a microgrid could be installed.

34		X		Not needed for technical evaluation but may be needed to prioritize locations for microgrid development.
35			X	Not needed for technical evaluation but may be needed to prioritize locations for microgrid development.

Switches				
Appendix 4.4 Line Number	Behind the Meter Microgrid	In Front of the Meter Microgrid	Not needed for Microgrid Applications	Comments
36		X		Only for critical switch locations, such as the microgrid-grid interconnection switch.
37		X		Only for critical switch locations, such as the microgrid-grid interconnection switch.
38		X		Only for critical switch locations, such as the microgrid-grid interconnection switch.
39		X		
40		X		Only for critical switch locations, such as the microgrid-grid interconnection switch.
41		X		Only for critical switch locations, such as the microgrid-grid interconnection switch.
42			X	Not needed for technical evaluation but may be needed to prioritize locations for microgrid development.
43			X	This would be done as part of the microgrid design based on available physical locations.
44		X		Sectionalization plans would be developed as part of the microgrid development. Current sectionalization is performed based on each grid condition.

Transformers (SCE assumes this mean Service transformers as opposed to substation transformers				
Appendix 4.4 Line Number	Behind the Meter Microgrid	In Front of the Meter Microgrid	Not needed for Microgrid Applications	Comments
45		X		Only for locations where service transformers are located.

46			X	This would be done as part of the microgrid design based on available physical locations.
47			X	
48		X		
49			X	Service transformer will continue to serve the same load regardless of the source (Grid or IFOM microgrid).
50			X	Service transformer will continue to serve the same load regardless of the source (Grid or IFOM microgrid).
51			X	Service transformer will continue to serve the same load regardless of the source (Grid or IFOM microgrid).
52			X	What is needed is the load profile and network electrical information, rather than which customers the microgrid serves.
53			X	What is needed is the load profile and network electrical information, rather than which customers the microgrid serves.
54			X	Not needed for technical evaluation but may be needed to prioritize locations for microgrid development.

8. **Is there other data essential for microgrid development not listed in the Appendix that could be identified, along with an explanation of its use? Please indicate whether the response reflects the data that is needed for the development of a microgrid that is behind the customer meter or in front of the customer meter.**

Other data that is essential for IFOM microgrid development includes, but may not be limited to the following:

- Customer DER and flexible load which may be integrated with IFOM microgrid controls.
- Communication methods and requirements for Utility to IFOM microgrid operator (if other than utility), IFOM microgrid control to customer's DERs and flexible load.
- End-to-end cybersecurity. requirements for the IFOM microgrid and DERs.
- Electrical models of relevant IFOM microgrid zones including all energy sources, load profiles, and protection elements that would be required to determine the microgrid operation and protection strategies.

- Data to determine the critical loads and the means of disconnecting non-critical loads from the microgrid.
- Automation schemes available for use in the applicable microgrid zones.

9. Should any of these proposals be modified before being adopted and/or implemented? If so, please describe and justify any changes.

As discussed in SCE's response to Question 1 regarding Proposal #1, part (b) in the Staff Proposal, while SCE tries to share as much information as possible or feasible about planned projects with local governments, the proposal should be modified to not require the following items because the information will vary from project to project and may not be available or known, and may evolve significantly as projects and programs are developed from planning through implementation:

- Identify by County and provide geographic location.
- Describe scope, schedule, cost and number of customers impacted.
- Confirm potential for minimizing customer outages due to public safety power shutoff.

Regarding Proposal #1, part (c) in the Staff Proposal, while SCE supports communicating and educating local jurisdictions, CCAs, and other stakeholders about the electric transmission and distribution infrastructure serving their communities, the proposal should be modified to remove the mandate to conduct semi-annual face-to-face workshops with each local government agency because it would be overly burdensome on all parties. In place of a mandate, a possible modification could be that the utility will conduct a face-to-face meeting if requested by a local government in their service area. In addition, the proposal should not require that the face-to-face workshops be in accordance to the characteristics and topics specified in the Staff Proposal. The utility and local government should determine what topics should be discussed and which participants should attend the meeting.

SCE supports Staff Proposals #2 and #3 and does not seek modification to either.

Rather than requiring the creation of a new portal for local and tribal governments, Proposal #5 should be modified to require utilities to work with stakeholders to determine what information they need as well as to determine methods that can be used to provide that

information. Through regular meetings between SCE's designated representatives and local governments, SCE intends to partner with those communities to better understand the data that they need and provide only the relevant information, leveraging existing platforms and processes to the greatest extent possible.

10. **Are there other options for each proposal that have not been listed? If so, please elaborate on the option(s) that should be considered. Include as much detail as possible.**

No. Staff has identified the appropriate issues and developed proposals to mitigate them. SCE has no further comments, but reserves the right to provide more feedback after reviewing intervenors' responses to this question.

3.4. IOU Proposals for Immediate Implementation of Resiliency Strategies, Including Partnership and Planning with Local Governments

3.4.1. All Investor Owned Utility Proposals

SCE views these questions as requiring responses from non-IOU parties to this proceeding, and SCE therefore reserves its right to provide feedback or further clarification, as warranted, in its Reply to the Comments filed in response to the below questions.

1. **Please indicate support of or opposition to each proposal and explain the rationale. In response, please clearly distinguish between the action proposed and the cost recovery mechanisms proposed, if any.**

   See above response.

2. **Is CPUC approval required in order to implement any of the proposals?**

   See above response.

3. **For proposals that require CPUC approval, what standards should be used to determine whether approval is justified?**

   See above response.

4. **For proposals that require CPUC approval, was sufficient information provided? If not, please describe what additional information is needed. Examples of possible additional information are provided below. Indicate whether the below information is necessary and why or why not. Please add any additional information that should be considered and why.**

See above response.

a. **Explanation of the criteria and reasoning for determining how to prioritize the locations and/or customers to be served (e.g., frequency of PSPS events or number of customers); and**

See above response.

b. **Costs and impacts of alternative approaches to achieving the goal of the proposal (e.g., reducing the impacts of PSPS outages) that were considered and rejected, such as alternative technologies or fuels, infrastructure hardening, distribution or transmission system sectionalization.**

See above response.

5. **Are there any other microgrid-related actions that CPUC should consider directing investor-owned utilities to undertake in addition or instead of these proposals in order to mitigate the impact of outages due to PSPS events or other causes in 2020? If so, please describe and justify that proposed action. For example, should CPUC direct PG&E accelerate the deployment of mid-feeder microgrids (formerly called "resilience zones") beyond the rate proposed in the PG&E General Rate Case?**

See above response.

3.4.2. Proposals Regarding Emergency Temporary Generation

SCE recommends that the CPUC coordinate any siting, operating, monitoring and reporting requirements with the California Air Resources Board and the local air quality agencies, which are responsible for regional air quality planning, monitoring, and stationary source and facility permitting. Creating separate monitoring and reporting methodologies has the potential to create inconsistencies and confusion for the public and air quality regulators.

SCE therefore reserves its right to provide feedback or further clarification, as warranted, in its Reply to the Comments filed in response to the below questions.

1. **Should CPUC impose any requirements on how the IOUs engage with local government agencies with regards to siting, equipment specification, or operating conditions before operating emergency temporary generation so that community concerns regarding noise, odor and potential health effects can be addressed? Why or why not? If so, what requirements should CPUC impose and why?**

See above response.

2. **If the CPUC should require monitoring and reporting of air quality, sound, odor, and/or health effects during operation of emergency backup power, please comment on how such information would further the public interest. For example, could it be used to mitigate future impacts or establish limits?**

   See above response.

3. **Please comment on what information should be provided, as a minimum, by a utility seeking authorization for the procurement of portable generators, whether utility-owned or contracted with a third party, to be used to provide emergency backup power to utility customers during emergencies. Indicate whether the below information should be required or not, and why or why not. Please add any additional information that should be required and discuss why it should be required.**

   a. **Type(s) of generator that would be deployed (type and capacity, in MW);**

   See above response.

   b. **Type(s) of fuel that would be used;**

   See above response.

   c. **Separate unit costs for equipment, fuel, carbon allowances, and permitting; and**

   See above response.

   d. **Greenhouse gas and criteria air pollutant emissions factors for each combination and generator and fuel type that would be operated, using standard assumptions (including assumptions used) to facilitate comparison.**

   See above response.

   e. **If conventional, fossil-based diesel or natural gas is proposed, quantitative and qualitative comparison with the most competitive alternative fuel sources and technologies and narrative explanation of why the fossil-based options are proposed instead of the most competitive non-fossil alternatives.**

   See above response.

III.

CONCLUSION

SCE appreciates the opportunity to file these Comments and looks forward to reviewing the feedback from all stakeholders on Staff's Track 1 Proposal and SCE's January 21, 2020 filing.

Respectfully submitted,

ANNA VALDBERG
ROBIN Z. MEIDHOF

/s/ Robin Z. Meidhof
By: Robin Z. Meidhof

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-6054
E-mail: Robin.Meidhof@sce.com
E-mail: Anna.Valdberg@sce.com

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