Working Group Two Final Report

October 31, 2018

California Public Utilities Commission
Interconnection Rulemaking (R.17-07-007)

Table of Contents

Working Group Two Background

Procedural Background

On July 13, 2017, the California Public Utilities Commission ("CPUC" or "Commission") issued an Order Instituting Rulemaking to consider a variety of refinements to the interconnection of distributed energy resources under Electric Rule 21. On October 2, 2017, the Commission issued a scoping ruling for R.17-07-007 directing Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E"), or the invester-owned utilities ("IOUs" or "utilities"), to convene eight working groups to develop proposals to address the issues.[1]

The scoping ruling tasked the second working group, "Working Group Two", with developing and filing a final report for recommending proposals to address four issues under the heading "Integration Capacity Analysis and Streamlining Interconnection Issues" no later than August 15, 2018. A subsequent email ruling extended the report deadline to September 15, 2018 and added the sixth issue from the scope of Working Group One to the scope of Working Group 2.[2] A subsequent Ruling extended the report deadline to October 31, 2018, scheduled a workshop on Working Group 2 proposals for November 7, 2018, scheduled an Administrative Law Judge ("ALJ") ruling requesting comments on Working Group 2 proposals by November 30, 2018, and established a due date for comments on Working Group 2 proposals by December 21, 2018.[3]

Working Group Scope

Working Group Two developed proposals addressing Issues 6 and 8-11 in the scoping ruling:

6. Should the Commission require the Utilities to develop forms and agreements to allow distributed energy resource aggregators to fulfill Rule 21 requirements related to smart inverters? If yes, what should be included in the forms and agreements?
8. How should the Commission incorporate the results of the Integration Capacity Analysis into Rule 21 to inform interconnection siting decisions, streamline the Fast Track process for projects that are proposed below the integration capacity at a particular point on the system, and facilitate interconnection process automation?

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[1] R.17-07-007 Scoping Ruling, October 2, 2017 (http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M196/K476/196476255.PDF).

[2] Email Ruling Revising Schedule and Reassigning Issue Six, February 14, 2018 (http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=211794527).

[3] Administrative Law Judge's ruling directing responses to Attached questions on working group one report and granting, in part, the IREC motion to modify schedule (filed August 15, 2018).

9. What conditions of operations should the Commission adopt in interconnection applications and agreements to allow distributed energy resources to perform within existing hosting capacity constraints and avoid triggering upgrades?
10. How can the Commission coordinate the Integration Capacity Analysis and each Utility's Rule 21 processes with the Rule 2, Rule 15, and Rule 16 processes in order to improve efficiency of the overall interconnection process? This is a coordination issue at this time.
11. However, modifications to Rules 2, 15, or 16 will be addressed if necessary. Should the Commission adopt a notification-based approach in lieu of an interconnection application for non-exporting storage systems that have a negligible impact on the distribution system? If so, what should the approach entail?

Working Group Process: *Issues 6 and 8-11*

Working Group Two met 28 times between March 14, 2018 and October 10, 2018 to develop proposals to address Issues 6 and 8-11. Two-thirds of the meetings were via teleconference and lasted either 1.0 hour (Issue 6) or 2.5 hours (Issues 8-11); one-third were in-person meetings at either the Commission's San Francisco offices, San Diego Electric & Gas offices (one meeting) or Southern California Edison offices (one meeting) and generally lasted 3.5–4 hours. Gridworks was contracted to facilitate the working group meetings, which included taking and issuing meeting notes, drafting proposals, soliciting and incorporating comments to proposals, and preparing final proposals.

The working group had seven one-hour meetings specific to Issue 6. Issue 8 was a discussion topic during 60% of the meetings involving Issue 8-11. Drafts proposals were prepared for each Issue, and multiple rounds of soliciting and incorporating comments were utilized to develop the Final Report. To meet the October 31 report deadline, an extensive amount of off-line discussions between various parties in lieu of discussions during working group meetings was required while the working group moved to the next Issue.

To ensure incorporation of stakeholder feedback, working group participants were given multiple opportunities to submit written comments on all draft issue proposals prior to the report's submission to the Commission, both during the Issue's allotted discussion time and during compilation of the Final Report. However, as discussed further within this report, proposals for which there was insufficient time to discuss with and receive feedback from Working Group members are included in the Appendix of this Final Report as a means to enable comments and other feedback during either a workshop or the comment process.

Consensus and Non-Consensus Proposals

Working group members made significant efforts to reach consensus on each Issue. For Issues where consensus was not reached, either because parties had fundamentally differing viewpoints or because the working group did not have sufficient time to work through differences, the working group attempted to document the various viewpoints to provide the Commission with sufficient information to make an informed decision.

Each proposal's consensus "status" is indicated immediately following the proposal. A proposal marked "consensus" received general support from all working group members who participated in meetings when that proposal was discussed. A proposal marked "non-consensus" received both support and opposition from members who participated in meetings when that proposal was discussed.

Non-consensus proposals also include a list of supporters and opponents to provide information about the extent to which the proposal was supported and opposed.

- The Issue 6 proposal contains a non-consensus Agreement, and an acknowledgement that additional work is required to develop applicable forms and fees.
- The Issue 8 proposal contains 29 sub-proposals within 23 main proposals, of which 8 are consensus and 21 are non-consensus.
- The Issue 9 proposal contains a non-consensus non-IOU proposal and the IOUs' counter-proposal as an Appendix (which reflects the IOU's proposal being submitted without time for stakeholders to review and/or provided feedback).
- The Issue 10 proposal contains 8 sub-proposals, of which 2 are consensus and 6 are non-consensus.
- The Issue 11 proposal contains a non-consensus proposal.

Additional background on sub-Issues and need for additional time

As is mentioned in the Motion requesting additional time,[4] working group 2 had been working diligently to address the five assigned Issues; however, during that process, it became clear that some of the Issues were relatively complex and contained numerous sub-issues, and as is seen within this Final Report, resulted in numerous proposals and sub-proposals that required more time to discuss than originally anticipated.

<u>Additional time</u>

- *Transition from Working Group One to Working Group Two*:
    - Aggressive schedule: As mentioned in the Scoping Memo, the initial schedule was acknowledged to be aggressive, and as such, working group members were encouraged to begin preparing a summary of each of the Issues and relevant framing questions prior to the initial working group meetings on each Issue. In retrospect, the schedule, which included initiating Working Group Two before the

[4] Motion of the Interstate Renewable Energy Council, Inc. to revise certain deadlines of the R.17-07-007 Scoping Memo (filed July 9, 2018).

Final Report for Working Group One had been filed, was too aggressive. Most members of Working Group Two were also members of Working Group One and did not have sufficient resources to start prepping for Working Group Two prior to the schedule commencement date.

  - *External Facilitator*: Based upon the resources required to facilitate the Working Group One meetings and develop the Final Report for Working Group One, the Energy Division and IOUs agreed to hire an external facilitator to facilitate the meetings and prepare the draft and Final Report for Working Group Two. The time commitment required for the IOUs to solicit for and then initiate and finalize a contract with a facilitator left insufficient time for the facilitator to coordinate the development of pre-initial workshop prep work.
- *Review of IOU's implementation of ICA methodology*: As characterized by the header in the Scoping Memo, Working Group Two was tasked with discussing how to utilize the results of the Integration Capacity Analysis ("ICA") to streamline the Rule 21 interconnection process. Of note is that the IOUs are some of the first utilities within the country to develop an ICA methodology, and as of July 2018, the IOUs have expanded their respective annual distribution planning processes to include, for the first time ever, the system-wide implementation of the Commission approved ICA methodology. The timing of the Working Group Two meetings (March–September 2018) compared to the timing of when the first ever ICA results would be available on a system-wide basis (July 2018) warranted allocated time during various working group 2 meetings for the IOUs to provide an overview/refresher of the implemented ICA methodology.
- *The initial schedule called for Working Group Two to discuss Issues and file a Final Report within a six-month period*.[5] Working Group Two had its initial meeting as required on March 14. However, the combined effect of the above three factors resulted in the first month of meetings being more focused on general background and level setting and not on specific proposals or questions to pursue consensus.
- *Complexity of Issues*: The first two Issues discussed were Issues 6 and Issues 8, and as mentioned above, an extensive amount of time was spent discussing only these two issues (approximately one-fourth of the meetings were specific to Issue 6, and approximately 60% of the meetings allocated to discussing Issues 8, 9, 10, and 11 included a discussion on Issue 8). The request for additional time was filed in July 2018 (four months into the allotted six-month schedule), and even though only one month remained to have meaningful discussion before focusing the last month on developing a draft and final report, the working group had not yet begun meaningful discussions on two of the Issues.

Sub-Issues

As reflected in each IOU's Rule 21 Interconnection Tariffs, there are at least 18 different "screens" performed by the IOUs as part of their process to review and approve an

[5] February 15 – August 15, 2018 per the Scoping Memo; March 15 - September 15, 2018 per the Ruling issued February 14, 2018.

Interconnection Application. The working group realized that a discussion of if/when/how the ICA results could be used to streamline the interconnection review and approval process was going to need to include a discussion on each of these individual screens. Each discussion pertaining to a different screen was basically a discussion on a different sub-Issue of Issue 8. This Final Report contains 29 sub-proposals for Issue 8, which means that Issue 8 alone could be considered as having between 18 and 29 sub-Issues.

Working Group Participants

The "working group" references all active parties participating in Working Group Two meetings, which include the IOUs, government representatives, DER developers, nonprofits, and independent advocates and consultants. The final report is the product of written and oral contributions from participants representing the following organizations.

- 33N
- ABB
- Also Energy
- APS
- Artwell Electric
- Bloom Energy
- Borrego Solar
- Bosch
- CalCom Solar
- California Public Advocates Office (former Office of Ratepayer Advocates)
- California Energy Commission ("CEC")
- California Solar and Storage Association ("CALSSA")
- California Energy Storage Alliance ("CESA")
- California Independent System Operator ("CAISO")
- Center Point Energy
- CES LTD.
- Chico Electric
- Clean Coalition
- Community Renewables
- Concentric Power
- California Public Utilities Commission
- Enphase Energy
- EPRI
- Foundation Wind Power
- Green Power Institute ("GPI")
- Gridcom
- Grid Innovation
- Interstate Renewable Energy Council ("IREC")
- JKB Energy
- KFW Law
- Kitu System

- National Grid
- OutBack Power Technologies
- Olivine
- Pacific Gas & Electric ("PG&E")
- S Power
- Small Business Utility Advocates ("SBUA")
- Southern California Edison ("SCE")
- San Diego Gas and Electric ("SDG&E")
- SGS Smarter Grid Solutions
- Stem
- SunPower
- SunRun
- SunWorks
- Tesla
- The Utility Reform Network ("TURN")
- Wind Power Foundation
- X Utility

ISSUE 6 PROPOSAL

Issue 6: Should the Commission require the Utilities to develop forms and agreements to allow distributed energy resource aggregators to fulfill Rule 21 requirements related to smart inverters? If yes, what should be included in the forms and agreements?

Proposal

The Working Group proposes to develop forms and agreements to allow distributed energy resource ("DER") Aggregators to fulfill Rule 21 requirements. The draft Agreement appended to this proposal represents substantial progress toward that end, providing a basis for continued consideration.

Status

Non-Consensus

Working Group participants did not take final positions on the Issue 6 proposal. The IOUs, Tesla, and Stem provided preliminary perspectives to support further consideration of Issue 6 as noted below.

Discussion

Background

Issue 6 is grounded in Rule 21 Section Hh which covers "Smart Inverter Generating Facility Design and Operating Requirements." In particular, the definition and role of an "Aggregator" was a key part of the Working Group's discussion as it pertains to Section Hh.5." Using SCE's Rule 21 as an example, this section includes the following (**emphasis added**):

> *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 mutually agreed to by Applicant and Distribution Provider.*

For the purposes of addressing Issue 6, the Working Group adopted the following definition of "DER Aggregator," which is rooted in Rule 21 Section Hh.5.:

> *An entity that provides the communication capability functions required in Section Hh on behalf of one or more Generating Facilities that utilize inverter-based technologies.*

> *An Aggregator is intended to perform a role that would otherwise be performed by individual Generating Facilities. The Aggregator shall act as a conduit, sending commands from the Distribution Provider to a Generating Facility and sending information from a Generating Facility to Distribution Provider.*

In further scoping and defining Issue 6, the Working Group noted Rule 21, Sections Hh.6 and Hh.8, which contain inverter function requirements that must be performed in response to communications made by the Distribution Provider and Rule 21, Section Hh.7 which contains requirements relating to information that an inverter-based Generating Facility must communicate to the Distribution Provider.

With these sections of Rule 21 as a foundation, the focus of the Working Group's discussion of Issue 6 sought to expand the understanding of communication functions the Aggregator would provide, technical and legal qualifications needed to provide those functions, and the development of an agreement to represent those qualifications.

The progress made by the Working Group toward that end is further documented by the appended agreement, which would govern the terms and conditions under which a DER Aggregator will provide the communication functions required under Section Hh.

For additional detail please consider the appended, draft Distributed Energy Resources Aggregation Agreement, including its preliminary specification of:

- The Agreement's applicability;
- Responsibilities of the Supplier (DER Aggregator), including communications functions, cybersecurity and privacy procedures, and dual participation restrictions;
- Rights for testing and approval;
- Terms and conditions;
- Insurance requirements;
- Confidentiality provisions;
- And notice requirements.

This draft agreement is recognized as incomplete and in development by the Working Group, but nevertheless can serve as a basis for continued consideration of Issue 6.

To complete its consideration of Issue 6, Working Group participants agree it will be necessary to the develop an application form and standards for supporting documentation.

IOU Perspective:

With regards to development of an application form and standards for supporting documentation, the following principles have been proposed by the IOUs but not evaluated by the Working Group:

- Joint IOUs propose Aggregators will be required to supply information in a consistent manner to ensure each IOU can assess their communication system, scheduling system, and performance capabilities, and the supplier will be responsible for costs associated with application review.
- SDG&E (only) proposes that, to be an eligible Aggregator, the Aggregator must first be able to demonstrate, to SDG&E's reasonable satisfaction, that the communications/dispatchability functionality required by the Aggregator agreement can be achieved during the duration of the agreement.

Tesla Perspective:

Tesla suggests the proposal demands greater clarity, offering the following observations:

> *"There isn't clarity at this point in terms of what this agreement encompasses. Specifically, is it a contract that requires entities to have certain capabilities vs. the actual use of those capabilities…?"*
>
> *"Further, the agreement should not be worded such that we are signing up for a potentially evolving set of obligations or capabilities. In other words, it should not be a sort of open-ended agreement that allows additional requirements to be inserted down the road that the developer would then be obligated to meet by virtue of having signed this agreement."*

Tesla recommends continued consideration of several sections of the agreement. Tesla's comments on these sections can be reviewed at https://gridworks.org/initiatives/rule-21-working-group-2/.

Stem Perspective:

As the lead Aggregator within Working Group 2 regarding Issue 6, Stem has raised three major issues that in its opinion require Commission clarification/resolution before the DER Aggregation Agreement can be finalized and executed

- Distinction between the Aggregator as a conduit of commands and the Aggregator as an executor of functions.
- Requirement for end-to-end testing for a Participating Generating Facility that elects the Aggregator option for Rule 21 compliance.
- The certification and approval status of Aggregators as software is changed over time.

Issue 6 APPENDIX

[*Agreement updated 10/8/18 by IOUs based on feedback received 10/3/18]*

RULE 21 DISTRIBUTED ENERGY RESOURCE AGGREGATION AGREEMENT

BETWEEN

[SUPPLIER]

AND

[COMPANY]

This Rule 21 Distributed Energy Resource Aggregation Agreement ("Agreement") is entered into by and between [Aggregator Name] ("Supplier"), a [form of entity and state of registration], and [Company Name] ("Company"), a California Corporation. Supplier and Company are sometimes referred to herein individually as "Party" or collectively as the "Parties." In consideration of the mutual promises and obligations stated in this Agreement and its attachments, the Parties agree as follows:

Article 1. Scope, Purpose, and Related Agreement

1.1 Applicability

1.1.1 This Agreement governs the terms and conditions under which the Supplier will provide the communication functions required under Section Hh of the Company's California Public Utilities Commission ("CPUC") approved Electric Rule 21 Tariff ("Rule 21") on behalf of one or more Participating Generating Facilities that utilize inverter-based technologies.

1.1.2 Each Participating Generating Facility has allowed the Supplier to provide, on its behalf, the communication functions required under Section Hh of Rule 21 consistent with, and pursuant to, a Participating Generating Facility-Aggregation Agreement(s) between the Participating Generating Facility and the Company. The Participating Generating Facility(ies) are listed in Appendix C, attached hereto.

1.1.3 This Agreement incorporates in its entirety the Company's Rule 21, subject to any modifications the CPUC may direct in the exercise of its jurisdiction. In the event of inconsistency between this Agreement and the terms of Rule 21, the provisions of the latter shall control.

1.2 Limitations

Nothing in this Agreement is intended to affect any other agreement between: (a) the Supplier and the Company, or (b) the Supplier and Participating Generating Facility(ies).

1.3 Capitalized Terms

When used in this Agreement, terms with initial capitalization that are not defined in Appendix A shall have the meanings specified in the Article in which they are used or in Rule 21.

1.4 Summary and Description of the Parties

1.4.1 The Company, to which the Supplier shall transmit information, is located at:

____

____

____

1.4.2 The Supplier certifies that, consistent with Rule 21, it is not co-located or part of Participating Generating Facility(ies). For purposes of providing notice, the Supplier is located at:

____
____
____

1.4.3 The Participating Generating Facility(ies) are listed in Appendix C attached hereto. The Parties reserve the right to update or revise Appendix C at any time without affecting the binding nature of this Agreement.

Article 2. Responsibilities of the Supplier

2.1 Compliance with Applicable Laws and Regulations

The Supplier shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice. The Supplier shall maintain all applicable certifications related to performance of the communication functions required by this Agreement and shall provide to the Company, upon request, proof of such certifications.

2.2 Communications Functions

2.2.1 The Supplier shall, at no cost to the Company, maintain communications and management systems to ensure (a) the provision of communication functions required under Section Hh of Rule 21, and (b) that the transmission of these communications between the Company, the Supplier, and the Participating Generating Facility(ies) is operating normally. This includes, but is not limited to the following capabilities or requirements:

2.2.1.1 The service(s) shall be capable of authorized communications;

2.2.1.2 The service(s) shall provide monitoring and control capabilities as defined by the IEEE 2030.5 Common Smart Inverter Profile ("CSIP") Version 2.1;

2.2.1.3 The Supplier shall be capable of remotely updating the software or firmware that facilitates communications between the Supplier and the Participating Generating Facility(ies);

2.2.1.4 The transport level protocol for communications between the Company and the Supplier shall be TCP/IP;

2.2.1.5 The application-level protocol for communications between the Company and the Supplier shall be IEEE 2030.5 as defined by CSIP Version 2.1;

2.2.1.6 The Supplier shall maintain direct contact with the Company;

2.2.1.7 The Supplier shall coordinate the transmission of all required data points telemetered to the Company;

2.2.1.8 The Supplier shall execute advanced smart inverter functionality as defined in Rule 21 and CSIP Version 2.1;

2.2.1.9 The Supplier shall maintain monitoring and management of its communication and control system according to the operational requirements set forth in Appendix B, including:

(a) The Supplier shall inform the Company of any outages in the communication between the Supplier and the Company if such outage exceeds __ (_____) minutes; and

(b) The Supplier shall inform the Company of any outages in communication between the Supplier and the Participating Generating Facility(ies) if such outage exceeds _ (_____) minutes.

2.2.1.10 The Supplier shall implement instrumentation and maintain logs demonstrating that the communication systems meet all mandated performance requirements under Rule 21.

2.3 Cybersecurity and Privacy Procedures

2.3.1 Prior to the Effective Date of this Agreement, at no cost to the Company, the Supplier shall implement the cybersecurity and privacy procedures set forth in Appendix B. As set forth in Article 2.3.3 below, the Company reserves the right to update the cybersecurity and privacy procedures set forth in Appendix B.

2.3.2 The Supplier shall maintain the cybersecurity and privacy procedures set forth in Appendix B throughout the duration of this Agreement.

2.3.3 The Company reserves the right to revise or update the cybersecurity and privacy procedures set forth in Appendix B at any time. Supplier shall obtain compliance with these revised or updated procedures within the time set forth in Appendix B.

2.4 Dual Participation Restrictions

2.4.1 In the event of inconsistency between this Agreement and the requirements of another program in which Supplier participates (for example, if Supplier has a

Multiple-Use Application ("MUA")), the provisions of this Agreement and Rule 21 shall control.

2.4.2 Generating Facilities may be enrolled with only one Aggregator. Accordingly, prior to Supplier entering into an agreement with a Participating Generating Facility to supply the communication functions required under Section Hh of Rule 21 on its behalf, Supplier shall: (a) notify the Participating Generating Facility of this dual participation restriction, and (b) ensure that the Participating Generating Facility has not already enrolled its Generating Facility(ies) with another Aggregator.

Article 3. Testing and Approval

3.1 <u>Communications Systems Testing by the Supplier</u>

3.1.1 The Supplier shall be responsible for performing the tests of its communication systems set forth in Appendix B prior to the provision of communication functions under this Agreement. Such testing shall be at the sole expense of the Supplier. Any and all testing shall include the end-to-end system environment reflecting the Participating Generating Facility(ies), not only the Supplier's internal systems environment and end-to-end system environment between Company and Supplier.

3.1.2 The Supplier shall be responsible for performing the tests that demonstrate its ability to comply communication functions required under this Agreement. Such testing shall be at the sole expense of the Supplier.

3.2 <u>Testing and Approval by the Company</u>

The Company shall have the right, but not the obligation, to test and approve the Supplier's communication functions at any time. Such testing and approval shall be at the sole expense of the Supplier. The Company may elect to inform the Supplier of any problems the Company observes and any recommendations it has for correcting such problems with the communication functions, and Supplier shall address such problems to the reasonable satisfaction of the Company. Should the Supplier fail to address the problems to the reasonable satisfaction of the Company, the Company shall have the right not to authorize the use of the Supplier's communication systems or, if the communication systems are already in operation, then to terminate this Agreement pursuant to Article 5.5.1 (Default).

Article 4. Effective Date, Term, and Termination

4.1 <u>Effective Date</u>

This Agreement shall become effective upon execution by the Parties.

4.2 Term of Agreement

This Agreement shall become effective on the Effective Date and shall remain in effect for a period of ______ (xx) years from the Effective Date or such other longer period as the Parties may agree and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with Article 4.3 of this Agreement.

4.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, and provided the Participating Generating Facility(ies) with ______ (xx) Business Days written notice of the termination.

4.3.1 The Parties may agree in writing to terminate this Agreement.

4.3.2 The Supplier may terminate this Agreement at any time by giving both the Company and the