Decision 19-03-013 March 28, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.	Rulemaking 17-07-007

DECISION ADOPTING PROPOSALS FROM MARCH 15, 2018 WORKING GROUP ONE REPORT

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DECISION ADOPTING PROPOSALS FROM MARCH 15, 2018 WORKING GROUP ONE REPORT

Summary

This decision adopts the following proposals from the March 15, 2018 Working Group One Final Report as refinements to the interconnection of distributed energy resources under Electric Tariff Rule 21:

- expanding the existing Screen Q exemption for net energy metering (NEM) facilities with net export less than or equal to 500 kilowatts (kW) by increasing the exemption size threshold to all NEM and inverter-based non-NEM projects with 1 Megavolt Amperes (MVA) or less nameplate capacity;
- creating a soft link within Screen Q to the California Independent System Operator tariff;
- directing Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly, the Utilities) to identify engineering review guidelines related to the evaluation of Screen Q;
- requiring the Utilities to develop illustrative metering configurations and cost tables to provide more transparency in the application of complex metering solutions, post information on their websites clarifying requirements for non-export relays and controls for solar plus storage systems to maintain Commission-required NEM Tariff integrity requirements, and support development of direct current metering standards by participating in the EMerge Alliance initiative or equivalent as utility resources allow;
- modifying Rule 21 to allow for agreed-upon Type I modifications to interconnection applications under Fast Track (*e.g.,* like-for-like equipment replacements, size reductions, and size reductions to avoid upgrades) and adopting certain process options, including a new notification-only approach, for working group developed

use cases that address Type II modifications to existing generating facilities;

- allowing the Utilities to require well-defined technical specifications for telemetry for systems between 250 kW and 9.9 megawatts (MW) when utility-related telemetry costs are estimated to be less than $20,000, if deemed necessary through a workshop and advice letter, but if deemed not necessary, maintaining the threshold for requiring telemetry at 1 MW;
- allowing customer ownership of behind-the-meter telemetry equipment where practicable to mitigate the costs associated with utility ownership of the equipment (*i.e.,* the Income Tax Component of Contribution and Cost of Ownership charges);
- neither requiring nor incentivizing activation of advanced functionality in Phase 1-compliant inverters installed before September 9, 2017;
- allowing customers to replace existing inverters with inverters of equal or greater ability, pursuant to Decision (D.) 14-12-035, and encouraging, but not requiring, customers to replace existing inverters with smart inverters at end of life; and
- retaining the status quo, in which each utility is authorized and retains the discretion pursuant to Commission D.87-09-026 and D.94-06-038 to collect or not collect Income Tax Component of Contribution security on safe harbor projects.

The Utilities shall file a Tier Two Advice Letter no later than 60 days from the issuance of this decision revising Rule 21 to be consistent with this decision.

This proceeding remains open to address issues in Working Groups Two, Three, and Four.

1. Background

The Commission adopted the Order Instituting Rulemaking (R.) 17-07-007 on July 13, 2017 to consider a variety of refinements to the interconnection of distributed energy resources under Electric Tariff Rule 21 of Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (jointly, the Utilities) and the equivalent tariff rules of the small and multi-jurisdictional electric utilities.[1]

The October 2, 2017 *Scoping Memo of Assigned Commissioner and Administrative Law Judge* (Scoping Memo) set forth the scope and schedule of the proceeding. The Scoping Memo also established a working group process in the proceeding whereby resolution of the issues of the proceeding (*see* Section 2 below) would be proposed by six working groups, Working Groups One through Six. In addition, four issues were assigned to the Smart Inverter Working Group, including issues 5 and 6.[2]

Working Group One and the Smart Inverter Working Group began meeting on October 16, 2017.

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1 The Rule 21 tariff describes the interconnection, operating, and metering requirements for certain generating and storage facilities seeking to connect to the electric distribution system. Rule 21 provides customers access to the electric grid to install generating or storage facilities while protecting the safety and reliability of the distribution and transmission systems at the local and system levels. (*See* R.17-07-007 at 2.)

2 The Smart Inverter Working Group grew out of a collaboration between the Commission and the California Energy Commission in early 2013. The collaboration identified the development of advanced inverter functionality as an important strategy to mitigate the impact of high penetrations of distributed energy resources.

In response to a January 25, 2018 motion filed by the California Solar Energy Industries Association, the Administrative Law Judge issued a ruling on February 14, 2018 that re-assigned Issue 6 from the Smart Inverter Working Group to Working Group Two because the development of forms and agreements necessary for Issue 6 are better suited to be addressed by legal and regulatory representatives instead of engineers.

Working Group One, with input on Issue 5 from the Smart Inverter Working Group, filed a *Working Group One Final Report* on March 15, 2018 (March Report).[3] The following parties filed comments to the March Report on April 16, 2018: the California Independent System Operator (CAISO), California Solar and Storage Association (CALSSA), Clean Coalition, Green Power Institute, Interstate Renewable Energy Council (IREC), Public Advocate's Office of the Public Utilities Commission (Public Advocates' Office)[4], Tesla and the Utilities.

On June 19, 2018, the Administrative Law Judge facilitated a workshop at which time representatives of Working Group One presented the proposals and recommendations from the March Report. The purpose of the workshop was to provide additional clarity to enable the Commission to determine whether to approve the proposals recommended in the March Report.

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[3] The following parties participated in Working Group One: Bosch, CALSSA, California Energy Storage Alliance (CESA), CAISO, Clean Coalition, Green Power Institute, Interstate Renewable Energy Council (IREC), ORA, PG&E, SDG&E, SCE, Tesla, The Utility Reform Network (TURN), and Sunrun. Several other stakeholders also participated. (*See* Working Group One Report at 119-120.)

[4] Senate Bill 854 (Stats. 2018, ch. 51) amended Pub. Util. Code Section 309.5(a) so that the Office of Ratepayer Advocates is now named the Public Advocate's Office of the Public Utilities Commission. We will refer to this party as the Public Advocate's Office.

On August 15, 2018, the Administrative Law Judge issued a ruling directing parties to respond to questions about the March Report in order to complete the record. The following parties filed responses on September 5, 2018: CALSSA, the California Energy Storage Association (CESA), IREC, PG&E jointly with SDG&E, SCE, Tesla, and TURN. On September 12, 2018, the following parties filed reply comments: Clean Coalition, IREC, PG&E jointly with SDG&E, SCE and Tesla.

This decision resolves the set of issues assigned to Working Group One as described in Section 2 below. R.17-07-007 remains open to address the issues assigned to Working Groups Two, Three, and Four.

2. Issues Before the Commission

Below are the six issues assigned to Working Group One in the Scoping Memo and addressed in the March Report. The numbering below corresponds to the issues as listed in the Scoping Memo. As previously stated, Issue 6 has been reassigned to Working Group Two.

1. Should the Commission modify Fast Track Screen Q to minimize the number of distributed energy resource projects subjected to transmission cluster studies and, if so, how?
2. Should the Commission clarify the definition of "complex metering solutions" for storage facilities and, if so, how?
3. How should the Commission clarify the definition of a material modification to a project and what should be the procedures for processing these modifications?
4. As the penetration levels of distributed energy resources increase, what changes to telemetry requirements should the Commission adopt to ensure adequate visibility while minimizing costs?

5. Should the Commission require activation of advanced functionality in Phase I-compliant inverters installed before September 9, 2017 and, if so, how?

7. Is there inconsistent application of the requirement to pay the Income Tax Component of Contribution charges across the Utilities? If yes, how should the Commission address this inconsistency?

3. Adoption of Working Group One Proposals

For each of the six issues listed above, this decision states the resolution to the issue, describes the issue and the proposed solutions, and then provides an explanation of the determination. Within 60 days of the issuance of this decision, the Utilities shall submit a Tier Two Advice Letter updating Rule 21 to be consistent with the directives of this decision.

3.1. Issue 1: Reducing Transmission Cluster Studies

We conclude that the Commission should modify Fast Track Screen Q to minimize the number of distributed energy resources projects subjected to transmission cluster studies because doing so could reduce project delays and costs while maintaining the safety and reliability of the electric grid. As discussed below, it is reasonable to adopt Proposals 1A, 1B, 2, and 3 as recommended in the March Report. Proposal 4 is not adopted as it could financially impact ratepayers with no known benefits.

3.1.1. Issue 1: Understanding Fast Track Screen Q and Transmission Cluster Studies

Issue 1 asks whether the Commission should modify Fast Track Screen Q to minimize the number of distributed energy resources projects subjected to transmission cluster studies and, if so, how. Fast Track Screen Q is an engineering test that evaluates whether a project is electrically independent of the transmission system. If a project is of sufficient size and located at a point of interconnection that it is reasonably anticipated to require or contribute to the need for upgrades to the transmission system (Network Upgrades), it will fail Screen Q, be withdrawn from Rule 21, and have the option of applying for interconnection under the Transmission Cluster Study Process of the Federal Energy Regulatory Commission Wholesale Distribution Tariff.[5] According to Working Group One, the Transmission Cluster Study Process can add one to two years to a project's construction time.[6] The working group's objective with respect to Issue 1 was to explore whether there are mechanisms to decrease the incidence of Fast Track Screen Q failure, while maintaining the safety and reliability of the grid.

In the March Report, the working group presented four proposals. None of the proposals are mutually exclusive, meaning that any combination of proposals can be adopted by the Commission. Three proposals (1A, 2, and 3) have consensus support from working group members, and two proposals (1-B and 4) do not. We describe each of the proposals in the following sections.

3.1.2. Issue 1: Proposal 1A

Proposal 1A would expand the existing Screen Q exemption for net energy metering (NEM) facilities with net export less than or equal to 500 kilowatts (kW) by increasing the exemption size threshold to 1 megavolt amperes (MVA).[7] All parties support this core proposal.

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[5] March Report at 7.

[6] *Ibid.*

[7] The fundamental unit of measurement under Proposal 1A shifts from watts to volt amps in order to reflect inverters and transformers increasingly being rated in MVA rather than MW to account for reactive power, which is an important consideration for maintaining grid safety and reliability.

Parties disagree as to whether a project's size should be measured using the equipment's nameplate capacity or the anticipated amount of net export. Contending that nameplate capacity does not properly reflect a project's impacts, IREC proposes an alternative that includes a threshold of 1 MVA "that may flow across the Point of Common Coupling" as well as nameplate capacity less than or equal to 1 MVA.[8] TURN, PG&E, SCE and SDG&E oppose the IREC proposal as it "effectively modif[ies] the exemption to 2 MVA or greater nameplate [capacity]" and could contribute to reliability and capacity concerns.[9]

3.1.3. Issue 1: Proposal 1B

Proposal 1B would modify Rule 21 to expand the Screen Q exemption from NEM-only projects to all projects less than or equal to 1 MVA. Supporters of this proposal (IREC, Clean Coalition, Green Power Institute, and CALSSA) contend that this proposal is consistent with the policy goal of keeping Rule 21 focused on reviewing the electrical impacts of projects rather than creating distinctions based on different procurement programs.[10]

3.1.4. Issue 1: Proposal 2

Working Group One reached consensus on the recommended proposal that the Commission modify Screen Q to create a soft link to the CAISO tariff. Specifically, the proposal recommends that the tariff be updated to cite the CAISO tariff in effect without naming the specific appendix. The March Report highlights that, in 2012, the CAISO moved the location of certain rules from one

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8 Tesla, Green Power Institute, and CESA also oppose using nameplate capacity for limited export or non-exporting projects.

9 March Report at 10.

10 *Id*. at 12.

appendix to another appendix, but the change was not identified until recently.[11] By not identifying the change earlier, the March Report states that the nine projects that failed Screen Q in 2016 should have otherwise passed Screen Q with the updated tariff.[12] The Utilities believe this proposal will reduce the likelihood of projects failing Screen Q. Members of Working Group One are in agreement and support this proposal.

3.1.5. Issue 1: Proposal 3

Consensus was also reached in Proposal 3, whereby the Utilities would identify engineering review guidelines related to the evaluation of Screen Q. The March Report explains that to assess a project's electrical interdependence with the transmission system, a utility performs an Electrical Independence Test. For projects that fail the Electrical Independence Test, a utility may perform additional engineering analyses to determine the need for Reliability Network Upgrades. If adopted, the Utilities agree to make the following guidelines available on interconnection websites:

1. List all generation projects in the current queue that are adjacent to the proposed project.
2. If current base-case is not complete, use last approved cluster base-case.
3. If a cluster is ongoing, with Reliability Network Upgrades (RNUs) not yet finalized, compare pre-project base-case and post-project base-case loading, when necessary, to determine if there is/are any potential Network Upgrade(s) required.

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[11] *Id.* at 13.

[12] *Id.* at 14.

4. If a cluster is ongoing, with RNUs finalized, compare pre-project base-case and post-project base-case with RNUs considered and determine if the subject interconnection request triggers a change in scope for that RNU.
5. Consult with the CAISO as necessary.[13]

In addition, the working group proposes minor modifications to Section G.3.a. of Rule 21 to improve clarity on the role of the additional engineering review following the Electrical Independence Test. Working Group One members agree on and support this proposal.

3.1.6. Issue 1: Proposal 4

Proposal 4 recommends the Commission create another venue to discuss a "Cost Cap" for qualifying distributed energy resources that fail Screen Q to proceed despite transmission dependence. A project would proceed with the interconnection approval process without participating in a transmission cluster study if willing to pay a "cost cap" fee, calculated based on either a proportionate share of the utility's applicable transmission-level RNUs based on historical average costs, or costs the utility reasonably believes will be incurred by the applicant, based on project specific cost estimates (comparable to the Rule 21 Cost Envelope review process).[14] The March Report clarifies that this is not a change in Screen Q, only in how costs may be assigned if a project seeks to proceed under the Cost Cap Fee Option and avoid the Transmission Cluster Study Process.[15] Green Power Institute, the originator of this proposal, asserts that distributed energy resources projects of less than or equal to 5 MVA that fail

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[13] *Id*. at 15.

[14] *Id*. at 16-17.

[15] *Id*. at 17.

Screen Q should be given this additional option since 5 MVA is the limit for lower-cost interconnection studies under the Rule 21 Independent Study Process.[16]

In addition to Green Power Institute, Proposal 4 is also supported by Clean Coalition but opposed by TURN, Public Advocates' Office, PG&E, SCE, and SDG&E. The utilities oppose this proposal as they believe it is out of scope and not practical for the utilities to adopt due to a lack of data. The Public Advocates' Office maintains that creating a cap would negatively affect ratepayers by requiring them to cover the remaining upgrade cost. Similarly, TURN opposes the proposal because costs exceeding the Cost Cap would be borne by ratepayers, and benefits may not exceed these costs.[17]

3.1.7. Resolving Issue 1 by Modifying Screen Q Requirements

We first acknowledge that the transmission cluster studies can be lengthy (potentially extending project development timelines by 1-2 years) and may increase project costs.[18] The fact that the Utilities report that projects not exempt from Screen Q have only failed the screen nine times, which would not have occurred under the corrected tariff language, suggests that few projects interconnecting under Rule 21 contribute to the need for transmission upgrades. This implies that there is an ample margin to raise the Screen Q exemption threshold while maintaining the safety and reliability of the grid. Hence, we conclude that the Commission should modify Fast Track Screen Q to reduce the

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[16] *Ibid*.

[17] *Id.* at 18.

[18] *Id.* at 7-8.

number of projects subjected to the lengthy and costly transmission cluster studies.

The core aspects of Proposal 1 should be adopted. Revising the exemption size measurement standard to MVA from MW is reasonable given that inverters and transformers are increasingly rated in MVA versus MW.[19] Noting that project developers, customers and utilities are accustomed to rules differentiating between projects smaller and larger than 1 MW, the March Report states that this revision would align Rule 21 with other 1 MW thresholds for NEM cost allocation.[20] Additionally, raising the screen's exemption threshold size to 1 MVA, rather than a higher value, should ensure that projects that contribute to the need for transmission network upgrades continue to be subject to Screen Q.[21] Working Group One is in agreement on these core aspects of Proposal 1.

With respect to the non-consensus aspect of this proposal, we agree that estimating the system's anticipated net export currently creates additional steps, leading to increased project time, disputes, and uncertainty.[22] Hence, we conclude the Commission should measure the exemption threshold size by nameplate capacity. Acknowledging the time and effort required to complete the cluster study process for these projects, we agree that the use of inverter power controls (software/firmware) to actively limit exports such that they

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19 *Id.* at 9.

20 *Ibid.*

21 *Id.* at 7-9.

22 *Id.* at 10-11.

never meet the 1 MVA threshold should address these concerns.[23] That being said, we recognize that any inverter power controls (software/firmware) to limit export would require certification, which does not currently exist but is imminent.[24] Relatedly, the Commission recently adopted D.19-01-030, acknowledging that monitoring and communication capability is an important and necessary prerequisite to approving a power control-based option, as it enables ongoing verification that systems operate according to regulatory requirements. The Commission also stated that in lieu of metering requirements, it is reasonable to approve control-based options that have certified to a national standard or a utility-approved interim testing procedure. Until the national standard is created, the Commission recommended that the electric utilities apply the same methods they use currently to ensure smart inverter settings (*e.g.*, voltage and reactive power (volt/var)) are configured correctly at installation and not subsequently changed.[25] Accordingly, we adopt Proposal 1A with the requirement that the threshold level be measured by the nameplate capacity.

Proposal 1B should also be adopted; this proposal expands the existing Screen Q exemption from NEM projects with net export less than or equal to 1 MVA to all projects with net export less than or equal to 1 MVA. While the utilities assert non-NEM projects are more likely to contribute to the need for Network Upgrades and/or reliability system upgrades, there is no data to substantiate this assertion.[26] We agree with arguments that Rule 21 should only

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[23] *Id*. at 11 and Tesla Responses to August 15, 2018 Ruling at 3.

[24] March Report at 11 and Tesla Responses to August 15, 2018 Ruling at 3.

[25] D.19-01-030 at 19-20.

[26] *Id*. at 12.

differentiate between projects on the basis of electrical impact, not enrollment in different procurement programs.[27] SCE pointed out that NEM projects are non-synchronous and non-NEM projects are more likely to be synchronous than NEM projects. Furthermore, SCE stated that synchronous and non-synchronous machines differ in short circuit duty contribution or short circuit current contribution.[28] Accordingly, because non-inverter-based generation has a higher short circuit duty contribution, we limit the exemption to inverter-based generating facilities.[29] Non-inverter-based non-NEM generating facilities of all sizes must continue to pass Screen Q. This proposal with the caveat results in a balanced treatment of projects, further streamlines Rule 21, but ensures safety.

We disagree with TURN's contention that expanding the Screen Q exemption to all projects would create a subsidy for these projects by allowing them to be exempt from any transmission network upgrade costs.[30] As stated above, the Utilities report that it is exceedingly rare for projects interconnecting under Rule 21 to fail Screen Q. This means that Rule 21 projects are highly unlikely to contribute to the need for transmission network upgrade costs. Since the proposed modifications to Rule 21 would only create an exemption for those non-NEM projects under 1 MVA, and larger projects would still be required to pass Screen Q, the total magnitude of transmission network upgrade costs that smaller non-NEM projects could escape is likely to be negligible.

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[27] March Report at 12. *See also* IREC Response to August 15, 2018 Ruling at 7-8.

[28] SCE Response to August 15, 2018 Ruling at 3 and 5.

[29] Tesla Response to August 15, 2018 Ruling at 5.

[30] TURN Response to August 15, 2018 Ruling at 3.

Proposals 2 and 3, consensus proposals, should also be adopted. Proposal 2 is an administrative change, which correctly revises the location of a CAISO tariff. Previously, the incorrect location led to projects applying under Rule 21 being subject to cost responsibility for Deliverability Network Upgrades when they should only be responsible for Reliability Network Upgrades.[31] Proposal 3 directs the Utilities to identify engineering review guidelines related to the evaluation of Screen Q. This proposal should lead to improved transparency into the Utilities' processes for performing additional review following failure of the Electrical Independence Test.[32]

Proposal 4 should not be adopted. This recommendation would allow projects that fail Screen Q to proceed with the interconnection approval process without participating in a transmission cluster study, if the customer is willing to pay a cost cap fee based upon the applicant's cost for Reliability Network Upgrades. Furthermore, TURN contends that costs exceeding the cap would be borne by ratepayers and argues that there is no evidence to indicate that there are any benefits to ratepayers or that the benefits exceed the costs.[33]

3.2. Issue 2: Clarifying Complex Metering Solutions

This decision concludes that the Commission should clarify the definition of complex metering solutions for storage facilities. As discussed below, we find all three recommended consensus proposals for this issue to be reasonable and, thus, should be adopted by the Commission.

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31 March Report at 13-14.

32 *Id*. at 14-15.

33 *Id*. at 18.

3.2.1. Issue 2: Requesting Greater Transparency with Respect to Complex Metering Solutions

Issue 2 asks whether the Commission should clarify the definition of "complex metering solutions" for storage facilities and, if so, how. The March Report explains that in D.14-05-033, the Commission ordered large NEM-paired storage generating facilities to install one of the following: 1) a non-export relay on the storage device; 2) an interval meter for the NEM-eligible generation, in order to meter the load and the total energy flows at the point of common coupling; or 3) an interval meter connected directly to the NEM-eligible generator. After solar and storage parties raised concerns that the cost of metering would be prohibitive, the decision established a cost cap of $600, but also said the Utilities can go beyond the cap if they determine that "complex metering solutions" are needed. Solar and storage companies state that a lack of a clear definition of when complex metering is required is problematic because it makes understanding meter configurations and costs more challenging. Stakeholders want greater transparency regarding how the need for complex metering is determined and applied. Stakeholders also express concern regarding complex metering for Direct Current (DC) coupled systems.

In the March Report, the working group presented three proposals. None of the proposals are mutually exclusive, meaning that any combination of proposals can be adopted by the Commission. All three proposals have consensus support. Each of the proposals is described below.

3.2.2. Issue 2: Proposal 1

Proposal 1 for Issue 2 would require each of the Utilities to post to its website the following materials:

a) An illustrative cost table based upon existing metering arrangements used by the utility, to include the anticipated cost of procuring, installing, and maintaining the required metering arrangements. For each meter type listed, the table will also provide the voltage, arrangement, amperage limitation, and whether the meter is a smart meter or non-smart meter.

b) Examples of common configurations that typically require standard or complex metering.

Working Group One members agree on and support this proposal.

3.2.3. Issue 2: Proposal 2

Proposal 2 for Issue 2 would provide that each utility uploads to its website information clarifying the requirements for non-export relays and controls for solar plus storage systems to protect NEM integrity. This information would include additional technical guidance for acceptable non-export relay and control configurations as well as citations to relevant provisions in the NEM and Rule 21 tariffs. Working Group One members agree on and support this proposal.

3.2.4. Issue 2: Proposal 3

Proposal 3 for Issue 2 would provide that each utility support the development of DC metering standards by participating in the EMerge Alliance initiative or equivalent, as utility resources allow. According to the March Report, a DC meter may be required to directly measure the output of the NEM-eligible generator on the DC side. Currently, there are no standards for revenue-grade DC meters. However, Duke Energy and EMerge Alliance are jointly developing a DC metering standard. The Utilities agree to participate in this effort, or an equivalent effort led by a nationally recognized testing laboratory, as resources allow. Working Group One members agree on and support this proposal.

3.2.5. Resolving Issue 2 by Providing Greater Transparency

In the March Report, CALSSA described circumstances where facilities that appeared to be similar in size and configuration had different metering solutions.[34] During working group meetings, the Utilities explained their rationale for different metering configurations. In response, CALSSA opined that improved transparency could lead to better understanding and predictability, which could also result in decreased tension between developers and the Utilities. The discussion in the March report indicates a need for improved clarity regarding what the Utilities consider to be complex metering solutions.[35] Hence, we conclude that the Commission should seek such clarification.

The three proposals presented as solutions to clarify the definition of complex metering are reasonable and should be adopted. Proposal 1, which would provide that the Utilities develop and upload to their websites illustrative cost tables and metering configurations, will result in improved transparency into the Utilities' complex metering practices.[36] Proposal 2 should also result in improved transparency, as it would provide that the Utilities post clarifying information on their websites explaining requirements for non-export relays and

[34] *Id.* at 26.

[35] *Id.* at 24-27.

[36] *Id.* at 27-28.

controls.[37] Proposal 3 would require the Utilities' participation in an effort to develop DC metering standards. Utility participation in this effort should assist in advancing the development of these standards, which may be used more often in the future.[38] Furthermore, this proposal should also lead to more technology-agnostic interconnection rules.[39] We underscore that no party opposed any of the three proposals. The Commission should clarify the definition of "complex metering solutions" for storage facilities by adopting Proposals 1, 2, and 3.

3.3. Issue 3: Defining Material Modifications and Establishing Procedures

This decision concludes that the Commission should clarify the definition of a material modification to interconnection applications and existing facilities. As discussed below, we adopt the revisions to Rule 21 to allow certain Type I modifications to interconnection applications, as described below in Table 1 and Section 3.3.1. We also adopt a process option(s) for each of the seven defined use cases for Type II modifications to existing facilities.

3.3.1. Issue 3: Modifying an Interconnection Application

Issue 3 asks how the Commission should clarify the definition of a "material modification" to a project and what should be the procedures for processing the modifications. The March Report explains that customers must make modifications to pending interconnection applications, at times, in response to dynamic conditions, including product availability. Rule 21 allows

[37] *Id*. at 28-30.

[38] *Id*. at 30-31.

[39] *Id*. at 31.

non-material modifications to be made, without submitting a new application. A material modification has a material impact on cost or timing of any interconnection request with a later queue priority date or a change in Point of Interconnection.[40] The Rule 21 Fast Track does not specify the modifications considered to be non-material.

Some working group members raised concerns that some circumstances are not within their control and require the need to make modification requests. Hence, the working group maintains that a refined definition of material modification is needed in the Fast Track process. Additionally, the March Report pointed to a concern of consistency across the utilities regarding modification requests. The Utilities agree that not all modification requests are equal, and some should be considered in cases where a system re-study is not required or where there is no material impact to another party.[41]

In the March Report, the working group presented a proposal for clarifying material modifications for interconnection applications; this proposal has consensus support. The working group also identified seven modification use cases and defined four possible options for processing modifications to existing facilities. With respect to processing modifications to existing facilities, party positions depend upon the use case. These proposals are further described in the following two sections.

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[40] *Id*. at 43-44. A material modification does not include a change in ownership of a generating facility.

[41] *Id.* at 45-46.

3.3.2. Issue 3: Proposal for Interconnection Applications

The Proposal for Issue 3, a consensus proposal, would allow certain modifications to the Fast Track interconnection applications. The proposed allowed modifications are listed in Table 1.

Table 1
Issue Three Core Proposal for Allowed Modifications to Interconnection Applications Under the Fast Track

1. Like-for-like[42] equipment replacements meeting the following criteria:
   - Does not increase facility size[43]
   - No size decrease exceeding 20 percent
   - No identified upgrades or mitigations
2. Size reductions meeting the following criteria:
   - No size reduction exceeding 20 percent
   - Identified upgrades or mitigations are paid for by the customer
3. Size reductions to avoid upgrades meeting the following criteria:
   - The re-study determines that no the modification affects no other distributed energy resource

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[42] Definition of "like for like" for the purposes of this decision: For inverters, like for like means certified, same nameplate or smaller, same fault current or smaller. For solar panels, like for like means certified, same CEC-AC rating of the system or smaller. For batteries, like for like means same or less kWh & kW rating (*see* the following footnote), and same operating profile. For transformers, like for like means same connection type, same or smaller impedance and capacity. (March Report at 46.)

[43] Definition of "size" for the purposes of this decision: System size is defined as the limiting factor that determines the maximum generating facility capacity. For solar systems, the limiting factor is the lesser of inverter nameplate capacity (kW) or maximum solar output (CEC-AC rating) for PG&E and SDG&E or inverter nameplate capacity (kW) for SCE. For energy storage systems, both the inverter nameplate capacity (kW) and the capacity of the storage device (kWh) are considered in the definition of size. For all other generation types, the limiting factor is the gross nameplate rating of the generator. (March Report at 46.)

In addition, the working group also asks that the Commission consider five other proposals. First, the Commission should limit to one the number of modification requests per interconnection request.

Second, the Commission should not require additional fees for the modification requests, except in the case of a size reduction to avoid upgrades; in that specific case, there should be a $300 fee to conduct a re-study to validate that no other resources are affected by the modification request.

Third, the Commission should establish a timeline of 10 business days to process a modification request or 20 business days for those requests requiring an engineering re-study. CALSSA proposes that the Commission limit the processing time to five days when no upgrades or mitigation is needed; the utilities oppose this as it does not mirror current Rule 21 timelines.

Fourth, the Commission should require that if a project downsizes and the revised size belongs to a different cost responsibility regime than the original request, the cost responsibility regime should remain that of the original request.

Fifth, the Commission should require that additional changes outside of the modification types identified herein will not be accepted within Fast Track. Other than the five-day recommendation for processing time where CALSSA and the Utilities disagree, no other party opposes any of these requested modifications.

3.3.3. Issue 3: Process Modifications for Existing Facilities by Use Case

The working group identified seven use cases in which customers may seek to make modifications to existing facilities. The working group also defined four possible options for processing modifications to existing facilities based on the modification's potential impact on the distribution system. Those process options are:

1) No notification is required;
2) Notification is required but the customer can proceed without waiting for utility approval;
3) Abridged/streamlined interconnection request is required and customer must wait for utility approval to turn on the system (engineering review not required); and
4) Interconnection request is required, and the customer must wait for utility approval to turn on the system (engineering review required).

The March Report underscores that process options 2 and 3 are not currently available; the utility interconnection portals would likely need to be modified to support these two options.

Table 2 below presents the use cases developed by the working group and indicates the process option (as defined above) supported by the Utilities and non-utility working group members.

Table 2
Party Positions on How to Process Modifications to Existing Facilities by Use Case

Case	Description	PG&E	SCE	SDG&E	Non-U
1	Replacing equipment with exact same equipment type or performing upgrades to inverter firmware that do not affect grip interactions	1	1	3	1
2	Replacing equipment "like-for-like," where system output does not exceed what is listed in the original interconnection agreement and operating mode is not adjusted.	3	2	3	1/2
3	Replacing equipment that may increase the nameplate capacity of the system, but which employ inverter power controls that limit the real power output to the inverter listed size in the original agreement.	4	4	4	2
4	Adding storage capacity to an existing storage facility without changing inverter.	3	3	3	1/2

5	Adding or replacing equipment such that system capacity increases and no inverter power controls are employed to limit the real power output to the inverter listed size in the original agreement.	4	4	4	4
6	Adding storage to an existing generating facility that does not have storage.	4	4	4	4
7	Changing inverter operating characteristics.	4	4	4	4

3.3.4. Resolving Issue 3: Adoption of Material Modification Definitions and Selection of Process Options for Use Cases

We begin with the definition of material modifications to interconnection applications. The Working Group One members reached consensus on a number of modifications to interconnection applications that should not be considered material, including like-for-like equipment replacements, size reductions, and size reductions to avoid upgrades. No party presented any opposing argument. As described in the March Report, these changes will grant developers additional flexibility and prevent them from having to withdraw and reapply, and subsequently, lose their queue position.[44] We find the revisions, provided in Table 1 above, to be reasonable and thus, the Commission should adopt them. The Utilities should update their Rule 21 tariffs accordingly.

We also find reasonable the additional recommendations regarding the number of modification requests allowed, fees for modifications, cost responsibility and other modifications. We clarify that each interconnection application will allow one modification request, which can contain multiple modifications.[45] We also give the Utilities discretion to allow additional

[44] March Report at 43-48.

[45] *Id*. at 47. *See* also SCE Response to August 15, 2018 Ruling at 6 and PG&E/SDG&E Response to August 15, 2018 Ruling at 5-6.

modification requests. The utilities are encouraged to exercise this discretion in instances when the utility has caused the need for an additional modification request.

Finally, we agree with the Utilities that the timelines for processing modification requests should mirror the timelines in Rule 21. We reject CALSSA's proposal that the Commission limit the processing time to five days when no upgrade or mitigation is needed. Whether an application is new or modified, the purpose of the review is to determine whether upgrades or mitigation may be needed. There is no basis for believing that the processing time for a modified application would require substantially less time to review than a new application. Hence it is reasonable to adopt a 10-day timeline for processing the modification requests. Being found reasonable, the Commission should adopt the additional recommendations as described above in Section 3.3.2.

With respect to the process modifications to existing facilities, we address each use case separately. Once again, the process options are:

1) No notification is required;
2) Notification is required but the customer can proceed without waiting for utility approval;
3) Abridged/streamlined interconnection request is required, and the customer must wait for utility approval to turn on the system (engineering review not required); and
4) Interconnection request is required, and the customer must wait for utility approval to turn on the system (engineering review required).

For use case 1, process option 1 should be adopted. Use case 1 involves replacing equipment with the exact same equipment type or performing upgrades to inverter firmware that do not affect grid interactions. We find that the replacement would not alter the underlying operational assumptions on which the original interconnection agreement was studied. Public Advocates' Office notes that the Commission should only require notifications or new interconnection applications when they are needed for safety or reliability concerns.[46] Only SDG&E opposes adoption of process option 1. In comment to the proposed decision, SDG&E explains that a new application should be required in every instance in which a permit, an electrical inspection, and an electrical release from the authority having jurisdiction (AHJ) must be obtained. If the work or upgrades meet the threshold for a permit from the AHJ, SDG&E holds that a new application for authorization to operate the new or upgraded electricity-generating equipment in parallel with SDG&E's system must be required. Therefore, SDG&E can only support Option 1 when a permit from the AHJ is not required.[47] However, SDG&E later responded that it is possible that an electrical permit could be required, and the project could be energized without an electric release.[48] We underscore that both PG&E and SCE supported this proposal. Furthermore, we note that while the AHJ may request permits, ensuring that the permits are filed is not the responsibility of the utilities. Thus, no notification to the utilities is necessary. Accordingly, no notification should be required for use case 1. Hence, the Commission should adopt process option 1 for use case 1.

For use case 2, we conclude that process option 2 should be adopted. Use case 2 involves replacing like-for-like equipment, where system output does not

[46] March Report at 56.

[47] SDG&E Opening Comments to the Proposed Decision, March 14, 2019 at 1-2.

[48] PG&E/SDG&E Response to August 15, 2018 Ruling at 10-11.

exceed what is listed in the original agreement and the operational profile does not change. Here again, the replacement would not alter the underlying operational assumptions on which the original interconnection agreement was studied. Hence the replacement would not affect a system's impact or interaction with the grid. Because we anticipate future growth in inverter replacement will repeat growth in NEM systems experienced over the past decade,[49] we consider process option 2, notification only, to be a more efficient process than the utilities-preferred process option 3, which is the abridged interconnection request without engineering review.

We recognize that process option 2 has not been developed at this time. As an interim solution, we will adopt SCE's recommendation to use a standard form template that would be sent to a dedicated utility email address.[50] The Utilities are directed to move forward with development of process option 2 , and are authorized to establish and record costs in a balancing account, funded by the interconnection fees, as suggested by the Utilities and TURN.[51] To implement the interim solution of using the standard form template, the Utilities shall jointly submit a Tier 2 Advice Letter describing the standard form template to be used on the interim basis. The Tier 2 Advice Letter shall be submitted no later than 90 days from the issuance of this decision.

For use case 3, we find that a hybrid approach is necessary to address the differences between projects above versus those at or below 100 kW. Use case 3

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[49] Inverters are assumed to have a useful life of 10 years.

[50] SCE Response to August 15, 2018 Ruling at 6.

[51] PG&E/SDG&E Response to August 15, 2018 Ruling at 10. *See also* SCE Response to August 15, 2018 Ruling at 7, and TURN Response to August 15, 2018 Ruling at 4.

involves replacing equipment that may increase the nameplate capacity of the system, but which employ inverter power controls that limit the real power output to the inverter's listed size. PG&E and SDG&E, along with SCE, support the adoption of process option 4 for use case 3 because of the need to verify that inverter power controls have been properly set, which may warrant a truck roll or a process to remotely verify the control system and associated certifications. SCE explains that the short circuit capability is based on inverter nameplate rating, and thus, while limiting the normal output via controls can solve the normal operation conditions, large inverters will cause a higher level of short circuit current contribution. SCE adds that this would require engineering evaluation to verify that existing systems are capable of withstanding the increased level of short circuit current from larger inverters that are limited through inverter power control. SCE notes that this relates mostly to larger installations and suggest that the Commission create a threshold of 100 kW or greater for the adoption of process option 4.[52] We find this to be a reasonable solution.

Tesla suggests establishing a threshold for capacity changes, rather than a threshold for the size of the project as a whole, below which the project would be subject to a notification-only requirement.[53] We do find that this suggestion is in alignment with the NEM grandfather language, which allows systems to increase to 110 percent of their original generating facility capacity as identified in its original permission to operate letter.[54] Accordingly, for projects at or below

[52] SCE Response to August 15, 2018 Ruling at 8.

[53] Tesla Opening Comments on the Proposed Decision at 13,

[54] March Report at 58.

100 kW, we find it reasonable to adopt process option 2 pending creation and implementation of certification schemes that proves inverter power controls can limit export. For projects above 100 kW, we find it reasonable to adopt process Option 4. For projects increasing capacity within 110 percent of original generating facility capacity as identified in its original permission to operate letter and maintaining the original permission to operate real power output via inverter power controls, we find it reasonable to adopt process option 2 to be in alignment with the NEM tariff grandfathering rules.

To aid in improving efficiencies in this process, we also find it reasonable to require the utilities to develop a calculator for process option 2 as part of the interconnection or retrofit application portal. The calculator, recommended by PG&E and SDG&E, would determine if a system could create safety or reliability problems, therefore needing a full engineering review under Process Option 4.[55] As noted by PG&E and SDG&E, the goal of this calculator is to create the ability to provide information quicker than the current three business day or less average cycle time. Such a calculator should improve efficiencies while ensuring safety and reliability of the grid and, thus, should be adopted by the Commission.

For use case 4, parties representing developers, including CALSSA and Tesla contend that adding kWh storage capacity does not change the impact of the system on the grid.[56] They explain that storage capacity determines the duration of time for which the system can charge or discharge. These parties also argue that customers should be allowed to add storage capacity to their

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[55] PG&E/SDG&E Response to August 15, 2018 Ruling at 11.

[56] March Report at 61-62.

systems, which does not impact the maximum charge/discharge rate, without waiting for utility approval or even notifying the utility.[57] PG&E and SDG&E state that adding additional cells to create a longer duration battery but not changing the maximum instantaneous energy does not trigger an engineering re-review and process option 3 is sufficient.[58] However, they contend that process option 3 and 4 are necessary because kWh is utilized to model the contribution of storage and the duration, for planning purposes.[59]

The determination in this decision of the process option for use case 4 is dependent upon a future outcome of Working Group Two that would consider measuring a generator's maximum output based on its rated capacity versus the generator's output profile. If the Commission determines that operational profiles of systems are to be used to determine system impacts, then process option 4 should be required because a full engineering review would be necessary.[60] However, if the Commission determines that a generator's maximum output should be based on its rated capacity, then process option 2 is sufficient to manage the use case. An engineering review would not be necessary because adding kWh storage capacity without changing the inverter does not increase the impact that the system can have on the grid at any given time. Accordingly, the Commission should utilize options 2 and 4 depending on the outcomes of Working Group Two.

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[57] *Ibid*.

[58] PG&E/SDG&E Response to August 15, 2018 Ruling at 14.

[59] March Report at 62.

[60] For the purposes of this decision, an operational profile is a system's output curve showing anticipated exports for each of the 8,760 hours in a year.

For use cases 5 through 7, process option 4, a consensus proposal, should be adopted. Use cases 5 through 7 entail system expansions and would increase the capacity of a system or materially change the system's operating characteristics.[61] Hence it is reasonable to adopt process option 4, which requires a normal interconnection request. All parties agree on the use of process option 4 for use cases 5 through 7. Accordingly, we conclude that the Commission should adopt process option 4 for use cases 5 through 7.

3.4. Issue 4: Modifying Telemetry Requirements to Ensure Adequate Visibility While Minimizing Costs

This decision concludes that the Commission should make a combination of changes to telemetry requirements in order to ensure adequate visibility while minimizing costs and addressing the situation of load masking. As discussed below, a combination of steps from Proposals 1 and 3, and Proposal 5, combined with a required 30-day deadline to repair or replace malfunctioning equipment, are deemed reasonable and should be adopted.

3.4.1. Issue 4: Telemetry Equals Visibility

The focal point of Issue 4 is obtaining visibility with telemetry. Telemetry, in this context, is the near real-time transmittal of information from a resource on the distribution system to the utilities. Telemetry provides distribution system operators with operational awareness of projects connected to the grid (*i.e.,* visibility) to inform decisions about grid operations. Currently, Section J of Rule 21 requires distributed energy resources larger than 1 MW to provide telemetry at the distributed energy resource owner's expense but only if less intrusive and/or more cost-effective options for providing the necessary data are

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[61] *Id.* at 62-63.

not available. The Utilities assert that increased use of real-time telemetry is necessary for grid visibility. The Commission's objective with regards to Issue 4 is to determine what changes, if any, to telemetry requirements the Commission should adopt to provide the level of visibility necessary to ensure adequate safety and reliability while minimizing costs.

The Utilities contend there is a need for increased use of real-time telemetry to maintain the safe operations of the grid and ensure reliable service. Specifically, the Utilities point to the concern of "load masking" where the lack of generation output visibility prevents system operators and engineers from determining the real system load condition which can inhibit the ability to plan and operate the distribution system.[62] Their contention is that if there is masked load, they may not have enough information to operate the grid in a way that safely handles unanticipated current flow.[63] The March Report states that this condition is caused equally by both exporting and non-exporting distributed energy resources installations, and from the point of view of the grid operator, the resource will reduce the localized electrical load served even if the resource does not export power into the grid.[64]

While parties want to ensure adequate visibility, all parties also recognize that telemetry costs in some cases have been prohibitive. According to the March Report, the developers state that current project telemetry costs ranged from

[62] *Id*. at 72.

[63] *Id* at 72-74.

[64] *Id.* at 72-73.

$10,000 to $250,000; the Utilities state that costs have generally ranged from $20,000 to $190,000.[65]

In the March Report, the working group presented five proposals to address Issue 4. The March Report explains that Proposals 1 and 2 are mutually exclusive; the Commission could adopt none or one of these proposals. None of Proposals 3, 4, and 5 are mutually exclusive; the Commission can adopt any combination of Proposals 3, 4, and 5. Also, whether or not the Commission adopts Proposal 1 or Proposal 2 does not affect whether it can adopt any combination of Proposals 3, 4, and 5. All five proposals are briefly described in the sections below.

3.4.2. Issue 4: Proposal 1

Proposal 1 for Issue 4 allows the utilities to require systems between 250 kW and 9.9 MW to provide telemetry if the estimated utility-related costs are less than $20,000. This is supported by TURN, PG&E, SCE, and SDG&E and opposed by CALSSA and its member companies. Supporters contend this reduces the telemetry threshold from the current 1 MW. However, the customer would be responsible for actual utility-related telemetry costs, which could exceed $20,000.

3.4.3. Issue 4: Proposal 2

Proposal 2 would maintain the 1 MW threshold for requiring telemetry. CALSSA and its member companies, as well as Clean Coalition, support Proposal 2 while TURN, PG&E, SCE, and SDG&E oppose the proposal.

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[65] *Id.* at 74-75.

3.4.4. Issue 4: Proposal 3

Proposal 3 for Issue 4 would require the utilities to adopt certain technical requirements for telemetry for systems larger than 1 MW to avoid unnecessary costs. CALSSA and its member companies, as well as Clean Coalition, support Proposal 3 while TURN, PG&E, SCE, and SDG&E oppose the proposal.

3.4.5. Issue 4: Proposal 4

Proposal 4 recommends applying the telemetry threshold to maximum facility export in the interconnection agreement if this value is different from the total nameplate rating of all generation on the site. CALSSA and its member companies support Proposal 4. TURN, PG&E, SCE, and SDG&E oppose the proposal.

3.4.6. Issue 4: Proposal 5

Proposal 5 of Issue 4 would allow customer ownership of behind-the-meter telemetry equipment, where practicable, to mitigate the costs associated with utility ownership of the equipment (i.e., the Income Tax Component of Contribution and Cost Ownership charges). CALSSA and its member companies and Clean Coalition support Proposal 5. SCE, and SDG&E also support the proposal contingent on interconnection agreement modifications. PG&E opposes Proposal 5.

3.4.7. Resolving Issue 4: A Cost-effective Telemetry Approach

Adopting portions of Proposals 1 through 3 provides the most cost-effective approach to ensure visibility and address load masking. However, additional information from the Utilities is necessary for implementation. This decision authorizes the Director of the Commission's Energy Division to facilitate a workshop in which each of the Utilities explains in detail: 1) their proposals for specific technical telemetry requirements for systems between 250 kW and 9.9

MW, and 2) why these requirements are in the best interests of ratepayers, including an analysis of the cost-effectiveness of the proposed requirements relative to other options for increasing distribution system visibility. The workshop should be held within 90 days of the issuance of this decision.

No later than 30 days following the workshop, each utility would be required to submit a Tier 3 Advice Letter describing the specific technical requirements, instead of specific equipment, for systems between 250 kW and 9.9 MW. The advice letters will be reviewed to determine: 1) whether the Utilities have presented a cost-benefit analysis showing that their recommended telemetry requirements and the lower 250 kW threshold provides a cost-effective means of collecting data on the distribution system and 2) whether the Utilities have demonstrated that other data sources, such as SCADA[66] and smart inverter data, would not be able to provide sufficient data to satisfy the Utilities' needs. If the Advice Letters are found to demonstrate that lowering the telemetry threshold is cost-effective (benefits are greater than the costs), then the resulting resolution should require systems between 250 kW and 9.9 MW to provide telemetry with a cost cap of $20,000 for estimated utility-related costs, as recommended in Proposal 1. The Advice Letters must propose technical specifications for telemetry rather than proposing specific equipment in order to allow the market to provide the most cost-effective solution. Furthermore, if the Advice Letters are found to demonstrate that other data sources can more cost-effectively provide data that is reasonably sufficient to address load masking, then the resulting resolution should direct the Utilities to adopt technical

[66] Supervisory Control and Data Acquisition System.

requirements for telemetry that could be met through other data sources, such as SCADA systems and smart inverters, in order to avoid unnecessary costs. As a result of adopting this combination of Proposals 1 through 3, we find that adoption of Proposal 4 is not necessary.

Proposal 5 recommends that customer ownership of behind-the-meter telemetry equipment be allowed where practicable to mitigate the costs associated with utility ownership of the equipment (*i.e.,* the Income Tax Component of Contribution[67] and Cost of Ownership charges).[68] Supporters of this proposal assert that ownership of the equipment, which includes the responsibility of equipment maintenance, is preferable to paying the Cost of Ownership charges and the Income Tax Component of Contribution.[69] This proposal is supported by SCE and SDG&E with the caveat that interconnection agreements be modified to allow for a cap of thirty days to repair or replace malfunctioning equipment as notified by the utility and if the malfunctioning equipment is not repaired by the thirtieth day, the utility can make the necessary repairs and charge the customer for related costs, or could disconnect the distributed energy resource.[70] We find that this proposal with the caveat meets the needs of the developers by better controlling their costs while meeting the

[67] The Income Tax Component of Contributions is a charge to cover a utility's resulting estimated liability for Federal and State Income Taxes for all Contributions in Aid of Construction.

[68] A cost of ownership charge reflects a utility's ongoing costs associated with owning and maintaining required telemetry equipment.

[69] March Report at 85.

[70] *Ibid*.

responsibility of the utilities to ensure the reliability of the grid. The Commission should adopt Proposal 5.

3.5. Issue 5: The Replacement of Existing Inverters with Smart Inverters

This decision concludes that the Commission should not require activation of advanced functionality in Phase 1-compliant inverters installed before September 9, 2017. However, while such activation is not required, we encourage the evolution toward smart inverters by adopting Proposals 1 and 2, as developed by the Smart Inverter Working Group and agreed upon by a consensus of Working Group One.

3.5.1. Issue 5: Inverters

An inverter is a device that converts the direct current (DC) power from a generating resource to the voltage and frequency of the alternating current (AC) power on the distribution grid. A smart inverter may mitigate some of the adverse grid impacts of distributed energy resources, enable greater penetration of distributed energy resources, and enhance the value of distributed energy resources by enabling grid services. The Commission adopted modifications to Rule 21 that incorporated technical requirements for inverters (*i.e.,* Phase I functions) that were recommended by the Smart Inverter Working Group.[71] Some inverters installed prior to September 8, 2017, may be capable of Phase I functions but lack the appropriate certification and software, firmware, or hardware updates. Issue 5 asks whether the Commission should require

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[71] Formed by parties of Rulemaking 11-09-011, the purpose of the working group was to develop proposals to take advantage of the new rapidly advancing technical capabilities of inverters.

activation of the advanced functionality of the Phase I-compliant inverters installed before September 8, 2017 and, if so, how.

As directed by the Scoping Memo, the Smart Inverter Working Group was assigned to and reviewed this issue. In the March Report, the Smart Inverter Working Group presented three proposals. Proposal 1 is independent of Proposals 2 and 3. Proposals 2 and 3 are mutually exclusive alternatives; the Commission could adopt either one or neither of the two. Proposals 1 and 2 have consensus support. Some parties, while supporting Proposal 2, prefer Proposal 3. Proposal 3 is only supported by the subset of parties that prefer it to Proposal 2. Each of the three proposals are described in the sections below.

3.5.2. Issue 5: Proposal 1

Proposal 1 recommends that the Commission would neither require nor incentivize activation of advanced functionality in Phase I-compliant inverters installed before September 9, 2017. The March Report states that while increasing the number of activated smart inverters on the grid is beneficial, the benefits do not outweigh the costs, including the effort to implement a mandatory or voluntary program. The March Report also points to legal concerns with respect to obtaining customer consent to implement such a program. Proposal 1 is supported by a consensus of Working Group One.

3.5.3. Issue 5: Proposal 3

Another consensus proposal, Proposal 2 recommends the Commission continue to permit customers to replace existing inverters with inverters of equal or greater ability and encourage, but not require, customers to replace existing inverters with smart inverters at end of life. The Smart Inverter Working Group underscores that instituting a requirement as opposed to encouragement would necessitate "a litany of exceptions to avoid unnecessary burden to customers."[72] Furthermore, it is likely that a majority of inverters at the end of their life will be replaced with smart inverters because this is what will be commonly available.[73] While this is a consensus proposal supported by all parties, the Utilities and TURN prefer Proposal 3 below.

3.5.4. Issue 5: Proposal 3

Proposal 3 takes the previous proposal one step further and recommends modification of Rule 21 whereby the Commission makes replacement of existing inverters with smart inverters at end of life a requirement. This proposal, supported by the Utilities and TURN, also recognizes that several exceptions would be needed. Exceptions are: a) if there would be an electrical conflict between existing and new inverters in systems with multiple inverters; b) if the physical space could not host a smart inverter without substantial reconstruction; c) if codes would require substantial new switches, fuses or other additional equipment; d) if the appropriate size smart inverter is not available; e) if the smart inverter would void a warranty; and f) if the smart inverter would cause the interconnection customer financial harm.[74] While acknowledging that a majority of inverters at the end of life will be replaced with smart inverters, the utilities maintain that it would not be logical to have a requirement to allow inverters to be replaced with non-smart inverters and then implement a program to update the inverters after the fact.[75]

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[72] March Report at 91.

[73] *Id*. at 92.

[74] *Id*. at 93.

[75] *Ibid*.

The March Report notes that the non-utility Smart Inverter Working Group members, except TURN, do not support this proposal. Clean Coalition does not oppose Proposal 3 but prefers Proposal 2.

3.5.5. Resolving Issue 5: Encouraging Not Requiring Smart Inverters

We find that it would not be cost-effective to require activation of advanced functionality in Phase 1-compliant inverters installed before September 9, 2017. However, given that most inverters will be replaced with commonly available smart inverters, we find it reasonable to adopt Proposals 1 and 2, where the Commission encourages customers to replace existing inverters with smart inverters at end of life.

With regards to Proposal 1, the Smart Inverter Working Group conducted a survey of its members in its effort to determine the portion of existing inverters that could be updated with all seven Phase 1 functions. Survey results indicated that only one to five percent of all inverter capacity can be updated.[76] Many older inverters are unable to support new capabilities due to hardware or other design limitations that prevent advanced function support. The Smart Inverter Working Group also reviewed the costs of updating inverters both remotely and onsite and providing a monetary incentive to customers; costs were estimated to be approximately $1.2 to $1.5 million.[77] Members of Working Group One agree that increasing the number of activated smart inverters is beneficial to the grid. The group surmises, and we agree, that the small percentage of inverters identified as capable of being updated would not produce the grid benefits

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[76] *Id.* at 89.

[77] *Id.* at 90.

sufficient to outweigh the costs and time required to implement a retrofit program.[78]

The costs for implementing a required activation or replacement program would also have to consider the administrative complexity of multiple exceptions. Smart Inverter Working Group members cautioned that a requirement to replace inverters at the end of life with smart inverters would require a "litany of exceptions to avoid unnecessary burden to customers."[79] Relatedly, the Smart Inverter Working Group members assert that a majority of inverters at their end of life will be replaced with smart inverters because that is what will be available.[80] It is reasonable to presume that in the future most inverters will be replaced with the commonly available smart inverters.

Accordingly, the Commission should adopt Proposals 1 and 2 where the Commission neither requires nor incentivizes activation of advanced functionality in Phase 1-compliant inverters, allows customers to replace existing inverters with inverters of equal or greater ability, and encourages customers to replace existing inverters with smart inverters at end of life. However, if a developer replaces an existing inverter with an inverter of greater ability, the new inverter shall have all the required functionalities and be set according to current Commission practices as of the date the new inverter was installed, unless the interconnection applicant can demonstrate that safety or operational needs necessitate otherwise.

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78 *Ibid*.

79 *Id.* at 91.

80 *Ibid*.

3.6. Issue 7: Income Tax Component of Contribution

This decision concludes that while there is inconsistent application of the requirement for customers to pay the Income Tax Component of Contribution, these applications are not in conflict with Commission directives. Furthermore, this decision determines that inconsistency is not the apex of this issue but, rather, the level of costs added to project costs. Developers contend that the question to be asked is whether it is good policy to require a developer to set aside substantial sums every year, over the term of an agreement, to protect the utility from the risk of an event that has never occurred.[81] Utilities argue that the Income Tax Component of Contribution security is a means for the utilities to protect itself from incurring costs for a future potential tax liability. As discussed below, this decision finds it reasonable to retain the status quo as it appropriately protects ratepayers.

3.6.1. Issue 7: Relevant Federal Income Tax Elements

Issue 7 asks the Commission to determine whether there is inconsistent application of the requirement to pay the Income Tax Component of Contribution Charges (as described below) across the Utilities and, if so, how the Commission should address the inconsistency. Issue 7 involves three federal income tax elements, which we describe below.

First, contributions in aid of construction (CIACs) are provided by customers to a utility to construct utility-owned assets what will benefit the customer by providing electric, gas, or other services; CIACs can take the form of

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[81] *Id.* at 101-102.

money and/or property. Internal Revenue Code Section 118(b) treats CIACs from customers as a taxable receipt to the utility.

Second, because utilities are cost-of-service regulated and the CIAC results in taxable income, the Utilities can collect an income tax component of contribution (ITCC) from the customer in addition to the CIAC, to make the utility and ratepayers whole. The tax burden associated with the CIAC is borne by the contributor based on the premise that the person who causes the tax should pay the tax. However, ITCC is not applicable when a transaction is considered nontaxable.

Third, in order for a transaction to be considered nontaxable, certain conditions must be satisfied, including satisfying the five percent test, which means that it is reasonably projected that, during the 10 taxable years beginning when the intertie[82] is placed in service, no more than five percent of the projected total power that flows over the intertie will flow to the generator. Other representations must also be satisfied. This exemption is referred to as the Safe Harbor or the Notice.[83]

Because the non-taxability treatment hinges upon satisfying certain conditions, the Commission recognized the utilities' exposure to tax risk and permitted the utilities to collect ITCC security on these projects.[84] Hence, even if

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82 Intertie is an interconnection permitting passage of current between two or more electric utility systems.

83 The Internal Revenue Service issued Notice 88-129, which exempted generator contributions from being treated as taxable under IRC 118(b) if the conditions are met.

84 D.94-06-038 established three options to assure payment to the purchasing utility for future tax: a) pay the ITCC; b) provide a letter of credit for the ITCC value; or c) executive an indemnity agreement and provide a guarantee for the ITCC value.

a contribution is nontaxable, a project may still be required to post a security instrument to protect the utility and ratepayers from a future tax risk.

In the March Report, the working group presented four proposals to address Issue 7. Proposals 1, 2, and 3 are mutually exclusive alternatives (only one can be adopted by the Commission). Proposal 4 is independent of the first three proposals. No proposal has consensus support. Each of the four proposals are described in the sections below.

3.6.2. Issue 7: Proposal 1

Proposal 1 for Issue 7 would retain the status quo, whereby each utility is authorized and retains the discretion to collect or not collect ITCC security on safe harbor projects. The Utilities and TURN support Proposal 1, Green Power Institute opposes this proposal.

3.6.3. Issue 7: Proposal 2

Proposal 2 recommends that, if the key outcome of this issue is consistency, the Commission revise the rules to require that all utilities collect ITCC security for safe harbor projects. If Proposal 1 is not adopted by the Commission, the Utilities and TURN support this proposal. Clean Coalition and Green Power Institute actively oppose this proposal.

3.6.4. Issue 7: Proposal 3

Proposal 3 for Issue 7 would prohibit the collection of security for safe harbor systems and authorize a recovery mechanism, whereby each utility recovers from ratepayers any actual costs realized as a result of ITCC charges. Clean Coalition and Green Power Institute support this proposal. The Utilities note that if the Commission adopts Proposal 3, the Utilities would support recovery through customer rates of costs incurred that are not recovered from the contributor for a taxable liability. TURN and the Public Advocates' Office oppose this proposal.

3.6.5. Issue 7: Proposal 4

Proposal 4 would expand the scope of this proceeding to consider whether there are ITCC practices that merit modification despite being consistent across utilities. Proposal 4 is supported by Clean Coalition, CALSSA, the Public Advocates' Office, and Green Power Institute. The Utilities oppose this proposal.

3.6.6. Resolving Issue 7: Maintaining the Status Quo

The March Report describes three proposals: 1) status quo, 2) requiring all utilities to collect a security for safe harbor projects; and 3) prohibit the collection of security and authorize a recovery mechanism whereby each utility recovers from ratepayers any actual costs realized as a result of the Income Tax Component of Contribution charge.

In the March Report, Clean Coalition asserts that posting the security represents a real cost to developers, adversely impacts project economics and can be an obstacle to smaller developers.[85] The developers maintain that while the security protects the utility from a potential tax liability, this policy may not be cost-effective for ratepayers and is bad policy because it could discourage the

[85] The developers present three arguments for reconsidering the ITCC security requirements. First, the developers assert that posting IRCC security represents a real cost to developers and can adversely impact project economics or become an obstacle to the project (for smaller developers unable to qualify for a letter of credit or load). Second, acknowledging the ITCC security posting protects the utilities and ratepayers, the developers contend the policy may not be cost-effective for ratepayers because it may result in discouraging the development of new renewable generation. Third, the developers maintain that risk of exposure for utilities is negligible while the cost to developers may be significant and may impede project development. *See* March Report at 101.

development of renewable generation. Hence, the developers do not see this issue as one of inconsistency versus consistency but rather as an issue of costs.

In reviewing this issue, the Utilities provided historical data on realized tax liability for safe harbor systems. The data indicates that this risk has not materialized under a tax audit in the past ten years.[86] The Utilities confirmed that the IRS has not identified, in a prior audit review, a project receiving safe harbor treatment (over the past ten years) that should be reclassified as taxable. The Utilities maintain this does not indicate that future reviews could not find a safe harbor transaction that fails the five percent test and triggers a subsequent taxable event.[87]

We disagree that the security requirement is bad for ratepayers. If not for this security, the Utilities would be at risk for a potential tax liability obligation, which would be funded by ratepayers. D.94-06-038 authorized options for the Utilities to protect themselves from this tax liability. The March Report indicates that the three utilities each have Rule 21 interconnections claiming safe harbor and each utility has different practices regarding ITCC security posting requirements, all of which are compliant with Commission rules and the IRS code.[88]

While the likelihood is low, the Utilities point to several factors that impact a generator's ability to remain in compliance with the Safe Harbor provisions, most of which are outside of the control of the Utilities, including: IRS code

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[86] *Id.* at 99.

[87] *Ibid*.

[88] Customers may meet ITCC security requirements by providing a letter of credit, corporate parent guarantee or cash deposit.

changes, economics, and generator size and interconnection.[89] Because inconsistency is not a documented concern, we find that the status quo protects the Utilities and ratepayers from this tax liability. Accordingly, the Commission should continue to authorize each utility to retain the discretion pursuant to D.87-09-026 and D.94-06-038 to collect or not collect security on safe harbor projects.

4. Comments on Proposed Decision

The proposed decision of Commissioner Michael Picker in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on March 14, 2019 by CESA, CALSSA, Green Power Institute, IREC, Public Advocates Office, SDG&E, SCE and PG&E (jointly) Tesla, and TURN, and reply comments were filed on March 19, 2019 by CALSSA, PG&E, SCE, Tesla, and TURN. In response, corrections and clarifications are made throughout this Decision.

5. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Kelly A. Hymes is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Transmission cluster studies are lengthy and costly to distributed energy resources projects.

2. Inverters and transformers are increasingly rated in MVA versus MW.

3. Project developers, customers, and utilities are accustomed to rules differentiating between projects smaller and larger than 1 MW.

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89 March Report at 102.

4. Establishing a 1 MVA threshold for the Screen Q exemption would align Rule 21 with other 1 MW thresholds for NEM cost allocation.

5. Raising the threshold for the Screen Q exemption to 1 MVA should reasonably avoid exempting projects from Screen Q that contribute to the need for Transmission Network Upgrades.

6. For Issue 1, Working Group One agrees on the core aspects of Proposal 1.

7. Measuring the system's anticipated net export creates additional steps, leading to increased study time, disputes, and uncertainty.

8. Inverter power controls to limit export and to limit short circuit duty contribution do not currently have certification schemes.

9. Rule 21 should only differentiate between projects on the basis of electrical impact, not enrollment in different procurement programs.

10. The Utilities provide no data to confirm their assertion that non-NEM projects are more likely to contribute to the need for Transmission Network Upgrades than equivalent NEM projects.

11. Non-inverter-based generation has a higher short circuit duty contribution than inverter-based generation.

12. Proposals 2 and 3 for Issue 1 are consensus proposals.

13. Proposal 2 for Issue 1 revises Rule 21 to reference the correct location of the CAISO tariff.

14. The incorrect citation to the CAISO tariff led to projects applying under Rule 21 being evaluated for responsibility of Deliverability Network Upgrades and Reliability Network Upgrades when they should only be responsible for Reliability Network Upgrades.

15. Proposal 3 for Issue 1 should lead to improved transparency into the Utilities' processes for performing additional review following failure of the Electrical Independence Test.

16. Proposal 4 for Issue 1 could result in increased ratepayer funding with unknown benefits to ratepayers.

17. The discussion in the March Report indicates a need for improved clarity regarding what the Utilities consider to be complex metering solutions.

18. Proposal 1 for Issue 2 will result in improved transparency into the Utilities' complex metering practices.

19. Proposal 2 for Issue 2 should also result in improved transparency because the Utilities would post clarifying information on their websites explaining requirements for non-export relays and controls.

20. Utility participation in the effort to develop DC metering standards, pursuant to Proposal 3 for Issue 2, should advance the development of these standards.

21. Proposal 3 for Issue 2 should lead to more technology-neutral interconnection rules.

22. No party opposed Proposals 1, 2, or 3 for Issue 2.

23. Working Group One members reached consensus in Issue 3 on the modifications to the definitions for like-for-like equipment replacements, size reductions, and size reductions to avoid upgrades.

24. No party presented any opposing argument to the definitions recommended in Issue 3.

25. The revised definitions in Issue 3 will provide developers additional flexibility and prevent them from having to withdraw and reapply and, subsequently, lose their queue position.

26. The revisions in Table 1 are reasonable.

27. The timelines described in Issue 3 should mirror timelines in Rule 21.

28. The recommendations provided in Section 3.3.2. regarding the number of modification requests allowed, fees for modifications, cost responsibility, and other modifications are reasonable.

29. The replacement referenced in use case 1 would not alter the underlying operational assumptions on which the original interconnection agreement was studied.

30. No notification should be required for use case 1.

31. The replacement referenced in use case 2 would not alter the underlying operational assumptions on which the original interconnection agreement was studied.

32. The replacement referenced in use case 2 would not affect a system's impact or interaction with the grid.

33. We anticipate future growth in inverter replacement due to the unprecedented growth in NEM systems over the past decade.

34. For use case 2, process option 2, notification only is a more efficient process than the utility-preferred process option 3, which is the abridged interconnection request without engineering review.

35. Process option 2 has not been developed at this time.

36. Using a standard form template that would be sent to a dedicated utility email address is a reasonable interim solution until process option 2 is developed.

37. A hybrid approach for use case 3 is necessary in order to address differences between projects at or above versus those below 100 kW.

38. Short circuit capability correlates with inverter nameplate rating and, while limiting the normal output via controls can solve the normal operation conditions, large inverters have the potential to cause a higher level of short circuit current contributions.

39. An engineering evaluation is required to verify that existing systems can withstand the potentially increased level of short circuit current from the larger inverters whose net export capacity is limited through inverter power controls.

40. For projects increasing capacity to below 100 kW, it is reasonable to adopt process option 2 for use case 3, pending the creation of certification schemes to limit export to the original generating facility's nameplate capacity.

41. For projects increasing capacity within 110 percent of original generating facility nameplate capacity, it is reasonable to adopt process option 2 for use case 3 because it is in alignment with the NEM tariff grandfathering rules.

42. It is reasonable to adopt process option 4 for projects that increase capacity to at or above 100 kW and more than 100 percent of the original generating facility's nameplate capacity for use case 3.

43. The development of a calculator, as part of the interconnection or retrofit application portal, will aid in improving efficiencies in process option 2.

44. The goal of the proposed calculator is to provide information quicker than the current three business days or less average cycle time.

45. The proposed calculator should improve efficiencies while ensuring safety and reliability of the grid.

46. Working Group Two will consider measuring a generator's maximum output based on its rated capacity versus the generator's output profile.

47. If the Commission determines that operational profiles of systems are to be used to determine system impacts, then process option 4 for use case 4 should be required because a full engineering review is necessary.

48. If the Commission determines that a generator's maximum output should be based on its rated capacity, then process option 2 is sufficient for use case 4 because an engineering review would not be necessary.

49. Working Group One agreed that for use cases 5 through 7, process option 4 should be adopted.

50. Use cases 5 through 7 entail system expansions and would increase the capacity of a system or materially change the system's operating characteristics.

51. Process option 4 requires a normal interconnection request.

52. Portions of Proposals 1 through 3 for Issue 4 provide a viable route to the most cost-effective telemetry approach that will ensure visibility and address load masking.

53. Additional information from the Utilities is needed to complete the record for Issue 4.

54. It is reasonable to require the Utilities to present the specific technical telemetry requirements for systems between 250 kW and 9.9 MW.

55. If the provided technical requirements proposed by the Utilities represent a more cost-effective approach to provide system visibility and address load masking (benefits outweigh the costs) and the Utilities can show that alternatives, such as SCADA and smart inverter data, cannot provide the data necessary to address load masking, it is reasonable to modify the telemetry requirement to between 250 kW and 9.9 MW on distribution voltage and require the Utilities to adopt technical requirements for telemetry with a cost cap of $20,000 for estimated utility-related costs.

56. If alternative data sources, such as SCADA and smart inverter data, represent a more cost-effective approach to provide system visibility and address load masking, then the Utilities should adopt technical requirements for telemetry that the alternative data sources can satisfy.

57. Proposal 5 for Issue 4, with a caveat that interconnection agreements be modified to allow for a cap of 30 days to repair or replace malfunctioning equipment, meets the needs of the developers by better controlling their costs and meets the responsibility of the Utilities to ensure the reliability of the grid.

58. It would not be cost-effective to require activation of advanced functionality in Phase 1-compliant smart inverters installed before September 9, 2017.

59. The one to five percent of inverters identified as capable of being updated would not produce the grid benefits sufficient to outweigh the cost and time required to implement a retrofit program.

60. The cost for implementing a required activation program would also have to consider the administrative complexity of multiple exceptions.

61. It is reasonable to presume that in the future most inverters will be replaced with commonly available smart inverters.

62. The developers do not see Issue 7 as one of inconsistency versus consistency.

63. Data indicates that the potential tax liability for safe harbor systems has not materialized under a tax audit in the past ten years.

64. The IRS has not identified, in a prior audit review, a distributed energy resources project receiving safe harbor treatment (over the past 10 years) that should be reclassified as taxable.

65. If not for the ITCC security requirement, the Utilities would be at risk for a potential tax liability obligation, which would be funded by ratepayers.

66. D.94-06-038 authorized options for the Utilities to protect themselves from this tax liability.

67. The Utilities point to several factors that impact a generator's ability to remain in compliance with the safe harbor provisions, most of which are outside the control of the Utilities including: IRS code changes, economics, and generator size and interconnection.

68. The status quo proposal protects the Utilities and ratepayers from this tax liability.

Conclusions of Law

1. The Commission should modify Fast Track Screen Q to reduce the number of projects subjected to transmission cluster studies.

2. The core aspects of Proposal 1 for Issue 1 should be adopted.

3. The Commission should measure the exemption threshold for Screen Q by nameplate capacity.

4. Proposal 1B for Issue 1 should be adopted.

5. The Commission should limit the exemption in Proposal 1B for Issue 1 to inverter-based generating facilities.

6. Proposal 2 and 3 for Issue 1 should be adopted.

7. Proposal 4 for Issue 1 should not be adopted.

8. The Commission should seek clarification regarding complex metering solutions.

9. Proposals 1, 2, and 3 for Issue 2 should be adopted.

10. The Commission should clarify the definition of complex metering solutions for storage facilities by adopting Proposals 1, 2, and 3 for Issue 3.

11. The revisions in Table 1 should be adopted.

12. The recommendations provided in Section 3.2.2. should be adopted.

13. For use case 1, process option 1 should be adopted.

14. For use case 2, process option 2 should be adopted.

15. The Commission should substitute a standard form template for process option 2 until process option 2 is developed.

16. For use case 3, the Commission should adopt process option 2 for projects increasing capacity to below 100 kW, following the creation of certification schemes to limit export to the original generating facility's nameplate capacity, and process option 4 for projects increasing capacity to at or above 100 kW and more than 100 percent of the original generating facility's nameplate capacity.

17. For use case 3, the Commission should adopt process option 2 for projects increasing capacity to at or above 100 kW and below 110 percent of the original generating facility's nameplate capacity, following the creation of certification schemes to limit export to the project's original nameplate capacity.

18. The Commission should require the development of the proposed calculator for process option 2.

19. The Commission should adopt either option 2 or 4 for use case 4 depending upon the outcomes of Working Group Two.

20. The Commission should adopt process option 4 for use cases 5 through 7.

21. The Commission should adopt Proposal 5 for Issue 4.

22. The Commission should adopt Proposals 1 and 2 for Issue 6, where the Commission neither requires nor incentivizes activation of advanced functionality in Phase 1-compliant inverters, allows customers to replace existing inverters with inverters of equal or greater ability, and encourages customers to replace existing inverters with smart inverters at end of life.

23. The Commission should continue to authorize each utility to retain the discretion pursuant to D.87-09-026 and D.94-06-038 to collect or not collect security on safe harbor projects.

O R D E R

IT IS ORDERED that:

1. Proposals 1A and 1B for Issue 1 from the March 15, 2018 Working Group One Final Report are adopted, expanding the existing Screen Q exemption for net energy metering (NEM) facilities with net export less than or equal to 500 kilowatts by increasing the exemption size threshold to all net energy metering and inverter-based projects with 1 megavolt ampere (MVA) or below nameplate capacity.

2. Proposal 2 for Issue 1 from the March 15, 2018 Working Group One Final Report is adopted, creating a soft link within Screen Q to the California Independent System Operator tariff.

3. Proposal 3 for Issue 1 from the March 15, 2018 Working Group One Final Report is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall identify engineering review guidelines related to the evaluation of Screen Q.

4. Proposals 1, 2, and 3 for Issue 2 from the March 15, 2018 Working Group One Final Report are adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall complete the following: develop illustrative metering configurations and cost tables to provide more transparency in the application of complex metering solutions, post information on their websites clarifying requirements for non-export relays and controls for solar plus storage systems to maintain Commission-required Net Energy Metering Tariff integrity requirements, and support development of

direct current metering standards by participating in the EMerge Alliance initiative or equivalent as utility resources allow.

5. All proposals for Issue 3 from the March 15, 2018 Working Group One Final Report that modify Rule 21 to allow for Type I modifications to interconnection agreements under Fast Track are adopted.

6. The process options for use cases for Type II modifications to existing projects, as indicated in Table 3 below, are adopted. For Use Case 3, process option 2 shall be used for projects increasing capacity to less than 100 kilowatt (kW), pending the creation of certification schemes for inverter power controls (software/firmware) to limit export, and process option 4 shall be used for projects increasing capacity to at or greater than 100 kW. For projects of any size that are requesting an increase in capacity within 110 percent of their original generating capacity, process option 2 shall be used. For Use Case 4, the use case will be based on a Commission determination on Working Group 2 proposals. If the Commission determines that operational profiles of systems should be used to determine system impacts, then process option 4 is adopted. If the Commission determines that a generator's maximum output should be based on its rated capacity, then process option 2 is adopted. Each process option is summarized in Table 3, below.

Table 3

Process Options Adopted for Modifications to Existing Facilities by Use Case

• *Process Option 1: No notification is required*
• *Process Option 2: Notification is required but the customer can proceed with building the system and turning on the system without waiting for utility approval*
• *Process Option 3: Abridged/Streamlined interconnection request is required and the customer must wait for utility approval to turn on the system (engineering review required)*
• *Process Option 4: Normal interconnection request*

Case	Description	Process Option
1	Replacing equipment with exact same equipment type or performing upgrades to inverter firmware that do not affect grip interactions	1
2	Replacing equipment "like-for-like", where system output does not exceed what is listed in the original interconnection agreement and operating mode is not adjusted.	2
3	Replacing equipment that may increase the nameplate capacity of the system, but which employ inverter power controls that limit the real power output to the inverter listed size in the original agreement.	2/4
4	Adding storage capacity to an existing storage facility without changing inverter.	2/4
5	Adding or replacing equipment such that system capacity increases and no inverter power controls are employed to limit the real power output to the inverter listed size in the original agreement.	4
6	Adding storage to an existing generating facility that does not have storage.	4
7	Changing inverter operating characteristics.	4

7. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall immediately begin to

develop process option 2 from Ordering Paragraph 6. The Utilities are authorized to establish and record costs in a balancing account, funded by the interconnection fees.

8. As an interim solution for process option 2 from Ordering Paragraph 6, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall use a standard form template to be sent to a dedicated utility email address. To implement the standard form template interim solution, no later than 90 days from the issuance of this decision the Utilities shall jointly submit a Tier 2 Advice Letter describing the template.

9. Proposals 1 or 2 for Issue 4 will be implemented depending upon the outcomes of a workshop and subsequent advice letters. The Director of the Commission Energy Division is authorized to hold a workshop within 90 days of the issuance of this decision at which time Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall present in detail the telemetry requirements for systems between 250 kilowatts (kW) and 9.9 megawatts (MW). No later than 30 days following the workshop, the Utilities shall submit Tier 3 Advice Letters describing the telemetry requirements, including a cost-benefit analysis of the telemetry as a means of collecting data on the distribution system, and providing information to indicate that Supervisory Control and Data Acquisition System (SCADA) and smart inverter data would not be able to provide sufficient data to satisfy the Utilities' needs. The ensuing resolution will implement Proposal 1, as modified below, if the telemetry is deemed necessary, which will then modify the telemetry requirement from 1 MW to between 250 kW and 9.9 MW on distribution voltage with a cost cap of $20,000 for estimated utility-related costs.

The Utilities shall publish technical requirements for telemetry rather than requiring specific equipment. The ensuing resolution will implement Proposal 3, if the Advice Letter indicates the Utilities' telemetry approach is not cost-effective. The Utilities' published technical requirements shall be able to be met through alternative data sources, such as SCADA and smart inverter data, if those options are shown to more cost-effectively produce the data necessary to provide system visibility and address load masking. The Utilities shall adopt certain technical requirements for telemetry only for systems larger than 1 MVA to avoid unnecessary costs.

10. Proposal 5 for Issue 4 from the March 15, 2018 Working Group One Final Report is adopted allowing customer ownership of behind-the-meter telemetry equipment where practicable to mitigate the costs associated with utility ownership of the equipment (i.e., the Income Tax Component of Contribution and Cost of Ownership charges).

11. Proposal 1 for Issue 5 from the March 15, 2018 Working Group One Final Report is adopted, which neither requires nor incentivizes activation of advanced functionality in Phase 1-compliant inverters installed before September 9, 2017.

12. Proposal 2 for Issue 5 from the March 15, 2018 Working Group One Final Report is adopted allowing customers to replace existing inverters with inverters of equal or greater ability, per D.14-12-035, and encouraging but not requiring customers to replace existing inverters with smart inverters at end of life. If a developer replaces an existing inverter with an inverter of greater ability, the replacement inverter shall have all the required functionalities and be set according to current Commission practices as of the date the new smart inverter is installed, unless the interconnection applicant can demonstrate that safety or operational needs necessitate otherwise.

13. Proposal 1 for Issue 7 from the March 15, 2018 Working Group One Final Report is adopted retaining the status quo, in which Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company are authorized and retain the discretion pursuant to Commission Decisions 87-09-026 and 94-06-038 to collect or not collect Income Tax Component of Contribution security on safe harbor projects.

14. Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company shall each file a Tier Two Advice Letter no later than 60 days from the issuance of this decision revising Electric Rule 21 to be consistent with this decision.

15. Rulemaking 17-07-007 remains open.

This order is effective today.

Dated March 28, 2019, at San Francisco, California.

MICHAEL PICKER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners