PUBLIC UTILITIES COMMISSION
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March 03, 2022

PG&E AL 6286-E,6286-E-A, and 6286-E-B
SCE AL 4559-E and 4559-E-A
SDG&E AL 3822-E, 3822-E-A, and 3822-E-B

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Subject: Staff Disposition of: PG&E AL 6286-E, 6286-E-A, and 6286-E-B; SCE AL 4559-E and 4559-E-A; and SDG&E AL 3822-E, 3822-E-A and 3822-E-B -- Modifications to Rule 21, Generating Facility Interconnections, Pursuant to Decision 20-09-035 Ordering Paragraphs 7, 49, 50 and 52 (SCE only)

Dear Dietz, Menon, Kaushik and Anderson:

Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric Company (SDG&E) submitted Advice Letters (ALs) 6286-E, AL 4559-E, and AL 3822-E, respectively, pursuant to Ordering Paragraph (OP) 55[1] of Decision (D.) 20-09-035. The ALs were protested by Tesla, Inc. (Tesla) and the Interstate Renewable Energy Council, Inc. (IREC). In response, PG&E, SCE and SDG&E submitted supplemental PG&E AL 6286-E-A, PG&E 6286-E-B, SCE AL 4559-E-A, SDG&E AL 3822-E-A and SDG&E AL 3822-E-B addressing selected contested topics. PG&E, SCE, and SDG&E have met the requirements set forth in D.20-09-035 Ordering

[1] OP 55 provides a list of the OPs in D.20-09-035 requiring changes to Electric Tariff Rule 21and the corresponding Advice Letter deadline for each change.

Paragraphs 7, 49, 50 and 52 (applicable to SCE only) by making the necessary tariff changes. PG&E AL 6286-E, 6286-E-A and 6286-E-B, SCE AL 4559-E and 4559-E-A, and SDG&E AL 3822-E, 3822-E-A and 3822-E-B and corresponding substitute sheets are approved with an effective date of August 6, 2021.

Attachment 1 contains a discussion of the ALs, the protests of Tesla and IREC, the IOUs replies to the protests and Energy Division staff's determination that PG&E AL 6286-E, 6286-E-A and 6286-E-B, SCE AL 4559-E and 4559-B, and SDG&E AL 3822-E, 3822-E-A, 3822-E-B and corresponding substitute sheets are compliant as modified with D. 20-09-035.

Please contact Jose Aliaga-Caro of the Energy Division staff at jc5@cpuc.ca.gov if you have any questions.

Sincerely,

Simon Baker
Interim Deputy Executive Director for Energy and Climate Policy /
Interim Director of Energy Division
California Public Utilities Commission

cc: Justin.Regnier@cpuc.ca.gov; Jose.Aliaga-Caro@cpuc.ca.gov; EDTariffUnit@cpuc.ca.gov; Service Lists R.11-09-011, and R.17-07-007. PGETariffs@pge.com; KELM@pge.com; AdviceTariffManager@sce.com; Karyn.Gansecki@sce.com; ACarrillo@sdge.com; SDGETariffs@sdge.com; anschwartz@tesla.com; stanfield@smwlaw.com

Attachment 1

I. BACKGROUND

Decision 20-09-035 *Adopting Recommendations from Working Groups Two, Three, and Subgroup*, (D.20-09-035 or the Decision) issued on September 30, 2020, in the Rulemaking (R.) 17-07-007,[2] directs the modification of Electric Tariff Rule 21[3] (Rule 21) of Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively the IOUs).

Ordering Paragraph (OP) 55[4] of the Decision orders PG&E, SCE and SDG&E to update Rule 21 in compliance with other OPs in the Decision; OP 55 provides a list of the OPs in the Decision requiring changes to Rule 21, the grouping of such changes, and the deadline for submitting the ALs. Per OP 55, the first set of ALs included changes ordered in seven (7) OPs: 7, 13, 14, 46, 49, 50 and 52.[5]

A. Initial ALs: PG&E AL 5988-E, SCE AL 4328-E, and SDG&E AL 3642-E

PG&E AL 5988-E, SCE AL 4328-E, and SDG&E AL 3642-E (the Initial ALs) were submitted on October 30, 2020 to respond to the OP 55 requirements. These ALs were timely protested on November 19, 2020. The IOUs submitted timely replies to the protests on November 30, 2020. In response to the protests, PG&E AL 5988-E-A, SCE AL 4328-E-A, and SDG&E AL 3642-E-A (collectively "the Supplementals to the Initial ALs") were submitted on May 19, 2021 addressing *selected* contested issues from the protests. These supplemental ALs resolved those contested issues that allowed for consensus between parties. These supplemental ALs, at Energy Division's guidance, did not contain all the content included in the Initial ALs and *only included* modifications to Rule 21 as ordered by OPs 13, 14, and 46. The Supplementals to the Initial ALs were disposed of separately and are not discussed herein.[6]

B. Current ALs Subject to this Disposition Letter: PG&E AL 6286-E, SCE AL 4559-E and SDG&E AL 3822-E

Modifications to Rule 21 in compliance with OPs 7, 49, 50 and 52 were *excluded* from the Supplementals to the Initial ALs. The reason for excluding content related to these OPs was because these modifications to Rule 21 required more in-depth discussions and were more complicated to resolve. Modifications in compliance with these OPs are the subject of this Disposition Letter.

Energy Division held meetings between February 2021 and July 2021 with the IOUs and the stakeholders who submitted protests to the Initial ALs. The purpose of the meetings was to clarify the

[2] Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.
[3] Rule 21 governs the interconnection of distributed energy resources to the utilities' electric grid.
[4] The OPs in D.20-09-035 contained errors in references to other OPs. These were the result of an OP that was deleted, from the draft, in the final decision, which changed the numbering sequence of subsequent OPs. D.21-01-027, issued on January 21, 2021, corrected the numbering sequence. Table 1 of this Disposition Letter reflects this correction.
[5] OP 52 is applicable to SCE only.
[6] PG&E's AL 5988-E-A and SDG&E AL 3642-E-A were approved by Energy Division disposition letter dated September 21, 2021; SCE AL 4328-E-A was approved by Energy Division disposition letter dated December 13, 2021.

issues, gain consensus and resolve issues related to the use of Power Control Systems (PCS). The cumulation of these discussions led to the filing of PG&E AL 6286-E, SCE AL 4559-E, SDG&E AL 3822-E (collectively "the Current ALs") on August 6, 2021 modifying Rule 21 in compliance with OPs 7, 49, 50 and 52 of the Decision. This Disposition Letter addresses the Current ALs and the associated protests.

C. Ordering Paragraph Requirements

OP 7: OP 7 adopted Option B of Proposal 8i which maintains the current process whereby non-exporting projects of all sizes skip Interconnection Rule 21 Screens K, L, and M.[7]

Although the current process is maintained, modifications to Rule 21 were still needed to include language mandated by OP 49 and 50. Modifications to Rule 21 for OP 7 are included in the IOUs' Rule 21 Section G.1.i--Screen I[8] (Engineering Review Details-Initial Review Screens-Screen I).[9]

OP 49 and OP 50: OP 49 and OP 50 adopted Proposal A-B-1 and Proposal A-B-2, respectively. These proposals allow the use of a PCS for non-export and limited-export applications. Specifically, OP 49 lists the requirements that a generating facility must meet to be treated as non-export or limited export, while OP 50 lists the requirements that a generating facility must meet to be treated as inadvertent export.

Modifications to Rule 21 for OP 49 and 50 are included in the IOUs' Rule 21 Sections:

- G.1.i: Engineering Review Details-Initial Review Screens-Screen I,
- Mm1.Option 8: Non-Export Utilizing Certified Power Control Systems,
- Mm2.Option 9: Limited Export Utilizing Certified Power Control Systems,
- Mm3. Option 10: Non-Export with Inadvertent Export Utilizing Certified Power Control Systems, and
- Mm4. Option 11: Limited Export with Inadvertent Export Utilizing Certified Power Control Systems.[10]

OP 52 (applicable to SCE only): OP 52 adopted Proposal A-B-4 only for customers of SCE. SCE was ordered to revise its Rule 21 tariff to require SCE customers applying for interconnection with a PCS to use only the systems on a pre-approved list. Modifications to Rule 21 for OP 52 are included in SCE's Rule 21 Section Hh.1.g (Smart Inverter Generating Facility Design and Operating Requirements-General Interconnection and Protective Functions Requirements).[11]

[7] Screen K asks whether a generating facility is a net energy metering project with a nameplate capacity equal to 500 kW or less. Screen L asks whether there are known transient stability limitation or if the proposed project has interdependencies with earlier-queued Transmission System interconnection requests. Screen M asks whether the total generation capacity on the line section is less than 15 percent of line section peak load for all time sections bounded by automatic sectionalizing devices.
[8] Screen I asks whether power will be exported across the Point of Common Coupling.
[9] PG&E AL 6286-E, at 7-8, SCE AL 4559-E at 4-5, and SDG&E AL 3822-E at 2-3.
[10] PG&E AL 6286-E at 12-16, SCE AL 4559-E at 5-12, and SDG&E AL 3822-E at 5.
[11] SCE AL 4559-E at 5.

D. Traditional Protective Relays and Power Control Systems (PCS) – Background for OP 49 Requirements

A traditional protective relay will physically disconnect the generating or storage facility from the grid if power flow is sensed in whichever direction power flow is not permitted. Its main function is to protect the electric grid by removing an element of the power system from service when it starts to operate in an abnormal manner that might damage or interfere with the effective operation of the electric grid. In the standard practice of the IOUs, the relay disconnects the generating facility if the relay senses reverse power flow for a time greater than 2 seconds. According to the Rule 21 Working Group 3 Report "if a customer installs a physical non-export relay it is relatively simple for the utility to validate that the system will not export. However, non-export relays can be prohibitively expensive."[12]

PCS are systems or devices that electronically limit or control the Alternating Current (AC) or Direct Current (DC) of a generating facility to a programmable limit or level. PCS have an Open Loop Response Time (OLRT) that is described by the Working Group 3 Report below:

> The example of a load-following generating facility with both solar and storage can illustrate the concepts of open-loop response time and inadvertent export. When load increases, the storage system discharges to meet that load. When the load decreases, the system reduces output or stops discharging but will inadvertently export to the grid for a period of time to the extent that instantaneous generation exceeds instantaneous load. **This time period is referred to as the open loop response time of the control system**. When load reduces quickly, power may be inadvertently exported to the grid during the time it takes for the system to sense the load reduction and tell the battery to stop discharging. If a system has been tested and certified under the UL CRD[13] for limited export, the generating facility can export power up to nameplate capacity until the control system makes a correction within its certified open-loop response time.
>
> Utilities must account for this inadvertent export while also recognizing that it is short-lived and non-coincidental among customers on a circuit segment because the load of neighboring customers does not go up and down in unison. Further, it should be noted that these control systems do not limit the number of export occurrences, and the instances of export are based on the customer's operating characteristics. Customers who have very cyclic loads will undergo inadvertent export many times, while customers who have relative steady load pattern will have very few instances of inadvertent export.[14]

A key difference between a traditional protective relay and a PCS has to do with the mechanism used to control power output to the electric grid. Once a relay registers a level of current that triggers the protective function, the relay will create a physical air gap between the generating system and the

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[12] Rule 21 *Working Group Three Final Report, June 14, 2019*, at 127.

[13] UL CRD refers to *Underwriters Laboratory Power Control Systems Certification Requirements Decision* which lists testing conformance for PCS. It "provides a way for inverters and power control systems to be tested and qualified for non-export and limited export…. A power control system certified to the UL CRD allows a device to demonstrate that it is capable of preventing or limiting export, within a time-delay of up to 30 seconds." (Rule 21 *Working Group Three Final Report*, June 14, 2019, at 127.)

[14] Rule 21 *Working Group Three Final Report, June 14, 2019*, at 129, emphasis added.

electric grid, thereby bringing the power output to the electric grid to zero. Once a PCS registers a level of current that triggers the protective function, a PCS will rely on electronics to control the power output to the electric grid and may not entirely bring power output to the grid to a zero value and may not necessarily retain it at or near zero within the OLRT. Additionally, the Working Group 3 Final Report reads:

> [A relay] acts in unexpected circumstances, when generating facility controls deviate from normal. A [PCS] device, in contrast, may operate much more frequently, or even continuously, to regulate system output under normal conditions. A further difference is the level of historical utility experience. Relays have been used for many decades, while very little experience yet exists with [PCS]. While power control systems have been used historically, they have not been relied upon historically in the same way that [PCS] devices without a physical non-export relay are now being relied upon.[15]

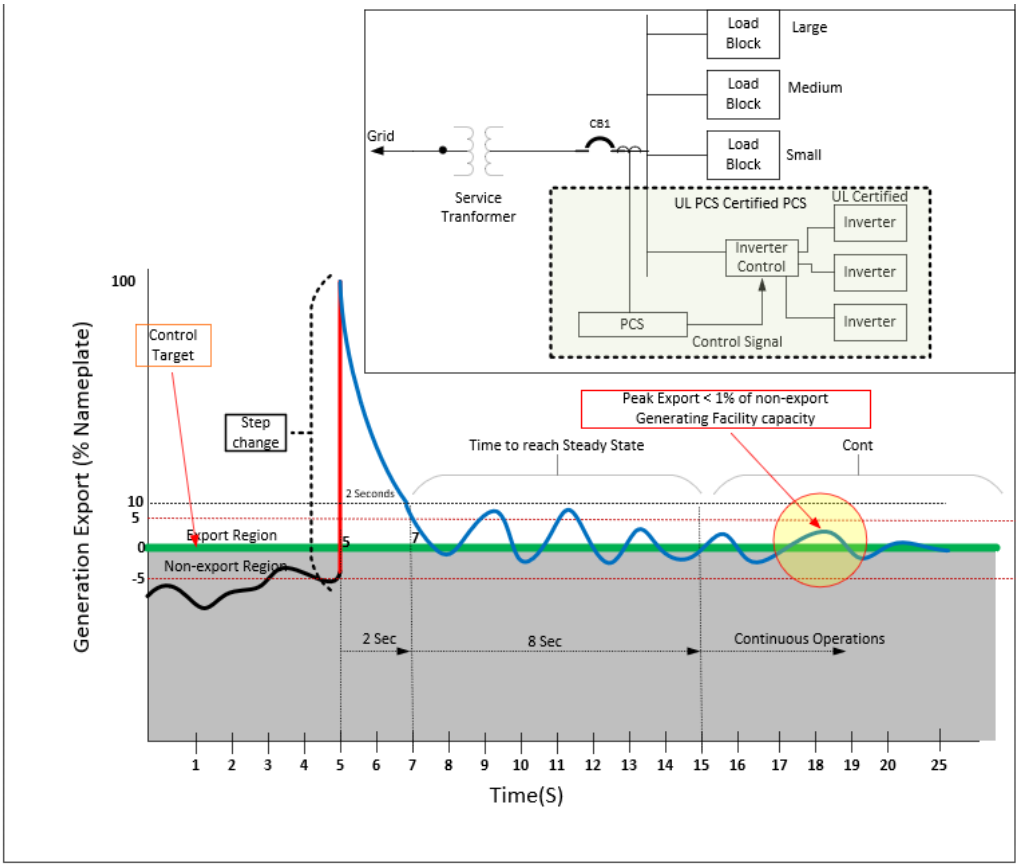
Discussions during the meetings Energy Division held with the IOUs and stakeholders centered on the OLRT and the limitations of a PCS to stop export of power within the OLRT of 2 seconds[16] per the requirements of OP 49. To reflect the inability of the PCS to act identically to a relay and make these proposals workable to ensure safety and reliability of the grid, the discussions revolved around adding a period of time after the OLRT for the PCS to reach a steady state value. Although no formal definition has been adopted in Rule 21 nor the standards for "steady state," in general terms, steady state is a system condition where the controlled parameter (e.g., output power) does not change over time or the change is bounded within certain values.

Figure 1 shows the concept of steady state for a 2 second ([s]) OLRT. Between time (t) equals (=) zero to t=5 [s] the generating facility is not exporting power to the electric grid and all power produced by the generating facility is being absorbed by the existing load (black squiggly line). At t=5 [s] there is a sudden drop in load and the facility starts exporting power to the electric grid (vertical red line the "step change") more than the allowed limit (horizontal green line). The period between t=5 and t=7 [s] is the 2-second OLRT during which time the PCS attempts to bring the export power value back down (blue descending line) to the allowed limit. But the PCS may not reach the allowed limit within the OLRT and there could be a time after the 2 [s] OLRT where the PCS exports and absorbs small amounts of power (blue squiggly line). To account for this operation, the IOUs have added, after the OLRT, an 8 [s] period of time for the PCS to reach steady state--the PCS must reach steady state within 10 [s] (at t=15) after the step change. After t=15 [s], during continuous operation, the PCS will keep the export value bounded and below a pre-determined value.

Figure 1: PCS Operation Responding to a Rapid Loss in Load

[15] Rule 21 *Working Group Three Final Report, June 14, 2019*, at 128.

[16] "A power control system certified to the UL CRD allows a device to demonstrate that it is capable of preventing or limiting export, within a time-delay of up to 30 seconds." (Rule 21 *Working Group Three Final Report, June 14, 2019*, at 127.)



Source: Diagram from informal discussions papers. E-mail from SCE on Tuesday 6/1/2021 at 5:10 P.M.

E. Protest by Tesla, and Replies by the IOUs

Tesla submitted a protest to the Current ALs on August 26, 2021. The IOUs filed timely replies on September 2, 2021 to Tesla's protest.

Tesla protested four topics. The protest and the IOUs' replies are summarized below:

1. **Section Mm1 should be expanded to explicitly indicate that non-exporting systems that meet the stated requirements and criteria enumerated as part of Option 8 shall be treated as non-exporting.** Tesla acknowledges that section Mm1 captures the requirements agreed upon, but requests language be added "that makes explicit that systems that meet the identified criteria will be treated as non-exporting."[17]

    - The IOUs reply that the change proposed is unnecessary and Tesla's proposed language is "the complement and tantamount to the same requirements that PG&E has included in its tariff,"[18] that the IOUs proposed language "adequately addresses Tesla's

[17] Tesla Protest at 2.
[18] PG&E Reply to Tesla's Protest at 3.

concern,"[19] and that "Tesla's proposed language is a different way to arrive at the same conclusion when compared to the existing language."[20]

2. **The thresholds included in the criteria applicable to systems greater 600 kVA should be revisited and revised in the future based on empirical data and/or study to ensure they are grounded in a more objective and fact-based assessment of practical impacts.** Tesla argues that revisions in sections Mm1 and Mm2 include thresholds for the steady state value of the PCS as 1 percent. This percentage was a result of informal discussions between the IOUs and selected stakeholders that had protested this language. Tesla states that the 1% value is not based on empirical data or evidence and that the ALs should be modified to indicate that the thresholds are interim and will be updated when more information is available "ideally via an expressly defined research and evaluation plan over the next year that will further assess the practical impacts of inadvertent export and what levels/durations would result in material impacts on the grid."[21]

    - PG&E replies that "there is no evidence indicating that these threshold values are not the "right" thresholds."[22] SCE replies "The proposed thresholds, which stakeholders supported, are appropriate and necessary to ensure grid safety and reliability given that it is not possible to determine the exact level, timing, and frequency at which a system would experience an issue" [23] and is not opposed to revisiting these values in the future as long as safety and reliability are not compromised. SDG&E also supports revising the existing criteria in the future based on new data.[24]

3. **The data requirements imposed on applicants that are included as part of Sections Mm3 and Mm4 regarding anticipated inadvertent exports are highly impractical and require additional work to operationalize.** Tesla acknowledges these requirements were included pursuant to OP 50 of the Decision, but is concerned that "they are highly impractical. In order to obtain this data the applicant would need to extensively meter their site at significant cost and then model how a storage or other DER system would operate to arrive at a reasonable estimate or characterization of anticipated inadvertent export"[25] and recommends "additional stakeholder dialogue to discuss how this information can be obtained without unduly burdening customers."[26]

    - The IOUs reply that this language was included in the Proposal A-B-2 which was a consensus proposal by stakeholders and was approved by the Decision. Additionally, the IOUs argue that it is impossible for them to determine how the system will operate and therefore must rely on the customer to provide this information.[27] SCE further

[19] SCE Reply to Tesla's Protest at 1.
[20] SDG&E Reply to Tesla's Protest at 1.
[21] Tesla Protest at 2.
[22] PG&E Reply to Tesla's Protest at 4.
[23] SCE Reply to Tesla's Protest at 2.
[24] SDG&E Reply to Tesla's Protest at 1.
[25] Tesla Protest at 3.
[26] Tesla Protest at 3.
[27] PG&E Reply to Tesla's Protest at 5; SCE Reply to Tesla's Protest at 2-3; and SDG&E Reply to Tesla's Protest at 2.

argues that because it was a consensus proposal and was "approved by the Commission, there is no need for additional stakeholder dialogue."[28]

4. **Additional clarification and information is needed regarding the distribution provider's approved list of PCS systems.** Tesla requests that the IOUs "provide additional information regarding the process by which an entity can request to have their PCS listed, how the utilities will evaluate the PCS, as well as a timeline for the review to be completed from start to finish."[29] Tesla also requests the IOUs to be directed to establish a uniform and coordinated review process.

    - PG&E replies that it "will prepare a website detailing the process for its review and approval of PCSs, as well as its list of approved PCS, as part of the implementation of OP 52."[30] SCE replies that this requirement is only applicable to SCE and states "While coordinating with the other IOUs is a good industry practice, it was not required as part of OP 52. SCE will maintain a website detailing the process for SCE to review and approve control systems, along with its list of approved control systems, as part of the implementation of OP 52."[31] SDG&E replies that this requirement is only applicable to SCE.[32]

F. Protest by IREC, and Replies by the IOUs

IREC submitted a protest to the Current ALs on September 2, 2021. Protests were due on August 26, 2021; therefore, this protest was submitted late. Energy Division informed the IOUs that IREC's late protest was accepted, and per GO 96-B, Section 7.4.4, the IOUs had five business days to reply. The IOUs filed timely replies on September 10, 2021 to IREC's protest.

IREC protested six topics. The protest and the IOUs' replies are summarized below:

1. **The requirements in the newly added Mm1 through Mm4 are unduly restrictive and are only acceptable as a temporary solution.** IREC argues the proposals "to establish requirements for the use of certified PCS are unduly restrictive, not supported by evidence of documented risks, and thus should only be used as a temporary solution."[33] IREC states that there is no evidence to demonstrate that there is a need to impose further restrictions on facilities using PCS, beyond requiring a two or ten second OLRT and believes it is more appropriate to require that PCS have an open loop response time of two or ten seconds and nothing more. IREC notes it agreed upon certain restrictions beyond requiring a two or ten second OLRT with the intent that these restrictions were temporary, and that IREC prepared a document, with input from the IOUs, describing the "next steps" IREC states that the IOUs had agreed to include the "next steps" document in their Advice Letters but failed to do so.

[28] SCE Reply to Tesla's Protest at 3.
[29] Tesla Protest at 3.
[30] PG&E Reply to Tesla Protest at 5.
[31] SCE Reply to Tesla Protest at 3.
[32] SDG&E Reply to Tesla Protest at 2.
[33] IREC Protest at 2.

- PG&E and SCE reply that there was a discussion on the "next steps"[34] document, but it is incomplete and consequently was not included in the Current ALs.[35] PG&E states it is committed to completing the analysis and "taking additional actions, including updating the appropriate Mm sections if the analysis supports that updates to these sections will not compromise equipment operations and/or grid safety."[36] SCE also shares this commitment[37] and SDG&E "supports revisiting existing criteria in the future, based upon new empirical data to avoid or add requirements."[38]

2. **No evidence indicates that an open loop response time of 2 or 10 seconds is insufficient to ensure the safe and reliable operation of the grid, and it is not rational to conclude that the Decision imposes additional restrictions.** IREC argues that to "interpret the language in the Decision[39] as imposing additional restrictions beyond the open loop response time is not rational…[and] Interpreting that language as an additional requirement involves developing substantial further technical specifications that go well beyond what the Commission adopted in its Decision."[40] While IREC asserts the additional requirements are unnecessary from a safety and reliability standpoint, it remains committed to addressing the IOUs' concerns. The "Next Steps" process IREC proposes identifies the list of concerns and research that can address them. IREC states that the Commission should either (1) adopt the Next Step process as a requirement for approving the Current ALs or (2) reject the Current ALs and "remove the additional requirement that projects cease operation within two seconds."[41] IREC argues that the IOUs have not identified any evidence that projects with PCS that meet the OLRT would cause safety or reliability impacts to the grid.[42] IREC argues that "In the absence of a Next Steps document, the Commission should require that PCS certified under the UL CRD have an open loop response time of 2 or 10 seconds, and nothing more."[43] IREC states "Essentially all the requirements in Ordering Paragraph 49 would remain except the duplicative language in item (ii) indicating systems should reduce export within two seconds."[44]

   - PG&E replies "acceptance of proposal A-B #1 and A-B #2 was based on the working group consensus that the control system would be able to reduce export to approve limit within a required time (2 seconds or 10 seconds)…[and that OP 49] is very clear about the two second requirement."[45] PG&E states that the additional proposed language regarding the steady state period of time in the tariff revisions was necessary to bring the PCS operational performance close to OP 49 requirements because the PCS failed

[34] As PG&E describes it, "The "next steps" process IREC mentions identifies the list of potential concerns the utilities have identified, research that can address those concerns, and provided that parties will evaluate and discuss the research." PG&E Reply to IREC Protest at 2-3.
[35] PG&E Reply to IREC Protest at 2-3; SCE Reply to IREC Protest at 1-2.
[36] PG&E Reply to IREC Protest at 3.
[37] SCE Reply to IREC Protest at 2.
[38] SDG&E Reply to IREC Protest at 1.
[39] Footnote 5 in IREC's Protest at 3-4 states "the language in question reads that a PCS shall: "be able to reduce export power to the approved export limit within two seconds of exceeding the approved export limit.""
[40] IREC Protest at 3-4.
[41] IREC Protest at 4.
[42] IREC Protest at 4.
[43] IREC Protest at 4.
[44] IREC Protest at 4.
[45] PG&E Reply to IREC Protest at 3-4.

to meet the Decision's requirements to "reduced export power to the approved export limit" as agreed upon in the Working Group 3 Report. PG&E states it is committed to continue to work through these issues with stakeholders once sufficient information is available to show there are no safety issues from the PCS and only then should the requirements be modified. Similarly, SCE states:

> SCE is not misinterpreting the Decision to impose additional restrictions. The language in the Decision is clear that the PCS "must be able to reduce export power to the approved export limit within two seconds of exceeding the approved export limit… To date, the PCS has been unable to meet OP 49's requirement to "reduce export power to the approved export limit" within two seconds.[46]

and:

> SCE is unable to ignore the export associated with these systems without evaluating the risks. However, SCE is committed to continuing to work on these issues with stakeholders. Indeed, SCE and stakeholders already agreed to add language to Sections Mm1 and Mm2 to bring the requirement closer to the PCS operational performance. (SCE added the following language to address the fact that the PCS cannot meet the Decision's requirements: "A PCS that is certified with an open-loop response time of two seconds or less, and a time to reach steady state of 10 seconds or less, meets this requirement.") Moreover, when sufficient information is available that shows that there are no safety issues due to the performance of the PCS, SCE would be supportive of reviewing and modifying the requirements.[47]

SDG&E "argues the opposite: no evidence existing to indicate the open-loop response time of 2 or 10 seconds is sufficient to ensure safety and reliability."[48] SDG&E also states that it is not misinterpreting the OP 49 language and that the language in the Decision is clear in stating that the PCS "must be able to reduced export power to the approved export limit within two seconds of exceeding the approved export limit."[49] SDG&E also expresses that "the PCS has fallen short of its expectations and cannot meet the performance requirements of OP 49 to 'reduce export power to the approved export limit.'"[50] SDG&E also states it is committed to continuing the discussions on these issues with stakeholders and that it supports modifications to the requirements once information is available that there are no safety issues due to the performance of the PCS.

3. **Section Mm1 needs revision to clearly state that projects will be treated as non- export during the screening process.** IREC argues that section Mm1 does not provide sufficient

[46] SCE Reply to IREC Protest at 2.
[47] SCE Reply to IREC Protest at 3.
[48] SDG&E Reply to IREC Protest at 1.
[49] D.20-09-035 at 222.
[50] SDG&E Reply to IREC Protest at 2.

clarity that qualifying projects will be treated as non-exporting projects in Screen N or other appropriate screens when they meet all the IOUs' requirements, and suggests language should be added to section Mm1(iii) to make that clear.

- The IOUs reply that the proposed language included in the Current ALs was drafted by IREC. Furthermore, the IOUs state that there was no conversation to include language related to Screen N within section Mm1 because projects under this section would not make it to Supplemental Review (Screen N) as these projects are considered non-export.[51]

4. **Section Mm4 is Missing Part of the Consensus Language.** IREC states that at the end of Rule 21 section Mm4 (Option 11, Limited Export OLRT between 2 and 10 seconds), the submitted advice letters failed to include language that was part of the consensus language agreed upon during discussions and should be added back to the tariff. Specifically, IREC argues that the following language be added "Use only the largest facility in the line section for aggregate evaluation for subsequent interconnection requests."

   - The IOUs reply that the language was intentionally left out because Section Mm4 is for exporting generators and are thus part of the interconnection queue and are used to study subsequent interconnection requests. Furthermore, "The language remains for Mm3, inadvertent export, because it is not expected that all projects would be in inadvertent export mode at the same time. However, Section Mm4 addresses exporting generators that are expected be exporting at the same time, so they must be studied as such."[52]

5. **PG&E's proposed language contains minor inconsistencies with the language proposed by the other IOUs.** IREC notes that it is important that the language used in Rule 21 be consistent across each of the IOUs' tariffs to avoid confusion and facilitate further revisions down the road and requests that this inconsistency be remedied.

   - PG&E states it "regrets it missed these differences and will submit a supplement to address them."[53]

6. **SCE proposes to revise its Interconnection Application forms, but PG&E and SDG&E have not.** IREC argues all the IOUs should revise their interconnection application forms. Additionally, IREC argues that SCE's interconnection application forms do not use Rule 21's defined terms, suggests revisions to SCE's forms; and recommends that if the other IOUs are required to revise their forms, they should pay attention to the use of defined terms.

   - IOUs' Replies: PG&E states that it has revised its Interconnection Application for Non-Export. PG&E states it:

[51] PG&E Reply to IREC Protest at 4-5; SCE Reply to IREC Protest at 3; SDG&E Reply to IREC Protest at 2-3.
[52] PG&E Reply to IREC Protest at 5; SCE Reply to IREC Protest at 3; SDG&E Reply to IREC Protest at 3.
[53] PG&E Reply to IREC Protest at 6.

included changes to address the various non-export scenarios in its updates to forms for the consolidated application portal – the Smart Connect/ You[r]Projects advice submittal, AL 6270-E.[54] While this AL is approved and effective, PG&E is open to additional changes on its forms for the non-export scenarios. PG&E is contemplating additional changes to its forms for its new portal in succeeding roll-out.[55]

SCE opposes most of IREC's proposed modifications to its Interconnection Application forms.[56] SDG&E "agrees to revise its Interconnection Application Form consistent with SCE's proposed revisions."[57]

G. Supplemental ALs Filed in Response to IREC's Protest: PG&E AL 6286-E-A and 6286-E-B, SCE AL 4559-E-A, and SDG&E 3822-E-A and 3822-E-B

On November 19, 2021 PG&E filed Supplemental AL 6288-E-A addressing IREC's protest regarding the inconsistent language in its Rule 21 modifications. On January 7, 2022 PG&E filed Supplemental AL 6288-E-B seeking to update its existing interconnection application forms to align with those of SCE and SDG&E.

On November 19, 2021 SDG&E filed Supplemental AL 3822-E-A addressing IREC's protest regarding aligning its interconnection forms with those of SCE. On January 7, 2022, SDG&E filed Supplemental AL 3822-E-B standardizing verbiage for the Interconnection Application Forms.

On January 7, 2022 SCE filed Supplemental AL 4559-E-A addressing IREC's protest and modifying Form 14-732, Generating Facility Interconnection Application and Form 14-918, Rule 21 Exporting Generating Facility Interconnection Request, to provide greater consistency among the IOUs.

On January 28, 222, the IOUs submitted substitute sheets correcting a typo in modifications to Section G.1.i (Screen I).

Details to these supplemental filings are described in Section II: Disposition.

II. DISPOSITION

Energy Division staff (Staff) has reviewed D.20-09-035, the IOUs' ALs (PG&E AL 6286-E, SCE AL 4559-E and SDG&E AL 3822-E), Tesla's and IREC's protests, the IOUs' replies to the protests, the Supplementals ALs (PG&E AL 6286-E-A and 6286-E-B, SCE 4559-E-A, and SDG&E AL 3822-E-A and 3822-E-B) and finds that PG&E AL 6286-E, 6286-E-A and 6286-E-B, SCE AL 4559-E and 4559-E-A, and SDG&E AL 3822-E, AL 3822-E-A, and AL 3822-E-B and corresponding substitute sheets are in compliance with OPs 7, 49, 50 and 52 of D.20-09-035.

A. Disposition of Tesla's Protested Topics

[54] PG&E AL 6270-E: Modifications to Various Pacific Gas and Electric Company's Electric Rule 21 Filed Forms to Support the Consolidation of its "YourProjects" Generator Application and Service Plan Application Online Portals
[55] PG&E Reply to IREC Protest at 6.
[56] SCE Reply to IREC Protest at 4.
[57] SDG&E Reply to IREC Protest at 3.

1. **Tesla: Section Mm1 should be expanded to explicitly indicate that non-exporting systems that meet the stated requirements and criteria enumerated as part of Option 8 shall be treated as non-exporting.**

Background: Section Mm1, Option 8 (Non-Export Utilizing Certified Power Control Systems) is added to Rule 21 to comply with OP 49. Section Mm1, Option 8 describes the requirements for non-export systems that use a PCS with an OLRT of no more than two seconds.

Protested Issue and Replies: Tesla requests language be added to Section Mm1, Option 8 to make explicit that systems that meet the identified criteria will be treated as non-exporting. The IOUs argue that the language Tesla proposes is redundant and unnecessary as it is already included in the proposed language. SCE states:

> SCE's proposed language adequately addresses Tesla's concern by making clear that a non-export system will be evaluated under screens I, J, K, M, N, and O utilizing the provided calculation only if it has an aggregate PCS controlled nameplate greater than 600 kVA and the maximum reported steady state value of the PCS is greater than 1 percent of the PCS controlled nameplate.[58]

The IOUs have proposed the following language:

> If the non-export system has an aggregate PCS controlled nameplate greater than 600 kVA and the maximum reported steady state value of the PCS is greater than 1% of the PCS controlled nameplate (as provided in the NRTL[59] testing reports), the evaluation may utilize the following calculation when determining the impacts to the grid under screens I, J, K, M, N, and O: The sum of the nameplate values of the exporting DER resource (if any) plus the maximum percentage steady state value of the PCS (as provided in the NRTL testing reports) times PCS controlled nameplate capacity.[60]

Tesla's proposes the following language should be added at the end of the IOUs proposed language:

> If the non-export system has an aggregate PCS controlled nameplate of 600 kVA or less, or the maximum reported steady state value of the PCS is 1% or less of the PCS controlled nameplate (as provided in the NRTL testing reports), then the system is considered non-exporting (export = zero) in screens I, J, K, M, N and O.[61]

Disposition: Tesla is concerned about a system being considered as non-export, under Option 8, in screens I, J, K, M, N and O if the system has an aggregate PCS controlled nameplate of 600 kVA or less, or the maximum reported steady state value of the PCS is 1% or less of the PCS controlled nameplate. We dispose of Tesla's concerns based on the Rule 21 screens:

[58] SCE Reply to Tesla Protest at 1-2.
[59] National Recognized Testing Laboratory, a private sector organizations that performs certification for certain products to ensure that they meet the requirements of both the construction and general industry electrical standards.
[60] PG&E AL 6286-E at 13, SCE AL 4559-E at 6, SDG&E AL 3822-E at 83 (Tariff Sheet: Cal. PUC. Sheet No. 35153-E)
[61] Tesla Protest at 2.

i. Screen I: Screen I asks "Will power be exported across the PCC?" This screen determines whether a project is considered export or non-export. All projects must go through this screen. Choosing any option within this screen determines that the project is non-export as long as the project meets the requirements in the option chosen. Therefore, Staff finds that inclusion of Tesla's proposed language is redundant since choosing Option 8, and passing the requirements, would already classify the project as non-export.

ii. Screens J, K, M: OP 7 of the Decision requires "Option B of Proposal 8i is adopted whereby non-exporting projects of all sizes skip Interconnection Rule 21 Screens K, L, and M."[62] Modifications in compliance with OP 7 are included in modifications to Screen I, whereby the IOUs propose the following language (strikethroughs signify deletions, underline signify additions):

- Screen I: Will power be exported across the PCC?
  - If Yes, Continue to Screen J. This includes Options 5, ~~and~~ 6, 9, 10 and 11 ~~below~~.
  - If No, then to ensure that the Generating Facility does not export across the PCC, the Generating Facility must incorporate ~~Protective Function~~ Options 1, 2, 3, 4, 7 or 8 below. Following that selection, Screen J, K, L, and M are skipped and Initial Review is complete. If ~~Protective Function~~ Option 8 is used, see section ~~Mm2~~ [Mm1[63]] to determine screen application.[64]

This language is inclusive of non-export systems of all sizes and states that Screens J, K, L, and M are skipped once an option is chosen. Staff determines that this language adequately addresses Tesla's concern of non-export systems skipping screens J, K and M upon choosing Option 8.

iii. Screens N and O: Under Rule 21, the Fast Track Review process consists of the Initial Review (Screens A through M) and, only if required, a Supplemental Review (Screens N through P). The need for Supplemental Review is determined based on the results of the Initial Review screens (Screens A-M). The modifications for OP 7, as stated above, guarantee that Initial Review is passed once a non-export option is chosen. Projects that pass the Initial Review and meet all the requirements of the option chosen may not be required to go to Supplemental Review.

Option 8 (Section Mm1) lists the minimum requirements for non-export systems that use a certified PCS with an OLRT of no more than 2 seconds or less. In addition, the tariff modification states "The PCS must reduce export to zero or less within two seconds of commencing export. A PCS that is certified with an open-loop response time of two seconds or less, and a time to reach steady state of 10 seconds or less, meets this requirement."[65] This language applies the time to reach steady state window which was discussed during the meetings Energy Division held between stakeholders—it allows the use of the PCS given its

[62] D.20-09-035 at 207.
[63] Substitute sheets submitted on January 28, 222 by the IOUs corrected a typo—the original proposed text referenced section Mm2, which is Option 9, not Option 8. The substitute sheets now reference Section Mm1 (Option 8).
[64] PG&E AL 6286-E-A at 7, SCE AL 4559-E at 4, SDG&E AL 3822-E at 2.
[65] PG&E AL 6286-E at 12, SCE AL 4559-E at 6, SDG&E AL 3822-E at 83 (Tariff Sheet: Cal. PUC. Sheet No. 35153-E).

limitations to reduce export to zero within 2 seconds. Option 8 also specifies, as the IOUs propose:

> If the non-export system has an aggregate PCS controlled nameplate greater than 600 kVA and the maximum reported steady state value of the PCS is greater than 1% of the PCS controlled nameplate (as provided in the NRTL testing reports), the evaluation may utilize the following calculation when determining the impacts to the grid under screens I, J, K, M, N, and O: The sum of the nameplate values of the exporting DER resource (if any) plus the maximum percentage steady state value of the PCS (as provided in the NRTL testing reports) times PCS controlled nameplate capacity.

The language above applies to systems **greater than** 600 kVA with the maximum reported steady state value of the PCS greater than 1% of the PCS controlled nameplate. It does not apply to systems below 600 kVA or below the steady state value of the PCS less than 1%, which concerns Tesla. Tesla's proposed additional language is the inverse of the language already proposed by the IOUs. If systems below the specified criteria pass the Mm1 screen, they will bypass Screens N and O. Therefore, Staff determines that this process addresses Tesla's concern of non-export systems skipping screen N and O.

For the foregoing reasons, Staff determines that the IOUs' language is sufficient under Section Mm 1, Option 8, and there is no need to add the additional language Tesla has requested and that Tesla's concern is addressed by the Rule 21 screening process. Should any issues arise regarding this topic through any formal or informal complaint, Staff may address it through an appropriate venue. Therefore, this request by Tesla is denied.

2. **Tesla: The thresholds included in the criteria applicable to systems greater 600 kVA should be revisited and revised in the future based on empirical data and/or study to ensure they are grounded in a more objective and fact-based assessment of practical impacts.**

Background: Revisions in sections Mm1, Option 8 (Non-Export Utilizing Certified Power Control Systems) and Mm2, Option 9 (Limited Export Utilizing Certified Power Control Systems) are added to Rule 21 in response to OP 49 and include thresholds for the steady state value of the PCS as one percent (1%). This percentage was a result of informal discussions Energy Division held between the IOUs and selected stakeholders that had protested this language in the Initial ALs. The percentage was chosen as a means to evaluate this screen given the limitations of the PCS in achieving the requirements set forth in the Decision.

Protested Issue and Replies: Tesla states that the 1% value is not based on empirical data or evidence and that the ALs should be modified to indicate that the thresholds are interim and will be updated when more information is available.

PG&E, in its reply, states that there is no evidence indicating that the thresholds are not the right ones and states "we are in a condition where the thresholds are not well understood and therefore, keeping grid safety and reliability in mind, it is more appropriate to side with keeping these assumptions on the

side of needing to perform additional analysis than to assume no safety issues will occur."[66] SCE and SDG&E state they are not opposed to revisiting this criteria in the future based on available information as long as safety and reliability are not compromised.

Disposition: While Staff finds merit in revisiting this topic, Staff does not agree that language to revisit this topic needs to be included in the Current ALs. The 1% requirement was a compromise to allow PCS, which perform differently than a traditional relay, to achieve the goals of the new screens (Mm1 and Mm2). Therefore, this request by Tesla is denied at this time.

This determination, however should not be interpreted as indicating that this issue is not worthy of discussion at a future date. Staff reminds stakeholders that there are venues to further discuss these topics, such as the Interconnection Discussion Forum (IDF) and the Smart Inverter Working Group (SIWG). Additionally, per D.21-06-002[67] OP 17 Energy Division will be compiling a list of topics to revisit in the future rulemaking. OP 17 of D.21-06-002 specifically states:

> One year from the closure of this proceeding, Commission Energy Division is authorized to seek informal comments on new interconnection issues and potential revisions to interconnection policies, from entities listed on this and future interconnection proceeding service lists. The comments shall be used to draft the preliminary scope in an Order Instituting Rulemaking for the successor interconnection rulemaking.[68]

Staff expects that by this time, if not sooner, the utilities will have better experience implementing these new screens and have more knowledge for the issue to be better addressed.

3. **Tesla: The data requirements imposed on applicants that are included as part of Sections Mm3 and Mm4 regarding anticipated inadvertent exports are highly impractical and require additional work to operationalize.**

Background: Sections Mm3, Option 10 (Non-Export with Inadvertent Export Utilizing Certified Power Control Systems) and Mm4, Option 11 (Limited Export with Inadvertent Export Utilizing Certified Power Control Systems) are added to Rule 21 in response to OP 50. OP 50 of the Decision states "during Supplemental Review the applicant shall identify, within 15 days, the frequency of inadvertent export, the real power level in watts of inadvertent export and the time duration of inadvertent export."

Protested Issue and Replies: Tesla argues that the OP 50 requirements are impractical for the customer and recommends additional stakeholder dialogue so as not to burden customers.

The IOUs reply that this language was approved by the Decision. Additionally, the IOUs argue that it is impossible for them to determine how the system will operate and therefore must rely on the customer to provide this information.

[66] PG&E Reply to Tesla Protest at 4.
[67] Decision 21-06-002 in R.17-07-007 resolved remaining issues from the Rule 21 Working Group 4 Report.
[68] D.21-06-002 at 92.

Disposition: The Decision adopted this requirement. Therefore, this request by Tesla is denied. Should this become an issue in the future, there are venues where it can be addressed such as the IDF or the SIWG. Alternatively, Tesla has the option to formally request modification of the Decision per the CPUC's Rules of Practice and Procedure.

4. Tesla: Additional clarification and information is needed regarding the distribution provider's approved list of PCS systems.

Background: Information regarding a pre-approved list is included for SCE only pursuant to OP 52.

Protested Issue and Replies: Tesla requests the utilities "provide additional information regarding the process by which an entity can request to have their PCS listed, how the utilities will evaluate the PCS, as well as a timeline for the review to be completed from start to finish."[69] Tesla also requests the IOUs to be directed to establish a uniform and coordinated review process.

PG&E replies that it "will prepare a website detailing the process for review and approval of PCSs and a list of approved PCS as part of the implementation of OP 52."[70] SCE replies that this requirement is only applicable to SCE and states that coordination with other IOUs was not required as part of OP 52. Furthermore, SCE replies it will maintain a website detailing the process for review and approval of control systems, and a list of approved control systems. SDG&E replies that this requirement is only applicable to SCE.

Disposition: Pursuant to OP 52 of the Decision and the Rule 21 Working Group 3 Report[71] the pre-approved list requirement is only applicable to SCE. While not explicitly obligated to do so, PG&E, in its reply, stated that it will maintain a website and list of approved PCS. Staff finds that PG&E's efforts are not mandated by the Decision but are welcomed as they will increase transparency and inform developers of approved PCSs. Staff also finds, that while these topics merit further discussion, they are beyond the scope of the requirements of OP 52 as the Decision did not order SCE to provide information on the process by which an entity can request approval and listing of a PCS. This topic is better suited for a discussion in the IDF, and Staff expects to place it on a future IDF agenda. Staff encourages SCE, SDG&E and PG&E, to informally provide additional transparency about their process to review and approve PCSs. Therefore, this request by Tesla is denied.

B. Disposition of IREC's Protested Topics

1. IREC: The requirements in the newly added Mm1 through Mm4 are unduly restrictive and are only acceptable as a temporary solution.

Background: Sections Mm1, Option 8 (Non-Export Utilizing Certified Power Control Systems) and Mm2, Option 9 (Limited Export Utilizing Certified Power Control Systems) are added to Rule 21 in response to OP 49; and Sections Mm3, Option 10 (Non-Export with Inadvertent Export Utilizing Certified Power Control Systems) and Mm4, Option 11 (Limited Export with Inadvertent Export Utilizing Certified Power Control Systems) are added to Rule 21 in response to OP 50. Energy

[69] Tesla Protest at 3.
[70] PG&E Reply to Tesla Protest at 5.
[71] Rule 21 *Working Group Three Final Report, June 14, 2019*, at 137-138.

Division held meetings between February 2021 and July 2021 with the IOUs and the stakeholders that protested the Rule 21 modifications arising from OP 49 in the Initial ALs. The purpose of the meetings was to analyze how to align the requirement of OP 49 with the operational capabilities of PCSs.

Protested Issue and Replies: IREC argues the proposals to establish requirements for the use of certified PCSs are "unduly restrictive, not supported by evidence of documented risks, and thus should only be used as a temporary solution…[and there is no evidence] to demonstrate that there is a verifiable need to impose further restrictions on facilities using PCS, beyond requiring a two or ten second open loop response time."[72] IREC states that the appropriate approach is to simply require that PCS have an open loop response time of two (Ordering Paragraph 49) or ten (Ordering Paragraph 50) seconds and nothing more. IREC notes it agreed upon certain restrictions during the Energy Division discussions beyond requiring a two or ten second OLRT with the intent that these restrictions were temporary, and that IREC prepared a document ("Next Steps on Power Control System Performance")[73] with input from the IOUs describing the next steps to be taken concerning the use of PCSs. The document lists steps to be taken to "identify whether, and to what extent, inadvertent export from certified power control systems may impact the distribution system."[74] The document outlined steps to be taken by the IOUs to evaluate transformer loading scenarios to determine impacts of inadvertent export on transformers, scenarios to be analyzed with regards to OP 49 and OP 50 to understand the impacts of PCS, timelines to conduct these analysis, and the IOUs' concerns. The document mentions Department of Energy research projects:

> that are expected to evaluate impacts from inadvertent export: The National Renewable Energy Laboratories (NREL) "Improving Solar and Solar+Storage Screening Techniques to Reduce Utility Interconnection Time and Costs" project and the Interstate Renewable Energy Council and the Electric Power Research Institute "Building a Technically Reliable Interconnection Evolution for Storage" (BATRIES)[75]

and includes a timeline for the CPUC Energy Division to re-convene discussions with stakeholders and the IOUs regarding these research projects. IREC states that the IOUs agreed to include the Next Steps on Power Control System Performance in their Advice Letters but failed to do so.

PG&E and SCE reply that there was a discussion regarding this document, but it is incomplete and consequently was not included in the Current ALs. PG&E, SCE and SDG&E state they support revisiting the criteria and updating the appropriate Mm sections if the analysis supports updates that will not compromise equipment operations and/or grid safety.

Disposition: While it was Energy Division's understanding that the "Next Steps on Power Control System Performance" document *would be* included in the Current ALs, after more consideration Staff determines that the "Next Steps on Power Control System Performance" document provided by IREC contains some information that is not appropriate for an advice letter, and is not necessary in order to

[72] IREC Protest at 2-3.
[73] See IREC Protest, Attachment A.
[74] IREC Protest, Attachment A at 1.
[75] IREC Protest, Attachment A at 2.

continue further discussions. Therefore, this request by IREC to include the document in the Current ALs is denied.

Denial of including the "Next Steps on Power Control System Performance" document in the Current ALs should not be interpreted, however, as Staff's determination that this issue is not worthy of discussion at a future date, or that the Utilities acted in good faith in drafting the ALs. While the document outlines a clear course of action, it contains wording that is inappropriate to include in an AL, such as mandating Energy Division to take certain actions[76] or mandating the CPUC to convene meetings to discuss the results of studies.[77] Staff finds that such mandates for Energy Division or the CPUC are not appropriate for a third-party to impose upon as a requirement for next steps to be taken concerning further discussions around the OLRT and PCS. Furthermore, there are venues to further discuss these topics, such as the IDF and the SIWG. Pursuant to D.21-06-002 OP 17 Energy Division will be compiling a list of topics to revisit in the future rulemaking. These venues allow Energy Division and the Commission to further explore this topic without the necessity for including a "next steps" document in the Current ALs. The IOUs support revisiting the criteria and updating the appropriate sections in Rule 21. Staff will work with IREC and the IOUs to schedule further discussions on this topic in the venues identified above.

2. **IREC: No evidence indicates that an open loop response time of 2 or 10 seconds is insufficient to ensure the safe and reliable operation of the grid, and it is not rational to conclude that the Decision imposes additional restrictions.**

Background: This issue is related to Section II.B.1 (Disposition of IREC Protested Topic 1) above.

Sections Mm1, Option 8 (Non-Export Utilizing Certified Power Control Systems) and Mm2, Option 9 (Limited Export Utilizing Certified Power Control Systems) are added to Rule 21 in response to OP 49; and Sections Mm3, Option 10 (Non-Export with Inadvertent Export Utilizing Certified Power Control Systems) and Mm4, Option 11 (Limited Export with Inadvertent Export Utilizing Certified Power Control Systems) are added to Rule 21 in response to OP 50. Energy Division held meetings between February 2021 and July 2021 with the IOUs and the stakeholders that had protested the Rule 21 modifications due OP 49 and 50 in the Initial ALs. The purpose of the meetings was to attempt to align the requirements of OP 49 and OP 50 with the operational capabilities of a PCS.

Protested Issue and Replies: IREC states that it was its understanding that

> based on the extensive discussions of the Working Group [3], that a two second open loop response time was sufficient. To interpret the language in the Decision[5] as imposing additional restrictions beyond the open loop response time is not rational.[78]

IREC states "Interpreting that language as an additional requirement involves developing substantial further technical specifications that go well beyond what the Commission adopted in its Decision."[79]

[76] Such as "In April 2022, the CPUC energy division will re-convene the stakeholders to discuss the BATRIES and NREL research results." IREC Protest, Attachment A at 2.
[77] IREC Protest, Attachment A at 1.
[78] IREC Protest at 3. IREC footnote 5 states: "the language in question reads that a PCS shall: "be able to reduce export power to the approved export limit within two seconds of exceeding the approved export limit"."
[79] IREC Protest at 4.

While IREC does not believe additional requirements are necessary from a safety and reliability standpoint, it remains committed to addressing the IOUs' concerns. IREC states that the Commission should adopt the process outlined in the "Next Steps on Power Control System Performance" document as a requirement for approving the Current ALs or "alternately, the Commission should reject the Advice Letters and instead simply remove the additional requirement that projects cease operation within two seconds."[80] IREC argues that the IOUs have not identified evidence that projects with PCS that meet the OLRT would cause safety or reliability impacts to the grid. IREC argues that "In the absence of a Next Steps ["Next Steps on Power Control System Performance"] document, the Commission should require that PCS certified under the UL CRD have an open loop response time of 2 or 10 seconds, and nothing more.[7]"[81]

SDG&E replies that there is no evidence existing to indicate the open-loop response time of 2 or 10 seconds is sufficient to ensure safety and reliability. PG&E replies that "acceptance of proposal A-B #1 and A-B #2 was based on the working group consensus that the control system would be able to reduce export to approve limit within a required time (2 seconds or 10 seconds)…[and that OP 49] is very clear about the two second requirement."[82] SCE and SDG&E also express that they are not misinterpreting the Decision to impose additional restrictions and that OP 49 is clear that the PCS must be able to reduce export power to the approved export limit within two seconds of exceeding the approved export limit.

PG&E states that the additional proposed language (i.e., the steady state language) in the tariff revisions was to bring the PCS operational performance close to OP 49 requirements because the PCS failed to meet the Decision's requirements to reduce export power to the approved export limit as agreed upon in the Working Group 3 Report. SCE and SDG&E also state that the PCS has been unable to meet OP 49's requirement to reduce export power to the approved export limit within the two seconds ordered by OP 49. Additionally, SCE states it is:

> unable to ignore the export associated with these systems without evaluating the risks…. Indeed, SCE and stakeholders already agreed to add language to Sections Mm1 and Mm2 to bring the requirement closer to the PCS operational performance. (SCE added the following language to address the fact that the PCS cannot meet the Decision's requirements: "A PCS that is certified with an open-loop response time of two seconds or less, and a time to reach steady state of 10 seconds or less, meets this requirement.")[83]

PG&E, SCE and SDG&E express commitment to continue to work through these issues with stakeholders once sufficient information is available to show there are no safety issues due to the performance of the PCSs and support reviewing and modifying the requirements in the future as additional information becomes available.

Disposition: IREC's protested issue is two-fold:

[80] IREC Protest at 4.
[81] IREC Protest at 4. IREC footnote 7 states "Essentially all the requirements in Ordering Paragraph 49 would remain except the duplicative language in item (ii) indicating systems should reduce export within two seconds…."
[82] PG&E Reply to IREC Protest at 3-4.
[83] SCE Reply to IREC Protest at 3.

(1) *Adoption of "Next Steps on Power Control System Performance" document as a Requirement to Approve the Current ALs:* While Staff recognizes the importance of future discussions that may lead to modifications of Sections Mm1 through Mm 4 in Rule 21, as discussed in Section II.B.1 of this Disposition Letter (Disposition of IREC Protested Topic 1) the document does not need to be formally adopted in order to continue discussions as there are other venues available to stakeholders, Energy Division, and the Commission to address this subject. Furthermore, although this document serves to outline future steps to take, it was not part of the requirement of the OPs in the Decision and thus it is not necessary to include the document in the Current ALs. Therefore, this request by IREC is denied.

However, the document does serve as a starting point for future discussions. Topics for future discussion include, but are not limited to:

- Transformer Impacts – The IOUs, working with transformer manufacturers, shall evaluate loading scenarios to determine potential impacts of inadvertent export on transformer life.
- DOE Funded Research Projects – Reconvene stakeholders to discuss the BATRIES and NREL research results, and relevant findings of these projects and applicability to inadvertent export and PCSs.
- Identify Further Concerns – The IOUs identified further concerns (e.g., Impact to Voltage Regulation Equipment, Impact on protection (fuses, reclosers), Impact on reactive power equipment (Capacitor banks) that need to be discussed further in light of new research findings and IOU experience with PCSs.

Staff will evaluate the topics and place them in the correct venues for discussion; these topics shall be on the agenda for the 2022 meetings for either IDF or SIWG. Depending on outcomes of those discussions, Staff will pursue any necessary steps needed for tariff modifications if such modifications are warranted.

(2) *Open Loop Response Time of Two (OP 49) Seconds—"Additional Requirement" and Steady-State Language:* OP 49 states:

> Proposal A-B 1 is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall modify their Rule 21 tariffs to allow the use of a power control system for non-export and limited export interconnection applications. Rule 21 shall be modified to establish the following five specifications that generating facilities must meet to be treated as non-export or limited export: i) use a power control system that passes the requirements of the Underwriters Laboratory (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol; ii) use a power control system that has an open-loop response time of no more than two seconds, as provided in the control systems specification data sheets, **and must be able to reduce export power to the approved export limit within two seconds of exceeding the approved export limit** [emphasis added]…

With regards to IREC's claim that "the Commission should reject the Advice Letters and instead simply remove the additional requirement that projects cease operation within two seconds" Staff clarifies that this is **not an additional requiremen**t. The Decision adopted Proposal A-B-1[84] without

[84] D.20-09-035 at 153.

modifications.[85] In the Working Group 3 Report, Proposal A-B-1, which was a consensus proposal that stakeholders agreed upon, specifically states "the PCS is required to reduce export power to the approved export limit within 2 seconds of exceeding the approved export limit."[86] The Working Group 3 Report also notes the proponent's position of CALSSA:

> A zero-export system uses power controls in lieu of a physical non-export relay but operates in an **equivalent** [emphasis added] fashion to a system with a physical non-export relay. **Rule 21 currently includes a maximum response time of two seconds for relays**. If a power control system **responds within the same timeframe** the resource should be treated the same as a resource using a relay. Also, limited export is no different. If it **will not export beyond the set amount for more than two seconds**, the controlled maximum export should be treated as the system capacity.[87]

The language in the Working Group 3 Report and the Decision is clear: the PCS is required to reduce export power to the approved export limit within 2 seconds. Therefore, Staff finds IREC's argument regarding this as being an "additional requirement" is inaccurate and the IOUs are not misinterpreting the language for this requirement.

Staff finds that because these are new technologies there is neither evidence for nor against the assertion that PCS OLRT of 2 or 10 seconds is sufficient to ensure grid safety and reliability. In adopting proposals A-B-1 (OP 49) and A-B-2 (OP 50) to allow the use of a power control system for non-export, limited export and inadvertent export for interconnection applications the Decision found that "that adoption of these recommendations allows the Commission to maintain technology neutrality, while fully utilizing new technologies that can **safely and reliably substitute non-export relays** [emphasis added] and limit the grid impacts of interconnecting generation."[88]

In keeping with the intent to keep the grid safe and reliable, and because the PCSs do not meet the requirements in the exact manner as a relay, a steady state period of time has been added to Rule 21 to align the current capabilities of PCS with the requirements of the Decision for OP 49. The steady state period of time for the PCS allows the power output of the generating facility to arrive at a well bounded level of export. For OP 49, the IOUs have included the following language "The PCS must reduce export to zero or less within two seconds of commencing export. A PCS that is certified with an open-loop response time of two seconds or less, and a time to reach steady state of 10 seconds or less, meets this requirement."[89] In so doing, the IOUs have met the requirements of OP 49 and have added language to better align the capabilities of the PCS to the intent of the Decision. Staff acknowledges that the time to reach steady state is an additional requirement. However, Staff finds inclusion of the steady state period of time strikes a balance between the 2-second zero current requirement as required by OP 49 and the capabilities of the PCS because it allows the use of a PCS in a manner "almost equivalent" to a relay. Out of abundance of caution to maintain a safe and reliable grid and minimizing grid impacts due to interconnecting generation, Staff finds the proposed language

[85] As opposed to Proposal A-B-3 (not discussed herein) in which the Decision specifically sates "We also adopt Proposal A-B-3 but modified…." (D.20-09-035 at 154)
[86] Rule 21 *Working Group Three Final Report, June 14, 2019*, at 131.
[87] Rule 21 *Working Group Three Final Report, June 14, 2019*, at 132, emphasis added.
[88] D.20-09-035 at 154.
[89] PG&E AL 6286-E at 12 and 14, SCE AL 4559-E at 6 and 7, and SDG&E AL 3822-E at 82 (Sheet 166) and 83 (Sheet 167).

by the IOUs complies with OP 49 and the intent of the Decision. The language complies with the requirement of the Decision as it does not prohibit a PCS from reaching that steady state within the 2-second OLRT.

For the reasons stated above, this request by IREC is denied.

3. **IREC: Section Mm1 needs revision to clearly state that projects will be treated as non-export during the screening process.**

Background: Section Mm1, Option 8 (Non-Export Utilizing Certified Power Control Systems) is added to Rule 21 to comply with OP 49. Section Mm1, Option 8 describes the requirements for non-export systems that use a PCS with an OLRT of no more than two sections.

Protested Issue and Replies: IREC argues that section Mm1 does not provide clarity that qualifying projects will be treated as non-exporting projects in Screen N, or other screens, when they meet all the IOUs' requirements, and suggests language should be added to section Mm1 to make that clear.

The IOUs reply that there was no discussion to include language related to Screen N within section Mm1 because projects under this section would not make it to Supplemental Review (Screen N) as these projects are considered non-export.

IREC proposes the following language be added, which is the same language proposed by Tesla (See Section II.A.1 of this Disposition Letter).

> If the non-export system has an aggregate PCS controlled nameplate of 600 kVA or less, or the maximum reported steady state value of the PCS is 1% or less of the PCS controlled nameplate (as provided in the NRTL testing reports), then the system is considered non-exporting (export = zero) in screens I, J, K, M, N and O.

Disposition: This language is the same language proposed by Tesla and the issue has already been disposed of in Section II.A.1 of this Disposition Letter. Therefore, the request by IREC is denied for the same reasons.

4. **IREC: Section Mm4 is Missing Part of the Consensus Language.**

Background: Sections Mm3, Option 10 (Non-Export with Inadvertent Export Utilizing Certified Power Control Systems) and Mm4, Option 11 (Limited Export with Inadvertent Export Utilizing Certified Power Control Systems) are added to Rule 21 in response to OP 50 adopting Proposal A-B-2 from the Rule 21 Working Group 3 Report.

Protested Issue and Replies: IREC argues that Section Mm 4, Option 11 (Limited Export with Inadvertent Export Utilizing Certified Power Control Systems) failed to include language agreed upon during the discussions with the IOUs and requests the following language be added:

> vi. Use only the largest facility in the line section for aggregate evaluation for subsequent interconnection requests.

The IOUs reply that this language ("the disputed language") was intentionally omitted from the Current ALs because Section Mm4 (Limited Export with Inadvertent Export Utilizing Certified Power Control Systems) is for exporting generators that are part of the interconnection queue and are used to study subsequent interconnection requests. The IOUs also assert that the language remains for Section Mm3, Option 10 (Non-Export with Inadvertent Export Utilizing Certified Power Control Systems).

In Section Mm3, Option 10 (Non-Export with Inadvertent Export Utilizing Certified Power Control Systems) the IOUs propose to include the same language proposed by IREC:

> The distribution provider evaluating generating facilities requesting interconnection under this section shall:
> …
> 6. Use only the largest facility in the line section for aggregate evaluation for subsequent interconnection requests.[90]

For Section Mm4, Option 11 (Limited Export with Inadvertent Export Utilizing Certified Power Control Systems) the above language is excluded.

Disposition: The Rule 21 Working Group 3 Report describes Issues A and B as follows:[91]

- Issue A: What changes are needed to clarify the parameters for approval of system design to achieve non-export and limited export?
- Issue B: How should utilities treat generating capacity for behind the meter paired solar and storage systems that are not certified non-export?

The Working Group 3 Report recognized that the two issues are interrelated and thus the proposals address them jointly.[92] In discussing Proposal A-B-1 the Working Group 3 Report states that Rule 21 language must be updated "to include the use of a PCS **for non-export and limited-export applications** [emphasis added]..."[93] In discussing Proposal A-B-2, the Working Group 3 Report states that the proposal needs to "Updated Rule 21 language to include the use of a PCS for **limited-export interconnection applications** [emphasis added]."[94] The Working Group 3 Report continues to discuss the process for the technical evaluations for Proposal A-B-2, which includes the language disputed herein: "For Existing Generating Facilities that meet the requirements under this proposal, only the largest generating facility in the line section would be used for aggregate evaluation for subsequent interconnection requests."[95] The Working Group 3 Report does not mention this language is applicable for non-export systems; it only mentions it in the context of limited-export interconnection applications. The Decision adopted Proposal A-B-1 and A-B-2[96] without modifications. The Decision states "We find Proposals A-B 1 and A-B 2, which are consensus proposals, both appropriately address Issues A and B."[97]

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[90] PG&E AL 6286-E at 15, SCE AL 4559-E at 9, SDG&E AL 3822-E at 85 (Tariff Sheet: Cal. PUC. Sheet No. 35155-E)
[91] Rule 21 *Working Group Three Final Report, June 14, 2019*, at 125.
[92] Rule 21 *Working Group Three Final Report, June 14, 2019*, at 125.
[93] Rule 21 *Working Group Three Final Report, June 14, 2019*, at 131.
[94] Rule 21 *Working Group Three Final Report, June 14, 2019*, at 133.
[95] Rule 21 *Working Group Three Final Report, June 14, 2019*, at 133.
[96] D.20-09-035 at 153.
[97] D.20-09-035 at 164.

OP 49 and OP 50 both list the requirements to be met for non-export and limited export interconnection applications. The difference is that OP 49 specifically lists the requirements to be met for generating facilities **to be treated as non-export or limited export**, while OP 50 lists the requirements to be met for generating facilities **to be treated as inadvertent export**. Non-export systems "are designed to prevent the transfer of electrical energy from the generating facility to the distribution or transmission system"[98] while limited export systems "are designed and set to **limit the level of export** [emphasis added] to some specified amount less than the nameplate capacity of the system."[99] Under Rule 21 Inadvertent Export is defined as "The unscheduled and uncompensated export of real power from a Generating Facility (GF) for a limited duration as specified in Sections M and Mm."[100]

OP 50 states:

> Proposal A-B 2 is adopted. [The IOUs] shall modify their Rule 21 tariffs to allow the use of a power control system for non-export and limited-export applications. Rule 21 tariffs shall be modified to require that, to be treated as inadvertent export, a generating facility must meet the following six specifications: … Upon meeting the six specifications, the Utilities shall review the facility as such: … and only the largest facility in the line section shall be used for aggregate evaluation for subsequent interconnection requests….

OP 50 makes the distinction of two different types of applications: non-export and limited-export, both having inadvertent export. For Section Mm3 (**non-export** with inadvertent export applications) the IOUs have modified Rule 21 to include the disputed language, and for Section Mm4 (**limited export** with inadvertent export) the disputed language is omitted. Under the Mm3, Option 10 the generating facility would apply as a non-export interconnection, while for Mm4, Option 11 it would apply as a limited export interconnection.

Staff has reviewed Proposal A-B-2 in the Working Group 3 Report and the language in the Decision concerning the adoption of this proposal and concludes that the Decision adopted this proposal without modifications. Staff reads the plain language of the Decision to exclude exporting generation (i.e., limited export) from the interconnection studies that may affect subsequent interconnection requests or exclude them from the interconnection queue. Therefore, Staff determines that the language IREC proposes, while it is appropriate for Section Mm3 which is for non-export, is not required in Section Mm4 because Section Mm4 is for the interconnection of limited-export projects. As the IOUs' have stated, under Mm4 the generating facility is still exporting and thus remains part of the interconnection queue and the export may affect subsequent interconnection requests. Therefore, this request by IREC is denied.

5. IREC: PG&E's proposed language contains minor inconsistencies with the language proposed by the other IOUs.

[98] D.20-09-035 at 154.
[99] D.20-09-035 at 156-157.
[100] PG&E Rule 21 at Section C (Definitions).

Protested Issue and Replies: IREC notes that PG&E's proposed language is inconsistent with the proposed language of the other IOUs. PG&E replies that it will submit a supplemental AL to correct this.

Disposition: PG&E submitted Supplemental AL 6286-E-A on November 19, 2021 correcting the inconsistencies. Staff finds PG&E has implemented the necessary changes to align its tariff with the other IOUs. Therefore, Staff finds this issue is resolved with the supplemental language submitted by PG&E.

6. IREC: SCE proposes to revise its Interconnection Application forms, but PG&E and SDG&E have not.

Protested Issue and Replies: IREC argues all the IOUs should revise their interconnection application forms. Additionally, IREC suggests revisions specific to SCE's forms and recommends that if the other IOUs are required to revise their forms, they should pay attention to the use of defined terms.

IREC further argues that "SCE's interconnection application forms do not use Rule 21's defined terms" and suggest the following revisions:[101]

- Replacing "rated output" and "rated capacity" with "Gross Nameplate Rating" and "net capacity" with "Nameplate Rating" (Form 14-918[102])
- Replacing "operating capacity" or "output" with "Generating Profile" (Form 14-918)
- Adding "Power" to "Certified Control System" (Form 14-918, Form 14-732[103]) and deleting "Generators" in the term "M. For Generators Certified Control System" (Form 14-918)

IREC also suggests that SCE should consider listing Protection Option No. 9 as a check box in Form 14-732 because SCE adds Protection Option Nos. 8 and 10, but not Protection Option No. 9.

PG&E replies that it included changes to address non-export scenarios in its update to forms in the Smart Connect/YourProjects AL 6270-E (Modifications to Various Pacific Gas and Electric Company's Electric Rule 21 Filed Forms to Support the Consolidation of its "YourProjects" Generator Application and Service Plan Application Online Portals). PG&E also states "While this AL is approved and effective, PG&E is open to additional changes on its forms for the non-export scenarios. PG&E is contemplating additional changes to its forms for its new portal in succeeding roll-out."[104]

SDG&E replies that it will revise its Interconnection Application Form consistent with SCE's proposed revisions.

SCE opposes most of IREC's proposed modifications to its Interconnection Application forms and states IREC's proposed language should be rejected as the section where IREC's proposed language is located was not modified by the AL filings. SCE gives the following reasons:

[101] IREC Protest at 6-8.
[102] Form 14-918 - Rule 21 Exporting Generating Facility Interconnection Request
[103] Form 14-732, Generating Facility Interconnection Application
[104] PG&E Reply to IREC Protest at 6.

- Form 14-918 - Rule 21 Exporting Generating Facility Interconnection Request:

    - Replacing “rated output” with “Gross Nameplate Rating” – SCE states that “rated output” is existing language and used consistently in Form 14-918 and Rule 21, and not intended to represent a Rule 21 defined term.
    - Replacing “operating capacity” with “Generating Profile” – SCE states that “Generating Profile” is not a defined term and is not used in Rule 21 or its Current AL.
    - Replacing “net capacity” with “Nameplate Rating” – SCE states that the section IREC recommends changes to was not modified by the AL filings and the term should be kept to retain consistent language in Form 14-918 and Rule 21.
    - Adding “power” to the term “certified [power] control system” SCE agrees and will make the change in a supplemental AL.

- Form 14-732, Generating Facility Interconnection Application: SCE states no changes are required because Option No. 9 is listed in Form 14-918, the Rule 21 Exporting Generating Facility Interconnection Request Form.

Disposition: PG&E’s AL 6270-E (Modifications to Various Pacific Gas and Electric Company's Electric Rule 21 Filed Forms to Support the Consolidation of its "YourProjects" Generator Application and Service Plan Application Online Portals) was not protested, was approved and became effective on August 30, 2021. The purpose of AL 6270-E was to modify PG&E’s Rule 21 Filed Forms 79-1174-02 (PG&E’s Rule 21 Generator Interconnection Application), 79-1151B (Application Net Energy Metering Interconnection for Solar And/Or Wind Electric Generating Facilities Of 30 Kilowatts or Less), and 79-1151B-02 Application Net Energy Metering (NEM2) Interconnection for Solar And/Or Wind Electric Generating Facilities Of 30 Kilowatts or Less). According to PG&E, the changes were made to improve and consolidate PG&E customer generator application, and service planning, web portals into a new portal called YourProjects (previously known as “Smart Connect”). The changes included, but were not limited to:

- Updates Non-Export option selection, as described in changes due to ongoing Working Group 2/3 discussions with stakeholders and IOUs.
- Adds limited export questions (related to the deployment of Power Control Systems [PCSs], relays, or derated inverters).
- Revisions related to back-up generator interconnections, with additional questions related to the nature of the control device being used (e.g., ATS, contactor, or breaker).

Future updates to the Smart Connect/YourProjects are beyond the scope of the Current ALs. Staff anticipates that PG&E will update its forms as necessary at the next roll-out of the Smart Connect/YourProjects tool. Therefore, because PG&E AL 6270-E (Modifications to Various Pacific Gas and Electric Company's Electric Rule 21 Filed Forms to Support the Consolidation of its "YourProjects" Generator Application and Service Plan Application Online Portals) was already approved and changes to this tool are beyond the scope of this AL, Staff finds that no further action is required by PG&E at this moment regarding the Smart Connect/YourProjects until its next roll out of this tool.

However, on January 7, 2022, PG&E submitted a partial supplemental to its AL (PG&E AL 6286-E-B) proposing changes to align verbiage for its interconnection application forms with those of the other IOUs. PG&E proposes the following modifications to:

- Form 79-1174-02, the Rule 21 Generator Interconnection Application:
    - Attachment B (Non-Export)
        - Inclusion of the word "Certified" when referring to Power Control Systems for Option 8 (Non-Export)
        - Edits to account for Option 10 (Inadvertent Export) and Option 11 (Inadvertent/Limited Export) and OLRT requirements
    - Attachment D (Solar Technology), Attachment E (Wind Turbine Technology), Attachment F (Machine-Based Technology), Attachment G (Fuel Cell Technology), and Attachment H (Energy Storage Technology)
        - Edits to account for PCS Option 9 (Limited Export)

Staff finds these edits align PG&E's forms with those of the other IOUs, therefore the issue of revising Interconnection Application Forms and aligning the forms with that of the other IOUs is resolved for PG&E.

SDG&E submitted Supplemental AL 3822-E-A on November 19, 2021 and AL 3822-E-B on January 7, 2022 updating its Interconnection Application Forms to align them with the other IOUs. Although SDG&E agreed to align its forms with that of SCE (which opposed the majority of IREC's recommended language), SDG&E instead implemented revisions to its forms using the language proposed by IREC. Staff finds SDG&E has implemented the necessary changes to its forms. Therefore, Staff finds this issue is resolved for SDG&E.

SCE submitted Supplemental 4559-E-A on January 7, 2022 modifying Form 14-732, Generating Facility Interconnection Application and Form 14-918, Rule 21 Exporting Generating Facility Interconnection Request, to provide consistency among forms of the other IOUs. SCE has adopted IREC's recommendations. Therefore, Staff finds this issue is resolved for SCE.

C. Conclusion

Staff finds that the IOUs have provided the necessary and clear language in the Rule 21 tariff modifications, and within the appropriate sections of Rule 21, to implement OPs 7, 49, 50 and 52 (SCE only) of D.20-09-035, including resolving topics 5 and 6 of IREC's protest in the Supplemental ALs. Therefore, Staff concludes the IOUs have adequately complied with these OPs in PG&E AL 6286-E, 6286-E-A and 6286-E-B, SCE AL 4559-E and 4559-E-A, and SDG&E AL 3822-E, 3822-E-A and 3822-E-B and corresponding substitute sheets.

For the foregoing reasons, Staff denies both Tesla's and IREC's protest for the topics not resolved in the Supplemental ALs, and concludes that PG&E, SCE and SDG&E have met the requirements set forth in D.20-09-035 OPs 7, 49, 50, and 52. Therefore, PG&E AL 6286-E, 6286-E-A and 6286-E-B, SCE AL 4559-E and 4559-E-A, and SDG&E AL 3822-E, 3822-E-A and 3822-E-B and corresponding substitute sheets are approved.

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August 6, 2021

Advice 6286-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Advice Letter Modifying Electric Rule 21 Pursuant to Ordering Paragraphs 7, 49, 50 Decision 20-09-035 for Working Group 2 and 3**

Purpose

Pacific Gas and Electric Company (PG&E) hereby submits this Tier 1 Advice Letter (AL) to update Electric Rule 21 - *Generating Facility Interconnections* - in compliance with the California Public Utilities Commission (CPUC, Commission) Decision (D.) D.20-09-035[1] (WG 2 & 3 Decision) Ordering Paragraph (OP) 55 and as described below, to address OPs 7, 49 and 50. This new Tier 1 advice letter is being prepared based on Energy Division guidance. For Ordering Paragraphs 7, 49 and 50, this advice letter replaces the proposals for those same ordering paragraphs in AL 5988-E.

Background

Rulemaking 17-07-007
On July 13, 2017, The Commission adopted Order Instituting Rulemaking (R.) 17-07-007 to consider refinements to 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, Utilities) regarding the interconnection of distributed energy resources.[2]

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[1] Decision 20-09-035 - Date of Issuance 9/30/2020 - *Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup*

[2] 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 p2.)

ACR Scoping Memo

On October 2, 2017, the Commission issued Scoping Memo of Assigned Commissioner and Administrative Law Judge (Scoping Memo) set forth the scope and schedule of the proceeding. It established the working group process, whereby resolution of the technical issues of the proceeding would be proposed by Working Groups One through Six. In addition, four issues were assigned to the Smart Inverter Working Group, including issues 5 and 6.[3]

Working Group 2

On February 14, 2018, a Ruling directed that Working Group Two would begin on March 15, 2018 and required that it subsequently file its recommendations report on September 15, 2018. The Ruling also reassigned Issue 6 to Working Group Two.

On August 15, 2018, the Administrative Law Judge issued a Ruling allowing additional time for Working Group Two to resolve issues, including sub-issues encountered, and delaying the filing of the recommendations report to October 31, 2018.

On October 31, 2018, the Working Group 2 final report was issued.[4]

On November 7, 2018, the Administrative Law Judge facilitated a workshop to discuss the recommendations provided in the Working Group 2 Final Report.

On December 7, 2018, in response to the November 7, 2018, workshop on the Working Group Two Report, and parties were directed to respond to questions on the report.

On February 1, 2019, responses to the questions, along with comments on the Working Group Report, were filed by the various parties

On February 22, 2019, replies were filed by the various parties.

Amended Scoping Memo and Working Group 3

On November 16, 2018, a Scoping Memo and Ruling (Amended Scoping Memo) delayed the start of Working Group Three until December 1, 2018 and required Working Group Three to file its recommendations report on June 14, 2019. The Amended Scoping Memo also decreased the number of working groups and redistributed issues across two

[3] The Smart Inverter Working Group (SIWG) 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. [as explained in footnote 2 in D. 20-09-035]

[4] Working Group Two Final Report filed jointly by the Utilities.

working groups and the Interconnection Discussion Forum[5] such that Working Group Three was assigned issues 12, 15, 16, 20, 22, 23, 24, 27 28, and New Issues A and B. On June 13, 2019, the Working Group Three Final Report[6] was issued followed by a workshop.

A November 27, 2019 Ruling directed parties to respond to questions on the Working Group Three Report.

On January 13, 2020, the various parties filed responses to the questions contained in the November 27, 2019, ruling, along with comments to the Working Group Three Report.

On January 27, 2020, various parties filed replies to the responses and Working Group Three Report comments

Vehicle to Grid Subgroup

An August 23, 2019 Ruling issued in R. 17-07-007 and in R.18-12-006 (the *Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification*) established the V2G AC Subgroup with meetings to begin on September 11, 2019. The purpose of this subgroup is to discuss and identify existing standards to fulfill safety requirements for the interconnection of mobile inverters. The ruling directed a final recommendations report from the subgroup to be filed on December 6, 2019.

A workshop on the subgroup report was held on December 17, 2019.

On December 11, 2019, the V2G Final Report was issued.[7]

On January 6, 2020, the following parties filed comments to the December 6, 2019, Final V2G AC subgroup report.

On January 13, 2020, various parties filed replies to the comments on the V2G AC subgroup report.

Decision 20-09-035

On August 20, 2020, a proposed decision was issued on Working Groups Two and Three. On September 9, 2020 comments were received. On September 22, 2020, replies were received.

On September 24, 2020, the Commission voted out D.20-09-035. D.20-09-035 was based on the recommendations of Working Groups Two and Three and the Vehicle-to-

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[5] In Resolution Administrative Law Judge-347, the Commission established the Interconnection Discussion Forum (formerly known as the Rule 21 Working Group) as a venue to encourage discussion and collaboration between the Utilities and developers. [as explained in footnote 3 in D. 20-09-035]

[6] Working Group Three Final Report filed by SDG&E

[7] Final Report of the Vehicle to Grid Alternating Current Interconnection Subgroup.

Grid Alternating Current Interconnection Subgroup (V2G AC Subgroup). D. 20-09-035 was issued September 30, 2020.

Decision.21-01-027
On January 21, 2021, the CPUC issued D. 21-01-027 *Correcting Errors in Decision 20-09-035.* It noted for the purposes of this advice letter that references to ordering paragraph numbers 47, 50, 51, 53, should reference final decision ordering paragraph number(s) 46, 49, 50, 52.[8]

Protests to AL 5988-E
On October 30, 2020, AL 5988-E was timely submitted to the CPUC. Protests were received from The Interstate Renewable Energy Council, Inc. (IREC) and from California Solar & Storage Association (CALSSA) on November 19, 2020. PG&E responded to those protests on November 30, 2020. Since that time five other advice letters have been submitted pursuant to D. 20-09-035[9]. To resolve AL 5988-E, Energy Division encouraged us to work with the protesting parties to resolve the consensus items for AL 5988-E. SCE thereupon coordinated a series of meeting in March and April with IREC (whose protest issues more or less aligned with those of CALSSA) to see where consensus could be achieved. Additionally, in mid- to late April Energy Division proposed that we split the supplemental Advice Letters into a supplemental advice letter for consensus issues (this advice letter), and a new advice letter for those issues where we could not achieve consensus with the protesting parties.

D. 20-09-035 OP 55 requires:

> *"55. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall update their respective Electric Rule 21 Tariff and, where necessary, Rules 2, 15, and 16 Tariffs, in compliance with the Ordering Paragraphs of this decision by submitting three advice letters pursuant to the table below The table provides the list of the ordering Paragraphs (OP) in this decision requiring changes to Rule 21. The table also indicates whether the advice letter associated with each ordering paragraph is required to be Tier 1 or Tier 2 and provides the deadline for submitting the Advice Letter."*

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[8] See D. 20-09-035 OP1 Table labeled *Decision 20-09-035 Ordering Paragraph Corrections,* last line under OP 55.

[9] AL 6014-E on November 30, 2020, AL 5915-E on January 28, 2021, AL 6058-E on January 28, 2021, AL 6093-E on February 22, 2021, and AL 6141-E on March 30, 2021. Additionally, two other advice letters were submitted in the same proceeding R.17-07-007 for Working Group 1 per D.19-03-013 and Resolution E-5035: both AL 6154-E and AL 6155-E on April 8, 2021.

Advice Letters 5988-E and 5999-E-A

Tier 1 AL 5988-E[10] was timely submitted October 30, 2020. It addressed OPs 7, 13, 14 46, 49, 50 and 52 (the last for SCE only) (numbers as corrected by D.21-01-027[11]). It was protested by several parties.

AL 5988-E-A was submitted May 19, 2021 but did not address OPs 7, 49, and 50. This advice letter addresses these ordering paragraphs based on subsequent discussion with the other utilities, stakeholders, and Energy Division staff.

This advice letter addresses the following ordering paragraphs:

OP[12]	Tier 1 Submit 30 days after issuance of decision	Issue Description
7	X	all sizes non-exporting projects skip Rule 21 Screens K, L, & M
49	X	allow power control system for non-export and limited export interconnections.
50	X	inadvertent export, projects must meet the following six specifications:

Therefore, based on the above identified Ordering Paragraphs, in this advice letter PG&E updated its proposed tariff revisions for the consensus items as addressed below.

Tariff Changes

1. Ordering Paragraph 7 – Skipping Screens K, L and M

Ordering Paragraph 7 requires:

> "*Option B of Proposal 8i is adopted whereby non-exporting projects of all sizes skip Interconnection Rule 21 Screens K, L, and M. Proposal 8i will be revisited during the ratesetting phase of Rulemaking 17-07-007.* "

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10 AL 5988-E - *Advice Letter Modifying Electric Rule 21 Pursuant to Decision 20-09-035 for Working Group 2 and 3*

11 D.21-01-027 *ORDER CORRECTING ERRORS IN DECISION 20-09-035* – issued January 21, 2021.

12 As corrected In D. 21-01-027.

IREC in its protest notes, “PG&E’s advice letter also updates the engineering screen flowchart to indicate that screens K, L, and M are skipped, while the other two advice letters contain no flowchart updates” and “requests the use of consistent language across each of the respective tariffs.” to reflect that non-exporting projects of all sizes may skip screens K, L, and M.

Also, “The advice letters employ slightly different language when describing the options on screen I under which a generating facility may qualify as exporting or non-exporting. IREC again requests that the IOUs use the same language in each of their respective tariffs to describe these options”

Finally, “IREC observes that PG&E’s proposed changes to the engineering screen flowchart may not be necessary. The flowchart clearly shows that if the facility qualifies as non-exporting under screen I, screens J, K, L, and M are skipped.”

PG&E notes OP 7 adopts Option B of Proposal 8i, “*whereby non-exporting projects of all sizes skip Rule 21 Screen K, L and M. Proposal 8i will be revisited during the ratemaking phase of Rulemaking 17-07-007.*”

In this advice letter, PG&E address the concerns raised with the following changes proposed to Rule 21. Some of the changes below apply to OP 50 on inadvertent export.

G. ENGINEERING REVIEW DETAILS (Cont'd.)
1. INITIAL REVIEW SCREENS (Cont'd.)

i. Screen I: Will power be exported across the PCC?

- If Yes, Continue to Screen J. This includes Options 5, ~~and~~ 6, 9, 10 and 11 below.

- If No, then to ensure that the Generating Facility does not export across the PCC, the Generating Facility must incorporate ~~Protective Function~~ Options 1, 2, 3, 4, 7 or 8 below. Following that selection, Screen J, K, L, and M are skipped and Initial Review is complete. If ~~Protective Function~~ Option 8 is used, see section Mm2 to determine screen application.

Option 1 ("Reverse Power Protection"): To ensure power is never exported across the PCC, a reverse power Protective Function may be provided. The default setting for this Protective Function shall be 0.1% (export) of the service transformer's rating, with a maximum 2.0 second time delay. For multiple tariff interconnections refer to Section J.8.

Option 2 ("Minimum Power Protection"): To ensure at least a minimum amount of power is imported across the PCC at all times (and, therefore, that power is not exported), an under-power Protective Function may be provided. The default setting for this Protective Function shall be 5% (import) of Generating Facility's total Gross Rating, with a maximum 2.0 second time delay.

Option 3 (Certified Non-Islanding Protection): To ensure the incidental export of power is limited to acceptable levels, this option requires that all of the following conditions be met: a) the total Gross Capacity of the Generating Facility must be no more than 25% of the nominal ampere rating of Producer's service equipment; b) the total Gross Capacity of the Generating Facility must be no more than 50% of Producer's service transformer capacity rating (this capacity requirement does not apply to Customers taking primary service without an intervening transformer); and c) the Generating Facility must be Certified as Non-Islanding.

The ampere rating of the Customer's service equipment to be used in this evaluation will be that rating for which the customer's utility service was originally sized or for which an upgrade has been approved. It is not the intent of this provision to allow increased export simply by increasing the size of the customer's service panel, without separate approval for the resize.

Option 4 (Relative Generating Facility Rating): This option, when used, requires the Net Rating of the Generating Facility to be so small in comparison to its host facility's minimum load, that the use

of additional Protective Functions is not required to ensure that power will not be exported to Distribution Provider's Distribution or Transmission System. This option requires the Generating Facility capacity to be no greater than 50% of Producer's verifiable minimum Host Load over the past 12 months.

Option 5: Inadvertent Export as described in Section M.

Option 6: Inadvertent Export utilizing UL-1741 or UL-1741 SA/SB-listed grid support (non-islanding) inverters as described in Section Mm.

Option 7: Non-Export utilizing Non-Export AC/DC Converter as described in Section O.

Option 8: Non-Export utilizing Certified Power Control Systems with an open loop response time no more than two seconds as described in Section Mm1.

Option 9: Limited Export utilizing Certified Power Control Systems with an open loop response time no more than two seconds as described in Section Mm2.

Option 10: Non-Export with Inadvertent Export utilizing Certified Power Control Systems with an open loop response time greater than two seconds and no more than ten seconds as described in Section Mm3.

Option 11: Limited Export with Inadvertent Export utilizing Certified Power Control Systems with an open loop response time greater than two seconds and no more than ten seconds as described in Section Mm4.

Significance:

1. If it can be assured that the Generating Facility will not export power, Distribution Provider's Distribution or Transmission System does not need to be studied for load-carrying capability or Generating Facility power flow effects on Distribution Provider voltage regulators.

2. This Screen permits the use of reverse-power or minimum-power relaying as a Non-Islanding Protective Function (Option 1, 2, and 3).

3. This Screen allows, under certain defined conditions, for Generating Facilities that incorporate Certified Non-Islanding protection to qualify for interconnection through the Fast Track process without implementing reverse power or minimum power Protective Functions (Option 3).

2. Ordering Paragraph 49 – PCS for Non-Export and Limited Export

Ordering Paragraph 49 Language requires:

"*Proposal A-B 1 is adopted.*
Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall modify their Rule 21 tariffs to allow the use of a power control system for ***non-export and limited export interconnection applications.***

Rule 21 shall be modified to establish the following five specifications that generating facilities must meet to be treated as ***non-export or limited export:***

i) use a power control system that passes the requirements of the Underwriters Laboratory (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol;

ii) use a power control system that has an open-loop response time of no more than two seconds, as provided in the control systems specification data sheets, and must be able to reduce export power to the approved export limit within two seconds of exceeding the approved export limit;

iii) Use only UL 1741 certified and/or UL 1741 SA listed grid-support non-islanding inverters;

iv) set the power control system to zero-export or some non-zero controlled maximum export value; and

v) maintain voltage fluctuations at the limits specified in Electric Rule 2.

Once meeting these five specifications, Utilities shall evaluate ***non-export*** *interconnection applications as such:*

- *a power control system can demonstrate non-export operations under Screen I; Screen D shall be omitted;*
- *and Screens F and G shall be reviewed based on the generating facility's gross nameplate rating.*

Once meeting these five specifications, Utilities shall evaluate ***limited-export*** *interconnections applications as such:*

- *limited export value can determine G will be based on the generating facility's nameplate rating. the impacts to the grid and in Screens D, I, J, K, M, N, O, and P;*

- *and Screens F and G will be based on the generating facility's nameplate rating."*
  [formatting and emphasis added]

In IREC's protest, it notes that PG&E re-styled the five qualification criteria from OP 49 as six criteria, and requests that the tariffs reflect only the five criteria outlined in OP 49 to ensure consistency across each of the tariffs and to more precisely comply with the Commission's order.

IREC also observes that PG&E has added a requirement not present in OP 49 that the generating facility's power control system must pass the most recent Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol.

Finally, IREC has concerns with language in each of the tariffs that requires power control systems to reduce export power to approved limits within two seconds.

As PG&E proposed in Section 1 above of this advice letter regarding OP 7, while many aspects of these the protests to these three OPs have been resolved, further stakeholder discussions are still underway. Once resolved, PG&E will address these ordering paragraphs, in a new proposed advice letter, consistent with guidance from the CPUC staff. PG&E withdraws the changes for this OP made in AL 5988-E.

3. Ordering Paragraph 50 - PCS for Inadvertent Export

Ordering Paragraph 50 requires:

> *"Proposal A-B 2 is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall modify their Rule 21 tariffs to allow the use of* ***a power control system for non-export and limited-export applications.***
>
> *Rule 21 tariffs shall be modified to require that, to be treated as* ***inadvertent export****, a generating facility must meet the following six specifications:*
>
> *i) use a power control system that passed testing in conformance with the Underwriters Laboratory (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol;*
>
> *ii) use a power control system with an open-loop response time of no more than ten seconds as provided in the control systems' specification data-sheets;*

iii) use only UL 1741 SA certified and/or UL 1741 SA listed grid-support non-islanding inverters;

iv) use a power control system set to zero-export or some non-zero controlled maximum export value;

v) maintain voltage fluctuations to the limits specified in Electric Rule 2; and

vi) have a nameplate capacity equal to or less than 1,000 kilovolt amperes.

Upon meeting the six specifications, the Utilities shall

- *review the facility as such: apply Screens A through M using the aggregate nameplate inverter rate;*
- *during Supplemental Review the applicant shall identify, within 15 days, the frequency of inadvertent export, the real power level in watts of inadvertent export and the time duration of inadvertent export;*
- *if distribution upgrades are identified, Screen P shall recognize power control parameters taking into account local feeder conditions;*
- *and only the largest facility in the line section shall be used for aggregate evaluation for subsequent interconnection requests.*

Utilities shall consider a customer's operating profile and the magnitude, duration, and frequency of anticipated export during the review of Screen P."
[formatting and emphasis added]

IREC notes in its protest, "*the proposed language in each of the advice letters fails to account for inadvertent export from facilities that limit their exports to some specified maximum value*" requesting that "*each tariff should include language that allows facilities with nameplate capacities less than 1,000 kVA and that limit their exports to qualify for review under the inadvertent export process*" and that "*that section Mm2 reflect the concerns expressed above for section Mm1 regarding potential future updates to the UL CRD test protocol and the requirement to reduce export below approved limits within ten seconds*"

4. Ordering Paragraph 49 and 50 – Changes Proposed to Rule 21

To address the issues relating to the use of Power Control Systems (PCS) for the various non-export scenarios addressed in OPs 49 and 50, PG&E proposes the following changes to Rule 21:

First, PG&E proposes an update to the definition of Inadvertent Export in Rule 21 in Section C (original Sheet 24) as follows:

> **Inadvertent Export:** The unscheduled and uncompensated export of real power from a Generating Facility (GF) for a limited duration as specified in Sections M,~~and~~ Mm and Mm3.

Next in Rule 21 PG&E proposes to add new Sections Mm1 through MM4 between existing Sections M and N.

> Mm1. OPTION 8: Non-Export Utilizing Certified Power Control Systems
>
> The following are the minimum requirements for Non-Export systems that use certified power control systems (PCS) with an open loop response time (OLRT) no more than two seconds. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.
>
> 1. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Non-export systems may use a PCS that passes later published revisions to the CRD test protocol or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the PCS conforms to the non-exporting functionality in accordance with the relevant CRD or UL published standard.
>
> 2. Use a PCS that is certified with an OLRT of two seconds or less, as provided in the PCS's specification data sheets.
>
> 3. The PCS must reduce export to zero or less within two seconds of commencing export. A PCS that is certified with an open-loop response time of two seconds or less, and a time to reach steady state of 10 seconds or less, meets this requirement.
>
> 4. Set the PCS to not export (zero-export).
>
> 5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff.

6. Maintain voltage fluctuations at the limits specified in Electric Rule 2.

The evaluation of a non-export system requesting interconnection under this section:

1. Shall omit evaluation for screen D;

2. Shall utilize the Generating Facility's Gross Nameplate Rating for screens F, F1, and G;

3. If the non-export system has an aggregate PCS controlled nameplate greater than 600 kVA and the maximum reported steady state value of the PCS is greater than 1% of the PCS controlled nameplate (as provided in the NRTL testing reports), the evaluation may utilize the following calculation when determining the impacts to the grid under screens I, J, K, M, N, and O: The sum of the nameplate values of the exporting DER resource (if any) plus the maximum percentage steady state value of the PCS (as provided in the NRTL testing reports) times PCS controlled nameplate capacity.

4. Screen P may be applied using the Generating Facility's Gross Nameplate Rating for evaluations that use fault current calculations. For other evaluations under screen P, the value identified in iii above may be used.

Mm2. <u>OPTION 9: Limited Export Utilizing Certified Power Control Systems</u>

The following are minimum requirements for limited export systems that use certified power control systems (PCS) with an open loop response time (OLRT) no more than two seconds to maintain a level of export that is lower than the nameplate rating. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.

1. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Limited export systems may use a PCS that passes later published revisions to the CRD test protocol, or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the PCS conforms to the export limiting functionality in accordance with the relevant CRD or UL published Standard.

2. Use a PCS that is certified with an OLRT of two seconds or less as provided in the PCS's specification data sheets.

3. The PCS must reduce export to the approved export limit, or less, within two seconds of exceeding the approved export limit. A PCS that is certified with an open-loop response time of two seconds or less, and a time to reach steady state of ten seconds or less, meets this requirement.

4. Set the PCS to not exceed the proposed level of export.

5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff.

6. Maintain voltage fluctuations at the limits specified in Electric Rule 2.

The evaluation of a limited export system requesting interconnection under this section:

1. Shall utilize the Generating Facility's Gross Nameplate Rating for screens F, F1, and G.
2. If the maximum steady state value is greater than 1% of the PCS controlled nameplate (as provided in the NRTL testing reports) utilize the requested limited export value plus the maximum steady state value of the PCS times the PCS controlled nameplate, to evaluate the impacts to the grid under screens D, I, J, K, M, N, and O. If the maximum steady state value is less than 1% of the PCS controlled nameplate (as provided in the NRTL testing reports), utilize only the requested limited export value under screens D, I, J, K, M, N and O.
3. Screen P shall be applied using the Generating Facility's Gross Nameplate Rating for evaluations that use fault current calculations. For other evaluations under screen P, the value identified in ii above may be used.

Mm3. <u>OPTION 10: Non-Export with Inadvertent Export Utilizing Certified Power Control Systems</u>

The following are the minimum requirements for Non-Export systems that use certified power control systems (PCS) with an open loop response time (OLRT) between two and ten seconds. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.

1. Have a nameplate capacity equal to or less than 1,000 kVA.

2. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Non-Export may use a PCS that pass later published revisions to the CRD test protocol, or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the

PCS conforms to the non-exporting functionality in accordance with the relevant CRD or UL published standard.

3. Use a PCS that is certified with an OLRT of no more than ten seconds, as provided in the PCS's specification data sheets.

4. Set the PCS to not export (zero-export).

5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff.

6. Maintain voltage fluctuations at the limits specified in Electric Rule 2.

The distribution provider evaluating generating facilities requesting interconnection under this section shall:

1. Apply screens A through M using the aggregate nameplate inverter rating.
2. Notify the applicant if supplemental review is required, and if so, require the applicant to identify, within 15 business days of being notified, the frequency of inadvertent export, the real power level in watts of inadvertent export, and the time duration of inadvertent export.
3. If distribution upgrades are identified, use screen P to recognize power control parameters, taking into account local feeder conditions; the customer's operating profile; and the magnitude, duration, and frequency of anticipated export.
4. Complete supplemental review within 15 days of receiving the required information specified under ii) above.
5. If the applicant does not provide the operating profile information within the specified 15 business days, perform supplemental review based on information included in the interconnection request within 30 business days of the request for customer operating profile information.
6. Use only the largest facility in the line section for aggregate evaluation for subsequent interconnection requests.

Mm4. OPTION 11: Limited Export with Inadvertent Export Utilizing Certified Power Control Systems

The following are the minimum requirements for limited export controlled systems that use certified power control systems (PCS) with an open loop response time (OLRT) between two and ten seconds to maintain a level of export that is lower than the nameplate rating. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.

1. Have a nameplate capacity equal to or less than 1,000 kVA.

2. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Limited export systems may use a PCS that pass later published revisions to the CRD test protocol, or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the PCS conforms to the export limiting functionality in accordance with the relevant CRD or UL published standard.

3. Use a PCS that is certified with an OLRT of no more than ten seconds, as provided in the PCS's specification data sheets.

4. Set the PCS to not to exceed the proposed level of export.

5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff.

6. Maintain voltage fluctuations at the limits specified in Electric Rule 2.

The distribution provider evaluating generating facilities requesting interconnection under this section shall:

1. Apply screens A through M using the aggregate nameplate inverter rating.

2. Notify the applicant if supplemental review is required, and if so, require the applicant to identify, within 15 business days of being notified, the frequency of inadvertent export, the real power level in watts of inadvertent export, and the time duration of inadvertent export.

3. If distribution upgrades are identified, use screen P to recognize power control parameters, taking into account local feeder conditions; the customer's operating profile; and the magnitude, duration, and frequency of anticipated export.

4. Complete supplemental review within 15 days of receiving the required information specified under ii) above.

5. If the applicant does not provide the operating profile information within the specified 15 business days, perform supplemental review based on information included in the interconnection request within 30 business days of the request for customer operating profile information.

Protests

*****Due to the COVID-19 pandemic, PG&E is currently unable to receive protests or comments to this advice letter via U.S. mail or fax. Please submit protests or comments to this advice letter to EDTariffUnit@cpuc.ca.gov and PGETariffs@pge.com*****

Any party wishing to protest this submittal may do so by letter sent via U.S. mail, facsimile or E-mail, no later than August 26, 2021, which is 20 days after the date of this submittal. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Sidney Bob Dietz II
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-3582
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Effective Date

Pursuant to General Order (GO) 96-B, Rule 5.1, this advice letter is submitted with a Tier 1 designation. PG&E requests that this Tier 1 advice letter submittal become effective upon date of submittal, which is August 6, 2021.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for R.17-07-007 (Rule .21), R. 14-07-002 (NEM Successor) and R.19-09-009 (Microgrid). Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/
Sidney Bob Dietz II
Director, Regulatory Relations

cc: Service List R.17-07-007
Service List R.14-07-002
Service List R.19-09-009

Attachments:
Attachment 1 –Clean version of updated Tariff
Attachment 2 – Redline Tariff Revisions

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (ID U39E)

Utility type:
☑ ELC ☐ GAS ☐ WATER
☐ PLC ☐ HEAT

Contact Person: Kimberly Loo
Phone #: (415)973-4587
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: KELM@pge.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6286-E

Tier Designation: 1

Subject of AL: Advice Letter Modifying Electric Rule 21 Pursuant to Ordering Paragraphs 7, 49, 50 Decision 20-09-035 for Working Group 2 and 3

Keywords (choose from CPUC listing): Compliance, Rule 21

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #: D.20-09-035

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? ☐ Yes ☑ No

Requested effective date: 8/6/21

No. of tariff sheets: 135

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: See Attachment 1

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Name: Sidney Bob Dietz II, c/o Megan Lawson
Title: Director, Regulatory Relations
Utility Name: Pacific Gas and Electric Company
Address: 77 Beale Street, Mail Code B13U
City: San Francisco, CA 94177
State: California Zip: 94177
Telephone (xxx) xxx-xxxx: (415)973-2093
Facsimile (xxx) xxx-xxxx: (415)973-3582
Email: PGETariffs@pge.com

Name:
Title:
Utility Name:
Address:
City:
State: District of Columbia Zip:
Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email:

Clear Form

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
50812-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 6	50322-E
50813-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 7	50323-E
50814-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 8	50324-E
50815-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 9	50325-E
50816-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 10	50326-E
50817-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 11	50327-E
50818-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 12	50328-E
50819-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 13	50329-E
50820-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 14	50330-E
50821-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 24	42321-E
50822-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 154	50424-E
50823-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 156	50426-E
50824-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 157	
50825-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 158	50427-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
50826-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 159	50428-E
50827-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 160	50429-E
50828-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 161	50430-E
50829-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 162	50431-E
50830-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 163	50432-E
50831-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 164	50433-E
50832-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 165	50434-E
50833-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 166	50435-E
50834-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 167	50436-E
50835-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 168	50437-E
50836-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 169	50438-E
50837-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 170	50439-E
50838-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 171	50440-E
50839-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 172	50441-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
50840-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 173	50442-E
50841-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 174	50443-E
50842-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 175	50444-E
50843-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 176	50445-E
50844-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 177	50446-E
50845-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 178	50447-E
50846-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 179	50448-E
50847-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 180	50449-E
50848-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 181	50450-E
50849-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 182	50451-E
50850-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 183	50452-E
50851-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 184	50453-E
50852-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 185	50454-E
50853-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 186	50455-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
50854-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 187	50456-E
50855-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 188	50457-E
50856-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 189	50458-E
50857-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 190	50459-E
50858-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 191	50460-E
50859-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 192	50461-E
50860-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 193	50462-E
50861-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 194	50463-E
50862-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 195	50464-E
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C. DEFINITIONS (Cont'd.)

Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority: Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Distribution Provider, or any Affiliate thereof.

Gross Rating; Gross Nameplate Rating; Gross Capacity or Gross Nameplate Capacity: The total gross generating capacity of a Generator or Generating Facility as designated by the manufacturer(s) of the Generator(s).

Host Load: The electrical power, less the Generator auxiliary load, consumed by the Customer, to which the Generating Facility is connected.

Inadvertent Export: The unscheduled and uncompensated export of real power from a Generating Facility (GF) for a limited duration as specified in Sections M, Mm and Mm3. (T)

Independent Study Process: The interconnection study process set forth in Section F.3.d.

Initial Review: See Section F.2.a.

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.)

1. INITIAL REVIEW SCREENS (Cont'd.)

h. Screen H: Is the line configuration compatible with the Interconnection type? (Cont'd.)

Significance: If the primary distribution line serving the Generating Facility is of a "three-wire" configuration, or if the Generating Facility's distribution transformer is single-phase and connected in a line-to-neutral configuration, then there is no concern about overvoltages to Distribution Provider's, or other Customer's equipment caused by loss of system neutral grounding during the operating time of the Non-Islanding Protective Function.

i. Screen I: Will power be exported across the PCC?

- If Yes, Continue to Screen J. This includes Options 5, 6, 9, 10, and 11 below. (T) (T)

- If No, then to ensure that the Generating Facility does not export across the PCC, the Generating Facility must incorporate Options 1, 2, 3, 4, 7, or 8 below. Following that selection, Screen J, K, L, and M are skipped and Initial Review is complete. If Option 8 is used, see section Mm2 to determine screen application. (T) | | (T)

Option 1 ("Reverse Power Protection"): To ensure power is never exported across the PCC, a reverse power Protective Function may be provided. The default setting for this Protective Function shall be 0.1% (export) of the service transformer's rating, with a maximum 2.0 second time delay. For multiple tariff interconnections refer to Section J.8.

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.)

1. INITIAL REVIEW SCREENS (Cont'd.)

i. Screen I: Will power be exported across the PCC? (Cont'd.)

Option 4 (Relative Generating Facility Rating): This option, when used, requires the Net Rating of the Generating Facility to be so small in comparison to its host facility's minimum load, that the use of additional Protective Functions is not required to ensure that power will not be exported to Distribution Provider's Distribution or Transmission System. This option requires the Generating Facility capacity to be no greater than 50% of Producer's verifiable minimum Host Load over the past 12 months.

Option 5: Inadvertent Export as described in Section M.

Option 6: Inadvertent Export utilizing UL-1741 or UL-1741 SA/SB listed grid support (Non-Islanding) inverters as described in Section Mm. (T)

Option 7: Non-Export utilizing Non-Export AC/DC Converter as described in Section O. (N)

Option 8: Non-Export utilizing Certified Power Control Systems with an open loop response time no more than two seconds as described in Section Mm1.

Option 9: Limited Export utilizing Certified Power Control Systems with an open loop response time no more than two seconds as described in Section Mm2.

Option 10: Non-Export with Inadvertent Export utilizing Certified Power Control Systems with an open loop response time greater than two seconds and no more than ten seconds as described in Section Mm3.

Option 11: Limited Export with Inadvertent Export utilizing Certified Power Control Systems with an open loop response time greater than two seconds and no more than ten seconds as described in Section Mm4. (N)

(L)

(L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

1. INITIAL REVIEW SCREENS (Cont'd.)

i. Screen I: Will power be exported across the PCC? (Cont'd.)

Significance:

1. If it can be assured that the Generating Facility will not export power, Distribution Provider's Distribution or Transmission System does not need to be studied for load-carrying capability or Generating Facility power flow effects on Distribution Provider voltage regulators.

2. This Screen permits the use of reverse-power or minimum-power relaying as a Non-Islanding Protective Function (Option 1, 2, and 3).

3. This Screen allows, under certain defined conditions, for Generating Facilities that incorporate Certified Non-Islanding protection to qualify for interconnection through the Fast Track process without implementing reverse power or minimum power Protective Functions (Option 3). (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

1. INITIAL REVIEW SCREENS (Cont'd.)

j. Screen J: Is the Gross Rating of the Generating Facility 11 kVA or less?

- If Yes (pass), skip Screens K, L and M; Initial Review is complete.
- If No (fail), continue to Screen K.[i]

Significance: The Generating Facility will have a minimal impact on fault current levels and any potential line overvoltages from loss of Distribution Provider's Distribution System neutral grounding.

k. Screen K: Is the Generating Facility a Net Energy Metering (NEM) Generating Facility with nameplate capacity less than or equal to 500 kW?

- If Yes (pass), skip screen L and continue to screen M.
- If No (fail), continue to screen L.

Significance: The purpose of this Screen is solely to facilitate interconnection of NEM facilities below this size threshold by allowing such facilities to bypass Screen M. The use of nameplate capacity expedites the Initial Review analysis. In Supplemental Review, the net export will be analyzed.

[i] Inadvertent Export systems that meet the requirements specified in Section Mm bypass Screens K and L, and are processed under Screen M as described in Section Mm. (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

1. INITIAL REVIEW SCREENS (Cont'd.)

l. Screen L: Transmission Dependency and Transmission Stability Test

Is the Interconnection Request for an area where: (i) there are known, or posted, transient stability limitations, or (ii) the proposed Generating Facility has interdependencies, known to Distribution Provider, with earlier-queued Transmission System interconnection requests. Where (i) or (ii) above are met, the impacts of this Interconnection Request to the Transmission System may require Detailed Study.

- If Yes (fail), Supplemental Review is required.
- If No (pass), continue to Screen M.

Significance: Special consideration must be given to those areas identified as having current or future (due to currently-queued interconnection requests) grid stability concerns.

m. Screen M: Is the aggregate Generating Facility capacity on the Line Section less than 15% of Line Section peak load for all line sections bounded by automatic sectionalizing devices? [ii]

- If Yes (pass), Initial Review is complete.
- If No (fail), Supplemental Review is required.

Significance:

1. Low penetration of Generating Facility capacity will have a minimal impact on the operation and load restoration efforts of Distribution Provider's Distribution System.

[ii] Inadvertent Export systems that meet the requirements specified in Section Mm are processed under Screen M as described in Section Mm. (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

1. INITIAL REVIEW SCREENS (Cont'd.)

m. Screen M: Is the aggregate Generating Facility capacity on the Line Section less than 15% of Line Section peak load for all line sections bounded by automatic sectionalizing devices? (Cont'd.)

2. The operating requirements for a high penetration of Generating Facility capacity may be different since the impact on Distribution Provider's Distribution System will no longer be minimal, therefore requiring additional study or controls.

The purpose of this Screen is solely to identify if the Generating Facility needs additional study and is not intended as justification for limiting the penetration of generation on a line section.

2. SUPPLEMENTAL REVIEW SCREENS

The Supplemental Review consists of Screens N through P. If any of the Screens are not passed, a quick review of the failed Screen(s) will determine the requirements to address the failure(s) or that Detailed Studies are required. In certain instances, Distribution Provider may be able to identify the necessary solution and determine that Detailed Studies are unnecessary. Some examples of solutions that may be available to mitigate the impact of a failed Screen are:

1. Replacing a fixed capacitor bank with a switched capacitor bank.

2. Adjustment of line regulation settings.

3. Simple reconfiguration of the distribution circuit. (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

2. SUPPLEMENTAL REVIEW SCREENS (Cont'd.)

a. Screen N: Penetration Test

Where 12 months of line section minimum load data is available, can be calculated, can be estimated from existing data, or determined from a power flow model, is the aggregate Generating Facility capacity on the Line Section less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the Generating Facility?

- If yes (pass), continue to Screen O.
- If no (fail), a quick review of the failure may determine the requirements to address the failure; otherwise Electrical Independence Tests and Detailed Studies are required. Continue to Screen O. (Note: If Electrical Independence tests and Detailed Studies are required, Applicants will continue to the Electrical Independence Tests and Detailed Studies after review of the remaining Supplemental Review Screens, if Applicant elects to proceed.)

Note 1: If none of the above options are available, this screen defaults to Screen M.

Note 2: The type of Generating Facility technology will be taken into account when calculating, estimating, or determining circuit or Line Section minimum load relevant for the application of this screen. For solar Generating Facilities with no battery storage, daytime minimum load will be used (i.e., 10 am to 4 pm for fixed panel solar Generating Facilities and 8 am to 6 pm for solar Generating Facilities utilizing tracking systems), while absolute minimum load will be used for all other Generating Facility technologies.

Note 3: When this screen is being applied to a NEM Generating Facility, the net export in kW, if known, that may flow across the Point of Common Coupling into Distribution Provider's Distribution System will be considered as part of the aggregate generation. (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

2. SUPPLEMENTAL REVIEW SCREENS (Cont'd.)

a. Screen N: Penetration Test (Cont'd.)

Note 4: Distribution Provider will not consider as part of the aggregate Generating Facility capacity for purposes of this screen Generating Facility capacity known to be already reflected in the minimum load data.

Note 5: NEM Generating Facilities with net export less than or equal to 500 kW that may flow across the Point of Common Coupling into Distribution Provider's Distribution or Transmission System will not be studied in the WDT Transmission Cluster Study Process, but may be studied under the Independent Study Process.

Significance: Penetration of Generating Facility capacity that does not result in power flow from the circuit back toward the substation will have a minimal impact on equipment loading, operation, and protection of the Distribution System.

b. Screen O: Power Quality and Voltage Tests

In aggregate with existing Generating Facility capacity on the Line Section, distribution circuit, and/or substation.

i) Can it be determined within the Supplemental Review that the voltage regulation on the line section can be maintained in compliance with Commission Rule 2 and/or Conservation Voltage Regulation voltage requirements under all system conditions?

ii) Can it be determined within the Supplemental Review that the voltage fluctuation is within acceptable limits as defined by IEEE 1453 or utility practice similar to IEEE1453? (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

2. SUPPLEMENTAL REVIEW SCREENS (Cont'd.)

b. Screen O: Power Quality and Voltage Tests (Cont'd.)

In aggregate with existing Generating Facility capacity on the Line Section, distribution circuit, and/or substation. (Cont'd.)

iii) Can it be determined within the Supplemental Review that the harmonic levels meet IEEE 519 limits at the Point of Common Coupling (PCC)? (L)

iv) Can it be determined within the Supplemental Review that the Generating Facility will not cause any voltage impacts considering the settings of the Volt-Var function and the characteristics of the circuit segment? (P)/(L) (P)/(L)

- If yes to all of the above (pass), continue to Screen P. (L)
- If no to any of the above (fail), a quick review of the failure may determine the requirements to address the failure; otherwise Electrical Independence Tests and Detailed Studies are required. Continue to Screen P. (Note: If Electrical Independence tests and Detailed Studies are required, Applicants will continue to the Electrical Independence Tests and Detailed Studies after review of the remaining Supplemental Review Screens.)

Significance: Adverse voltages and undesirable interference may be experienced by other Customers on Distribution Provider's Distribution System caused by operation of the Generating Facility(ies).

c. Screen P: Safety and Reliability Tests

Does the location of the proposed Generating Facility or the aggregate generation capacity on the Line Section create impacts to safety or reliability that cannot be adequately addressed without Detailed Study?

- If yes (fail), review of the failure may determine the requirements to address the failure; otherwise Electrical Independence Tests and Detailed Studies are required. Continue to Section G.3.
- If no (pass), Supplemental Review is complete. (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

2. SUPPLEMENTAL REVIEW SCREENS (Cont'd.)

c. Screen P: Safety and Reliability Tests (Cont'd.)

Significance: In the safety and reliability test, there are several factors that may affect the nature and performance of an Interconnection. These include, but are not limited to:

1. Generating Facility energy source
2. Modes of synchronization
3. Unique system topology
4. Possible impacts to critical load customers
5. Possible safety impacts

The specific combination of these factors will determine if any system study requirements are needed. The following are some examples of the items that may be considered under this screen:

1. Does the Line Section have significant minimum loading levels dominated by a small number of customers (i.e. several large commercial customers)?
2. Is there an even or uneven distribution of loading along the feeder?
3. Is the proposed Generating Facility located in close proximity to the substation (i.e. <2.5 electrical line miles), and is the distribution line from the substation to the customer composed of large conductor/cable (i.e. 600A class cable)? (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

2. SUPPLEMENTAL REVIEW SCREENS (Cont'd.)

c. Screen P: Safety and Reliability Tests (Cont'd.)

4. Does the Generating Facility incorporate a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time?

5. Is operational flexibility reduced by the proposed Generating Facility, such that transfer of the line section(s) of the Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues?

6. Does the Generating Facility utilize Certified anti-islanding functions and equipment?

3. DETAILED STUDY SCREENS

a. Screen Q: Is the Interconnection Request electrically Independent of the Transmission System?

Distribution Provider, in consultation with the CAISO, will determine, based on knowledge of the interdependencies with earlier-queued interconnection requests under any tariff, whether the Interconnection Request to the Distribution System is of sufficient MW size and located at a point of interconnection such that it is reasonably anticipated to require or contribute to the need for Reliability Network Upgrades. In making this determination, the Distribution Provider will make a Determination of Electrical Independence for the CAISO Controlled Grid as set forth in the applicable CAISO Tariff in effect at the time the Electrical Independence Test begins.

If Distribution Provider determines that no interdependencies exist, or that interdependencies do exist but the proposed Generating Facility is not reasonably anticipated to require or contribute to the need for Reliability Network Upgrades, then the Interconnection Request will be deemed to have passed Distribution Provider's Determination of Electrical Independence for the CAISO Controlled Grid.

If Distribution Provider determines that interdependencies exist and that they are reasonably anticipated to require or contribute to the need for Reliability Network Upgrades, then Interconnection Request may be studied under the WDT Transmission Cluster Study Process as set forth in Section F.3.d. (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

3. DETAILED STUDY SCREENS (Cont'd.)

a. Screen Q: Is the Interconnection Request electrically Independent of the Transmission System? (Cont'd.)

Distribution Provider will coordinate with the CAISO if necessary to conduct the Determination of Electrical Independence for the CAISO Controlled Grid as set forth in the applicable CAISO Tariff** in effect at the time the Electrical Independence Test (EIT) begins. The results of the incremental power flow, aggregate power flow, and short-circuit current contribution tests set out in the applicable CAISO Tariff in effect at the time the EIT begins will determine whether the Interconnection Request is electrically independent from the CAISO Controlled Grid.

- If Yes (pass), continue to Screen R.
- If No (fail), proceed to Section F.3.d.

Exemptions: All NEM Generating Facilities and all inverter-based Generating Facilities with a nameplate capacity less than or equal to 1 MVA will not be studied in the WDT Transmission Cluster Study Process, but may be studied under the Independent Study Process. For an Applicant that agrees to the installation, at Applicant's cost, of Distribution Provider-approved software/firmware controlled devices or equipment Nationally Recognized Testing Laboratory certified to limit the Generating Facility's net export so that it will never exceed the 1 MVA exemption limit, the Generating Facility's net export will be considered exempt from the WDT Transmission Cluster Study Process for purposes of this section.

Significance: Generating Facilities that are electrically interdependent with the Transmission System must be studied with other interconnection requests that have Transmission System interdependencies. It is possible to pass this Screen Q (i.e., be found to have no electrical interdependencies with earlier-queued Distribution System and/or Transmission System interconnection requests as set out above), be studied under the Independent Study Process, and still trigger a Reliability Network Upgrade.

** The currently effective CAISO Tariff can be accessed at the following CAISO website http://www.caiso.com/rules/Pages/Regulatory/Default.aspx (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

3. DETAILED STUDY SCREENS (Cont'd.)

b. Screen R: Is the Interconnection Request independent of other earlier-queued and yet to be studied interconnection requests interconnecting to the Distribution System?

For Interconnection Requests that are electrically independent from the CAISO Controlled Grid, Distribution Provider will evaluate each Interconnection Request for known or reasonably anticipated relationships between the Interconnection Request and any earlier-queued interconnection requests in the Distribution Group Study Process, the Independent Study Process, or interconnection requests studied under predecessor interconnection procedures that have yet to complete their respective interconnection studies. Distribution Provider may conduct incremental power flow, aggregate power flow, and/or short-circuit duty tests using existing interconnection studies, Base Case data, overall system knowledge, and engineering judgment to determine whether an Interconnection Request can be studied independently of earlier-queued interconnection requests. If the Interconnection Request being evaluated for electrical independence on the Distribution System may be electrically related to earlier-queued interconnection requests that have yet to complete interconnection studies, then it fails the evaluation of electrical independence for the Distribution System.

- If Yes (pass), continue to Independent Study Process
- If No (fail), continue to the Distribution Group Study Process

Significance: Interconnection Requests that are electrically related to earlier-queued interconnection requests that have not yet been studied do not qualify for independent study. (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

3. DETAILED STUDY SCREENS (Cont'd.)

c. Independent Study Process and Distribution Group Study Process Interconnection Studies

The Interconnection Studies shall consist of an Interconnection System Impact Study and an Interconnection Facilities Study for the Independent Study Process or the DGS Phase I Interconnection Study and the DGS Phase II Interconnection Study for the Distribution Group Study Process. The Interconnection Studies will identify Interconnection Facilities, Distribution Upgrades and Reliability Network Upgrades necessary to mitigate thermal overloads and voltage violations, and address short circuit, dynamic/stability, and reliability issues associated with the requested Interconnection Service. If Distribution Provider anticipates that Reliability Network Upgrades will be required, or the Interconnection Studies identify the need for Reliability Network Upgrades, then Distribution Provider will coordinate with the CAISO during the study process as set forth in Sections F.3.b or F.3.c above.

The estimated costs of short circuit related upgrades and shared interconnection facilities, if any, identified through a Distribution Group Study shall be assigned as provided in E.4.e.

i) Interconnection System Impact and DGS Phase I Interconnection Study.

(1) Scope of the Interconnection System Impact and DGS Phase I Interconnection Study.

The Interconnection System Impact or DGS Phase I Interconnection Study in the case of the Distribution Group Study Process may consist of a localized short circuit analysis, a stability/dynamic analysis, a power flow analysis, and any other studies that are deemed necessary. The localized short circuit analysis will evaluate impacts to the Distribution and Transmission System only with any local short circuit-duty related Reliability Network Upgrades allocated to the Generating Facility or Generating Facilities that require(s) the upgrades. Short circuit duty impacts to the (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

3. DETAILED STUDY SCREENS (Cont'd.)

c. Independent Study Process and Distribution Group Study Process Interconnection Studies (Cont'd.)

i) Interconnection System Impact and DGS Phase I Interconnection Study. (Cont'd.)

(1) Scope of the Interconnection System Impact and DGS Phase I Interconnection Study. (Cont'd.)

CAISO Controlled Grid are appropriately evaluated only in the WDT Transmission Cluster Study Process as set forth in Section F.3.d. The short circuit duty contribution of any Interconnection Requests studied in the Independent Study Process or Distribution Group Study Process that are subsequently identified in the Cluster Study Process will be allocated its pro rata share of the short circuit duty-related Reliability Network Upgrades on the basis of the short circuit duty contribution of each Generating Facility.

The Interconnection System Impact Study or DGS Phase I Interconnection Study in the case of the Distribution Group Study Process, shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested Interconnection Service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the Interconnection.

The Interconnection System Impact or DGS Phase I Interconnection Study shall provide a list of Distribution Provider's Interconnection Facilities, Distribution Upgrades, and Reliability Network Upgrades that are required as a result of the Interconnection Request along with a non-binding good faith estimate of cost responsibility and the amount of construction time required.

If at any time the Distribution Provider determines that it will not meet the required time frame for completing the DGS Phase I Interconnection Study due to the large number of (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

3. DETAILED STUDY SCREENS (Cont'd.)

c. Independent Study Process and Distribution Group Study Process Interconnection Studies (Cont'd.)

i) Interconnection System Impact and DGS Phase I Interconnection Study. (Cont'd.)

(1) Scope of the Interconnection System Impact and DGS Phase I Interconnection Study. (Cont'd.)

Interconnection Requests in the Distribution Group Study Application window, study complexity, or unavailability of resources on a reasonable basis to perform the study in the required time frame, the Distribution Provider shall notify the Interconnection Customer(s) within the Distribution Group Study as to the schedule status of the DGS Phase I Interconnection Study and provide an estimated completion date with an explanation of the reasons why additional time is required.

Upon request, the Distribution Provider shall provide the Applicant(s) all supporting documentation, work papers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the DGS Phase I Interconnection Study, subject to confidentiality arrangements as outlined in Section D.7.

ii) Interconnection Facilities Study and DGS Phase II Interconnection Study.

(1) Scope and Purpose of the Interconnection Facilities and DGS Phase II Interconnection Study.

The Interconnection Facilities Study or DGS Phase II Interconnection Study in the case of the Distribution Group Study Process shall specify and estimate the cost of the equipment, engineering, procurement, and construction work (including overheads) needed to implement the conclusions of the Interconnection System Impact Study or DGS Phase I Interconnection Study technical analyses in accordance with (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

3. DETAILED STUDY SCREENS (Cont'd.)

c. Independent Study Process and Distribution Group Study Process Interconnection Studies (Cont'd.)

ii) Interconnection Facilities Study and DGS Phase II Interconnection Study. (Cont'd.)

(1) Scope and Purpose of the Interconnection Facilities and DGS Phase II Interconnection Study. (Cont'd.)

Good Utility Practice to physically and electrically connect the Generating Facility to the Distribution or Transmission System. The Interconnection Facilities Study or DGS Phase II Interconnection Study shall also identify (i) the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Distribution Provider's Interconnection Facilities, Distribution Upgrades, and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities. The analyses in the Interconnection System Impact Study (or DGS Phase I Interconnection Study in the case of the Distribution Group Study Process) will be updated as necessary in the Interconnection Facilities Study (or DGS Phase II Interconnection Study), to account for withdrawal of interconnection requests in the interconnection queue.

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS

Section H shall be used for interconnection of non-inverter based technologies.

Section H shall also continue to be used for interconnection of inverter based technologies until September 8, 2017. Following such date, Section Hh shall apply for interconnection of inverter based technologies. Until such date, Section Hh may be used in all or in part, for inverter based technologies by mutual agreement of the Distribution Provider and the Applicant. (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS

This section is consistent with the requirements of ANSI/IEEE 1547-2003 Standard for Interconnecting Distributed Resources with Electric Power Systems (IEEE 1547). Exceptions are taken to IEEE 1547 Clauses 4.1.4.2 Distribution Secondary Spot Networks and Clauses 4.1.8.1 or 5.1.3.1, which address Protection from Electromagnetic Interference. These are being studied for inclusion in a subsequent version of this Rule. Also, Rule 21 does not adopt the Generating Facility power limitation of 10 MW incorporated in IEEE 1547.

The Protective Functions and requirements of this Rule are designed to protect Distribution Provider's Distribution and Transmission System and not the Generating Facility. A Producer shall be solely responsible for providing adequate protection for its Generating Facility and Interconnection Facilities. Producer's Protective Functions shall not impact the operation of other Protective Functions on Distribution Provider's Distribution and Transmission System in a manner that would affect Distribution Provider's capability of providing reliable service to its customers.

a. Protective Functions Required

Generating Facilities operating in parallel with Distribution Provider's Distribution or Transmission System shall be equipped with the following Protective Functions to sense abnormal conditions on Distribution Provider's Distribution or Transmission System and cause the Generating Facility to be automatically disconnected from Distribution Provider's Distribution or Transmission System or to prevent the Generating Facility from being connected to Distribution Provider's Distribution or Transmission System inappropriately:

i) Over and under voltage trip functions and over and under frequency trip functions;

ii) A voltage and frequency sensing and time-delay function to prevent the Generating Facility from energizing a de-energized Distribution or Transmission System circuit and to prevent the Generating Facility from reconnecting with Distribution Provider's (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS (Cont'd.)

a. Protective Functions Required (Cont'd.)

ii) Distribution or Transmission System unless Distribution Provider's Distribution System service voltage and frequency is within the ANSI C84.1-1995 Table 1 Range B voltage Range of 106 volts to 127 volts (on a 120 volt basis), inclusive, and a frequency range of 59.3 Hz to 60.5 Hz, inclusive, and are stable for at least 60 seconds; and

iii) A function to prevent the Generating Facility from contributing to the formation of an Unintended Island, and cease to energize Distribution Provider's Distribution System within two seconds of the formation of an Unintended Island.

The Generating Facility shall cease to energize Distribution Provider's Distribution System for faults on Distribution Provider's Distribution System circuit to which it is connected (IEEE 1547-4.2.1). The Generating Facility shall cease to energize Distribution Provider's Distribution circuit prior to re-closure by Distribution Provider's Distribution System equipment (IEEE 1547-4.2.2).

b. Momentary Paralleling Generating Facilities

With Distribution Provider's approval, the transfer switch or scheme used to transfer Producer's loads from Distribution Provider's Distribution or Transmission System to Producer's Generating Facility may be used in lieu of the Protective Functions required for Parallel Operation.

c. Suitable Equipment Required

Circuit breakers or other interrupting equipment located at the Point of Common Coupling (PCC) must be Certified or "Listed" (as defined in Article 100, the Definitions Section of the National Electrical Code) as suitable for their intended application. This includes being capable of (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS (Cont'd.)

c. Suitable Equipment Required (Cont'd.)

interrupting the maximum available fault current expected at their location. Producer's Generating Facility and Interconnection Facilities shall be designed so that the failure of any single device or component shall not potentially compromise the safety and reliability of Distribution Provider's Distribution and Transmission System. The Generating Facility paralleling-device shall be capable of withstanding 220% of the Interconnection Facility rated voltage (IEEE 1547-4.1.8.3). The Interconnection Facility shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE Std C62.41.2-2002 or IEEE Std C37.90.1-2002 as applicable and as described in L.3.e (IEEE 1547-4.1.8.2).

d. Visible Disconnect Required

When required by Distribution Provider's operating practices, Producer shall furnish and install a ganged, manually-operated isolating switch (or a comparable device mutually agreed upon by Distribution Provider and Producer) near the Point of Interconnection to isolate the Generating Facility from Distribution Provider's Distribution or Transmission System. The device does not have to be rated for load break nor provide over-current protection.

The device must:

i) allow visible verification that separation has been accomplished. (This requirement may be met by opening the enclosure to observe contact separation.)

ii) include markings or signage that clearly indicates open and closed positions.

iii) be capable of being reached:

a) for Emergency purposes quickly and conveniently 24 hours a day by Distribution Provider personnel for construction, (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS (Cont'd.)

d. Visible Disconnect Required (Cont'd.)

iii) be capable of being reached: (Cont'd.)

a) operation, maintenance, inspection, testing or to isolate the Generating Facility from Distribution Provider's Distribution or Transmission System without obstacles or requiring those seeking access to obtain keys, special permission, or security clearances.

b) for Non-Emergency purposes during normal business hours. Distribution Provider, where possible, will provide notice to Customer for gaining access to Customer's premises.

iv) be capable of being locked in the open position,

v) be clearly marked on the submitted single line diagram and its type and location approved by Distribution Provider prior to installation. If the device is not adjacent to the PCC, permanent signage must be installed at a Distribution Provider approved location providing a clear description of the location of the device. If the switch is not accessible outside the locked premises, signage with contact information and a Distribution Provider approved locking device for the premises shall be installed.

Generating Facilities with Non-Islanding inverters totaling one (1) kilovolt-ampere (kVA) or less are exempt from this requirement.

e. Drawings Required

Prior to Parallel Operation or Momentary Parallel Operation of the Generating Facility, Distribution Provider shall approve Producer's Protective Function and control diagrams. Generating Facilities equipped with Protective Functions and a control scheme previously approved by Distribution Provider for system-wide application or only Certified Equipment may satisfy this requirement by reference to previously approved drawings and diagrams. (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS (Cont'd.)

f. Generating Facility Conditions Not Identified

In the event this Rule does not address the Interconnection conditions for a particular Generating Facility, Distribution Provider and Producer may agree upon other arrangements

2. PREVENTION OF INTERFERENCE

Producer shall not operate Generating or Interconnection Facilities that superimpose a voltage or current upon Distribution Provider's Distribution or Transmission System that interferes with Distribution Provider operations, service to Distribution Provider Customers, or communication facilities. If such interference occurs, Producer must diligently pursue and take corrective action at its own expense after being given notice and reasonable time to do so by Distribution Provider. If Producer does not take corrective action in a timely manner, or continues to operate the facilities causing interference without restriction or limit, Distribution Provider may, without liability, disconnect Producer's facilities from Distribution Provider's Distribution or Transmission System, in accordance with Section D.9 of this Rule. To eliminate undesirable interference caused by its operation, each Generating Facility shall meet the following criteria:

a. Voltage Regulation

The Generating Facility shall not actively regulate the voltage at the PCC while in parallel with Distribution Provider's Distribution System. The Generating Facility shall not cause the service voltage at other customers to go outside the requirements of ANSI C84.1-1995, Range A (IEEE 1547-4.1.1). (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

b. Voltage Trip Setting

The voltage ranges in Table H.1 define protective trip limits for the Protective Function and are not intended to define or imply a voltage regulation Function. Generating Facilities shall cease to energize Distribution Provider's Distribution System within the prescribed trip time whenever the voltage at the PCC deviates from the allowable voltage operating range. The Protection Function shall detect and respond to voltage on all phases to which the Generating Facility is connected.

i) Generating Facilities (30 kVA or less)

Generating Facilities with a Gross Rating of 30 kVA or less shall be capable of operating within the voltage range normally experienced on Distribution Provider's Distribution System from plus to minus 5% of the nominal voltage (e.g. 114 volts to 126 volts, on a 120 volt base), at the service panel or PCC. The trip settings at the generator terminals may be selected in a manner that minimizes nuisance tripping between 106 volts and 132 volts on a 120-volt base (88%-110% of nominal voltage) to compensate for voltage drop between the generator terminals and the PCC. Voltage may be detected at either the PCC or the Point of Interconnection. However, the voltage range at the PCC, with the generator on-line, shall stay within +/-5% of nominal. (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

b. Voltage Trip Setting (Cont'd.)

ii) Generating Facilities (greater than 30 kVA)

Distribution Provider may have specific operating voltage ranges for Generating Facilities with Gross Ratings greater than 30 kVA, and may require adjustable operating voltage settings. In the absence of such requirements, the Generating Facility shall be capable of operating at a range between 88% and 110% of the applicable interconnection voltage. Voltage shall be detected at either the PCC or the Point of Interconnection, with settings compensated to account for the voltage at the PCC. However, the voltage range at the PCC, with the generator on-line, shall stay within +/-5% of nominal.

iii) Voltage Disturbances

Whenever Distribution Provider's Distribution System voltage at the PCC varies from and remains outside normal (Nominally 120 volts) for the predetermined parameters set forth in Table H-1, the Generating Facility's Protective Functions shall cause the Generator(s) to become isolated from Distribution Provider's Distribution System: (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

b. Voltage Trip Setting (Cont'd.)

iii) Voltage Disturbances (Cont'd.)

Table H.1: Voltage Trip Settings for Generating Facilities*

Voltage at Point of Common Coupling (the ranges below are used to trip the generator during abnormal distribution system conditions)		Maximum Trip Time**	
Assuming 120 Volt Base	% of Nominal Voltage	# of Cycles (Assuming 60 Hz Nominal)	Seconds
Less than 60 volts	Less than 50%	10 Cycles	0.16 Seconds
Greater than or equal to 60 volts but less than 106 volts	Greater than or equal to 50% but less than 88%	120 Cycles	2 Seconds
Greater than 132 volts but less than or equal to 144 volts	Greater than 110% but less than or equal to 120%	60 Cycles	1 Second
Greater than 144 volts	Greater than 120%	10 Cycles	0.16 Seconds

**For Generating Facilities with a Rating greater than 30 kVA, set points shall be field adjustable and different voltage set points and trip times from those in Table H.1 may be negotiated with Distribution Provider*

*** "Maximum Trip Time" refers to the time between the onset of the abnormal condition and the Generating Facility ceasing to energize Distribution Provider's Distribution System. Protective Function equipment and circuits may remain connected to Distribution Provider's Distribution System to allow sensing of electrical conditions for use by the "reconnect" feature. The purpose of the allowed time delay is to allow for a Generating Facility to minimize tripping during short term system disturbances. Set points shall not be user adjustable for generating facilities less than 30 kW.*

(L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

c. Paralleling

The Generating Facility shall parallel with Distribution Provider's Distribution or Transmission System without causing a voltage fluctuation at the PCC greater than plus/minus 5% of the prevailing voltage level of Distribution Provider's Distribution or Transmission System at the PCC, and meet the flicker requirements of Section H.2.d. Section L, Certification and Testing Criteria, provides technology-specific tests for evaluating the paralleling Function. (IEEE 1547-4.1.3)

d. Flicker

The Generating Facility shall not create objectionable flicker for other customers on Distribution Provider's Distribution or Transmission System. To minimize the adverse voltage effects experienced by other customers (IEEE 1547-4.3.2), flicker at the PCC caused by the Generating Facility should not exceed the limits defined by the "Maximum Borderline of Irritation Curve" identified in IEEE 519-1992 (IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems, IEEE STD 519-1992). This requirement is necessary to minimize the adverse voltage affects experienced by other Customers on Distribution Provider's Distribution or Transmission System. Generators may be connected and brought up to synchronous speed (as an induction motor) provided these flicker limits are not exceeded. (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

e. Integration with Distribution Provider's Distribution System Grounding

The grounding scheme of the Generating Facility shall not cause over-voltages that exceed the rating of the equipment connected to Distribution Provider's Distribution System and shall not disrupt the coordination of the ground fault protection on Distribution Provider's Distribution System (IEEE 1547-4.1.2) (See Section G.1.i, line configuration).

f. Frequency

Distribution Provider controls system frequency, and the Generating Facility shall operate in synchronism with Distribution Provider's Distribution or Transmission System. Whenever Distribution Provider's Distribution or Transmission System frequency at the PCC varies from and remains outside normal (nominally 60 Hz) by the predetermined amounts set forth in Table H.2, the Generating Facility's Protective Functions shall cease to energize Distribution Provider's Distribution or Transmission System within the stated maximum trip time. (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

f. Frequency (Cont'd.)

Table H.2
Frequency Trip Settings

Generating Facility Rating	Frequency Range (Assuming 60Hz Nominal)	Maximum Trip Time *[1]* (Assuming 60 Cycles per Second)
Less or equal to 30kW	Less than 59.3 Hz	10 Cycles
	Greater than 60.5 Hz	10 Cycles
Greater than 30 kW	Less than 57.0 Hz	10 Cycles
	Less than an adjustable value between 59.8 Hz and 57 Hz but greater than 57 Hz. *[2]*	Adjustable between 10 and 18,000 Cycles. *[2, 3]*
	Greater than 60.5 Hz.	10 Cycles

[1] – "Maximum Trip time" refers to the time between the onset of the abnormal condition and the Generating Facility ceasing to energize Distribution Provider's Distribution or Transmission System. Protective Function sensing equipment and circuits may remain connected to Distribution Provider's Distribution or Transmission System to allow sensing of electrical conditions for use by the "reconnect" feature. The purpose of the allowed time delay is to allow a Generating Facility to "ride through" short-term disturbances to avoid nuisance tripping. Set points shall not be user adjustable (though they may be field adjustable by qualified personnel). For Generating Facilities with a Gross Rating greater than 30 kVA, set points shall be field adjustable and different voltage set points and trip times from those in Table H.2 may be negotiated with Distribution Provider.

[2] – Unless otherwise required by Distribution Provider, a trip frequency of 59.3 Hz and a maximum trip time of 10 cycles shall be used.

[3] – When a 10 cycle Maximum trip time is used, a second under frequency trip setting is not required. (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

g. Harmonics

When the Generating Facility is serving balanced linear loads, harmonic current injection into Distribution Provider's Distribution or Transmission System at the PCC shall not exceed the limits stated in Table H.3. The harmonic current injections shall be exclusive of any harmonic currents due to harmonic voltage distortion present in Distribution Provider's Distribution or Transmission System without the Generating Facility connected (IEEE 1547-4.3.3.). The harmonic distortion of a Generating Facility shall be evaluated using the same criteria as for the Host Loads.

Table H.3

Maximum harmonic current distortion in percent of current (I) [1,2]

Individual harmonic order, h (odd harmonics) [3]	h<11	11≤ h<17	17≤ h<23	23≤ h<35	35≤ h	Total demand distortion
Max Distortion (%)	4.0	2.0	1.5	0.6	0.3	5.0

[1] – IEEE1547-4.3.3

[2] – I = the greater of the maximum Host Load current average demand over 15 or 30 minutes without the GF, or the GF rated current capacity (transformed to the PCC when a transformer exists between the GF and the PCC).

[3] – Even harmonics are limited to 25% of the odd harmonic limits above. (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

h. Direct Current Injection

Generating Facilities should not inject direct current greater than 0.5% of rated output current into Distribution Provider's Distribution or Transmission System.

i. Power Factor

Producer shall provide adequate reactive power compensation on site to maintain the Generating Facility power factor near unity at rated output or a Distribution Provider specified power factor within a power factor range from 0.9 leading to 0.9 lagging, based on local system conditions. While not required, for generators that do not have inherent reactive power control capability Distribution Provider at its option may offer reactive power support in the form of power factor correction capacitors on its Distribution or Transmission System, under a Generator Interconnection Agreement or an Added Facilities or Special Facilities agreement, as described in Rule 2.H, as applicable. (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

3. TECHNOLOGY SPECIFIC REQUIREMENTS

a. Technology Specific Requirements

Three-Phase Synchronous Generators: For three phase Generators, the Generating Facility circuit breakers shall be three-phase devices with electronic or electromechanical control. Producer shall be responsible for properly synchronizing its Generating Facility with Distribution Provider's Distribution or Transmission System by means of either manual or automatic synchronous equipment. Automatic synchronizing is required for all synchronous Generators that have a Short Circuit Contribution Ratio (SCCR) exceeding 0.05. Loss of synchronism protection is not required except as may be necessary to meet Section H.2.d (Flicker) (IEEE1547-4.2.5). Unless otherwise agreed upon by Producer and Distribution Provider, synchronous Generators shall automatically regulate power factor, not voltage, while operating in parallel with Distribution Provider's Distribution System. A power system stabilization Function is specifically not required for Generating Facilities under 10 MW Net Rating.

b. Induction Generators

Induction Generators (except self-excited Induction Generators) do not require a synchronizing Function. Starting or rapid load fluctuations on induction Generators can adversely impact Distribution Provider's Distribution or Transmission System voltage. Corrective step-switched capacitors or other techniques may be necessary and may cause undesirable ferro-resonance. When these counter measures (e.g. additional capacitors) are installed on Producer's side of the PCC, Distribution Provider must review these measures. Additional equipment may be required as determined in a Supplemental Review or an Interconnection Study. (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

3. TECHNOLOGY SPECIFIC REQUIREMENTS (Cont'd.)

c. Inverters

Grid-interactive inverters do not require separate synchronizing equipment. Non-grid-interactive or "stand-alone" inverters shall not be used for Parallel Operation with Distribution Provider's Distribution or Transmission System.

d. Limitations on Inverters Not Classified as Smart Inverters

i) Inverter based systems may continue to be installed per Section H until September 8, 2017. Section Hh may be used in all or in part, for inverter based technologies by mutual agreement of the Distribution Provider and the Applicant.

ii) The replacement of an existing inverter to an inverter that is of equal or greater ability than the original is allowed per Section H. Section Hh may be used in all or in part, for replacement inverter-based technologies by mutual agreement of the Distribution Provider and the Applicant. 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, per D.19-03-013 OP 12.

e. Non-Export AC/DC Converters

A Non-Export AC/DC Converter must satisfy the definition in Section C. (L)

(Continued)

H. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

4. SUPPLEMENTAL GENERATING FACILITY REQUIREMENTS

a. Fault Detection

A Generating Facility with an SCCR exceeding 0.1 or one that does not cease to energize Distribution Provider's Distribution or Transmission System within two seconds of the formation of an Unintended Island shall be equipped with Protective Functions designed to detect Distribution or Transmission System faults, both line-to-line and line-to-ground, and cease to energize Distribution Provider's Distribution or Transmission System within two seconds of the initiation of a fault.

b. Transfer Trip

For a Generating Facility that cannot detect Distribution or Transmission System faults (both line-to-line and line-to-ground) or the formation of an Unintended Island, and cease to energize Distribution Provider's Distribution or Transmission System within two seconds, Distribution Provider may require a Transfer Trip system or an equivalent Protective Function.

c. Reclose Blocking

Where the aggregate Generating Facility capacity exceeds 15% of the peak load on any automatic reclosing device, Distribution Provider may require additional Protective Functions, including, but not limited to reclose-blocking on some of the automatic reclosing devices.

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS

Section H shall continue to be used for interconnection of inverter based technologies until September 8, 2017. Following such date, Section Hh shall apply for interconnection of inverter based technologies. Until such date, Section Hh may be used in all or in part, for inverter based technologies by mutual agreement of the Distribution Provider and the Applicant.

[1] "The Standard for Inverters, Converters, and Controllers for Use in Independent Power Systems". (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

The inverter requirements are intended to be consistent with UL 1741 - Supplement SA using Section Hh of Rule 21 as the source requirement document and ANSI/IEEE 1547-2003 and 1547a Standard for Interconnecting Distributed Resources with Electric Power Systems (IEEE 1547 including amendment 1547a), where possible. In the event of conflict between this Rule, and UL 1741 - Supplement SA, and/or IEEE 1547-2003 or IEEE 1547a, this Rule shall take precedence. Exceptions are taken to IEEE 1547 Clauses 4.1.4.2 Distribution Secondary Spot Networks and Clauses 4.1.8.1 or 5.1.3.1, which address Protection from Electromagnetic Interference. Rule 21 does not adopt the Generating Facility power limitation of 10 MW incorporated in IEEE 1547. (L)

The Smart Inverter default settings and default activation states may be modified upon mutual agreement between Applicant and Distribution Provider. (P)/(L) (P)/(L)

Process for changing default settings for new Interconnection Requests: (P)/(L)

Distribution Provider, in the study process for new Generating Facilities, may determine and provide the optimum Smart Inverter Settings for the reactive power settings, including changes to the reactive power default settings (Example: Deactivate Volt/Var and activate Fixed Power Factor at given power factor).

Distribution Provider, in the study process for new Generating Facilities, may determine and provide the optimum Smart Inverter Settings for the Ramp Rate settings depending on the Generating Facility technology (such as solar, storage).

Distribution Provider, in the study process for new Generating Facilities, may determine the optimum Smart Inverter Settings for the volt/watt settings including changes to the default settings (Example: Change the volt/watt set points). The Applicant may select to agree on the new settings or select to perform upgrades to operate using the existing default volt/watt settings.

Default settings for voltage ride-through, frequency ride-through requirements, and Frequency/Watt should not be modified on an individual project basis unless the Interconnection Studies have determined that the default settings may not meet grid reliability requirements. (P)/(L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (P)/(L)

Process for changing default settings for Generating Facilities with an executed Interconnection Agreement:

When grid changes or Generating Facility changes require that the Smart Inverter operating parameters be reevaluated, the Distribution Provider or Producer may request changes to the Smart Inverter operating parameters. The request must include the reason for and timing of the proposed changes. The requested changes must be within the Smart Inverter function adjustability limits, must be within the limits specified in this tariff, and must be mutually agreed upon. (P)/(L)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS (L)

The Protective Functions and requirements of this Rule are designed to protect Distribution Provider's Distribution and Transmission System and not the Generating Facility. A Producer shall be solely responsible for providing adequate protection for its Generating Facility and Interconnection Facilities. Producer's Protective Functions shall not impact the operation of other Protective Functions on Distribution Provider's Distribution and Transmission System in a manner that would affect Distribution Provider's capability of providing reliable service to its customers.

a. Protective Functions Required

Smart Inverters operating in parallel with Distribution Provider's Distribution or Transmission System shall be equipped with the following Protective Functions to sense abnormal conditions on Distribution Provider's Distribution or Transmission System and cause the Smart Inverter to be automatically disconnected from Distribution Provider's Distribution or Transmission System or to prevent the Smart Inverter from being connected to Distribution Provider's Distribution or Transmission System inappropriately:

(i) Over and under voltage trip functions and over and under frequency trip functions; (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS (Cont'd.)

a. Protective Functions Required (Cont'd.)

(ii) A voltage and frequency sensing and time-delay function to prevent the Smart Inverter from energizing a de-energized Distribution or Transmission System circuit and to prevent the Smart Inverter from reconnecting with Distribution Provider's Distribution or Transmission System unless Distribution Provider's Distribution System service voltage and frequency is within the ANSI C84.1-1995 Table 1 Range B voltage Range of 106 volts to 127 volts (on a 120 volt basis), inclusive, and a frequency range of 58.5 Hz to 60.5 Hz, inclusive, and are stable for at least 15 seconds; and

(iii) A function to prevent the Smart Inverter from contributing to the formation of an Unintended Island, and cease to energize Distribution Provider's Distribution System within two seconds of the formation of an Unintended Island.

The Smart Inverter shall cease to energize Distribution Provider's Distribution System for faults on Distribution Provider's Distribution System circuit to which it is connected (IEEE 1547-4.2.1). The Smart Inverter shall cease to energize Distribution Provider's Distribution circuit prior to re-closure by Distribution Provider's Distribution System equipment (IEEE 1547-4.2.2).

b. Momentary Paralleling Generating Facilities

With Distribution Provider's approval, the transfer switch or scheme used to transfer Producer's loads from Distribution Provider's Distribution or Transmission System to Producer's Generating Facility may be used in lieu of the Protective Functions required for Parallel Operation. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS (Cont'd.)

c. Suitable Equipment Required

Circuit breakers or other interrupting equipment located at the Point of Common Coupling (PCC) must be Certified or "Listed" (as defined in Article 100, the Definitions Section of the National Electrical Code) as suitable for their intended application. This includes being capable of interrupting the maximum available fault current expected at their location. Producer's Smart Inverter and Interconnection Facilities shall be designed so that the failure of any single device or component shall not potentially compromise the safety and reliability of Distribution Provider's Distribution and Transmission System. The Smart Inverter paralleling-device shall be capable of withstanding 220% of the Interconnection Facility rated voltage (IEEE 1547-4.1.8.3). The Interconnection Facility shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE Std C62.41.2-2002 or IEEE Std C37.90.1-2002 as applicable and as described in L.3.e (IEEE 1547-4.1.8.2).

d. Visible Disconnect Required

When required by Distribution Provider's operating practices, Producer shall furnish and install a ganged, manually-operated isolating switch (or a comparable device mutually agreed upon by Distribution Provider and Producer) near the Point of Interconnection to isolate the Smart Inverter from Distribution Provider's Distribution or Transmission System. The device does not have to be rated for load break nor provide over-current protection.

The device must:

(i) allow visible verification that separation has been accomplished. (This requirement may be met by opening the enclosure to observe contact separation.) (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS (Cont'd.)

   d. Visible Disconnect Required (Cont'd.)

      (ii) include markings or signage that clearly indicates open and closed positions.

      (iii) be capable of being reached:

         a) for Emergency purposes quickly and conveniently 24 hours a day by Distribution Provider personnel for construction, operation, maintenance, inspection, testing or to isolate the Smart Inverter from Distribution Provider's Distribution or Transmission System without obstacles or requiring those seeking access to obtain keys, special permission, or security clearances.

         b) for Non-Emergency purposes during normal business hours. Distribution Provider, where possible, will provide notice to Customer for gaining access to Customer's premises.

      (iv) be capable of being locked in the open position.

      (v) be clearly marked on the submitted single line diagram and its type and location approved by Distribution Provider prior to installation. If the device is not adjacent to the PCC, permanent signage must be installed at a Distribution Provider approved location providing a clear description of the location of the device. If the switch is not accessible outside the locked premises, signage with contact information and a Distribution Provider approved locking device for the premises shall be installed.

   Generating Facilities with Non-Islanding inverters totaling one (1) kilovolt-ampere (kVA) or less are exempt from this requirement. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS (Cont'd.)

   e. Drawings Required

      Prior to Parallel Operation or Momentary Parallel Operation of the Smart Inverter, Distribution Provider shall approve Producer's Protective Function and control diagrams. Generating Facilities equipped with Protective Functions and a control scheme previously approved by Distribution Provider for system-wide application or only Certified Equipment may satisfy this requirement by reference to previously approved drawings and diagrams.

   f. Generating Facility Conditions Not Identified

      In the event this Rule does not address the Interconnection conditions for a particular Smart Inverter, Distribution Provider and Producer may agree upon other arrangements.

2. PREVENTION OF INTERFERENCE

   Producer shall not operate Smart Inverters that superimpose a voltage or current upon Distribution Provider's Distribution or Transmission System that interferes with Distribution Provider operations, service to Distribution Provider Customers, or communication facilities. If such interference occurs, Producer must diligently pursue and take corrective action at its own expense after being given notice and reasonable time to do so by Distribution Provider. If Producer does not take corrective action in a timely manner, or continues to operate the facilities causing interference without restriction or limit, Distribution Provider may, without liability, disconnect Producer's facilities from Distribution Provider's Distribution or Transmission System, in accordance with Section D.9 of this Rule. To eliminate undesirable interference caused by its operation, each Smart Inverter shall meet the following criteria: (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

a. Voltage Regulation

If approved by the Distribution Provider, the Smart Inverter may actively regulate the voltage at the PCC while in parallel with Distribution Provider's Distribution System. The Smart Inverter shall not cause the service voltage at other customers to go outside the requirements of ANSI C84.1-1995, Range A (IEEE 1547-4.1.1).

b. Voltage Trip and Ride-Through Settings

The voltage ranges in Table Hh-.1 define protective trip limits for the Protective Function and are not intended to define or imply a voltage regulation Function. Generating Facilities shall cease to energize Distribution Provider's Distribution System within the prescribed trip time whenever the voltage at the PCC deviates from the allowable voltage operating range. The Protection Function shall detect and respond to voltage on all phases to which the Generating Facility is connected.

(i) Smart Inverters

Smart Inverters shall be capable of operating within the voltage range normally experienced on Distribution Provider's Distribution System from plus to minus 5% of the nominal voltage (e.g. 114 volts to 126 volts, on a 120 volt base), at the service panel or PCC. The trip settings at the generator terminals may be selected in a manner that minimizes nuisance tripping in accordance with Table Hh-.1 to compensate for voltage drop between the generator terminals and the PCC. Voltage may be detected at either the PCC or the Point of Interconnection. However, the voltage range at the PCC, with the generator on-line, shall stay within +/-5% of nominal. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

b. Voltage Trip and Ride-Through Settings (Cont'd.)

(ii) Voltage Disturbances

Whenever Distribution Provider's Distribution System voltage at the PCC varies from and remains outside near Nominal voltage for the predetermined parameters set forth in Table Hh-.1, the Smart Inverter's Protective Functions shall cause the Smart Inverter(s) to become isolated from Distribution Provider's Distribution System:

1. The Smart Inverter shall stay connected to the Distribution Provider's Transmission or Distribution System while the grid remains within the "Ride-Through Until" voltage-time range and must stay connected in the corresponding "Operating Mode.

2. For voltage excursions beyond the near Nominal (NN) magnitude range and within the range of the HV1 or LV3 regions, the Smart Inverter shall momentarily cease to energize within 0.16 seconds.

3. In the HV1 region, the Smart Inverter is permitted to reduce power output as a function of voltage under mutual agreement between the Producer and the Distribution Provider.

4. If the distribution system voltage does not exit the ride-through region and recovers to normal system voltage, the Smart Inverter shall restore continuous operation within 2 seconds.

5. If the Distribution Provider's Transmission or Distribution System voltage does not exit the ride-through region and returns from the LV3 region to the LV2 or LV1 region, the Smart Inverter shall restore available current within 2 seconds.

6. Different voltage-time settings could be permitted by the Distribution Provider. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

b. Voltage Trip and Ride-Through Settings (Cont'd.)

(ii) Voltage Disturbances (Cont'd.)

Table Hh.1: Voltage Ride-Through Table

Region	Voltage at Point of Common Coupling (% Nominal Voltage)	Ride-Through Until	Operating Mode	Maximum Trip Time
High Voltage 2 (HV2)	V ≥120			0.16 seconds
High Voltage 1 (HV1)	110 < V < 120	12 seconds	Momentary Cessation	13 seconds
Near Nominal (NN)	88 ≤ V ≤ 110	Indefinite	Continuous Operation	Not Applicable
Low Voltage 1 (LV1)	70 ≤ V < 88	20 seconds	Mandatory Operation	21 seconds
Low Voltage 2 (LV2)	50 ≤ V < 70	10 seconds	Mandatory Operation	11 seconds
Low Voltage 3 (LV3)	V < 50	1 seconds	Momentary Cessation	1.5 seconds

(L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

c. Paralleling

The Generating Facility shall parallel with Distribution Provider's Distribution or Transmission System without causing a voltage fluctuation at the PCC greater than plus/minus 5% of the prevailing voltage level of Distribution Provider's Distribution or Transmission System at the PCC, and meet the flicker requirements of Section H.2.d. Section L, Certification and Testing Criteria, provides technology-specific tests for evaluating the paralleling Function. (IEEE 1547-4.1.3)

d. Flicker

The Generating Facility shall not create objectionable flicker for other customers on Distribution Provider's Distribution or Transmission System. To minimize the adverse voltage effects experienced by other customers (IEEE 1547-4.3.2), flicker at the PCC caused by the Generating Facility should not exceed the limits defined by the "Maximum Borderline of Irritation Curve" identified in IEEE 519-1992 (IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems, IEEE STD 519-1992). This requirement is necessary to minimize the adverse voltage affects experienced by other Customers on Distribution Provider's Distribution or Transmission System. Generators may be connected and brought up to synchronous speed (as an induction motor) provided these flicker limits are not exceeded.

e. Integration with Distribution Provider's Distribution System Grounding

The grounding scheme of the Generating Facility shall not cause over-voltages that exceed the rating of the equipment connected to Distribution Provider's Distribution System and shall not disrupt the coordination of the ground fault protection on Distribution Provider's Distribution System (IEEE 1547-4.1.2) (See Section G.1.i, line configuration). (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

f. Frequency

Distribution Provider controls system frequency, and the Generating Facility shall operate in synchronism with Distribution Provider's Distribution or Transmission System. Whenever Distribution Provider's Distribution or Transmission System frequency at the PCC varies from and remains outside normal (nominally 60 Hz) by the predetermined amounts set forth in Table H.2, the Generating Facility's Protective Functions shall cease to energize Distribution Provider's Distribution or Transmission System within the stated maximum trip time.

(i) Frequency Ride-Through Requirements

Smart Inverter based systems shall remain connected to the Distribution Provider's Distribution or Transmission System while the grid is within the frequency-time range indicated in Table Hh-.2, and shall disconnect from the electric grid during a high or low frequency event that is outside that frequency-time range.

The frequency values are shown in Table Hh.2. These values provide default interconnection system response to abnormal frequencies. The inverter shall disconnect by the default clearing times. In the high frequency range between 60.2 Hz and 61.5 Hz, or some other mutually agreed range, the Smart Inverter is permitted to reduce real power output until it ceases to export power by 61.5 Hz, or other frequency value mutually agreed between the generating facility operator and the Distribution Provider. Islands and microgrids may need different default frequency settings. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

f. Frequency (Cont'd.)

(i) Frequency Ride-Through Requirements(Cont'd.)

Table Hh.2: Frequency Ride-Through and Trip Settings Table

System Frequency Default Settings (Hz)	Minimum Range of Adjustability (Hz)	Ride-Through Until	Ride-Through Operational Mode	MaximumTrip Time
f > 62	62 - 64	No Ride Through	Not Applicable	0.16 seconds
60.5 < f ≤ 62	60.1 - 62	299 seconds	Mandatory Operation	300 seconds
58.5 ≤ f ≤ 60.5	Not Applicable	Indefinite	Continuous Operation	Not Applicable
57.0 ≤ f < 58.5	57 - 59.9	299 seconds	Mandatory Operation	300 seconds
f < 57.0	53 - 57	No Ride Through	Not Applicable	0.16 seconds

g. Harmonics

When the Smart Inverter is serving balanced linear loads, harmonic current injection into Distribution Provider's Distribution or Transmission System at the PCC shall not exceed the limits stated in Table Hh-.43. The harmonic current injections shall be exclusive of any harmonic currents due to harmonic voltage distortion present in Distribution Provider's Distribution or Transmission System without the Smart Inverter connected (IEEE 1547-4.3.3.). The harmonic distortion of a Smart Inverter shall be evaluated using the same criteria as for the Host Loads. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

g. Harmonics (Cont'd.)

Table Hh.3

Maximum harmonic current distortion in percent of current (I) [1,2]

Individual harmonic order, h (odd harmonics) [3]	h<11	11≤ h<17	17≤ h<23	23≤ h<35	35≤ h	Total demand distortion
Max Distortion (%)	4.0	2.0	1.5	0.6	0.3	5.0

[1] – IEEE1547-4.3.3

[2] – I = the greater of the maximum Host Load current average demand over 15 or 30 minutes without the GF, or the GF rated current capacity (transformed to the PCC when a transformer exists between the GF and the PCC).

[3] – Even harmonics are limited to 25% of the odd harmonic limits above.

h. Direct Current Injection

Smart Inverter should not inject direct current greater than 0.5% of rated output current into Distribution Provider's Distribution or Transmission System.

i. Fixed Power Factor

Producer shall provide adequate reactive power compensation on site to maintain the Smart Inverter power factor near unity at rated output or a Distribution Provider specified power factor in accordance with the following requirements:

(i) Default Power Factor setting: Absorbing reactive power at 0.95 lagging power factor.

(ii) Aggregate generating facility is greater than 15 kW: 1.0 +/- 0.15 (0.85 Lagging to 0.85 Leading) down to 20% rated power irrespective of Real Power Production. (L)

(Continued)

ELECTRIC RULE NO. 21 Sheet 201
GENERATING FACILITY INTERCONNECTIONS

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

i. Fixed Power Factor (Cont'd.)

(iii) Aggregate generating facility is less than or equal to 15 kW: 1.0 +/- 0.10 (0.90 Lagging to 0.90 Leading) down to 20% rated power irrespective of Real Power Production.

j. Dynamic Volt/VAR Operations

The Smart Inverter shall be capable of operating dynamically within a power factor range of +/- 0.85 PF for larger (>15 kW) systems, down to 20% of rated active power, and +/- 0.9 PF for smaller systems (≤15 kW), down to 20% of rated active power, irrespective of Real Power Production. This dynamic Volt/VAR capability shall be able to be activated or deactivated in accordance with Distribution Provider requirements.

The Distribution Provider may permit or require the Smart Inverter systems to operate in larger power factor ranges, including in 4-quadrant operations for storage systems with the implementation of additional anti-islanding protection as determined by the Distribution Provider.

The Smart Inverter shall be capable of providing dynamic reactive power compensation (dynamic Volt/VAR operation) within the following constraints:

- The Smart Inverter shall be able to consume reactive power in response to an increase in line voltage, and produce reactive power in response to a decrease in line voltage.
- The reactive power provided shall be per the range irrespective of real power production, but the maximum reactive power provided to the system shall be as directed by the Distribution Provide
- Reduction of real power production is allowed to meet the required reactive power ranges. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

j. Dynamic Volt/VAR Operations (Cont'd.)

Dynamic Volt/Var Operations Default Settings

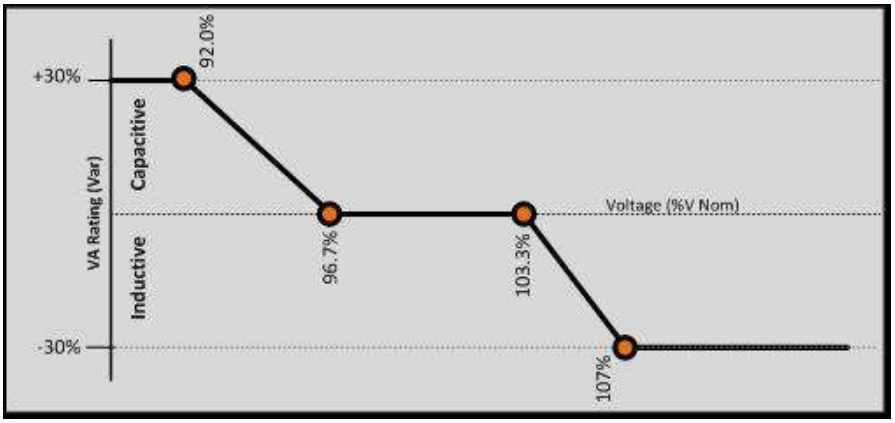
Table Hh-4 and Figure Hh-1 depict the default settings, which should be applied for all inverter sizes. Specific volt/var settings may be required for larger Generating Facilities (such as 100 kw or greater), or for specific areas with the Distribution Systems as determined by the Distribution Provider.

Default Open Loop Response Time for volt/var operation should be five (5) seconds.

Table Hh-4: Voltage and Reactive Default Settings

Voltage Setpoint	Voltage Value	Reactive Setpoint	Reactive Value	Operation
V1	92.0%	Q1	30%	Reactive Power Injection
V2	96.7%	Q2	0	Unity Power Factor
V3	103.3%	Q3	0	Unity Power Factor
V4	107.0%	Q4	30%	Reactive Power Absorption

Figure Hh-1: Voltage and Reactive Default Settings



(L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

k. Ramp Rate Requirements

The Smart Inverter is required to have the following ramp controls for at least the following four conditions. These functions can be established by multiple control functions or by one general ramp rate control function. Ramp rates are contingent upon sufficient energy available from the Smart Inverter.

- Normal ramp-up rate: For transitions between energy output levels over the normal course of operation. The default value is 100% of maximum current output per second with a range of adjustment between 1% to 100%, with specific settings as mutually agreed by the Distributor Provider and the Producer.

- Connect/Reconnect Ramp-up rate: Upon starting to inject power into the grid, following a period of inactivity or a disconnection, the inverter shall be able to control its rate of increase of power from 1 to 100% maximum current per second. The default value is 2% of maximum current output per second, with specific settings as mutually agreed upon by the Distribution Provider and the Producer.

l. Frequency-Watt Requirements

This requirement will become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after February 22, 2019, nine (9) months following the approval of the SunSpec Alliance Communication Protocol Certification Test Standard.

The utilization of this function is permissible under mutual agreement between the utility and the generating facility before the effective date.

Smart Inverters shall reduce their real power production as a function of system frequency, in accordance with the following:

- When system frequency exceeds 60.036 Hz, the active power output produced by the Smart Inverter shall be reduced by 50% of real power nameplate rating per hertz (5% of real power nameplate rating reduction per 0.1 hertz) (L)

(Continued)

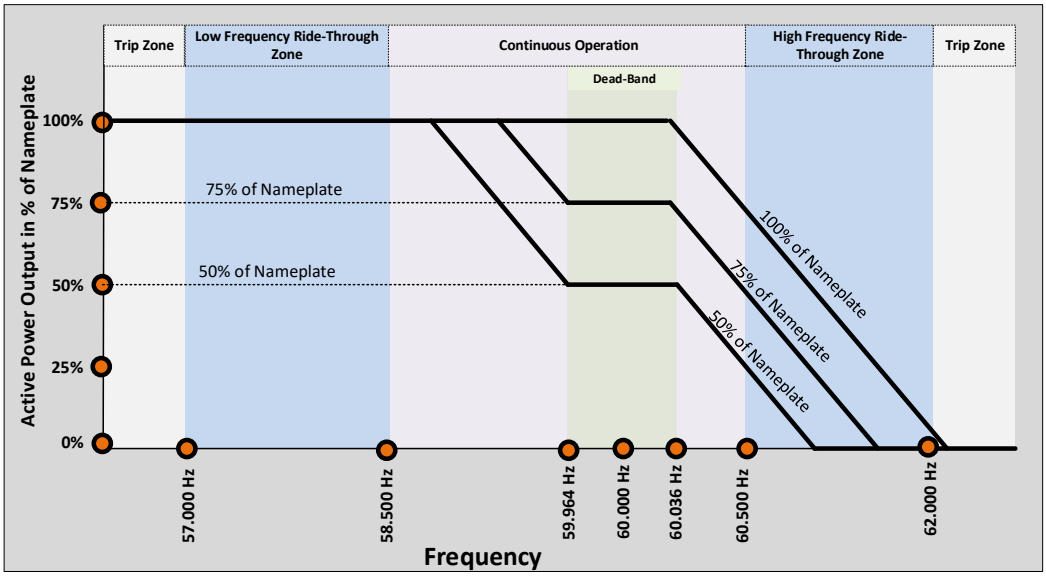
Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

l. Frequency-Watt Requirements (Cont'd.)

- When system frequency moves under 59.964 Hz, the active power output produced by the Smart Inverter shall be increased by 50% of real power nameplate rating per hertz (5% of real power nameplate rating increase per 0.1 hertz) when inverter is capable of increasing real power production.
- The default dead-band should be +/- 0.036 Hz from 60 Hertz (59.964 Hz to 60.036 Hz). When the system frequency is in range of 59.964 Hz and 60.036 Hz, the Smart Inverter is not required to decrease power as a function of system frequency.
- Open loop response time for Frequency –Watt shall be 5 seconds.
- Figure Hh-2 illustrated this requirement for three levels of output power. Figure Hh-2 is for illustration purposes only.

Figure Hh-2: Active Power as a Function of System Frequency



Note: the frequency markers on the horizontal axis are not drawn to scale. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

m. Voltage-Watt Default Settings Requirements

This requirement will become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after February 22, 2019, nine (9) months following the approval of the SunSpec Alliance Communication Protocol Certification Test Standard.

The utilization of this function is permissible under mutual agreement between the utility and the generating facility before the effective date.

Smart Inverters shall reduce their real power production as a function of measured voltage at the inverter terminals or at the Generating Facility Point of Common Coupling (PCC) in accordance with the following:

- When the measured voltage is greater than 106% of nominal voltage (for example: 127.2 volts on a 120 volts nominal), the export of active power at the PCC or the production of active power by the Smart Inverter shall be reduced at a rate of 25% of active power nameplate rating per one percent of nominal voltage. Figure Hh-3 – Volt-Watt Requirements – illustrates the required rate of reduction. When export of active power is controlled, a certified inverter and control system shall be used. (L)

(Continued)

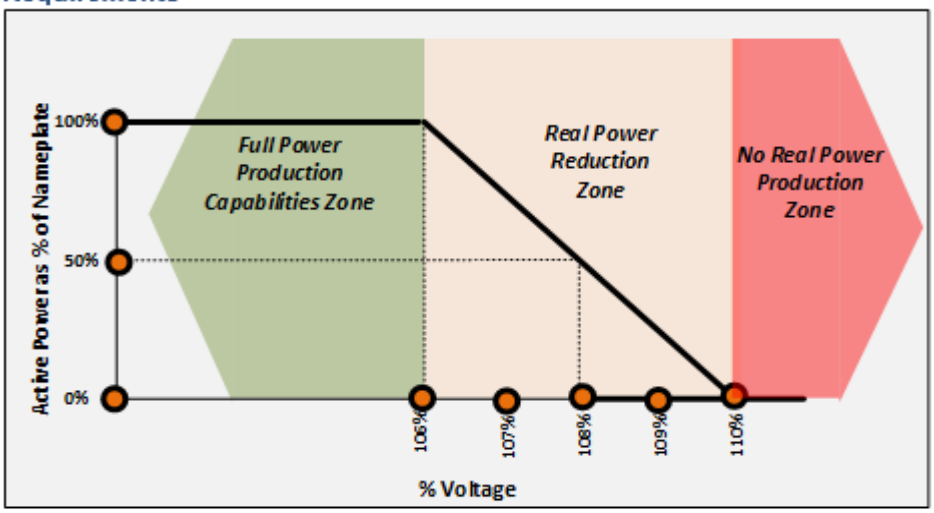
Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

m. (Cont'd.)

- When the measured voltage is greater than 110% of nominal voltage (Example: 132 volts on a 120 volts nominal), the export of active power output to the grid at the PCC or the production of active power by the Smart Inverter shall be reduced to 0 watts

Figure HH-3 – Volt-Watt Requirements



Percent (%) of nominal voltage (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

n. Dynamic Reactive Power Support Function

The capability for this requirement will become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted twelve (12) months after approval of a nationally recognized standard that includes the function.

The utilization of this function is allowed and optional upon the mutual agreement of the Distribution Provider and the Applicant, before the effective date.

o. Default Activation States

Unless otherwise provided by Distribution Provider, pursuant to Distribution Provider's Distribution Generation Interconnection Handbook, the default settings will be as follows:

	Function	**State**
1	Anti-islanding	activated
2	Low/High Voltage Ride-Through	activated
3	Low/High Frequency Ride-Through	activated
4	Dynamic Volt/VAR operations	activated
5	Ramp rates	activated
6	Fixed power factor	deactivated
7	Reconnect by "soft-start" methods	activated
8	Frequency-Watt*	activated
9	Volt/Watt*	activated
10	Set Active Power Function Mode (Optional)	activated under mutual agreement
11	Dynamic Reactive Power Support Mode (Optional)	activated under mutual agreement

These default activation states may be modified by mutual agreement between Distribution Provider and Producer.

* These functions must be activated for Interconnection Requests submitted on or after February 22, 2019. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

p. Phase 3 Functions

Table of Phase 3 Effective Dates Pursuant to Resolution E-4898 and Resolution E-5000 and CPUC Letter of March 20, 2020 responding to a request to extend the date for Functions 1, 2, 3 and 8:

Phase 3 Function #		
	Description	**Effective Date (note)**
1	Monitor Key DER Data	**June 22, 2020**
2	DER Disconnect and Reconnect Command (Cease to Energize and Return to Service)	**June 22, 2020**
3	Limit Maximum Active Power Mode	**June 22, 2020**
4	Set Active Power Mode	12 months after approval of a nationally recognized standard that includes the function.
5	Frequency Watt Mode	**February 22, 2019**, which is 9 months following SunSpec Alliance Communication Protocol Certification Test Standard.
6	Volt Watt Mode	**February 22, 2019**, which is 9 months following SunSpec Alliance Communication Protocol Certification Test Standard.
7	Dynamic Reactive Support	12 months after approval of a nationally recognized standard that includes the function.
8	Scheduling Power Values and Modes	**June 22, 2020**

Note: The utilization of any of these functions is permissible under mutual agreement between the utility and the generating facility before the effective date. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

2. PREVENTION OF INTERFERENCE (Cont'd.)

q. Load Shedding or Transfer

The voltage and frequency ride-through requirements of Hh.2.b.(ii) and Hh.2.f.(i) shall not apply if either: a) The real power across the Point of Common Coupling is continuously maintained at a value less than 10% of the aggregate rating of the Smart Inverters connected to the Generation Facility prior to any voltage disturbance, and the Generation Facility disconnects from the Distribution Provider's T&D system, along with Generation Facility load, such that the net change in real power flow from or to the Distribution Provider is less than 10% of the aggregate Smart Inverter capacity; or b) Generation Facility load real power demand equal to 90% to 120% of the pre-disturbance aggregate Smart Inverter real power output is shed within 0.1 seconds of Smart Inverter disconnection.

3. TECHNOLOGY SPECIFIC REQUIREMENTS

Grid-interactive inverters do not require separate synchronizing equipment. Non grid-interactive or "stand-alone" inverters shall not be used for Parallel Operation with Distribution Provider's Distribution or Transmission System. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

4. SUPPLEMENTAL SMART INVERTER REQUIREMENTS

a. Fault Detection

A Smart Inverter with an SCCR exceeding 0.1 or one that does not cease to energize Distribution Provider's Distribution or Transmission System within two seconds of the formation of an Unintended Island shall be equipped with Protective Functions designed to detect Distribution or Transmission System faults, both line-to-line and line-to-ground, and cease to energize Distribution Provider's Distribution or Transmission System within two seconds of the initiation of a fault.

b. Transfer Trip

For a Generating Facility that cannot detect Distribution or Transmission System faults (both line-to-line and line-to-ground) or the formation of an Unintended Island, and cease to energize Distribution Provider's Distribution or Transmission System within two seconds, Distribution Provider may require a Transfer Trip system or an equivalent Protective Function.

c. Reclose Blocking

Where the aggregate Generating Facility capacity exceeds 15% of the peak load on any automatic reclosing device, Distribution Provider may require additional Protective Functions, including, but not limited to reclose-blocking on some of the automatic reclosing devices. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

5. COMMUNICATION REQUIREMENTS

a. The communication protocol requirements included in this section Hh.5 shall become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted June 22, 2020. Until such date, this subsection may be used in all or in part by inverter-based technologies by mutual agreement of the Distribution Provider and the Applicant. The communications requirements herein shall be between:

(i) the Distribution Provider and the individual Generating Facility's inverter control or energy management system;

(ii) the Distribution Provider and communication to the Generating Facility through an aggregator not co-located or part of the Generating Facility; or

(iii) other communication options as are mutually agreed to are by Applicant and the Distribution Provider. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

5. COMMUNICATION REQUIREMENTS (Cont'd.)

b. Generating Facilities utilizing inverter-based technologies must adhere to all of the following communication protocol requirements for communications between Distribution Provider and communication option selected in section Hh. 5. This Rule does not specify the communication between the selected communication option and Smart Inverter but performance will be enforced by in compliance with this Rule:

(i) Shall be capable of communications;

(ii) Software shall be updateable via communications remotely;

(iii) The transport level protocol shall be TCP/IP; and,

(iv) The default application-level protocol shall be IEEE 2030.5 (i.e., Smart Energy Profile 2.0 (SEP 2)) as defined in the California IEEE 2030.5 Implementation Guide, but other application-level protocols may be used by mutual agreement of the parties including IEEE 1815/DNP3 for SCADA real-time monitoring and control and IEC 61850. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

5. COMMUNICATION REQUIREMENTS (Cont'd.)

c. Additional communication protocol requirements shall also apply to Generating Facilities utilizing inverter-based technologies as provided in the following documents:

(i) Distribution Provider Generation Interconnection Handbook, which shall include:

a) Details and guidelines for the implementation of communications with Generating Facilities utilizing inverter-based technologies;

b) Cybersecurity and privacy requirements (these may additionally or alternatively be included in the application-level protocol implementation guide); and,

c) Generic device communications registration management requirements, including how to register individual Generating Facilities, Generating Facilities with energy management systems, and aggregators (these requirements additionally or alternatively may be included in the application-level protocol implementation guide).

(ii) Application-Level Protocol Implementation Guide, which shall provide:

a) Communication requirements and implementation guidelines to ensure consistent interoperability of the Generating Facilities with all California investor-owned utilities under the Commission's jurisdiction. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

6. SCHEDULING CAPABILITY REQUIREMENTS

a. Generating Facilities which incorporate Smart Inverters shall incorporate scheduling capabilities with a minimum scheduling memory capability of at least 24 events. The capability for this requirement will be mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after June 22, 2020.

The utilization of this function is permissible under mutual agreement between the utility and the generating facility before the effective date.

Each event is composed of modifications to each, selected group of, or all of the following Smart Inverter function.

(i) Modifications to the voltage and reactive set-points of the Dynamic volt/var function.

(ii) Modifications to the reactive power set-points for the fixed power factor function.

(iii) Modifications to the voltage and watt-reduction level set-points for the volt/watt function. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

6. SCHEDULING CAPABILITY REQUIREMENTS (Cont'd.)

b. The Generating Facility's scheduling capability requirement herein shall be met by one or more of the following options.

(i) Scheduling capability requirements may be stored at the Generating Facility Energy Management System (GFEMS). The GFEMS shall communicate the necessary commands to the Smart Inverters within 10 minutes from when GFEMS received the scheduling information:

(ii) Scheduling capability requirements may be stored at the Smart Inverter Control Unit (SMCU) within the Generating Facility. The SMCU shall communicate necessary commands to the Smart Inverters within 10 minutes from when SCMU received the scheduling information.

(iii) Scheduling capability requirements may be stored at an aggregator not co-located within the Generating Facility. The aggregator shall communicate the necessary commands to the Smart Inverters within 15 minutes of the aggregator receiving the scheduling information.

(iv) Other options may be utilized by mutual agreement between the Applicant and Distribution Provider.

c. The selected scheduling control system shall store the schedules and shall send operational commands to the Smart Inverters as required by the schedule received from the Distribution Provider. The Smart Inverter shall respond by changing its mode of operation as commanded at the schedule start time with no unreasonable delay.

Each scheduled mode of operation shall include and start-time and duration. The Smart Inverter should return to its default settings at the end of the duration time or shall enter a new operational mode as directed by the scheduling control system. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

7. MONITORING AND TELEMETRY REQUIREMENTS

a. The capability for this requirement will be mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after June 22, 2020.

The utilization of this function is permissible under mutual agreement between the utility and the generating facility before the effective date.

Smart Inverter shall have the capability to communicate its performance information including:

(i) Smart Inverter production or consumption of active power (Watts).

(ii) Smart Inverter consumption or production of reactive power (VARs)

(iii) Phase measured at the AC terminals of the Smart Inverter (Volts)

(iv) Frequency measured at the AC terminals of the Smart Inverter (Hz) (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

7. MONITORING AND TELEMETRY REQUIREMENTS (Cont'd.)

b. When the Generating Facility includes energy-storage with Smart Inverters, the following monitoring and telemetry capability are required:

(i) The Smart Inverter shall be capable of communicating the operational state of charge as a percentage of energy storage capacity.

c. Operational State as In-Service or not In-service communication capability requirements. The Smart Inverter shall be capable of communicating when the Smart Inverter is capable of providing electric services as follows:

(i) In-Service state: An operational state which indicates that the Smart Inverter is connected to the electric system and operating as determined locally by the Generating Facility operator or by a scheduling control system as outlined in section Hh.6

(ii) Not In-Service state: An operating state which indicates that the Smart Inverter is not capable of connecting to the electric system and not capable of providing any type of electrical support as required locally or as commanded by a scheduling control system as outlined in section Hh. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

7. MONITORING AND TELEMETRY REQUIREMENTS (Cont'd.)

d. Monitoring and performance information should be communicated in aggregate at the Generating Facility as follows:

(i) When the Generating Facility includes only Smart Inverters: The production or consumption of active and reactive power shall be communicated as an aggregate of all Smart Inverters within the Generating Facility.

(ii) When a Generating Facility includes Smart Inverters and other technologies such as synchronous or induction generation systems, the Generating Facility should communicate the following:

a) The production or consumption of active and reactive power shall be communicated in aggregate of all Smart Inverters within the Generating Facility

b) The production or consumption of active and reactive power shall be communicated in aggregate of all the other technologies within the Generating Facility

(iii) When the Generating Facility with Smart Inverters includes one or multiple energy storage systems: The available operational energy should be communicated as an aggregate of all the energy storage systems. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

8. CONTROL THROUGH COMMUNICATION CAPABILITIES

a. The capability for these requirements will be mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after the earlier of the dates shown in the "Table of Phase 3 Effective Dates Pursuant to Resolution E-4898" in Section Hh.2.p.

The utilization of these functions is permissible under mutual agreement between the utility and the generating facility before the effective date.

Smart Inverters shall have the capabilities of accepting an operational controls through communications in accordance to the following:

(i) Cease to energize control command. When the Smart Inverter receives a cease-to-energize command through communication it must enter into a cease-to-energize state of operation or shall initiate the opening of the DER switch referenced in the ECP in order to galvanically isolate the DER system from the Distribution System

(ii) Return to service control command. When the Smart Inverter receives a return-to-service control command, the Smart Inverter may return to service operation as required by Generating Facility operator or as required by the scheduling control system as required by section H.6

(iii) Limit Active Power command. When the Smart Inverter receives a command to limit its production of real power, the Smart Inverter shall reduce its real power production to the specified percent of real power capacity of the Smart Inverter or to a specified real power value.

(iv) Set Active Power Level Mode Function. The capability for this requirement will become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted twelve (12) months after approval of a nationally recognized standard that includes the function.

(v) Suspension of Active Power restriction. When the Smart Inverter receives a command to suspend the command for active power reduction, the Smart Inverter may return to normal operation as required by Generating Facility operator or as required by the scheduling control system as required by section H.6. (L)

(Continued)

ELECTRIC RULE NO. 21 Sheet 220
GENERATING FACILITY INTERCONNECTIONS

I. THIRD-PARTY INSTALLATIONS, RESERVATION OF UNUSED FACILITIES, AND REFUND OF SALVAGE VALUE (L)

1. INTERCONNECTION FACILITIES AND DISTRIBUTION UPGRADES

Except as provided for in the Generator Interconnection Agreement of this Rule, Interconnection Facilities connected to Distribution Provider's side of the PCC and Distribution Upgrades shall be provided, installed, owned, and maintained by Distribution Provider at Producer's expense.

2. THIRD-PARTY INSTALLATIONS (L)

Producer may, at its option, employ a qualified contractor that meets the Contractor Qualifications set forth under Electric Rule 15, Section G, to provide and install Interconnection Facilities or Distribution Upgrades, to be owned and operated by Distribution Provider, on Distribution Provider's side of the PCC.* Such Interconnection Facilities and Distribution Upgrades shall be installed in accordance with Distribution Provider's design and specifications. Upon final inspection and acceptance by Distribution Provider, Producer shall transfer ownership of such Producer installed Interconnection Facilities or Distribution Upgrades to Distribution Provider and such facilities shall thereafter be owned and maintained by Distribution Provider at Producer's expense. Producer shall pay Distribution Provider's reasonable cost of design, administration, and monitoring of the installation for such facilities to ensure compliance with Distribution Provider's requirements. Producer shall also be responsible for all costs, including any income tax liability, associated with the transfer of Producer installed Interconnection Facilities and Distribution Upgrades to Distribution Provider. (P)/(L) (P)/(L) (L) (L) (P)/(L) (L) (L)

* Only duly authorized employees of utility are allowed to connect to, disconnect from, or perform any work upon Utility's facilities. (P)/(L) (P)/(L)

(Continued)

I. THIRD-PARTY INSTALLATIONS, RESERVATION OF UNUSED FACILITIES, AND REFUND OF SALVAGE VALUE (Cont'd.) (L)

3. RESERVATION OF UNUSED FACILITIES

When a Producer wishes to reserve Distribution Provider-owned Interconnection Facilities or Distribution Upgrades installed and operated as Added Facilities for Producer at Producer's expense, but idled by a change in the operation of Producer's Generating Facility or otherwise, Producer may elect to abandon or reserve such facilities consistent with the terms of its agreement with Distribution Provider. If Producer elects to reserve idle Interconnection Facilities or Distribution Upgrades, Distribution Provider shall be entitled to continue to charge Producer for the costs related to the ongoing operation and maintenance of the Added Facilities.

4. REFUND OF SALVAGE VALUE

When a Producer elects to abandon the Special Facilities or Added Facilities for which it has either advanced the installed costs or constructed and transferred to Distribution Provider, Producer shall, at a minimum, receive from Distribution Provider a credit for the net salvage value of the Added Facilities.

J. METERING, MONITORING AND TELEMETERING

1. GENERAL REQUIREMENTS

All Generating Facilities shall be metered in accordance with this Section J and shall meet all applicable standards of Distribution Provider contained in Distribution Provider's applicable tariffs and published Distribution Provider manuals dealing with Metering specifications.

2. METERING BY NON-DISTRIBUTION PROVIDER PARTIES

The ownership, installation, operation, reading, and testing of revenue Metering Equipment for Generating Facilities shall be by Distribution Provider except to the extent that the Commission authorizes any or all these services be performed by others. (L)

(Continued)

J. METERING, MONITORING AND TELEMETERING (Cont'd.) (L)

3. NET GENERATION OUTPUT METERING

Generating Facility customers may be required to install Net Generation Output Metering for evaluation, monitoring, and verification purposes and to determine applicable standby and non-bypassable charges as defined in Distribution Provider's tariffs, to satisfy applicable California Independent System Operator (CAISO) reliability requirements, and for Distribution System planning and operations.

However, Generating Facility customers do not need to install Net Generation Output Metering where less intrusive and/or more cost effective options, for Producer/Customer, are available for providing generator data to Distribution Provider. These Generating Facilities may opt to have Distribution Provider estimate load data in accordance with Distribution Provider's applicable tariffs to determine or meet applicable standby and non-bypassable and other applicable charges and tariff requirements. However, if a Generating Facility customer objects to Distribution Provider's estimate of the Generator(s) output, the customer may elect to install the Net Generation Output Metering, or have Distribution Provider install Net Generation Output Metering at the customer's expense.

(a) All metering options available to the customer must conform to the requirements set forth in Distribution Provider's Rule 22. If Distribution Provider does not receive meter data in accordance with Rule 22, Distribution Provider shall have the right to install Distribution Provider-owned Net Generation Output Metering at the customer's expense. The relevant factors in determining the need for Net Generation Output Metering are as listed below:

i) Data requirements in proportion to need for information;

ii) Producer's election to install equipment that adequately addresses Distribution Provider's operational requirements; (L)

(Continued)

J. METERING, MONITORING AND TELEMETERING (Cont'd.) (L)

3. NET GENERATION OUTPUT METERING (Cont'd.)

iii) Accuracy and type of required Metering consistent with purposes of collecting data;

iv) Cost of Metering relative to the need for and accuracy of the data;

v) The Generating Facility's size relative to the cost of the Metering/monitoring;

vi) Other means of obtaining the data (e.g. Generating Facility logs, proxy data, etc.);

vii) Requirements under any Generator Interconnection Agreement with Producer.

The requirements in this Section may not apply to Metering of Generating Facilities operating under Distribution Provider's Net Energy Metering tariffs. Nothing in this Section J.3 supersedes Section D.4, Compliance with Laws, Rules and Tariff Schedules.

Distribution Provider will report to the Commission or designated authority, on a quarterly basis, the rationale for requiring Net Generation Output Metering equipment in each instance along with the size and location of the facility. (L)

The standard timeline for installation of Net Generation Output Meters is as follows: (P)/(L)

i) 20 business for design and 20 business days for construction, or

ii) design and construction timelines as agree with the customer.

The 20-day clock commences upon payment and after the customer had done everything necessary on their end to prepare for construction. By mutual agreement, Applicant and Distribution Provider may agree to a timeline that is different from the timeline described above. (P)/(L)

(Continued)

J. METERING, MONITORING AND TELEMETERING (Cont'd.) (L)

4. POINT OF COMMON COUPLING (PCC) METERING

For purposes of assessing Distribution Provider's charges for retail service, Producer's PCC Metering shall be reviewed by Distribution Provider, and if required, replaced to ensure that it will appropriately measure electric power according to the provisions of the Customer's electric service Tariff. Where required, the Customer's existing meter may be replaced with a bi-directional meter so that power deliveries to and from Producer's site can be separately recorded. Alternately, Producer may, at its sole option and cost, require Distribution Provider to install multi-metering equipment to separately record power deliveries to Distribution Provider's Distribution System and retail purchases from Distribution Provider. Where necessary, such PCC Metering shall be designed to prevent reverse registration.

Generating Facilities participating in Net Energy Metering shall have metering provided pursuant to the terms of the applicable Net Energy Metering tariff schedule.

5. TELEMETERING

If the nameplate rating of the Generating Facility is 1 MW or greater, Telemetering equipment at the Net Generation Output Metering location may be required at Producer's expense. If the Generating Facility is Interconnected to a portion of Distribution Provider's Distribution System operating at a voltage below 10 kV, then Telemetering equipment may be required on Generating Facilities 250 kW or greater. Distribution Provider shall only require Telemetering to the extent that less intrusive and/or more cost effective options for providing the necessary data in real time are not available. Distribution Provider will report to the Commission or designated authority, on a quarterly basis, the rationale for requiring Telemetering equipment in each instance along with the size and location of the facility.

Customer-owned, behind-the-meter, telemetry equipment is allowed where practicable to mitigate the costs associated with Distribution Provider's ownership of the equipment (i.e., the Income Tax Component of Contribution and Cost of Ownership charges), per D.19-03-013 Ordering Paragraph 5. Distribution Provider will allow for a cap of thirty calendar days to repair or replace malfunctioning equipment as notified by the Distribution Provider and if the malfunctioning equipment is not repaired by the thirtieth day, the Distribution Provider can make the necessary repairs and charge the customer for related costs or can disconnect the distributed energy resource. (L)

(Continued)

J. METERING, MONITORING AND TELEMETERING (Cont'd.) (L)

6. LOCATION

Where Distribution Provider-owned Metering is located on Producer's premises, Producer shall provide, at no expense to Distribution Provider, a suitable location for all such Metering Equipment.

7. COSTS OF METERING

Producer will bear all costs of the Metering required by this Rule, including the incremental costs of operating and maintaining the Metering Equipment.

8. MULTIPLE TARIFF METERING

The requirements of Section J.3 may not apply where a Generating Facility includes multiple generators eligible for service under more than one Net Energy Metering (NEM) tariff schedule (e.g. NEM-1, NEM-2, NEMBIO, NEMFC), or where a Generating Facility consists of one or more NEM-eligible generators in combination with one or more non-NEM eligible generators without Non-Export relays ("Reverse Power Protection"). To ensure proper tariff administration, metering will be required at the PCC and at each of the NEM eligible generator groups eligible for service under the same NEM tariff schedule. For combinations of multiple NEM eligible generators under different tariffs, billing administration and metering requirements will be as specified in the appropriate NEM tariff schedule.

Where a Generating Facility consists of one or more NEM eligible generator groups in combination with one or more non-NEM generators, metering of the non-NEM generators is not required, except as specified in Section J.3. (L)

(Continued)

K. DISPUTE RESOLUTION PROCESS (L)

In addition to the informal procedures for timeline-related disputes set out in Section F.1.d, the following procedures will apply for disputes arising from this Rule:

1. SCOPE

The Commission shall have initial jurisdiction to interpret, add, delete or modify any provision of this Rule or of any agreements entered into between Distribution Provider and Applicant or Producer to implement this tariff ("Implementing Agreements") and to resolve disputes regarding Distribution Provider's performance of its obligations under Commission-jurisdictional tariffs, the applicable agreements, and requirements related to the interconnection of Applicant's or Producer's Generating Facility or Interconnection Facilities pursuant to this Rule.

2. PROCEDURES

Any dispute arising between Distribution Provider and Producer (individually referred to in Section K as "Party" and collectively "the Parties") regarding Distribution Provider's or Producer's performance of its obligations under its tariffs, the Implementing Agreements, and requirements related to the interconnection of Producer's Facilities pursuant to this Rule shall be resolved according to the following procedures:

a. The dispute shall be documented in a written notice ("notice") by the aggrieved Party to the other Party containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the aggrieved Party that it is invoking the procedures under this Section. The notice shall be sent to the Party's email address and physical address set forth in the Generator Interconnection Agreement or Interconnection Request, if there is no Generator Interconnection Agreement. A copy of the notice shall also be sent to the Energy Division, Office of the Director, at the Commission. The receiving Party shall acknowledge the notice within five (5) Calendar Days of its receipt. (L)

(Continued)

K. DISPUTE RESOLUTION PROCESS (Cont'd.) (L)

2. PROCEDURES (Cont'd.)

a Upon the aggrieved Party notifying the other Party of the dispute, each Party must designate a representative with the authority to make decisions for its respective Party to review the dispute within seven (7) Calendar Days. In addition, upon receipt of the notice, Distribution Provider shall provide the aggrieved Party with all relevant regulatory and/or technical details and analysis regarding any Distribution Provider interconnection requirements under dispute within twenty-one (21) Calendar Days.

Within forty-five (45) Calendar Days of the date of the notice, the Parties' authorized representatives will be required to meet and confer to try to resolve the dispute. Parties are expected to operate in good faith and use best efforts to resolve the dispute.

b. If a resolution is not reached in forty-five (45) Calendar Days from the date of the notice, either 1) a Party may request to continue negotiations for an additional forty-five (45) Calendar Days or 2) the Parties may by mutual agreement make a written request for mediation to the ADR Coordinator in the Commission's ALJ Division. The request may be submitted by electronic mail to adr_program@cpuc.ca.gov. Alternatively, both Parties by mutual agreement may request mediation from an outside third-party mediator with costs to be shared equally between the Parties.

c. At any time, either Party may file a formal complaint before the Commission pursuant to California PUC section 1702 and Article 4 of the Commission's Rules of Practice and Procedure.

Nothing in this section shall be construed to limit the rights of any Party to exercise rights and remedies under Commission law. (L)

(Continued)

K. DISPUTE RESOLUTION PROCESS (Cont'd.) (L)

3. PERFORMANCE DURING DISPUTE

Pending resolution of any dispute under this Section, the Parties shall proceed diligently with the performance of their respective obligations under this Rule and the Implementing Agreements, unless the Implementing Agreements have been terminated. Disputes as to the Interconnection Request and implementation of this Section shall be subject to resolution pursuant to the procedures set forth in this Section.

L. CERTIFICATION AND TESTING CRITERIA

1. INTRODUCTION

This Section describes the test procedures and requirements for equipment used for the Interconnection of Generating Facilities to Distribution Provider's Distribution or Transmission System. Included are Type Testing, Production Testing, Commissioning Testing, and Periodic Testing. The procedures listed rely heavily on those described in appropriate Underwriters Laboratory (UL), Institute of Electrical and Electronic Engineers (IEEE), and International Electrotechnical Commission (IEC) documents—most notably UL 1741 and IEEE 929 as well as the testing described in *May 1999 New York State Public Service Commission's Interconnection Requirements.* As noted in Section B, this Rule has been revised to be consistent with ANSI/IEEE 1547-2003 Standard for Interconnecting Distribution Resources with Electric Power Systems. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

1. INTRODUCTION (Cont'd.)

The tests described here, together with the technical requirements in Section H of this Rule, are intended to provide assurance that the Generating Facility's equipment will not adversely affect Distribution Provider's Distribution or Transmission System and that a Generating Facility will cease providing power to Distribution Provider's Distribution or Transmission System under abnormal conditions. The tests were developed assuming a low level of Generating Facility penetration or number of connections to Distribution Provider's Distribution or Transmission System. At high levels of Generating Facility penetration, additional requirements and corresponding test procedures may need to be defined.

Section L also provides criteria for "Certifying" Generators, inverters or converters. Once a Generator, inverter or converter has been Certified per this Rule, it may be considered suitable for Interconnection with Distribution Provider's Distribution or Transmission System. Subject to the exceptions described in Section L, Distribution Provider will not repeat the design review or require retesting of such Certified Equipment. It should be noted that the Certification process is intended to facilitate Generating Facilities Interconnections. Certification is not a prerequisite to interconnect a Generating Facility for Section H, except for Non-Export AC/DC Converters seeking an expedited process, but it is a prerequisite for inverters installed after September 8, 2017, pursuant to Section Hh of this Rule. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

2. CERTIFIED AND NON-CERTIFIED INTERCONNECTION EQUIPMENT

a. Certified Equipment

Equipment tested and approved (i.e. "Listed") by an accredited NRTL as having met both the Type Testing and Production Testing requirements described in this document is considered to be Certified Equipment for purposes of Interconnection with Distribution Provider's Distribution or Transmission System. Certification may apply to either a pre-packaged system or an assembly of components that address the necessary functions. Type Testing may be done in the manufacturer's factory or test laboratory, or in the field. At the discretion of the testing laboratory, field-certification may apply only to the particular installation tested. In such cases, some or all of the tests may need to be repeated at other installations.

When equipment is Certified by a NRTL, the NRTL shall provide to the manufacturer, at a minimum, a Certificate with the following information for each device:

Administrative:

(1) The effective date of Certification or applicable serial number (range or first in series), and/or other proof that certification is current;

(2) Equipment model number(s) of the Certified equipment;

(3) The software version utilized in the equipment, if applicable;

(4) Test procedures specified (including date or revision number); and

(5) Laboratory accreditation (by whom and to what standard). (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

2. CERTIFIED AND NON-CERTIFIED INTERCONNECTION EQUIPMENT (Cont'd.)

a. Certified Equipment (Cont'd.)

Technical (as appropriate):

(1) Device ratings (kW, kV, Volts, amps, etc.);

(2) Maximum available fault current in amps;

(3) In-rush Current in amps;

(4) Trip points, if factory set (trip value and timing);

(5) Trip point and timing ranges for adjustable settings;

(6) Nominal power factor or range if adjustable;

(7) If the equipment is Certified as Non-Exporting and the method used (reverse power or underpower);

(8) If the equipment is Certified as Non-Islanding; and

(9) If the equipment is Certified as a Non-Export AC/DC Converter.

It is the responsibility of the equipment manufacturer to ensure that Certification information is made publicly available by the manufacturer, the testing laboratory, or by a third party.

b. Non-Certified Equipment

For non-Certified equipment, some or all of the tests described in this Rule may be required by Distribution Provider for each Generating and/or Interconnection Facility. The manufacturer or a laboratory acceptable to Distribution Provider may perform these tests. Test results for non-Certified equipment must be submitted to Distribution Provider for the Supplemental Review. Approval by Distribution Provider for equipment used in a particular Generating and/or Interconnection Facility does not guarantee Distribution Provider's approval for use in other Generating and/or Interconnection Facilities. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

3. TYPE TESTING

a. Type Tests and Criteria for Interconnection Equipment Certification

Type testing provides a basis for determining that equipment meets the specifications for being designated as Certified equipment under this Rule. The requirements described in this Section cover only issues related to Interconnection and are not intended to address device safety or other issues.

Table L.1 defines the test criteria by Generator or inverter technology. While UL 1741(1) and UL 1741 – Supplement SA were written specifically for inverters, the requirements are readily adaptable to synchronous Generators, induction Generators, as well as single/multi-function controllers and protection relays. Until a universal test standard is developed, Distribution Provider or NRTL shall adopt the procedures referenced in Table L.1 as appropriate and necessary for a Generating Facility and/or Interconnection Facilities or associated equipment performance and its control and Protection Functions. These tests shall be performed in the sequence shown in Table L.2.

Non-Export AC/DC Converters must satisfy the requirements in its definition in Section C. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

3. TYPE TESTING (Cont'd.)

a. Type Tests and Criteria for Interconnection Equipment Certification (Cont'd.)

Table L.1, Type Test and Requirements for Interconnection Equipment Certification

Type Test	Reference 1	Inverter (6)	Smart Inverter (7)	Synchronous Generators	Induction Generators
Utility Interaction	UL 1741 – 39, 40	X	X	X	X
Utility Compatibility (Required testing to 1547 & 1547.1)	UL 1741 - 46	X	X	X	X
DC Isolation	IEEE 1547.1(8) -5.6	X	X	-	-
Dielectric Voltage Withstand	IEEE 1547.1(8) -5.5.3	X	X	X	X
Harmonic Distortion	IEEE 1547.1(8) -5.11	X	X	X	X
DC Injection	IEEE 1547.1(8) -5.6	X	X	-	-
Distribution Provider Voltage Variation	IEEE 1547.1(8) -5.2	X	-	X	X
Distribution Provider Frequency Variation	IEEE 1547.1(8) -5.3	X	-	X	X
Abnormal Tests	UL 1741 – 47				
Loss of Control Circuit	UL 1741 – 47.8	X	X	X	X
Short Circuit	UL 1741 - 47.3	X	X	X	X
Load Transfer	UL 1741 - 47.7	X	X	X	X
Surge Withstand Capability	L.3.e	X	X	X	X
Anti-Islanding (non-Smart Inverters)	L.3.b	(2)	-	(2)	(2)
Non-Export	L.3.c	(3)	(3)	(3)	(3)
In-rush Current	L.3.d	-	-	-	(4)
Synchronization	L.3.f	(5)	(5)	X	(5)
Anti-islanding (Smart Inverters)	UL 1741 SA - SA8	-	X	-	-
Low and High Voltage Ride-through (L/H VRT)	UL 1741 SA – SA9	-	X	-	-
Low and High Frequency Ride-through (L/H FRT)	UL 1741 SA - SA10	-	X	-	-
Normal and Soft-Start Ramp Rate (RR)	UL 1741 SA - SA11	-	X	-	-
Specified Power Factor	UL 1741 SA - SA12	-	X	-	-
Volt/Var Mode (Q(V))	UL 1741 SA - SA13	-	X	-	-
Frequency-Watt(FW) - optional	UL 1741 SA - SA14	-	X	-	-
Volt-Watt (VW) - optional	UL 1741 SA - SA15	-	X	-	-
Markings and Instructions	UL 1741 SA6, SA16	-	X	-	-

Table Notes:

(1) References are to section numbers in either UL 1741 and/or UL 1741-Supplement SA (Inverters, Converters and Charge Controllers for Use in Independent Power Systems) or this Rule. References in UL 1741 to "photovoltaics" or "inverter" may have to be adapted to the other technologies by the testing laboratory to appropriately apply in the tests to other technologies.
(2) Required only if Non-Islanding designation.
(3) Required only if Non-Export designation is desired.
(4) Required for Generators that use Distribution Provider power to motor to speed.
(5) Required for all self-excited induction Generators as well as Inverters that operate as voltage sources when connected to Distribution Provider's Distribution or Transmission System.
(6) Inverters compliant with Section H.
(7) Inverters compliant with Section Hh.
(8) IEEE 1547.1 refers to 2005 revision.

"X" = Required "-" = Not Required

(L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

3. TYPE TESTING (Cont'd.)

a. Type Tests and Criteria for Interconnection Equipment Certification (Cont'd.)

Table L.2 Type Tests Sequence for Interconnection Equipment Certification

Test No.	Type Test
1	Distribution Provider Voltage and Frequency Variation
2	Synchronization
3	Surge Withstand Capability
4	Distribution Provider Voltage and Frequency Variation, including ride through
5	Synchronization
6	Other Required and Optional Tests

Tests 1, 2, and 3 must be done first and in the order shown. Tests 4 and on follow in order convenient to the test agency.

b. Anti-Islanding Test

Devices that pass the Anti-Islanding test procedure described in UL 1741 Section 46.3 will be considered Non-Islanding for the purposes of these Interconnection requirements. The test is required only for devices for which a Certified Non-Islanding designation is desired.

c. Non-Export Test

Equipment that passes the Non-Export test procedure described in Section L.7.a will be considered Non-Exporting for the purposes of these Interconnection requirements. This test is required only for devices for which a Certified Non-Export designation is desired. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

3. TYPE TESTING (Cont'd.)

d. In-rush Current Test

Generation equipment that utilizes Distribution Provider power to motor up to speed will be tested using the procedure defined in Section L.7.b to determine the maximum current drawn during this startup process. The resulting In-rush Current is used to estimate the Starting Voltage Drop.

e. Surge Withstand Capability Test

The interconnection equipment shall be tested for the surge withstand requirement in Section H.1.c in all normal operating modes in accordance with IEEE Std C62.45-2002 for equipment rates less than 1000 V to confirm that the surge withstand capability is met by using the selected test level(s) from IEEE Std C62.41.2-2002. Interconnection equipment rated greater than 1000 V shall be tested in accordance with manufacturer or system integrator designated applicable standards. For interconnection equipment signal and control circuits, use IEEE Std C37.90.1-2002. These tests shall confirm the equipment did not fail, did not misoperate, and did not provide misinformation (IEEE 1547-5.1.3.2).

The location/exposure category for which the equipment has been tested shall be clearly marked on the equipment label or in the equipment documentation. External surge protection may be used to protect the equipment in harsher location/exposure categories. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

3. TYPE TESTING (Cont'd.)

f. Synchronization Test

This test is applied to synchronous Generators, self-excited induction generators, and inverters capable of operating as voltage-source while connected to Distribution Provider's Distribution or Transmission System. The test is also applied to the resynchronization Function (transition from stand-alone to parallel operation) on equipment that provides such functionality. This test may not need to be performed on both the synchronization and re-synchronization functions if the manufacturers can verify to the satisfaction of the testing organization that monitoring and controls hardware and software are common to both functions. This test is not necessary for induction generators or current-source inverters. Instead, the ln-rush Current test Section L.3.d shall be applied to those generators.

This test shall demonstrate that at the moment of the paralleling-device closure, all three synchronization parameters in Table L.3 are within the stated limits. This test shall also demonstrate that if any of the parameters are outside of the limits stated in the table, the paralleling-device shall not close (IEEE 1547-5.1.2A). The test will start with only one of the three parameters: (1) voltage difference between Generating Facility and Distribution Provider's Distribution or Transmission System; (2) frequency difference; or (3) phase angle outside of the synchronization specification. Verify that the Generating Facility is brought within specification prior to synchronization. Repeat the test five times for each of the three parameters. For manual synchronization with synch check or manual control with auto synchronization, the test must verify that paralleling does not occur until the parameters are brought within specifications. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

3. TYPE TESTING (Cont'd.)

f. Synchronization Test (Cont'd.)

Table L.3
***Synchronization Parameter Limits* [1]**

Aggregate Rating of Generator Units (kVA)	Frequency Difference (Δf, Hz)	Voltage Difference (ΔV, %)	Phase Angle Difference (ΔΦ,°)
0-500	0.3	10	20
> 500-1,500	0.2	5	15
> 1,500-10,000	0.1	3	10

[1] – IEEE 1547-5.1.1B

g. Paralleling Device Withstand Test

The di-electric voltage withstand test specified in Section L.1 shall be performed on the paralleling device to ensure compliance with those requirements specified in Section H.1.c (IEEE 1547-5.1.3.3).

h. Backfeed Test

Non-Export AC/DC Converters must satisfy the requirements in its definition in Section C.

4. PRODUCTION TESTING

At a minimum, each interconnection system shall be subjected to Distribution Provider Voltage and Frequency Variation Test procedure described in UL1741 under Manufacturing and Production Tests, Section 68 and the Synchronization test specified in Section L.3.f. Interconnection systems with adjustable set points shall be tested at a single set of set points as specified by the manufacturer. This test may be performed in the factory or as part of a Commissioning Test (Section L.5). (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

5. COMMISSIONING TESTING

a. Commissioning Testing

Commissioning Testing, where required, will be performed on-site to verify protective settings and functionality. Upon initial Parallel Operation of a Generating Facility, or any time interface hardware or software is changed that may affect the functions listed below, a Commissioning Test must be performed. An individual qualified in testing protective equipment (professional engineer, factory–certified technician, or licensed electrician with experience in testing protective equipment) must perform Commissioning Testing in accordance with the manufacturer's recommended test procedure to verify the settings and requirements per this Rule.

Distribution Provider may require written Commissioning test procedure be submitted to Distribution Provider at least 10 working days prior to the performance of the Commissioning Test. Distribution Provider has the right to witness Commissioning Test. Distribution Provider may also require written certification by the installer describing which tests were performed and their results. Protective Functions to be tested during commissioning, particularly with respect to non-Certified equipment, may consist of the following:

(1) Over and under voltage

(2) Over and under frequency

(3) Anti-Islanding function (if applicable)

(4) Non-Exporting function (if applicable)

(5) Inability to energize dead line (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

5. COMMISSIONING TESTING (Cont'd.)

a. Commissioning Testing (Cont'd.)

(6) Time delay on restart after Distribution Provider source is stable

(7) Distribution Provider system fault detection (if used)

(8) Synchronizing controls (if applicable)

(9) Other Interconnection Protective Functions that may be required as part of the Generator Interconnection Agreement

Commissioning Test shall include visual inspections of the interconnection equipment and protective settings to confirm compliance with the interconnection requirements.

b. Review, Study, and Additional Commissioning Test Verification Costs

A Producer shall be responsible for the reasonably incurred costs of the reviews, studies and additional Commissioning Test verifications conducted pursuant to Section E of this Rule. If the initial Commissioning Test verification is not successful through no fault of Distribution Provider, Distribution Provider may impose upon Producer a cost based charge for subsequent Commissioning Test verifications. All Costs for additional Commissioning Test verifications shall be paid by Producer within thirty days of receipt of Distribution Provider's invoice. The invoice provided by Distribution Provider shall consist of the hourly rate multiplied by the hours incurred by Distribution Provider and will separately specify the amount of time spent on-site from that spent in roundtrip travel to the Commissioning Test site. Additional cost, if any, will be specified on the invoice. If the initial Commissioning Test verification is not successful through the fault of Distribution Provider, that visit will not be considered the initial Commissioning Test verification. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

5. COMMISSIONING TESTING (Cont'd.)

c. Other Checks and Tests

Other checks and tests that may need to be performed include:

(1) Verifying final Protective Function settings

(2) Trip test (L.5.g)

(3) In-service tests (L.5.h)

d. Certified Equipment

Generating Facilities qualifying for interconnection through the Fast Track process incorporate Certified Equipment that have, at a minimum, passed the Type Tests and Production Tests described in this Rule and are judged to have little or no potential impact on Distribution Provider's Distribution or Transmission System. For such Generating Facilities, it is necessary to perform only the following tests:

(1) Protective Function settings that have been changed after Production Testing will require field verification. Tests shall be performed using injected secondary frequencies, voltages and currents, applied waveforms, at a test connection using a Generator to simulate abnormal Distribution Provider voltage or frequency, or varying the set points to show that the device trips at the measured (actual) Distribution Provider voltage or frequency.

(2) The Non-Islanding function shall be checked by operating a load break disconnect switch to verify the Interconnection equipment ceases to energize Distribution Provider's Distribution or Transmission System and does not re-energize it for the required time delay after the switch is closed. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

5. COMMISSIONING TESTING (Cont'd.)

d. Certified Equipment (Cont'd.)

(3) The Non-Exporting function shall be checked using secondary injection techniques. This function may also be tested by adjusting the Generating Facility output and local loads to verify that the applicable Non-Exporting criteria (i.e., reverse power or underpower) are met.

The Supplemental Review or an Interconnection Study may impose additional components or additional testing.

e. Non-Certified Equipment

Non-certified Equipment shall be subjected to the appropriate tests described in Type Testing (Section L.3) as well as those described in Certified Equipment Commissioning Tests (Section L.5.d). With Distribution Provider's approval, these tests may be performed in the factory, in the field as part of commissioning, or a combination of both. Distribution Provider, at its discretion, may also approve a reduced set of tests for a particular Generating Facility or, for example, if it determines it has sufficient experience with the equipment.

f. Verification of Settings

At the completion of Commission testing, Producer shall confirm all devices are set to Distribution Provider-approved settings. Verification shall be documented in the Commissioning Test Certification. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

5. COMMISSIONING TESTING (Cont'd.)

g. Trip Tests

Interconnection Protective Functions and devices (e.g. reverse power relays) that have not previously been tested as part of the Interconnection Facilities with their associated interrupting devices (e.g. contactor or circuit breaker) shall be trip tested during commissioning. The trip test shall be adequate to prove that the associated interrupting devices open when the protective devices operate. Interlocking circuits between Protective Function devices or between interrupting devices shall be similarly tested unless they are part of a system that has been tested and approved during manufacturing.

h. In-service Tests

Interconnection Protective Functions and devices that have not previously been tested as part of the Interconnection Facilities with their associated instrument transformers or that are wired in the field shall be given an in-service test during commissioning. This test will verify proper wiring, polarity, CT/PT ratios, and proper operation of the measuring circuits. The in-service test shall be made with the power system energized and carrying a known level of current. A measurement shall be made of the magnitude and phase angle of each Alternating Current (AC) voltage and current connected to the protective device and the results compared to expected values. For protective devices with built-in Metering Functions that report current and voltage magnitudes and phase angles, or magnitudes of current, voltage, and real and reactive power, the metered values may be used for in-service testing. Otherwise, portable ammeters, voltmeters, and phase-angle meters shall be used. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

6. PERIODIC TESTING

Periodic Testing of Interconnection-related Protective Functions shall be performed as specified by the manufacturer, or at least every four years. All Periodic Tests prescribed by the manufacturer shall be performed. Producer shall maintain Periodic Test reports or a log for inspection by Distribution Provider. Periodic Testing conforming to Distribution Provider test intervals for the particular Line Section may be specified by Distribution Provider under special circumstances, such as high fire hazard areas. Batteries used to activate any Protective Function shall be checked and logged once per month for proper voltage. Once every four years, the battery must be either replaced or a discharge test performed.

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS

This Section describes the additional Type Tests necessary to qualify a device as Certified under this Rule. These Type Tests are not contained in Underwriters Laboratories UL 1741 Standard *Inverters, Converters and Controllers for Use in Independent Power Systems,* or other referenced standards.

a. Non-Exporting Test Procedures

The Non-Exporting test is intended to verify the operation of relays, controllers and inverters designed to limit the export of power and certify the equipment as meeting the requirements of Screen I, Options 1 and 2, of the review process. Tests are provided for discrete relay packages and for controllers and inverters with the intended Functions integrated. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

i) Discrete Reverse Power Relay Test

This version of the Non-Exporting test procedure is intended for discrete reverse power and underpower relay packages provided to meet the requirements of Options 1 and 2 of Screen I. It should be understood that in the reverse power application, the relay will provide a trip output with power flowing in the export (toward Distribution Provider's Distribution or Transmission System) direction.

Step 1: Power Flow Test at Minimum, Midpoint and Maximum Pickup Level Settings

Determine the corresponding secondary pickup current for the desired export power flow of 0.5 secondary watts (the minimum pickup setting, assumes 5 amp and 120V CT/PT secondary). Apply nominal voltage with minimum current setting at zero (0) degrees phase angle in the trip direction. Increase the current to pickup level. Observe the relay's (LCD or computer display) indication of power values. Note the indicated power level at which the relay trips. The power indication should be within 2% of the expected power. For relays with adjustable settings, repeat this test at the midpoint, and maximum settings. Repeat at phase angles of 90, 180 and 270 degrees and verify that the relay does not operate (measured watts will be zero or negative). (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

i) Discrete Reverse Power Relay Test (Cont'd.)

Step 2: Leading Power Factor Test

Apply rated voltage with a minimum pickup current setting (calculated value for system application) and apply a leading power factor load current in the non-trip direction (current lagging voltage by 135 degrees). Increase the current to relay rated current and verify that the relay does not operate. For relays with adjustable settings, this test should be repeated at the minimum, midpoint, and maximum settings.

Step 3: Minimum Power Factor Test

At nominal voltage and with the minimum pickup (or ranges) determined in Step 1, adjust the current phase angle to 84 or 276 degrees. Increase the current level to pickup (about 10 times higher than at 0 degrees) and verify that the relay operates. Repeat for phase angles of 90, 180 and 270 degrees and verify that the relay does not operate.

Step 4: Negative Sequence Voltage Test

Using the pickup settings determined in Step 1, apply rated relay voltage and current at 180 degrees from tripping direction, to simulate normal load conditions (for three-phase relays, use Ia at 180, Ib at 60 and Ic at 300 degrees). Remove phase-1 voltage and observe that the relay does not operate. Repeat for phases-2 and 3. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

i) Discrete Reverse Power Relay Test (Cont'd.)

Step 5: Load Current Test

Using the pickup settings determined in Step 1, apply rated voltage and current at 180 degrees from the tripping direction, to simulate normal load conditions (use Ia at 180, Ib at 300 and Ic at 60 degrees). Observe that the relay does not operate.

Step 6: Unbalanced Fault Test

Using the pickup settings determined in Step 1, apply rated voltage and 2 times rated current, to simulate an unbalanced fault in the non-trip direction (use Va at 0 degrees, Vb and Vc at 180 degrees, Ia at 180 degrees, Ib at 0 degrees, and Ic at 180 degrees). Observe that the relay, especially single phase, does operate properly.

Step 7: Time Delay Settings Test

Apply Step 1 settings and set time delay to minimum setting. Adjust the current source to the appropriate level to determine operating time, and compare against calculated values. Verify that the timer stops when the relay trips. Repeat at midpoint and maximum delay settings. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

i) Discrete Reverse Power Relay Test (Cont'd.)

Step 8: Dielectric Test

Perform the test described in IEC 414 using 2 kV RMS for 1 minute.

Step 9: Surge Withstand Test

Perform the surge withstand test described in IEEE C37.90.1.1989 or the surge withstand capability test described in L.3.e.

ii) Discrete Underpower Relay Test

This version of the Non-Exporting test procedure is intended for discrete underpower relay packages and meets the requirements of Option 2 of Screen I. A trip output will be provided when import power (toward Producer's load) drops below the specified level.

Note: For an underpower relay, pickup is defined as the highest power level at which the relay indicates that the power is less than the set level. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

ii) Discrete Underpower Relay Test (Cont'd.)

Step 1: Power Flow Test at Minimum, Midpoint and Maximum Pickup Level Settings

Determine the corresponding secondary pickup current for the desired power flow pickup level of 5% of peak load minimum pickup setting. Apply rated voltage and current at 0 (zero) degrees phase angle in the direction of normal load current.

Decrease the current to pickup level. Observe the relay's (LCD or computer display) indication of power values. Note the indicated power level at which the relay trips. The power indication should be within 2% of the expected power. For relays with adjustable settings, repeat the test at the midpoint, and maximum settings. Repeat at phase angles of 90, 180 and 270 degrees and verify that the relay operates (measured watts will be zero or negative).

Step 2: Leading Power Factor Test

Using the pickup current setting determined in Step 1, apply rated voltage and rated leading power factor load current in the normal load direction (current leading voltage by 45 degrees). Decrease the current to 145% of the pickup level determined in Step 1 and verify that the relay does not operate. For relays with adjustable settings, repeat the test at the minimum, midpoint, and maximum settings. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

ii) Discrete Underpower Relay Test (Cont'd.)

Step 3: Minimum Power Factor Test

At nominal voltage and with the minimum pickup (or ranges) determined in Step 1, adjust the current phase angle to 84 or 276 degrees. Decrease the current level to pickup (about 10% of the value at 0 degrees) and verify that the relay operates. Repeat for phase angles 90, 180 and 270 degrees and verify that the relay operates for any current less than rated current.

Step 4: Negative Sequence Voltage Test

Using the pickup settings determined in Step 1, apply rated relay voltage and 25% of rated current in the normal load direction, to simulate light load conditions. Remove phase 1 voltage and observe that the relay does not operate. Repeat for Phases-2 and 3.

Step 5: Unbalanced Fault Test

Using the pickup settings determined in Step 1, apply rated voltage and two times rated current, to simulate an unbalanced fault in the normal load direction (use Va at 0 degrees, Vb and Vc at 180 degrees, Ia at 0 degrees, Ib at 180 degrees, and Ic at 0 degrees). Observe that the relay (especially single-phase types) operates properly. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

ii) Discrete Underpower Relay Test (Cont'd.)

Step 6: Time Delay Settings Test

Apply Step 1 settings and set time delay to minimum setting. Adjust the current source to the appropriate level to determine operating time, and compare against calculated values. Verify that the timer stops when the relay trips. Repeat at midpoint and maximum delay settings.

Step 7: Dielectric Test

Perform the test described in IEC 414 using 2 kV RMS for 1 minute.

Step 8: Surge Withstand Test

Perform the surge withstand test described in IEEE C37.90.1.1989 or the surge withstand test described in Section L.3.e. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

iii) Tests for Inverters and Controllers with Integrated Functions

Inverters and controllers designed to provide reverse or underpower functions shall be tested to certify the intended operation of this function. Two methods are acceptable:

Method 1: If the inverter or controller utilizes external current/voltage measurement to determine the reverse or underpower condition, then the inverter or controller shall be functionally tested by application of appropriate secondary currents and potentials as described in the Discrete Reverse Power Relay Test, Section L.7.a.i of this Rule.

Method 2: If external secondary current or voltage signals are not used, then unit-specific tests must be conducted to verify that power cannot be exported across the PCC for a period exceeding two seconds. These may be factory tests, if the measurement and control points are integral to the unit, or they may be performed in the field.

iv) Tests for Inadvertent Export Inverters

Test requirements for certified inverters with integrated functions for Inadvertent Export shall verify the performance requirements specified in Section Mm of this Rule.

(L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

v) Interim Tests for Non-Export AC/DC Converters ("Converter")

Step 1: Limitation of Back-feed Under Steady State Conditions

Apply the nominal DC operating voltage of the Converter across its DC terminals with a battery source or simulated equivalent of a battery source. Vary the battery source by 100%, 75%, 50%, 25%, and 10% of Converter rated output power. The measured steady-state DC current component at each of the AC terminals of the Converter is required to be less than 0.5% of the Converter's rated RMS AC current. This test is to be repeated for 80% nominal DC operating voltage and for 125% nominal DC operating voltage. Testing requirements can be modified upon mutual agreement of the Distribution Provider and the Applicant.

Step 2: Back-feed Under Fault Conditions – DC Output Shorted

With a battery source or simulated equivalent of a battery source connected to the DC terminals, apply rated conditions of the Converter then short its DC terminals for 200 milliseconds. After 5 cycles of inducing the short circuit, record the measured peak current at each of the AC terminals of the Converter. These peak currents within this time interval are each required to be less than 0.5% of the Converter's rated RMS AC current. Testing requirements can be modified upon mutual agreement of the Distribution Provider and the Applicant. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

v) Interim Tests for Non-Export AC/DC Converters ("Converter") (Cont'd.)

Step 3: Back-feed Under Fault Conditions – AC Input Shorted: Phase-Ground, Phase-Phase, and 3-Phase

With a battery source or simulated equivalent of a battery source connected to the DC terminals, apply rated conditions of the Converter, then apply a short between any two phases on the grid side of the Converter for 200 milliseconds. After 5 cycles of inducing the short circuit, record the measured peak current at each of the AC terminals of the Converter. These peak currents within this time interval are each required to be less than 0.5% of the Converter's rated RMS AC current. This test is to be repeated for phase-ground and 3-phase shorts. Testing requirements can be modified upon mutual agreement of the Distribution Provider and the Applicant.

Step 4: Back-feed Under Fault Conditions – Component Faults

Distribution Provider can elect to test for back-feed under the condition of a short circuit across certain components which are internal to the Converter. Potential tests can include inducing a short circuit across different terminals for electronic switches and/or across different terminals for internal transformers. Ultimately, the components used for testing will be chosen on a case-by-case basis and will depend on the Converter's circuit topology. Testing requirements can be modified upon mutual agreement of the Distribution Provider and the Applicant.

Step 5: Harmonics Testing

Under normal loading conditions at 10%, 25%, 50%, 75%, and 100% of the Converter's rated power output, conduct harmonic current distortion measurements on each of the AC terminals. Measurements should be below the maximum harmonic current distortion requirements given in IEEE 1547-4.3.3. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

b. In-rush Current Test Procedures

This test will determine the maximum In-rush Current drawn by the Generator.

i) Locked-Rotor Method

Use the test procedure defined in NEMA MG-1 (manufacturer's data is acceptable if available).

ii) Start-up Method

Install and setup the Generating Facility equipment as specified by the manufacturer. Using a calibrated oscilloscope or data acquisition equipment with appropriate speed and accuracy, measure the current draw at the Point of Interconnection as the Generating Facility starts up and parallels with Distribution Provider's Distribution or Transmission System. Startup shall follow the normal, manufacturer-specified procedure. Sufficient time and current resolution and accuracy shall be used to capture the maximum current draw within 5%. In-rush Current is defined as the maximum current draw from Distribution Provider during the startup process, using a 10-cycle moving average. During the test, Distribution Provider source, real or simulated, must be capable of maintaining voltage within +/- 5% of rated at the connection to the unit under test. Repeat this test five times. Report the highest 10-cycle current as the In-rush Current. A graphical representation of the time-current characteristic along with the certified In-rush Current must be included in the test report and made available to Distribution Provider. (L)

(Continued)

M. INADVERTENT EXPORT (L)

Under certain operating conditions, an Applicant may choose to completely offset their facility load by installing generation systems which are optimally sized to meet their peak demand with load following functionality on the Generator controls to ensure conditional export of electrical power from the Generating Facility to Distribution Provider's Distribution or Transmission System. In situations where the loading changes rapidly and/or the Generator cannot ramp down quickly enough, the Generating Facility may need to export small amounts of power for limited duration. The event of exporting uncompensated power for a short time is referred to as Inadvertent Export.

The following are the minimum requirements for Inadvertent Export systems. Other factors relevant to the interconnection study process (e.g. 15% screen results, short circuit current ratio, etc.) may necessitate additional technical requirements (e.g. reclose block, transfer trip, ground bank, etc.) that are not explicitly noted here. Inadvertent Export may not be available for interconnections to Networked Secondary Systems.

1. For Inadvertent Export interconnection requests, additional Protective Functions and equipment to detect Distribution or Transmission System faults (per Distribution Provider's standard practices) may be required over and above the basic Protective Functions and equipment associated with the four options in the Export Screen. Protective Functions may include, but are not limited to, directional overcurrent/voltage-restraint overcurrent Protective Functions for line-to-line fault detection and overcurrent/overvoltage Protective Functions for line-to-ground detection. The addition of a ground bank or ground detector may also be necessary. (L)

(Continued)

M. INADVERTENT EXPORT (Cont'd.) (L)

2. The effect on equipment ratings can be mitigated by limiting the amount of inadvertent export allowed. To a large degree, Voltage Regulation may be similarly handled. The amount of Inadvertent Export is dependent on specific Distribution Provider requirements and should be limited to the lesser of the following values:

   a. 50% of the Generating Facility Capacity, or

   b. 10% of the continuous conductor rating in watts at 0.9 power factor for the lowest rated feeder conductor upstream of the GF (i.e. 200kW @ 12kV), or

   c. 110% of the largest load block in the facility, or

   d. 500kW or some other maximum level indicated by Distribution Provider

3. In addition to the limits above, the following are required:

   a. A reverse power Protective Function will be provided to trip the connected Generator(s) within two seconds if the proposed amount of Inadvertent Export is exceeded.

   b. The frequency of Inadvertent Export occurrences should be less than two occurrences per 24-hour period.

   c. A separate reverse power or underpower Protective Function will be required (in addition to the reverse power Protective Function described in 3a. above) to trip the connected Generator(s) if the duration of reverse power or underpower (i.e. ANY export) exceeds 60 seconds. (L)

(Continued)

Mm. INADVERTENT EXPORT FOR INTERCONNECTION REQUESTS UTILIZING UL-1741 CERTIFIED OR SA LISTED GRID SUPPORT (NON-ISLANDING) INVERTERS (L)

The following are the minimum requirements for Inadvertent Export systems that meet the criteria specified below. Other factors relevant to the interconnection study process (e.g., 15% screen results, short circuit current ratio, etc.) may necessitate additional technical requirements (e.g., reclose block, transfer trip, ground bank, etc.) that are not explicitly noted here. Inadvertent Export may not be available for interconnections to Networked Secondary Systems.

The certified control functions internal to the inverter control or external control system may be used to replace the discrete reverse/under power relay functions described in Section M provided the requirements outlined below are met.

1) All of the following requirements must be met by the Generating Facility to qualify for Inadvertent Export under this Section.

   a. The Generating Facility must utilize only UL-1741 certified or UL-1741 SA listed grid support non-islanding inverters; and,

   b. The Generating Facility must have an aggregate maximum nameplate capacity of 500 kVA or less; and,

   c. The Generating Facility's total energy export must not exceed its nameplate rating (kVA-gross) multiplied by 0.1 hours per day over a rolling 30-day period (e.g., for a 100 kVA-gross nameplate Generating Facility, the maximum energy allowed to be exported for a 30-day period is 300 kWh) ; and,

   d. Export from the Generating Facility across the PCC to the Distribution System is less than 100 kVA. (L)

(Continued)

Mm. INADVERTENT EXPORT FOR INTERCONNECTION REQUESTS UTILIZING UL-1741 CERTIFIED OR SA LISTED GRID SUPPORT (NON-ISLANDING) INVERTERS (Cont'd.) (L)

2) To govern the level of Inadvertent Export allowable under this Section, the Generating Facility must utilize a NRTL-certified control system or NRTL-certified inverter system that meets all of the following requirements.

a. Must result in the Generating Facility disconnecting from the Distribution System, ceasing to energize the Distribution System or halting energy production within two (2) seconds after either:

i. The period of continuous export exceeds 30 seconds;

or,

ii. The level of export exceeds 100 kVA.

b. Must monitor that the total energy export is maintained within the allowable energy export outlined above 1.c and provide an indication or notification (e.g., electronic, alarm) if that energy export limit is exceeded.

c. Failure of the of the control or inverter system for more than thirty (30) seconds, resulting from loss of control signal, loss of control power or a single component failure or related control sensing of the control circuitry, must result in the Generating Facility entering Non-Export operation where no energy is exported across to the PCC to the Distribution System.

Interim approval of the control or inverter system may be permitted upon mutual agreement of PG&E and the Producer. (L)

(Continued)

Mm. INADVERTENT EXPORT FOR INTERCONNECTION REQUESTS UTILIZING UL-1741 CERTIFIED OR SA LISTED GRID SUPPORT (NON-ISLANDING) INVERTERS (Cont'd.) (L)

3) Applicability of Engineering Review Screens.

Inadvertent Export systems that meet the requirements described herein are processed under Initial Review Screens A through J as described in Section H. If these systems fail Screen J, they then bypass Screens K and L and are processed under Screens M and M1 as described below.

Screen M: Is the aggregate Generating Facility capacity on the Line Section less than 15% of Line Section peak load for all line sections bound by automatic sectionalizing devices?

- If Yes (pass), Initial Review is complete.
- If No (fail), continue to Screen M1.

Screen M1: Is the aggregate of all distributed energy resources (DER) causing reverse power flow (1) at a line section with a voltage regulator device(s) or (2) at a protection device, including the circuit breaker / field recloser?*,**

- If No (pass), existing DER does not cause reverse power flow at (1) or (2) and Initial Review is complete.
- If Yes (fail), existing DER causes reverse power flow at (1) or (2); fail Initial Review and Supplemental Review is required.

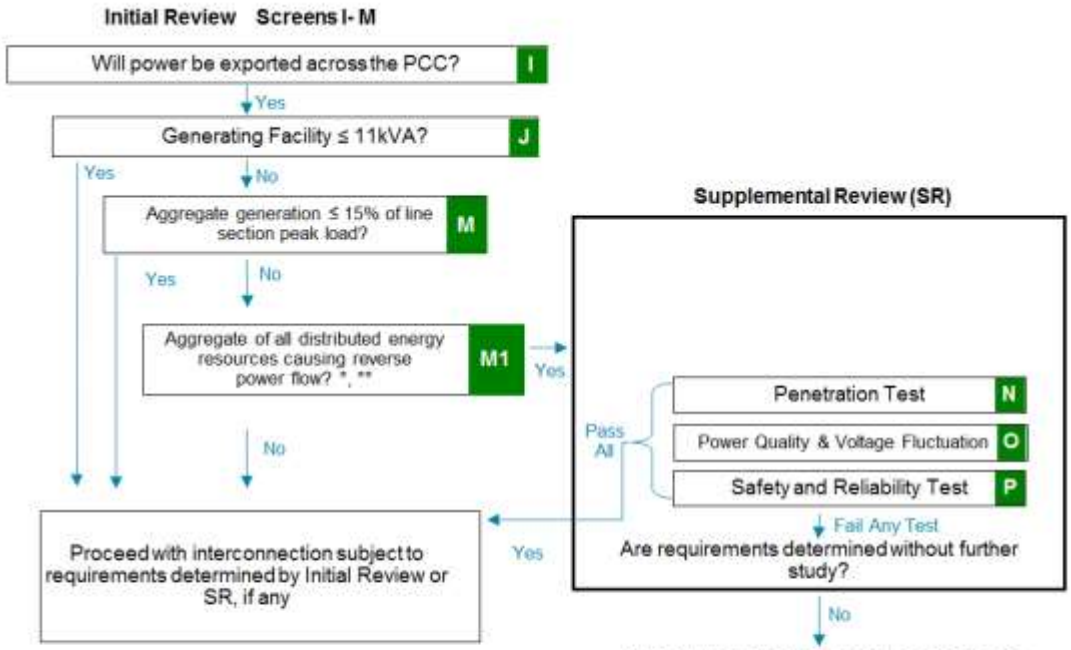
* For the purposes of applying Screen M1 herein, Distribution Provider shall utilize a zero coincidence factor when considering the impact of other Inadvertent Export systems that meet the requirements of Section Mm (i.e., projects that qualify for Option 6 under Section G.1.i) such that those Inadvertent Export systems do not impact Screen M1's aggregate analysis determination for the individual Inadvertent Export project being evaluated.

** The presence of existing non-certified DER on the line section may require additional review to ensure safe and reliable grid operation. (L)

(Continued)

Mm. INADVERTENT EXPORT FOR INTERCONNECTION REQUESTS UTILIZING UL-1741 CERTIFIED OR SA LISTED GRID SUPPORT (NON-ISLANDING) INVERTERS (Cont'd.) (L)

3) Applicability of Engineering Review Screens. (Cont'd.)



* For the purposes of applying Screen M1 herein, Distribution Provider shall utilize a zero coincidence factor when considering the impact of other Inadvertent Export systems that meet with the requirements of Section Mm (i.e., projects that qualify for Option 6 under Section G.1.i) such that those Inadvertent Export systems do not impact Screen M1's aggregate analysis determination for the individual analysis determination for the individual Inadvertent Export project being evaluated.

** The presence of existing non-certified DER on the line section may require additional review to ensure safe and reliable grid operation. (L)

(Continued)

Mm1. OPTION 8: Non-Export Utilizing Certified Power Control Systems (N)

The following are the minimum requirements for Non-Export systems that use certified power control systems (PCS) with an open loop response time (OLRT) no more than two seconds. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.

1. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Non-export systems may use a PCS that passes later published revisions to the CRD test protocol or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the PCS conforms to the non-exporting functionality in accordance with the relevant CRD or UL published standard.

2. Use a PCS that is certified with an OLRT of two seconds or less, as provided in the PCS's specification data sheets.

3. The PCS must reduce export to zero or less within two seconds of commencing export. A PCS that is certified with an open-loop response time of two seconds or less, and a time to reach steady state of 10 seconds or less, meets this requirement.

4. Set the PCS to not export (zero-export).

5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff.

6. Maintain voltage fluctuations at the limits specified in Electric Rule 2. (N)

(Continued)

Mm1. OPTION 8: Non-Export Utilizing Certified Power Control Systems (Cont'd) (N)

The evaluation of a non-export system requesting interconnection under this section:

1. Shall omit evaluation for screen D;

2. Shall utilize the Generating Facility's Gross Nameplate Rating for screens F, F1, and G;

3. If the non-export system has an aggregate PCS controlled nameplate greater than 600 kVA and the maximum reported steady state value of the PCS is greater than 1% of the PCS controlled nameplate (as provided in the NRTL testing reports), the evaluation may utilize the following calculation when determining the impacts to the grid under screens I, J, K, M, N, and O: The sum of the nameplate values of the exporting DER resource (if any) plus the maximum percentage steady state value of the PCS (as provided in the NRTL testing reports) times PCS controlled nameplate capacity.

4. Screen P may be applied using the Generating Facility's Gross Nameplate Rating for evaluations that use fault current calculations. For other evaluations under screen P, the value identified in iii above may be used.

(N)

(Continued)

Mm2. OPTION 9: Limited Export Utilizing Certified Power Control Systems (N)

The following are minimum requirements for limited export systems that use certified power control systems (PCS) with an open loop response time (OLRT) no more than two seconds to maintain a level of export that is lower than the nameplate rating. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.

1. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Limited export systems may use a PCS that passes later published revisions to the CRD test protocol, or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the PCS conforms to the export limiting functionality in accordance with the relevant CRD or UL published Standard.

2. Use a PCS that is certified with an OLRT of two seconds or less as provided in the PCS's specification data sheets.

3. The PCS must reduce export to the approved export limit, or less, within two seconds of exceeding the approved export limit. A PCS that is certified with an open-loop response time of two seconds or less, and a time to reach steady state of ten seconds or less, meets this requirement.

4. Set the PCS to not exceed the proposed level of export.

5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff.

6. Maintain voltage fluctuations at the limits specified in Electric Rule 2. (N)

(Continued)

Mm2. OPTION 9: Limited Export Utilizing Certified Power Control Systems (Cont'd) (N)

The evaluation of a limited export system requesting interconnection under this section:

1. Shall utilize the Generating Facility's Gross Nameplate Rating for screens F, F1, and G.

2. If the maximum steady state value is greater than 1% of the PCS controlled nameplate (as provided in the NRTL testing reports) utilize the requested limited export value plus the maximum steady state value of the PCS times the PCS controlled nameplate, to evaluate the impacts to the grid under screens D, I, J, K, M, N, and O. If the maximum steady state value is less than 1% of the PCS controlled nameplate (as provided in the NRTL testing reports), utilize only the requested limited export value under screens D, I, J, K, M, N and O.

3. Screen P shall be applied using the Generating Facility's Gross Nameplate Rating for evaluations that use fault current calculations. For other evaluations under screen P, the value identified in ii above may be used. (N)

(Continued)

Mm3. OPTION 10: Non-Export with Inadvertent Export Utilizing Certified Power Control Systems (N)

The following are the minimum requirements for Non-Export systems that use certified power control systems (PCS) with an open loop response time (OLRT) between two and ten seconds. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.

1. Have a nameplate capacity equal to or less than 1,000 kVA.

2. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Non-Export may use a PCS that pass later published revisions to the CRD test protocol, or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the PCS conforms to the non-exporting functionality in accordance with the relevant CRD or UL published standard.

3. Use a PCS that is certified with an OLRT of no more than ten seconds, as provided in the PCS's specification data sheets.

4. Set the PCS to not export (zero-export).

5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff.

6. Maintain voltage fluctuations at the limits specified in Electric Rule 2. (N)

(Continued)

Mm3. OPTION 10: Non-Export with Inadvertent Export Utilizing Certified Power Control Systems (Cont'd) (N)

The distribution provider evaluating generating facilities requesting interconnection under this section shall:

1. Apply screens A through M using the aggregate nameplate inverter rating.

2. Notify the applicant if supplemental review is required, and if so, require the applicant to identify, within 15 business days of being notified, the frequency of inadvertent export, the real power level in watts of inadvertent export, and the time duration of inadvertent export.

3. If distribution upgrades are identified, use screen P to recognize power control parameters, taking into account local feeder conditions; the customer's operating profile; and the magnitude, duration, and frequency of anticipated export.

4. Complete supplemental review within 15 days of receiving the required information specified under ii) above.

5. If the applicant does not provide the operating profile information within the specified 15 business days, perform supplemental review based on information included in the interconnection request within 30 business days of the request for customer operating profile information.

6. Use only the largest facility in the line section for aggregate evaluation for subsequent interconnection requests. (N)

(Continued)

Mm4. OPTION 11: Limited Export with Inadvertent Export Utilizing Certified Power Control Systems (N)

The following are the minimum requirements for limited export controlled systems that use certified power control systems (PCS) with an open loop response time (OLRT) between two and ten seconds to maintain a level of export that is lower than the nameplate rating. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.

1. Have a nameplate capacity equal to or less than 1,000 kVA.

2. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Limited export systems may use a PCS that pass later published revisions to the CRD test protocol, or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the PCS conforms to the export limiting functionality in accordance with the relevant CRD or UL published standard.

3. Use a PCS that is certified with an OLRT of no more than ten seconds, as provided in the PCS's specification data sheets.

4. Set the PCS to not to exceed the proposed level of export.

5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff.

6. Maintain voltage fluctuations at the limits specified in Electric Rule 2. (N)

(Continued)

Mm4. OPTION 11: Limited Export with Inadvertent Export Utilizing Certified Power Control Systems (Cont'd) (N)

The distribution provider evaluating generating facilities requesting interconnection under this section shall:

1. Apply screens A through M using the aggregate nameplate inverter rating.

2. Notify the applicant if supplemental review is required, and if so, require the applicant to identify, within 15 business days of being notified, the frequency of inadvertent export, the real power level in watts of inadvertent export, and the time duration of inadvertent export.

3. If distribution upgrades are identified, use screen P to recognize power control parameters, taking into account local feeder conditions; the customer's operating profile; and the magnitude, duration, and frequency of anticipated export.

4. Complete supplemental review within 15 days of receiving the required information specified under ii) above.

5. If the applicant does not provide the operating profile information within the specified 15 business days, perform supplemental review based on information included in the interconnection request within 30 business days of the request for customer operating profile information. (N)

(Continued)

N. EXPEDITED INTERCONNECTION PROCESS FOR NON-EXPORT ENERGY STORAGE GENERATING FACILITIES (L)

Applicants with Interconnection Requests for Non-Export Energy Storage Generating Facilities who meet the requirements outlined below are eligible for expedited interconnection in accordance with the Fast Track Process technical review requirements of Section F.2. Applicants with Non-Export AC/DC Converters that meet the requirements outlined in O. below are also eligible. (L) (P)/(L) (L)

1. ELIGIBILITY REQUIREMENTS

Applicants seeking to interconnect a Generating Facility under the provisions of this Section N must meet the following eligibility requirements.

a. Applicant must electronically submit a completed Interconnection Request, including completing all application fields and submitting all supporting documentation necessary to facilitate the expedited review as required by Distribution Provider. Such documentation may include, but is not limited to, single line diagrams with specific details, manufacturer data sheets for proposed equipment, description of control systems, validation of the right to do business in the state, etc. Distribution Provider shall clearly communicate these requirements as part of the application process. Applicant shall select this process option in the Interconnection Request.

b. Applicant's Generating Facility must meet the requirements outlined in Section N.2 below.

c. Applicant's Interconnection Request must be eligible for and select the Fast Track Process.

d. Applicant's Interconnection Request must pass Fast Track Initial Review and not require any Interconnection Facilities, Distribution Upgrades or Network Upgrades to remain eligible under this Section. As such, Interconnection Requests that select the Cost Envelope Option are not eligible.

e. Applicants selecting this section shall use the corresponding interconnection agreement type provided for eligible Generating Facilities. (L)

(P)

(P)

(Continued)

N. EXPEDITED INTERCONNECTION PROCESS FOR NON-EXPORT ENERGY STORAGE GENERATING FACILITIES (Cont'd.) (L)

2. GENERATING FACILITY ELIGIBILITY CRITERIA

An Applicant's Generating Facility must meet and adhere to the following criteria.

a. The Generating Facility must be comprised solely of the following specific categories of generation technology: Non-Exporting battery storage.

b. The Generating Facility must have an aggregate maximum inverter nameplate rating of no greater than 500 kW. There is no limitation on an energy storage device's kWh capacity rating.

c. The Generating Facility must be located behind an existing single retail meter and Point of Common Coupling with a single, clearly marked and accessible disconnect. No other Generators, other than isolated back-up Generators, may be at the same Point of Interconnection or Point of Common Coupling.

d. The Generating Facility must utilize Option 3 or Option 4 to meet the non-export protection requirements of Screen I in Section G.1.i.

e. The Generating Facility must have a single or coordinated control system for all charging functions if utilizing multiple inverters. The control system must also ensure that there is no increase in the Interconnection Customer's existing peak load demand.

f. The Generating Facility must utilize only inverter-based, UL 1741 and UL 1741 SA-listed equipment. Additionally, all installed equipment must meet Distribution Provider's current electric service requirements with no violations or variances. (L)

(Continued)

O. Non-Export AC/DC CONVERTER ELIGIBILITY CRITERIA (L)

Applicants with Non-Export AC/DC Converters who meet the eligibility criteria below qualify for the expedited interconnection process outlined in Section N of this Rule.

1. The Non-Export AC/DC Converter must have an aggregate maximum inverter nameplate rating of no greater than 500 kW. There is no limitation on an energy storage device's kWh capacity rating.

2. Applicant's Interconnection Request must be eligible for and select the Fast Track Process.

3. Applicant's Interconnection Request must pass Fast Track Initial Review and not require any Interconnection Facilities, Distribution Upgrades or Network Upgrades to remain eligible under this Section.

4. Applicants selecting this section shall use the corresponding interconnection agreement type provided for Non-Export AC/DC Converters eligible under this Section. As such, Interconnection Requests that select the Cost Envelope Option are not eligible.

5. Applicant's Non-Export AC/DC converter must meet the Certification requirements in the Section C Definition of "Non-Export AC/DC Converters". (L)

(Continued)

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Appendix A Forms Associated with Rule 21 Generating Facility Interconnections			
Form Number	Title	Associated Tariffs	Use Guidance
Pre-Application Request			
79-1181	Rule 21 Pre-Application Report Request	Rule 21	For Generator Developer to request basic info about local distribution circuit
Study Agreement			
79-1162	Rule 21 Detailed Study Agreement	Rule 21	Independent Study and Distribution Group Study Process Study Agreement
NEM and Non-Export Interconnection Forms			
79-978	Interconnection Agreement for Net Energy Metering of Solar or Wind Electric Generating Facilities of 1,000 kW or Less, Other Than Facilities of 30 kW or Less	NEM, Rule 21	Solar and/or Wind > 30 kW and ≤ 1 MW expanded NEM used with Form 79-1174-02
79-978-02	Interconnection Agreement for Net Energy Metering (NEM2) of Solar or Wind Electric Generating Facilities of 1,000 Kilowatts or Less, Other than Facilities of 30 Kilowatts or Less	NEM2, Rule 21	Solar and/or Wind > 30 kW and ≤ 1 MW expanded NEM2 used with Form 79-1174-02
79-997	Interconnection Agreement for Net Energy Metering of Biogas Digester Generating Facilities	NEM, Rule 21	NEMBIO (Closed to new applicants), NEMBIOA Interconnection Agreement used with Form 79-1174
79-1010	Interconnection Agreement for Net Energy Metering of Fuel Cell Generating Facilities	NEM, Rule 21	NEMFC Interconnection Agreement used with Form 79-1174
79-1069	Generating facility Interconnection Agreement (Multiple Tariff)	NEM, Rule 21	NEMMT Interconnection Agreement used with Form 79-1174
79-1069-02	Generating Facility Interconnection Agreement (Multiple Tariff NEM2MT)	NEM2, Rule 21	NEM2MT Interconnection Agreement used with Form 79-1174-02
79-1109 ***	Virtual Net Energy Metering Application and Interconnection Agreement For The Building Owner of Multifamily Affordable Housing With A Solar Generating Facility of 1 Megawatt or Less	NEM, Rule 21	NEMV Interconnection Agreement used with Form 79-974

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(Continued)

Appendix A (Cont'd.) Forms Associated with Rule 21 Generating Facility Interconnections			
Form Number	Title	Associated Tariffs	Use Guidance
NEM and Non-Export Interconnection Forms (Cont'd.)			
79-1193	AGREEMENT AND CUSTOMER AUTHORIZATION Net Energy Metering (NEM) Interconnection For Solar And/Or Wind Electric Generating Facilities Of 30 Kilowatts Or Less with Energy Storage of 10 Kilowatts Or Less or Energy Storage with Power Control System Certification	NEM	For NEM pair storage scenarios using Power Control Systems to ensure NEM integrity
79-1193-02	AGREEMENT AND CUSTOMER AUTHORIZATION Net Energy Metering (NEM2) Interconnection For Solar And/Or Wind Electric Generating Facilities Of 30 Kilowatts Or Less with Energy Storage of 10 Kilowatts Or Less or Energy Storage with Power Control System Certification	NEM2	For NEM2 pair storage scenarios using Power Control Systems to ensure NEM integrity
79-1109-02***	NEM2VMSH Virtual Net Energy Metering Application and Interconnection Agreement for the Building Owner of Multifamily Affordable Housing with a Solar Generating Facility of 1 Megawatt or Less	NEM2VMSH, Rule 21	NEM2VMSH Interconnection Agreement used with Form 79-1174-02
79-1151A	Net Energy Metering Interconnection for Solar And/or Wind Electric Generating Facilities Of 30 Kilowatts Or Less Agreement and Customer Authorization	NEM, Rule 21	NEMS Interconnection Agreement be used with 79-1151B Application
79-1151A-02	Agreement And Customer Authorization - Net Energy Metering (NEM2) Internconnection For Solar And/Or Wind Electric Generating Facilities Of 30 Kilowatts Or Less	NEM2, Rule 21	NEM2S Application to be used with 79-1151A Interconnection Agreement
79-1151B	Net Energy Metering Interconnection For Solar And/or Wind Electric Generating Facilities Of 30 Kilowatts Or Less Application	NEM, Rule 21	NEMS Application to be used with 79-1151A Interconnection Agreement
79-1151B-02	Application - Net Energy Metering (NEM2) Interconnection For Solar And/Or Wind Electric Generating Facilities Of 30 Kilowatts Or Less	NEM2, Rule 21	NEM2S Application to be used with 79-1151A-02 Interconnection Agreement
79-1124 ***	Eligible Low Income Development Virtual Net Energy Metering Application and Interconnection Agreement for Multifamily Affordable Housing with Solar Generation Totaling 1 Megawatt or Less	NEMVMASH, Rule 21	NEMVMASH Interconnection Agreement

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Appendix A (Cont'd.)
Forms Associated with Rule 21
Generating Facility Interconnections

Form Number	Title	Associated Tariffs	Use Guidance
NEM and Non-Export Interconnection Forms (Cont'd.)			
79-1124-02***	Eligible Low Income Development Virtual Net Energy Metering (NEM2VMSH) Application and Interconnection Agreement for Multifamily Affordable Housing with Solar Generation Totaling 1 Megawatt or Less	NEM2VMSH, Rule 21	NEM2VMSH Interconnection Agreement
79-1131 ***	NEMV Application and Interconnection Agreement for a Solar (PV) or Wind Generating Facility of 1 MW or Less *Serving Multiple Tenants Served at a Single Property Delivery Point*	NEM, Rule 21	NEMV Interconnection Agreement
79-1131-02***	NEM2V Application and Interconnection Agreement for a Solar (PV) or Wind Generating Facility of 1 MW or Less *Serving Multiple Tenants Served at a Single Property Delivery Point*	NEM2V, Rule 21	NEM2V Interconnection Agreement
79-1137	Interconnection Agreement for Net Energy Metering for a Renewable Electrical Generation Facility of 1,000 kW or Less, Except Solar or Wind (SB 489)	NEM, Rule 21	NEMV, NEMEXP, NEMEXPM Interconnection Agreement typically used with Forms 79-974 and 79-1142 Applications
79-1137-02	Interconnection Agreement for Net Energy Metering (NEM2/NEM2V) for a Renewable Electricity Generation Facility of 1,000 Kilowatts or Less, Except Solar or Wind	NEM2, NEM2V, Rule 21	NEM2V, NEM2EXP, NEM2EXPM Interconnection Agreement typically used with Forms 79-1174-02
79-1142 ***	NEMV Interconnection Application for a Renewable Electrical Generation Facility of 1 Megawatt or Less	NEM, Rule 21	Used with Form 79-1137 (L)
79-973	Generating Facility Interconnection Agreement For Non-Export Generating Facilities (Rule 21 Interconnection Agreement)	Rule 21	Interconnection Agreement used for RESBCT and non-NEM generation with Application 79-974 and 79-1112
79-992	Customer Generation Agreement (Third party Generator on Premises, Non-Exporting)	Rule 21	Used with Forms 79-1174
79-1070	Export Addendum to Generating Facility Interconnection Agreement for Non-Export Generating Facilities (Form 79-973) Sized 2 Megawatts or Less	Rule 21	Export addendum used with Form 79-973
79-1136	PG&E Interconnection Agreement For an Existing Small Generating Facility Interconnecting to the Distribution System under Rule 21	Rule 21	Used for existing QFs with Form 79-974 (L)

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Appendix A (Cont'd.)
Forms Associated with Rule 21
Generating Facility Interconnections

Form Number	Title	Associated Tariffs	Use Guidance
Other NEM and Non-Export Forms (Cont'd.)			
79-1192	Interconnection Agreement for Non-Export Storage Generating Facilities 500KW or Less	Rule 21	Used for expedited interconnection of non-export energy storage, pursuant to Rule 21 Section N, PG&E AL 4941-E & E-A and D.16-06-052, & Attachment C, Section II.1
79-1199	Agreement And Customer Authorization Non-Export Stand-Alone Energy Storage Of 30 Kilowatts Or Less	Rule 21	Interconnection Agreement For non-export storage ≤ 30 kW
79-1206-02	Eligible Low-Income Development Virtual Net Energy Metering (NEM2VSOM) Interconnection Agreement For The Solar On Multifamily Affordable Housing (SOMAH) Program With Solar Generation Totaling 1 Mw Or Less	NEM2VSOM	NEM2VSOM Interconnection agreement for solar 1 MW or less.
79-1130	Request to Opt-out of / Opt-in to Compensation for Surplus Electricity	NEM	AB 920- Opt not to receive compensation for net annual excess energy
79-1202 ****	Load Aggregation Appendix	NEM, NEM2, Rule 21	Use as an Appendix with Form 79-1151A, 79-1151A-02, 79-978, 79-978-02,79-1137, 79-1137-02, 79-1069 or 79-1069-02
79-1155	Schedules NEM, NEMV, NEMVMASH, Net Surplus Electricity (NSE) Renewable Energy Credits Compensation	NEM, Rule 21	
79-1155-02	Schedules NEM2, NEM2V, NEM2VMSH, Net Surplus Electricity (NSE) Renewable Energy Credits Compensation	NEM2 NEM2V NEM2VMSH, Rule 21	
79-1174	Rule 21 Generator Interconnection Application	NEM (NEMEXP, NEMMT and NEMA), NEMFC, NEMV, NEMVMASH, RES-BCT, Rule 21	Rule 21 customer interconnection application form for expanded net-energy metered (all NEM > 30 kw and all non-Solar/Wind NEM), NEMFC, NEMV, NEMVMASH, RES-BCT, and non-export and limited export Rule 21 generation. (Standard NEM for solar and/or wind ≤ 30 kw will continue to use the 79-1151B application.)

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Appendix A (Cont'd.)
Forms Associated with Rule 21
Generating Facility Interconnections

Form Number	Title	Associated Tariffs	Use Guidance
Other NEM and Non-Export Forms (Cont'd.)			
79-1174-02	Rule 21 Generator Interconnection Application	NEM2 (NEM2EXP, NEM2MT and NEM2A), NEMFC, NEM2V, NEM2VMSH, RES-BCT, Rule 21	Rule 21 customer interconnection application form for expanded net-energy metered (all NEM2 > 30 kw and all non-Solar/Wind NEM), NEMFC, NEM2V, NEM2VMSH, RES-BCT, and non-export and limited export Rule 21 generation. (Standard NEM for solar and/or wind ≤ 30 kw will continue to use the 79-1151B application.)
Export for Sale Interconnection Forms			
79-1145	Rule 21 Exporting Generator Interconnection Request	Rule 21	Preferred online application: https://www.pge.com/en_US/large-business/services/alternatives-to-pge/electric-generation-interconnection.page
79-1197	Local Government Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) Re-Allocation Request	RES-BCT	Use to establish RES-BCT benefiting account re-allocations
79-1198-02	Interconnection Agreement For Net Energy Metering (NEM2) And Renewable Electrical Generating Facility Sized Greater Than 1,000 Kw	NEM2	FT and Detailed Study Interconnection Agreement for >1MW NEM2 Generating Facilities
79-1200	Rule 21 Generator Interconnection Agreement For Exporting Generating Facilities	Rule 21	FT and Detailed Study Interconnection Agreement for Exporting Generating Facilities
Other Agreements			
79-280	Agreement for Installation of Allocation of Special Facilities for Parallel Operation of Non-Utility-Owned Generation and/or Electrical Standby Service (Electric Rules 2 and 21)	Rule 21	Special Facilities Agreement to be used with Form 79-702
79-702	Appendix A: Detail of Special Facilities Charges to be used in concert with form 79-280	Rule 21	Used with Form 79-280

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*** The application section of these forms is replaced by 79-1174.
**** For NEMA expanded customers, use the online 79-1174 form.

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APPENDIX B (L)

Unit Cost Guide

Distribution Provider shall publish a Unit Cost Guide for facilities generally required to interconnect generation in Distribution Provider's Distribution System. The Unit Cost Guide shall not be binding for actual facility costs and is provided only for additional cost transparency, developer reference, and Distribution Provider's reference when preparing the cost estimate provided in any applicable studies. The Unit Cost Guide shall not replace the estimated cost provided by Distribution Provider in an Interconnection Study or an initial or supplemental review under the Fast Track Process.

The Unit Cost Guide shall include the anticipated cost of procuring and installing Interconnection Facilities and Distribution Upgrades generally utilized by the Applicant. An annual adjustment shall be performed within the Unit Cost Guide for five (5) years to account for the anticipated timing of procurement to accommodate a potential range of Commercial Operation Dates.

The Unit Cost Guide shall be updated annually in accordance with the process set forth in D.16-06-052. (L)

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Advice 6286-E
August 6, 2021

Attachment 2

Redline Tariff Revisions

For convenience of the reader, PG&E has included redline revisions in Attachment 2. Where Electric Rule 21 has been revised, the affected sheets are included in Attachment 1.

In this advice letter and accordance to CPUC General Order 96B, Section 9.5.3, PG&E has implemented the use of the "(P)" symbol to signify material subject to change under a pending advice letter. The redlines in Attachment 2 are color coded to the specific advice letter. The color coding is as follows:

Redline Text Color	Advice Letter	Subject	Comments
	5988-E-A	Supplemental: Advice Letter Modifying Electric Rule 21 Pursuant to Decision 20-09-035 for Working Group 2 and 3	Effective as of May 19, 2021
	6014-E-A	Supplemental: Advice Letter Modifying Electric Rule 21 Pursuant to Decision 20-09-035 for Working Group 2 and 3 (due 60 Days from Issuance)	Pending Approval
	6286-E	Advice Letter Modifying Electric Rule 21 Pursuant to Ordering Paragraphs 7, 49, 50 Decision 20-09-035 for Working Group 2 and 3	In this advice letter, the redline tariff revisions do not show sheets that only have location changes.

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e. Integration with Distribution Provider's Distribution System Grounding 197 ~~6~~ | (T)

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b. Transfer Trip 210~~09~~

c. Reclose Blocking 210~~09~~

5. COMMUNICATION REQUIREMENTS 211~~0~~

a. Generating Facilities utilizing inverter-based technologies must adhere to all of the following communication protocol requirements: 211~~0~~ (T)

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ELECTRIC RULE NO. 21 Sheet 11
GENERATING FACILITY INTERCONNECTIONS

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ELECTRIC RULE NO. 21 Sheet 14
GENERATING FACILITY INTERCONNECTIONS

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(Continued)

C. DEFINITIONS (Cont'd.)

Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority: Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Distribution Provider, or any Affiliate thereof.

Gross Rating; Gross Nameplate Rating; Gross Capacity or Gross Nameplate Capacity: The total gross generating capacity of a Generator or Generating Facility as designated by the manufacturer(s) of the Generator(s).

Host Load: The electrical power, less the Generator auxiliary load, consumed by the Customer, to which the Generating Facility is connected.

Inadvertent Export: The unscheduled and uncompensated export of real power from a Generating Facility (GF) for a limited duration as specified in Sections M, ~~and~~ Mm and Mm3. (T)

Independent Study Process: The interconnection study process set forth in Section F.3.d.

Initial Review: See Section F.2.a.

(Continued)

E. INTERCONNECTION REQUEST SUBMISSION PROCESS (Cont'd.)

2. INTERCONNECTION REQUEST PROCESS (Cont'd.)

b. Applicant Selects a Study Process

An Applicant may select one of two interconnection evaluation processes in accordance with the following eligibility requirements:

i) Fast Track Eligibility

~~Non-Exporting Generating Facilities and NEM-1 Generating Facilities are eligible for Fast Track evaluation regardless of the Gross Nameplate Rating of the proposed Generating Facility. NEM-2 Generating Facilities and Exporting Generating Facilities with a Gross Nameplate Rating no larger than 3.0 MW on a 12 kV or higher voltage interconnection point for PG&E are also eligible for Fast Track evaluation.~~ (P)

~~For an Exporting Generating Facility that agrees to the installation of Distribution Provider-approved protective devices at Applicant's cost such that the Exporting Generating Facility's net export will never exceed the Fast Track eligibility limits, the Generating Facility's net export will be considered for purposes of Fast Track eligibility. However, these Interconnection Requests will be required to complete Supplemental Review and Applicants should pre-pay for Supplemental Review at the time the Interconnection Request is submitted.~~

The Distribution Provider shall evaluate Non-Exporting Generating Facilities and NEM-1 Generating Facilities under the Fast Track Review Process described in Section F.2 below. Applicants for all other Generating Facilities may request that the Distribution Provider evaluate their project under the Fast Track Review Process described in Section F.2 below. Customers are encouraged to review the ICA for information relevant to their project. (P)

ii) Detailed Study Eligibility

Interconnection Requests that are not eligible for Fast Track evaluation must apply for Detailed Study. An Applicant may also choose to apply directly for Detailed Studies. Detailed Study shall require (i) an Independent Study Process, (ii) a Distribution Group Study Process, or (iii) a WDT Transmission Cluster Study Process. The specific study process used will depend on the results of the Electrical Independence Tests for the Transmission (T)

(Continued)

and Distribution Systems.

(Continued)

E. INTERCONNECTION REQUEST SUBMISSION PROCESS (Cont'd.)

2. INTERCONNECTION REQUEST PROCESS (Cont'd.)

b. Applicant Selects a Study Process (Cont'd.)

iii) Request for Deliverability Assessment

Unless specified otherwise in the Interconnection Request, Generating Facilities eligible to be studied under the Fast Track Process, Independent Study Process or Distribution Group Study Process will be assumed to have selected Energy-Only Deliverability Status. Nothing herein will prohibit an Applicant from seeking a deliverability assessment in accordance with the WDT. Applicants studied under the WDT Transmission Cluster Study Process may seek a deliverability assessment in accordance with the applicable provisions of the WDT. (T)

Applicant may submit a request to convert their Interconnection Request to the Federal Energy Regulatory Commission (FERC) jurisdiction Wholesale Distribution Tariff (WDT) process subject to PG&E's WDT Section 6.8.1.1 requirements. Additional information is available at: https://www.pge.com/egi (P)

c. Applicant Completes an Interconnection Request

All Applicants shall submit a complete and valid Interconnection Request. When applicable per Table E.1, a nonrefundable $800 Interconnection Request fee, and for Applicants that elect Detailed Study in the Interconnection Request, a study deposit shall be required per instructions in the Interconnection Request. Applicants who proceed to Detailed Study after Fast Track will provide a Detailed Study deposit as specified in Section E.3.a.

Applicant shall submit a separate Interconnection Request for each Point of Interconnection. An Interconnection Request for the expansion of capacity of an existing operating Generating Facility shall be treated the same as an Interconnection Request for a new Generating Facility pursuant to this Rule.

i) Interconnection Requests for the Independent Study Process will be accepted throughout the year, except during the Distribution Group Study windows. All Detailed Study Interconnection Requests (except those applying directly to the WDT Transmission Cluster Study Process) submitted during the Distribution Group Study Windows will be processed as (T)

(Continued)

Distribution Group Study Process Applicants.

(Continued)

E. INTERCONNECTION REQUEST SUBMISSION PROCESS (Cont'd.)

2. INTERCONNECTION REQUEST PROCESS (Cont'd.)

c. Applicant Completes an Interconnection Request (Cont'd.)

TABLE E.1

Summary of Interconnection Request Fees, Deposits and Exemptions

Generating Facility Type	Interconnection Request Fee	Supplemental Review Fee	Detailed Study Deposit	Additional Commissioning Test Verification	Cost Envelope Option Deposit****	Modifications Fee per Ee *****	
Non-Net Energy Metering and > 1 MW NEM-2	$800	$2,500*	For a Generating Facility with a Gross Nameplate Rating of 5 MW or less and applying to the Independent Study Process, $10,000 for a System Impact Study or the DGS Phase I Interconnection Study in the case of the Distribution Group Study Process; and $15,000 for an Interconnection Facilities Study or DGS Phase II Interconnection Study in the case of the Distribution Group Study Process. For a Generating Facility with a Gross Nameplate Rating above 5 MW, $50,000 plus $1,000 per MW of electrical output of the Generating Facility, or the increase in electrical output of the existing Generation Facility, as applicable, rounded up to the nearest whole MW, up to a maximum of $250,000.	$150/Person Hour**	$2,500	$0	(N) (N)
≤ 1 MW NEM-2***	$145	$0	$0	N/A	$2,500	$0	(N)
NEM-1	$0	$0	$0	N/A	$2,500	n/a	
Non-NEM Solar ≤ 1MW******	First $5,000 of study fees waived			$150/Person Hour**	$2,500	$0	(N)

* Optional $1,000 additional fault current study fee pursuant to Section F.2.c.ii. Pursuant to D. 20-09-035, Applicants have the option to pre-pay the non-refundable Supplemental Review Fee (such as concurrently with the Interconnection Request fee) or separately upon completion of the Initial Review. (P) (P)

** Plus additional costs for travel, lodging and meals.

*** Applicants that participate in the Single-Family Affordable Solar Homes (SASH) program are exempt from the Interconnection Request fee.

**** Interconnection Requests that have selected the Cost Envelope Option and that subsequently qualify for and pass the Fast Track Process evaluation, as well as NEM Generating Facilities and Solar ≤ 1 MW Generating Facilities evaluated under the Independent Study Process, must provide the Cost Envelope Option deposit in accordance with Section F.7 to remain eligible for the Cost Envelope Option.

***** The fee will be set to $0 for now, until PG&E submits a new Advice Letter to increase it. Note: the fee does not apply to NEM-1 nor NEMFC by statute. SASH is also exempt from this fee per D. 16-01-044. (N) (N)

****** Solar ≤ 1MW that does not sell power to Distribution Provider (per D.01-07-027) nor participate in NEM-1 or NEM-2

(Continued)

E. INTERCONNECTION REQUEST SUBMISSION PROCESS (Cont'd.)

4. INTERCONNECTION COST RESPONSIBILITY (Cont'd.)

f. Summary Tables (Cont'd.)

Table E.3 Summary of Producer Cost Responsibility for Multiple Tariff Interconnections

Existing Generating Facility	New Generating Facility	Interconnection Request Fee		Supplemental Review Fee		Detailed Study Cost		Interconnection Facilities Cost		Distribution Upgrades Cost	
		YES	NO	YES	NO	YES	NO	YES	NO	YES	NO
NEM	Non-NEM, NEM-2 (>1 MW)	X		X		X		X		X[b]	
NEM-1	NEM-1		X		X		X	X			X
NEM-1	NEM-2 (≤1MW)*	X			X		X	X			X
Non-NEM	NEM-1		X[c]		X[c]		X[c]	X			X[b,c]
Non-NEM	NEM-2 (>1 MW)	X		X		X		X		X	
Non-NEM	NEM-2 (≤1MW)*	X			X[c]		X[c]	X			X[b,c]
Simultaneous NEM and Non-NEM		X		X		X		X		X[b]	

a) Except as provided in Section D.13.e

b) Proration will be based upon the annual expected energy output (kWh) derived from the nameplate of the Generator(s) modified by technology-specific capacity/availability factors of all NEM and non-NEM Generators for the costs that cannot be clearly assigned to each type of tariff.

c) Change of operation of a non-NEM eligible Generator at any time to export is treated as a simultaneous NEM and non-NEM Interconnection Request, resulting in associated costs being allocated to Producer.

g. Cost Reconciliation

Unless agreed to otherwise between Applicant and Distribution Provider, Distribution Provider shall provide Applicant a detailed reconciliation of the costs on interconnection facilities and distribution upgrades within 12 months of project completion. (P)

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

1. OVERVIEW OF THE INTERCONNECTION REVIEW PROCESS (Cont'd.)

b. Fast Track Review

Fast Track evaluation allows for rapid review of the Interconnection of those Generating Facilities that do not require Detailed Study. Regardless of study process, all Generating Facilities shall be designed to meet the applicable requirements of Section H which identifies Generating Facility Design and Operation Requirements.

Fast Track review consists of an Initial Review and, if required, a Supplemental Review. The need for Supplemental Review will be determined based on the results of Initial Review Screens A through M in Section G.1. Applicants that successfully pass Initial Review Screens A through M will be allowed to interconnect without Supplemental Review.

Non-Export AC/DC Converter installations that have a complete and valid Interconnection Request will be eligible to bypass screens B through D and F through M.

If Supplemental Review is required, Distribution Provider will notify Applicant and Applicant must pay a nonrefundable Supplemental Review fee, per Table E-1 or withdraw its Interconnection Request. If the Applicant pre-paid the Supplemental Review fee (such as concurrently with the Interconnection Request Fee), the Supplemental Review, if required, will be conducted upon completion of the Initial Review. Supplemental Review shall consist of the application of Screens N through P in Section G.2. Applicants that pass Screens N through P will be allowed to interconnect without additional review. (P) (P)

If Supplemental Review reveals that a proposed Generating Facility cannot be interconnected to Distribution Provider's Distribution System by means of Fast Track evaluation, Distribution Provider will notify Applicant that Detailed Study will be required.

Failure to pass Fast Track evaluation means only that further review and/or study are required before the Generating Facility can be interconnected with Distribution Provider's Distribution System. It does not mean that the Generating Facility cannot be interconnected.

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.) (L)

1. OVERVIEW OF THE INTERCONNECTION REVIEW PROCESS (Cont'd.)

d. Compliance with Timelines (Cont'd.)

(i) Contact the ombudsman designated by Distribution Provider;

(ii) If the Distribution Provider ombudsman is unable to resolve the dispute within ten (10) Business Days, Applicant may either:

a) Contact the Consumer Affairs Branch (CAB) at the Commission.

b) Upon mutual agreement with Distribution Provider, make a written request for mediation to the Alternative Dispute Resolution (ADR) Coordinator in the Commission's Administrative Law Judge (ALJ) Division. The request may be made by electronic mail to adr_program@cpuc.ca.gov, and shall state "Rule 21" in the subject line. The request shall contain the relevant facts of the timeline dispute. A copy of the request shall be sent to the Distribution Provider ombudsman. Provided that resources are available, the mediator assigned shall schedule a mediation with Applicant and Distribution Provider within ten (10) Business Days of receiving the request.

At any time, Applicant may file a formal complaint before the Commission pursuant to California PUC Section 1702 and Article 4 of the Commission's Rules of Practice and Procedure. (L)

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

2. FAST TRACK INTERCONNECTION REVIEW PROCESS

a. Initial Review (Cont'd.)

For Interconnection Requests that fail Initial Review, Distribution Provider shall provide the technical reason, data and analysis supporting the Initial Review results in writing and provide Applicant the option to either attend an Initial Review results meeting or proceed directly to Supplemental Review. NEM-1 and ≤1 MW NEM-2 Applicants covered under Section D.13.a, and Applicants that pre-pay for the Supplemental Review (such as concurrently with the Interconnection Request Fee), shall proceed directly to Supplemental Review without an Initial Review results meeting. Applicant shall notify Distribution Provider within ten (10) Business Days following such notification whether to (i) proceed to an Initial Review results meeting, (ii) proceed to Supplemental Review, or (iii) withdraw the Interconnection Request. Applicant may request one extension of no more than ten (10) Business Days to respond. If Applicant fails to notify Distribution Provider within ten (10) Business Days of such notification, or at the end of the extension, if one was requested, the Interconnection Request shall be deemed withdrawn. (P) (P)

No changes may be made to the planned Point of Interconnection or Generating Facility size included in the Interconnection Request during the Fast Track Process, except as provided in Table F.1 below, or unless such changes are agreed to by Distribution Provider. Where agreement has not been reached, Applicants choosing to change the Point of Interconnection or Generating Facility size, except as provided for in Table F.1, must reapply and submit a new Interconnection Request.

Applicants that elect to proceed to Supplemental Review, unless the Applicant has pre-paid, shall provide a nonrefundable Supplemental Review fee set forth in Section E.2.c with their response. The Supplemental Review fee shall be waived for Interconnection Requests requesting Interconnection of NEM-1 or ≤1 MW NEM-2 Generating Facilities and for solar-powered non-NEM ≤1 MW Generating Facilities that do not sell power to Distribution Provider, per Commission D.01-07-027. (P) (P)

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

2. FAST TRACK INTERCONNECTION REVIEW PROCESS (Cont'd.)

b. Optional Initial Review Results Meeting

Within five (5) Business Days of Applicant's request for an Initial Review results meeting, Distribution Provider shall contact Applicant and offer to convene a meeting at a mutually acceptable time to review the Initial Review screen analysis and related results to determine what modifications, if any, may permit the Generating Facility to be connected safely and reliably without Supplemental Review.

In the event the Applicant has pre-paid the Supplemental Review fee (such as concurrently with the Interconnection Request Fee), the Distribution Provider will proceed, if necessary, with Supplemental Review upon completion of Initial Review and shall not be required to offer an Initial Review results meeting. (P)

If modifications that obviate the need for Supplemental Review are identified, and Applicant and Distribution Provider agree to such modifications, Distribution Provider shall provide Applicant with a Generator Interconnection Agreement within fifteen (15) Business Days of the Initial Review results meeting if no Interconnection Facilities or Distribution Upgrades are required. If Interconnection Facilities or Distribution Upgrades are required, Distribution Provider shall provide Applicant with a non-binding cost estimate of any Interconnection Facilities or Distribution Upgrades within fifteen (15) Business Days of the Initial Review results meeting. For those Interconnection Requests where Applicant has selected the Cost Envelope Option, within ten (10) Business Days of providing Applicant the non-binding cost estimate for the required Interconnection Facilities and/or Distribution Upgrades, Applicant shall provide the Distribution Provider the Cost Envelope Option deposit, in accordance with Section F.7.a.i.3. If Applicant fails to provide the Cost Envelope Option deposit in accordance with Section F.7.a.i.3, Applicant's request for the Cost Envelope Option shall be deemed withdrawn and the Interconnection Request shall not be eligible for the Cost Envelope Option.

For all Interconnection Requests that pass Initial Review, refer to Section F.2.e for cost responsibility and time frames for completing the Generator Interconnection Agreement.

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

2. FAST TRACK INTERCONNECTION REVIEW PROCESS (Cont'd.)

b. Optional Initial Review Results Meeting (Cont'd.)

If Applicant and Distribution Provider are unable to identify or agree to modifications that enable Applicant to pass Initial Review, Applicant shall notify Distribution Provider within ten (10) Business Days of the Initial Review results meeting whether it would like to proceed with Supplemental Review or withdraw its Interconnection Request. Applicant may request one extension of no more than ten (10) Business Days to respond. If Applicant fails to notify Distribution Provider within ten (10) Business Days of the Initial Review results meeting, or at the end of the extension, if one was requested, the Interconnection Request shall be deemed withdrawn.

c. Supplemental Review

i) If Applicant requests Supplemental Review and submits a nonrefundable Supplemental Review fee, if required, Distribution Provider shall complete Supplemental Review within twenty (20) Business Days, absent extraordinary circumstances, following authorization and receipt of the fee. Supplemental Review determines if (i) the Generating Facility qualifies for Fast Track Interconnection, or (ii) the Generating Facility requires Detailed Study.

ii) If the Applicant pre-paid the Supplemental Review fee (such as concurrently with the Interconnection Request Fee), Distribution Provider will complete the Supplemental Review, if required, within twenty (20) Business Days from the completion of the Initial Review. (P)

iii) If the Applicant chooses to move to Supplemental Review or has pre-paid the non-refundable Supplemental Review fee, they have the option to elect that the Distribution Provider provide a fault current study as part of the Supplemental Review. This fault current study would extend the Supplemental Review time by up to ten (10) Business Days, and would require an additional nonrefundable fee of $1,000. (P) (P)

This fault current study will determine if the Generating Facility can detect phase and ground faults on the Distribution Provider's Distribution System or the distribution feeder breaker where the Applicant proposes to connect the Generating Facility.

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

2. FAST TRACK INTERCONNECTION REVIEW PROCESS (Cont'd.)

c. Supplemental Review (Cont'd.)

iii) The result of the fault current study will determine if direct transfer trip (DTT) will be required from the Distribution System to the Generating Facility site. Note that for Applicants proposing to interconnect to the Distribution System where there is expected to be power backfeed to the Transmission System, DTT from the transmission may still be required and a Detailed Interconnection Study will be required to make this determination (Cont'd). (P)

Should the Applicant request a Supplemental Review results meeting, as described in Section F.2d, the optional fault current study analysis and related results shall, at the Applicant's request, be reviewed to determine what modifications, if any, may permit the Generating Facility to be connected safely and reliably.

~~If the Applicant chooses to move to Supplemental Review, they have the option to elect that the Distribution Provider provide a fault current study as part of the Supplemental Review. This fault current study would extend the Supplemental Review time by up to ten (10) Business Days, and would require an additional nonrefundable fee of $1,000. (Cont'd.)~~ (P)

The Applicant must provide the following data to Distribution Provider when requesting Supplemental Review in order to select this option:

Generator:
- MVA Rating
- kV Rating
- Base MVA
- Base kV
- Xd" (direct axis subtransient reactance)
- Xd' (direct axis transient reactance)
- Xd (Synchronous reactance)
- X2 (Negative Sequence reactance)
- X0 (Zero Sequence reactance)

XFMR Data:
- Winding configuration (delta-Wye grd or Wye grd-Delta)
- MVA Rating
- KV Rating
- Base MVA

(Continued)

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GENERATING FACILITY INTERCONNECTIONS

Base KV
Z1 HV-LV
Z0 HV-LV

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

2. FAST TRACK INTERCONNECTION REVIEW PROCESS (Cont'd.)

c. Supplemental Review (Cont'd.)

iii) Line Data: (P)
Impedance data for line from XFMR to POI (if applicable)
Z1
Z0

POI Location~~:~~ (P)

~~iii~~iv) For Interconnection Requests that pass Supplemental Review and do not require Interconnection Facilities or Distribution Upgrades, Distribution Provider shall provide Applicant with a Generator Interconnection Agreement within fifteen (15) Business Days of providing notice of Supplemental Review results. For Interconnection Requests that pass Supplemental Review and do require Interconnection Facilities or Distribution Upgrades, within fifteen (15) Business Days of providing notice of Supplemental Review results, Distribution Provider shall provide Applicant with a non-binding cost estimate of any Interconnection Facilities or Distribution Upgrades. For those Interconnection Requests where Applicant has selected the Cost Envelope Option, within ten (10) Business Days of providing Applicant the non-binding cost estimate for the required Interconnection Facilities and/or Distribution Upgrades, Applicant shall provide the Distribution Provider the Cost Envelope Option deposit, in accordance with Section F.7.a.i.3. If Applicant fails to provide the Cost Envelope Option deposit in accordance with Section F.7.a.i.3, Applicant's request for the Cost Envelope Option shall be deemed withdrawn and the Interconnection Request shall not be eligible for the Cost Envelope Option. (P)

For all Interconnection Requests that pass Supplemental Review, refer to Section F.2.e for cost responsibility and time frames for completing the Generator Interconnection Agreement.

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

2. FAST TRACK INTERCONNECTION REVIEW PROCESS (Cont'd.)

c. Supplemental Review (Cont'd.)

~~i~~v) For Interconnection Requests that fail Supplemental Review, Distribution Provider shall provide the technical reason, data and analysis supporting the Supplemental Review results in writing, including, if Distribution Provider can make the determination, which Detailed Study track Applicant qualifies for, and provide Applicant the option to attend a Supplemental Review results meeting or proceed directly to Detailed Study. Applicant shall notify Distribution Provider within fifteen (15) Business Days following such notification whether to (i) proceed to a Supplemental Review results meeting, (ii) proceed to Detailed Study, or (iii) withdraw the Interconnection Request. Applicant may request one extension of no more than fifteen (15) Business Days to respond. If Applicant fails to notify Distribution Provider within fifteen (15) Business Days of such notification, or at the end of the extension, if one was requested, the Interconnection Request shall be deemed withdrawn. (P)

Applicants that elect to proceed to Detailed Study shall provide the applicable study deposit set forth in Section E.3.a with their response. Detailed Study fees for solar Generating Facilities up to 1 MW interconnecting to the Distribution System that do not sell power to Distribution Provider will be waived up to the amount of $5,000. Except as provided for in Section F.3.d, NEM-1 and ≤1 MW NEM-2 Generating Facilities are exempt from any costs associated with Detailed Studies.

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

2. FAST TRACK INTERCONNECTION REVIEW PROCESS (Cont'd.)

e. Execution of the Generator Interconnection Agreement (Cont'd.)

shall negotiate concerning the cost estimate, or any disputed provisions of the appendices to a draft Generator Interconnection Agreement, for not more than ninety (90) Calendar Days after Distribution Provider provides Applicant with the Generator Interconnection Agreement. If Applicant determines that negotiations are at an impasse, it may request termination of the negotiations and initiate Dispute Resolution procedures pursuant to Section K. If Applicant fails to sign the Generator Interconnection Agreement or initiate Dispute Resolution within ninety (90) Calendar Days, the Interconnection Request shall be deemed withdrawn.

After Applicant, or a Producer where those are different entities, has executed the Generator Interconnection Agreement, Distribution Provider will commence design, procurement, construction and installation of Distribution Provider's Distribution Upgrades and/or Interconnection Facilities that have been identified in the Generator Interconnection Agreement. Distribution Provider and Producer will use good faith efforts to meet schedules in accordance with the requirements of the Generator Interconnection Agreement and estimated costs as appropriate. Producer is responsible for all applicable costs associated with Parallel Operation to support the safe and reliable operation of the Distribution System and Transmission System as set forth in Section E.4.

Distribution Provider and Producer shall negotiate in good faith concerning a schedule for the construction of Distribution Provider's Interconnection Facilities and Distribution Upgrades. (P)

Unless agreed to otherwise between Applicant and Distribution Provider, Distribution Provider shall schedule a mitigation work scoping meeting no later than 10 business days after receiving the payment for the engineering advance.

Distribution Provider shall provide quarterly updates on substation upgrades to Producers whose projects are dependent on a substation upgrade. (P)

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

3. DETAILED STUDY INTERCONNECTION REVIEW PROCESS (Cont'd.)

b. Independent Study Process

i) Scoping Meeting

Within five (5) Business Days after Distribution Provider notifies Applicant that the Interconnection Request has passed Screens Q and R and is thus eligible for the Independent Study Process, Distribution Provider shall contact Applicant to establish a date agreeable to Applicant and Distribution Provider for a scoping meeting. Distribution Provider shall inform Applicant of the Detailed Study start date. (P) (P)

The purpose of the scoping meeting shall be: (i) to discuss reasonable Commercial Operation Dates and alternative interconnection options; (ii) to exchange information, including any transmission data that would reasonably be expected to impact Applicant's interconnection options; (iii) to analyze such information; and (iv) to determine feasible Points of Interconnection and eliminate alternatives given resources and available information.

Distribution Provider will bring to the scoping meeting, as reasonably necessary to accomplish its purpose, such already available technical data, including, but not limited to; (i) general facility loadings, (ii) general instability issues, (iii) general short circuit issues, (iv) general voltage issues, and (v) general reliability issues.

Applicant will bring to the scoping meeting, in addition to the technical data in Attachment A of the Rule 21 Exporting Generating Facility Interconnection Request form, any system studies previously performed. Distribution Provider, the CAISO, if applicable, and Applicant will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Applicant shall designate its Point of Interconnection. The duration of the meeting shall be only what is sufficient to accomplish its purpose.

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

3. DETAILED STUDY INTERCONNECTION REVIEW PROCESS (Cont'd.)

b. Independent Study Process (Cont'd.)

ix) Interconnection Facilities Study Results Meeting

If requested by Applicant, a results meeting shall be held among Distribution Provider, the CAISO, if applicable, and Applicant to discuss the results of the Interconnection Facilities Study, including assigned cost responsibility. Within five (5) Business Days of the request, Distribution Provider shall contact Applicant to establish a date agreeable to Applicant, Distribution Provider and the CAISO, if applicable, for the results meeting.

Within thirty (30) Calendar Days after the Interconnection Facilities Study results meeting, Distribution Provider shall tender a draft Generator Interconnection Agreement, together with draft appendices, to Applicant.

x) Second and Third Postings of Interconnection Financial Security

Applicant will post its second and third postings of Interconnection Financial Security as set forth in Sections F.4.c and F.4.d based on the cost responsibility for Network Upgrades, Distribution Upgrades, and Distribution Provider's Interconnection Facilities set forth in the final Interconnection Facilities Study, or the final Interconnection System Impact Study if the Interconnection Facilities Study is waived in accordance with Section F.3.b.vii.

c. Distribution Group Study Process

i) Initiation of Distribution Study Process

Applicants that apply for the Independent Study Process that pass Screen Q but fail Screen R will be eligible for inclusion in a Distribution Study Group. Applicant must submit all materials required to complete their Interconnection Request no later than ten (10) Business Days after the close of the relevant Distribution Group Study window. This includes notification from Applicant that they want to proceed with the Distribution Group Study Process, if applicable, in accordance with Section F.3.a. Distribution Provider shall inform Applicant of the Detailed Study start date. (P) (P)

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

3. DETAILED STUDY INTERCONNECTION REVIEW PROCESS (Cont'd.)

c. Distribution Group Study Process (Cont'd.)

xvi) Automatic Timing Extension

If during any six month period, the number of Interconnection Requests exceeds by fifty (50) percent the number of active Interconnection Request in the preceding six month period, the study timelines for Distribution Group Studies begun during the next twelve (12) months will automatically increase as follows. The time to complete the DGS Phase I Interconnection Study pursuant to Section F.3.c.iv will increase from sixty (60) Business Days to one hundred twenty (120) Business Days. The time to complete the DGS Phase II Interconnection Study pursuant to Section F.3.c.x will increase from sixty (60) Business Days to one hundred twenty (120) Business Days. The time to tender a draft Generator Interconnection Agreement pursuant to F.3.e.i will increase from thirty (30) Calendar Days to forty-five (45) Calendar Days. Distribution Provider will notify Applicants in the Distribution Study Group in writing after commencement of DGS Phase I Interconnection Study of the extension.

d. WDT Transmission Cluster Study Process (T)

If Applicant's Interconnection Request fails Screen Q or elects to be studied under the WDT Transmission Cluster Study Process, (T)
Applicant shall have the option of applying for Interconnection under the WDT Transmission Cluster Study Process of the Wholesale (T)
Distribution Tariff in accordance with its provisions. If Applicant fails Screen Q, Applicant's Interconnection Request shall be deemed withdrawn under this Rule regardless of whether Applicant applies for Interconnection under the WDT. Distribution Provider shall inform (P)
Applicant of the Detailed Study start date. (P)

(Continued)

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

3. DETAILED STUDY INTERCONNECTION REVIEW PROCESS (Cont'd.)

e. Generator Interconnection Agreement (Cont'd.)

ii) Negotiation (Cont'd.)

DGS Phase II Interconnection Facilities Study report (or the final DGS Phase I Interconnection Study report if the DGS Phase II Interconnection Study is waived) in the case of the Distribution Group Study Process or Interconnection Facilities Study report (or final Interconnection System Impact Study report if the Interconnection Facilities Study is waived) in the case of the Independent Study Process, it shall be deemed to have withdrawn its Interconnection Request.

Unless agreed to otherwise between Applicant and Distribution Provider, Distribution Provider will send an invoice to Applicant within five business days of execution of the Interconnection Agreement. (P)

Unless agreed to otherwise between Applicant and Distribution Provider, Distribution Provider shall schedule a mitigation work scoping meeting no later than 10 business days after receiving the payment for the engineering advance. (P)

iii) Extensions of Commercial Operation Date

Extensions of the Commercial Operation Date will be agreed upon in the executed Generator Interconnection Agreement. Reasonable Commercial Operation Dates will be discussed at the DGS Phase II Interconnection Study results meeting, or the DGS Phase I Interconnection Study results meeting if the DGS Phase II Interconnection Study results meeting is waived, in the case of the Distribution Group Study Process, the Interconnection Facilities Study results meeting, or the Interconnection System Impact Study results meeting if the Interconnection Facilities Study is waived in the case of the Independent Study Process. A request for an extension of the Commercial Operation Date after the Generator Interconnection Agreement is executed will be agreed to provided that, the Producer is still responsible for funding any Distribution Upgrades and Network Upgrades as specified in the Generator Interconnection Agreement and under the same payment schedule agreed upon in the Generator Interconnection Agreement. This provision has no impact on any power purchase

(Continued)

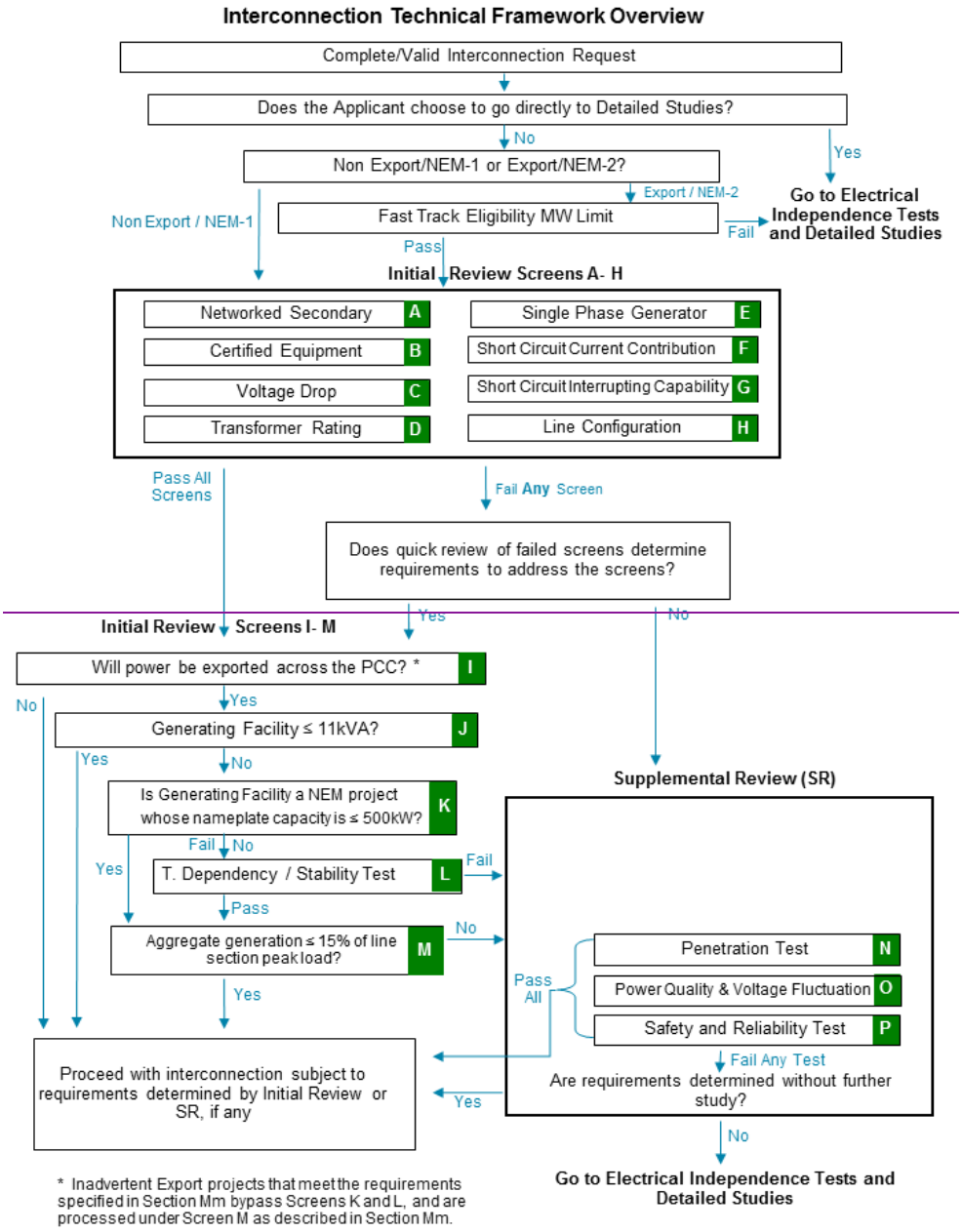
agreement terms.

(Continued)

G. ENGINEERING REVIEW DETAILS

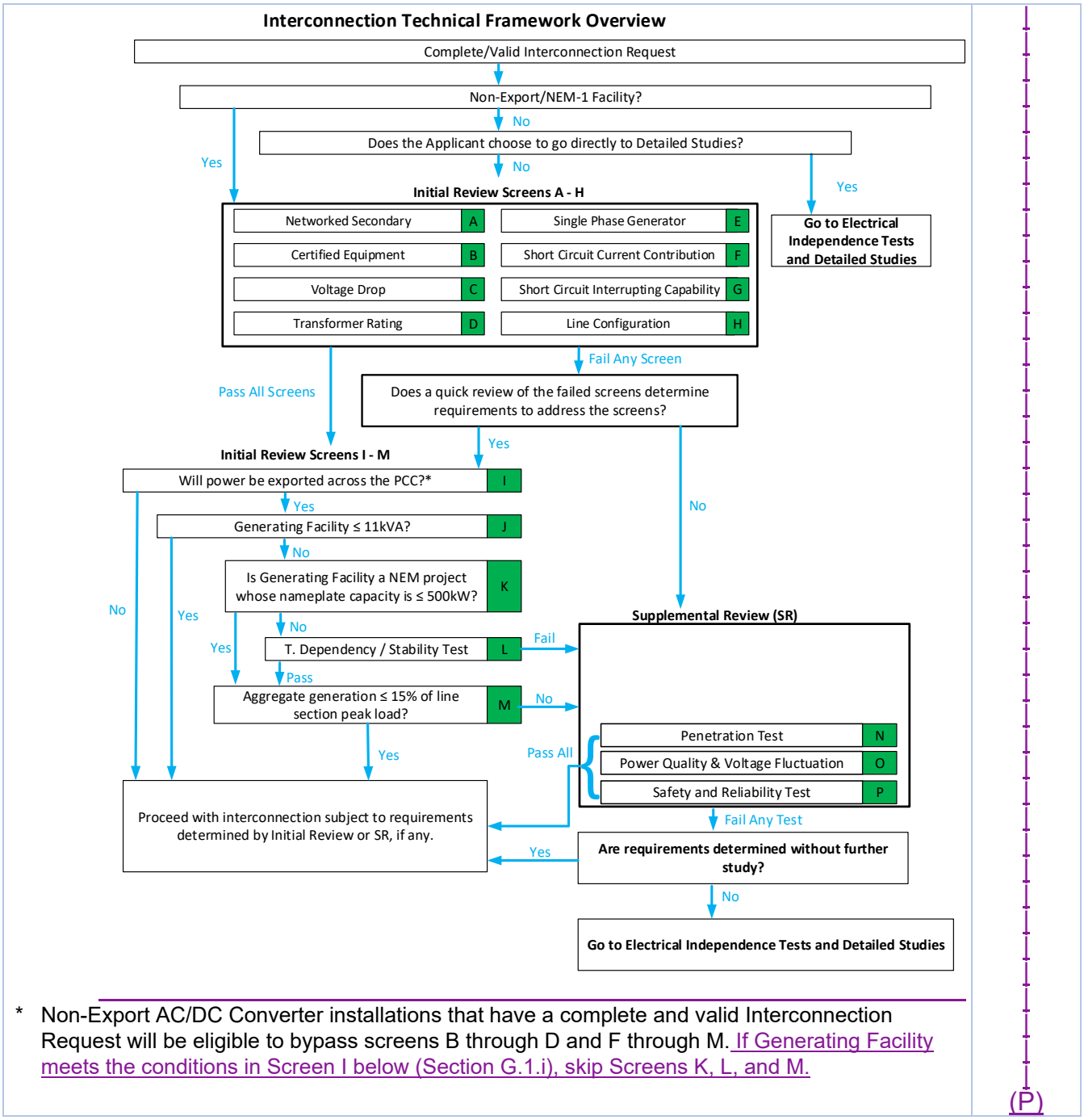
Delete table below:

(P)



Add table below:

(Continued)



* Non-Export AC/DC Converter installations that have a complete and valid Interconnection Request will be eligible to bypass screens B through D and F through M. If Generating Facility meets the conditions in Screen I below (Section G.1.i), skip Screens K, L, and M.

(P)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.)

1. INITIAL REVIEW SCREENS (Cont'd.)

h. Screen H: Is the line configuration compatible with the Interconnection type? (Cont'd.)

Significance: If the primary distribution line serving the Generating Facility is of a "three-wire" configuration, or if the Generating Facility's distribution transformer is single-phase and connected in a line-to-neutral configuration, then there is no concern about overvoltages to Distribution Provider's, or other Customer's equipment caused by loss of system neutral grounding during the operating time of the Non-Islanding Protective Function.

i. Screen I: Will power be exported across the PCC?

- If Yes, Continue to Screen J. This includes Options 5, ~~and~~ 6, 9, 10, and 11 below. (T) (T)

- If No, then to ensure that the Generating Facility does not export across the PCC, the Generating Facility must incorporate ~~one of the first four options shown~~ Options 1, 2, 3, 4, 7, or 8 below. Following that selection, Screen J, K, L, and M are skipped and Initial Review is complete. If Option 8 is used, see section Mm2 to determine screen application. (T) (T)

Option 1 ("Reverse Power Protection"): To ensure power is never exported across the PCC, a reverse power Protective Function may be provided. The default setting for this Protective Function shall be 0.1% (export) of the service transformer's rating, with a maximum 2.0 second time delay. For multiple tariff interconnections refer to Section J.8.

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.)

1. INITIAL REVIEW SCREENS (Cont'd.)

i. Screen I: Will power be exported across the PCC? (Cont'd.)

Option 4 (Relative Generating Facility Rating): This option, when used, requires the Net Rating of the Generating Facility to be so small in comparison to its host facility's minimum load, that the use of additional Protective Functions is not required to ensure that power will not be exported to Distribution Provider's Distribution or Transmission System. This option requires the Generating Facility capacity to be no greater than 50% of Producer's verifiable minimum Host Load over the past 12 months.

Option 5: Inadvertent Export as described in Section M.

Option 6: Inadvertent Export utilizing UL-1741 or UL-1741 SA/SB listed grid support (Non-Islanding) inverters as described in Section Mm. (T)

Option 7: Non-Export utilizing Non-Export AC/DC Converter as described in Section O. (N)

Option 8: Non-Export utilizing Certified Power Control Systems with an open loop response time no more than two seconds as described in Section Mm1.

Option 9: Limited Export utilizing Certified Power Control Systems with an open loop response time no more than two seconds as described in Section Mm2.

Option 10: Non-Export with Inadvertent Export utilizing Certified Power Control Systems with an open loop response time greater than two seconds and no more than ten seconds as described in Section Mm3.

Option 11: Limited Export with Inadvertent Export utilizing Certified Power Control Systems with an open loop response time greater than two seconds and no more than ten seconds as described in Section Mm4. (N)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.) (L)

1. INITIAL REVIEW SCREENS (Cont'd.)

i. Screen I: Will power be exported across the PCC? (Cont'd.)

Significance:

1. If it can be assured that the Generating Facility will not export power, Distribution Provider's Distribution or Transmission System does not need to be studied for load-carrying capability or Generating Facility power flow effects on Distribution Provider voltage regulators.

2. This Screen permits the use of reverse-power or minimum-power relaying as a Non-Islanding Protective Function (Option 1, 2, and 3).

3. This Screen allows, under certain defined conditions, for Generating Facilities that incorporate Certified Non-Islanding protection to qualify for interconnection through the Fast Track process without implementing reverse power or minimum power Protective Functions (Option 3). (L)

(Continued)

G. ENGINEERING REVIEW DETAILS (Cont'd.)

2. SUPPLEMENTAL REVIEW SCREENS (Cont'd.)

b. Screen O: Power Quality and Voltage Tests (Cont'd.)

In aggregate with existing Generating Facility capacity on the Line Section, distribution circuit, and/or substation. (Cont'd.)

iii) Can it be determined within the Supplemental Review that the harmonic levels meet IEEE 519 limits at the Point of Common Coupling (PCC)?

iv) Can it be determined within the Supplemental Review that the Generating Facility will not cause any voltage impacts considering the settings of the Volt-Var function and the characteristics of the circuit segment? (P)

- If yes to all of the above (pass), continue to Screen P.
- If no to any of the above (fail), a quick review of the failure may determine the requirements to address the failure; otherwise Electrical Independence Tests and Detailed Studies are required. Continue to Screen P. (Note: If Electrical Independence tests and Detailed Studies are required, Applicants will continue to the Electrical Independence Tests and Detailed Studies after review of the remaining Supplemental Review Screens.)

Significance: Adverse voltages and undesirable interference may be experienced by other Customers on Distribution Provider's Distribution System caused by operation of the Generating Facility(ies).

c. Screen P: Safety and Reliability Tests

Does the location of the proposed Generating Facility or the aggregate generation capacity on the Line Section create impacts to safety or reliability that cannot be adequately addressed without Detailed Study?

- If yes (fail), review of the failure may determine the requirements to address the failure; otherwise Electrical Independence Tests and Detailed Studies are required. Continue to Section G.3.
- If no (pass), Supplemental Review is complete.

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

The inverter requirements are intended to be consistent with UL 1741 - Supplement SA using Section Hh of Rule 21 as the source requirement document and ANSI/IEEE 1547-2003 and 1547a Standard for Interconnecting Distributed Resources with Electric Power Systems (IEEE 1547 including amendment 1547a), where possible. In the event of conflict between this Rule, and UL 1741 - Supplement SA, and/or IEEE 1547-2003 or IEEE 1547a, this Rule shall take precedence. Exceptions are taken to IEEE 1547 Clauses 4.1.4.2 Distribution Secondary Spot Networks and Clauses 4.1.8.1 or 5.1.3.1, which address Protection from Electromagnetic Interference. Rule 21 does not adopt the Generating Facility power limitation of 10 MW incorporated in IEEE 1547.

The Smart Inverter default settings and default activation states may be modified upon mutual agreement between Applicant and Distribution Provider. (P) (P)

Process for changing default settings for new Interconnection Requests: (P)

Distribution Provider, in the study process for new Generating Facilities, may determine and provide the optimum Smart Inverter Settings for the reactive power settings, including changes to the reactive power default settings (Example: Deactivate Volt/Var and activate Fixed Power Factor at given power factor).

Distribution Provider, in the study process for new Generating Facilities, may determine and provide the optimum Smart Inverter Settings for the Ramp Rate settings depending on the Generating Facility technology (such as solar, storage).

Distribution Provider, in the study process for new Generating Facilities, may determine the optimum Smart Inverter Settings for the volt/watt settings including changes to the default settings (Example: Change the volt/watt set points). The Applicant may select to agree on the new settings or select to perform upgrades to operate using the existing default volt/watt settings.

Default settings for voltage ride-through, frequency ride-through requirements, and Frequency/Watt should not be modified on an individual project basis unless the Interconnection Studies have determined that the default settings may not meet grid reliability requirements.

Process for changing default settings for Generating Facilities with an executed Interconnection Agreement:

When grid changes or Generating Facility changes require that the Smart

(Continued)

Inverter operating parameters be reevaluated, the Distribution Provider or Producer may request changes to the Smart Inverter operating parameters. The request must include the reason for and timing of the proposed changes. The requested changes must be within the Smart Inverter function adjustability limits, must be within the limits specified in this tariff, and must be mutually agreed upon. (P)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS

The Protective Functions and requirements of this Rule are designed to protect Distribution Provider's Distribution and Transmission System and not the Generating Facility. A Producer shall be solely responsible for providing adequate protection for its Generating Facility and Interconnection Facilities. Producer's Protective Functions shall not impact the operation of other Protective Functions on Distribution Provider's Distribution and Transmission System in a manner that would affect Distribution Provider's capability of providing reliable service to its customers.

a. Protective Functions Required

Smart Inverters operating in parallel with Distribution Provider's Distribution or Transmission System shall be equipped with the following Protective Functions to sense abnormal conditions on Distribution Provider's Distribution or Transmission System and cause the Smart Inverter to be automatically disconnected from Distribution Provider's Distribution or Transmission System or to prevent the Smart Inverter from being connected to Distribution Provider's Distribution or Transmission System inappropriately:

(i) Over and under voltage trip functions and over and under frequency trip functions;

(Continued)

ELECTRIC RULE NO. 21 Sheet 214
GENERATING FACILITY INTERCONNECTIONS

I. THIRD-PARTY INSTALLATIONS, RESERVATION OF UNUSED FACILITIES, AND REFUND OF SALVAGE VALUE

1. INTERCONNECTION FACILITIES AND DISTRIBUTION UPGRADES

Except as provided for in the Generator Interconnection Agreement of this Rule, Interconnection Facilities connected to Distribution Provider's side of the PCC and Distribution Upgrades shall be provided, installed, owned, and maintained by Distribution Provider at Producer's expense.

2. THIRD-PARTY INSTALLATIONS

~~Subject to the approval of Distribution Provider, a~~ Producer may, at its option, employ a qualified contractor that meets the Contractor Qualifications set forth under Electric Rule 15, Section G, to provide and install Interconnection Facilities or Distribution Upgrades, to be owned and operated by Distribution Provider, on Distribution Provider's side of the PCC.* Such Interconnection Facilities and Distribution Upgrades shall be installed in accordance with Distribution Provider's design and specifications. Upon final inspection and acceptance by Distribution Provider, Producer shall transfer ownership of such Producer installed Interconnection Facilities or Distribution Upgrades to Distribution Provider and such facilities shall thereafter be owned and maintained by Distribution Provider at Producer's expense. Producer shall pay Distribution Provider's reasonable cost of design, administration, and monitoring of the installation for such facilities to ensure compliance with Distribution Provider's requirements. Producer shall also be responsible for all costs, including any income tax liability, associated with the transfer of Producer installed Interconnection Facilities and Distribution Upgrades to Distribution Provider. (P) | (P)

* Only duly authorized employees of utility are allowed to connect to, disconnect from, or perform any work upon Utility's facilities. (P) | (P)

(Continued)

J. METERING, MONITORING AND TELEMETERING (Cont'd.)

3. NET GENERATION OUTPUT METERING (Cont'd.)

iii) Accuracy and type of required Metering consistent with purposes of collecting data;

iv) Cost of Metering relative to the need for and accuracy of the data;

v) The Generating Facility's size relative to the cost of the Metering/monitoring;

vi) Other means of obtaining the data (e.g. Generating Facility logs, proxy data, etc.);

vii) Requirements under any Generator Interconnection Agreement with Producer.

The requirements in this Section may not apply to Metering of Generating Facilities operating under Distribution Provider's Net Energy Metering tariffs. Nothing in this Section J.3 supersedes Section D.4, Compliance with Laws, Rules and Tariff Schedules.

Distribution Provider will report to the Commission or designated authority, on a quarterly basis, the rationale for requiring Net Generation Output Metering equipment in each instance along with the size and location of the facility.

The standard timeline for installation of Net Generation Output Meters is as follows: (P)

i) 20 business for design and 20 business days for construction, or
ii) design and construction timelines as agree with the customer.

The 20-day clock commences upon payment and after the customer had done everything necessary on their end to prepare for construction. By mutual agreement, Applicant and Distribution Provider may agree to a timeline that is different from the timeline described above. (P)

4. POINT OF COMMON COUPLING (PCC) METERING

For purposes of assessing Distribution Provider's charges for retail service, Producer's PCC Metering shall be reviewed by Distribution Provider, and if required, replaced to ensure that it will appropriately measure electric power according to the provisions of the Customer's electric service Tariff. Where required, the Customer's existing meter may be replaced with a bi-directional meter so that power deliveries to and from Producer's site can be separately recorded. Alternately,

(Continued)

Mm1. OPTION 8: Non-Export Utilizing Certified Power Control Systems (N)

The following are the minimum requirements for Non-Export systems that use certified power control systems (PCS) with an open loop response time (OLRT) no more than two seconds. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.

1. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Non-export systems may use a PCS that passes later published revisions to the CRD test protocol or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the PCS conforms to the non-exporting functionality in accordance with the relevant CRD or UL published standard.

2. Use a PCS that is certified with an OLRT of two seconds or less, as provided in the PCS's specification data sheets.

3. The PCS must reduce export to zero or less within two seconds of commencing export. A PCS that is certified with an open-loop response time of two seconds or less, and a time to reach steady state of 10 seconds or less, meets this requirement.

4. Set the PCS to not export (zero-export).

5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff.

6. Maintain voltage fluctuations at the limits specified in Electric Rule 2. (N)

(Continued)

Mm1. OPTION 8: Non-Export Utilizing Certified Power Control Systems (Cont'd) (N)

The evaluation of a non-export system requesting interconnection under this section:

1. Shall omit evaluation for screen D;

2. Shall utilize the Generating Facility's Gross Nameplate Rating for screens F, F1, and G;

3. If the non-export system has an aggregate PCS controlled nameplate greater than 600 kVA and the maximum reported steady state value of the PCS is greater than 1% of the PCS controlled nameplate (as provided in the NRTL testing reports), the evaluation may utilize the following calculation when determining the impacts to the grid under screens I, J, K, M, N, and O: The sum of the nameplate values of the exporting DER resource (if any) plus the maximum percentage steady state value of the PCS (as provided in the NRTL testing reports) times PCS controlled nameplate capacity.

4. Screen P may be applied using the Generating Facility's Gross Nameplate Rating for evaluations that use fault current calculations. For other evaluations under screen P, the value identified in iii above may be used.

(N)

(Continued)

Mm2. OPTION 9: Limited Export Utilizing Certified Power Control Systems (N)

The following are minimum requirements for limited export systems that use certified power control systems (PCS) with an open loop response time (OLRT) no more than two seconds to maintain a level of export that is lower than the nameplate rating. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.

1. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Limited export systems may use a PCS that passes later published revisions to the CRD test protocol, or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the PCS conforms to the export limiting functionality in accordance with the relevant CRD or UL published Standard.

2. Use a PCS that is certified with an OLRT of two seconds or less as provided in the PCS's specification data sheets.

3. The PCS must reduce export to the approved export limit, or less, within two seconds of exceeding the approved export limit. A PCS that is certified with an open-loop response time of two seconds or less, and a time to reach steady state of ten seconds or less, meets this requirement.

4. Set the PCS to not exceed the proposed level of export.

5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff.

6. Maintain voltage fluctuations at the limits specified in Electric Rule 2. (N)

(Continued)

Mm2. OPTION 9: Limited Export Utilizing Certified Power Control Systems (Cont'd) (N)

The evaluation of a limited export system requesting interconnection under this section:

1. Shall utilize the Generating Facility's Gross Nameplate Rating for screens F, F1, and G.

2. If the maximum steady state value is greater than 1% of the PCS controlled nameplate (as provided in the NRTL testing reports) utilize the requested limited export value plus the maximum steady state value of the PCS times the PCS controlled nameplate, to evaluate the impacts to the grid under screens D, I, J, K, M, N, and O. If the maximum steady state value is less than 1% of the PCS controlled nameplate (as provided in the NRTL testing reports), utilize only the requested limited export value under screens D, I, J, K, M, N and O.

3. Screen P shall be applied using the Generating Facility's Gross Nameplate Rating for evaluations that use fault current calculations. For other evaluations under screen P, the value identified in ii above may be used. (N)

(Continued)

Mm3. OPTION 10: Non-Export with Inadvertent Export Utilizing Certified Power Control Systems (N)

The following are the minimum requirements for Non-Export systems that use certified power control systems (PCS) with an open loop response time (OLRT) between two and ten seconds. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.

1. Have a nameplate capacity equal to or less than 1,000 kVA.

2. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Non-Export may use a PCS that pass later published revisions to the CRD test protocol, or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the PCS conforms to the non-exporting functionality in accordance with the relevant CRD or UL published standard.

3. Use a PCS that is certified with an OLRT of no more than ten seconds, as provided in the PCS's specification data sheets.

4. Set the PCS to not export (zero-export).

5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff.

~~1.~~6. Maintain voltage fluctuations at the limits specified in Electric Rule 2 (N)

(Continued)

Mm3. OPTION 10: Non-Export with Inadvertent Export Utilizing Certified Power Control Systems (Cont'd) (N)

The distribution provider evaluating generating facilities requesting interconnection under this section shall:

1. Apply screens A through M using the aggregate nameplate inverter rating.

2. Notify the applicant if supplemental review is required, and if so, require the applicant to identify, within 15 business days of being notified, the frequency of inadvertent export, the real power level in watts of inadvertent export, and the time duration of inadvertent export.

3. If distribution upgrades are identified, use screen P to recognize power control parameters, taking into account local feeder conditions; the customer's operating profile; and the magnitude, duration, and frequency of anticipated export;

4. Complete supplemental review within 15 days of receiving the required information specified under ii) above.

5. If the applicant does not provide the operating profile information within the specified 15 business days, perform supplemental review based on information included in the interconnection request within 30 business days of the request for customer operating profile information.

6. Use only the largest facility in the line section for aggregate evaluation for subsequent interconnection requests. (N)

(Continued)

Mm4. OPTION 11: Limited Export with Inadvertent Export Utilizing Certified Power Control Systems (N)

The following are the minimum requirements for limited export controlled systems that use certified power control systems (PCS) with an open loop response time (OLRT) between two and ten seconds to maintain a level of export that is lower than the nameplate rating. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.

1. Have a nameplate capacity equal to or less than 1,000 kVA.

2. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Limited export systems may use a PCS that pass later published revisions to the CRD test protocol, or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the PCS conforms to the export limiting functionality in accordance with the relevant CRD or UL published standard.

3. Use a PCS that is certified with an OLRT of no more than ten seconds, as provided in the PCS's specification data sheets.

4. Set the PCS to not to exceed the proposed level of export.

5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff. (N)

6. Maintain voltage fluctuations at the limits specified in Electric Rule 2.

(Continued)

Mm4. OPTION 11: Limited Export with Inadvertent Export Utilizing Certified Power Control Systems (Cont'd) (N)

The distribution provider evaluating generating facilities requesting interconnection under this section shall:

1. Apply screens A through M using the aggregate nameplate inverter rating.

2. Notify the applicant if supplemental review is required, and if so, require the applicant to identify, within 15 business days of being notified, the frequency of inadvertent export, the real power level in watts of inadvertent export, and the time duration of inadvertent export.

3. If distribution upgrades are identified, use screen P to recognize power control parameters, taking into account local feeder conditions; the customer's operating profile; and the magnitude, duration, and frequency of anticipated export.

4. Complete supplemental review within 15 days of receiving the required information specified under ii) above.

5. If the applicant does not provide the operating profile information within the specified 15 business days, perform supplemental review based on information included in the interconnection request within 30 business days of the request for customer operating profile information.

(N)

(Continued)

N. EXPEDITED INTERCONNECTION PROCESS FOR NON-EXPORT ENERGY STORAGE GENERATING FACILITIES

Applicants with Interconnection Requests for Non-Export Energy Storage Generating Facilities who meet the requirements outlined below are eligible for expedited interconnection in accordance with the Fast Track Process technical review requirements of Section F.2.[1] Applicants with Non-Export AC/DC Converters that meet the requirements outlined in O. below are also eligible. (P)

1. ELIGIBILITY REQUIREMENTS

Applicants seeking to interconnect a Generating Facility under the provisions of this Section N must meet the following eligibility requirements.

a. Applicant must electronically submit a completed Interconnection Request, including completing all application fields and submitting all supporting documentation necessary to facilitate the expedited review as required by Distribution Provider. Such documentation may include, but is not limited to, single line diagrams with specific details, manufacturer data sheets for proposed equipment, description of control systems, validation of the right to do business in the state, etc. Distribution Provider shall clearly communicate these requirements as part of the application process. Applicant shall select this process option in the Interconnection Request.

b. Applicant's Generating Facility must meet the requirements outlined in Section N.2 below.

c. Applicant's Interconnection Request must be eligible for and select the Fast Track Process.

d. Applicant's Interconnection Request must pass Fast Track Initial Review and not require any Interconnection Facilities, Distribution Upgrades or Network Upgrades to remain eligible under this Section. As such, Interconnection Requests that select the Cost Envelope Option are not eligible.

e. Applicants selecting this section shall use the corresponding interconnection agreement type provided for eligible Generating Facilities.

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[1] ~~In accordance with Advice 4941-E-A, the provisions provided for in Section N are being implemented under a pilot approach with a July 1, 2017 through June 30, 2018 reporting period. As such, the provisions may be continued, modified and/or withdrawn as determined by the Commission~~ (P)

(P)

(Continued)

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Cenergy Power
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

East Bay Community Energy Ellison Schneider & Harris LLP Energy Management Service
Engineers and Scientists of California

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
IGS Energy
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

Office of Ratepayer Advocates
OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy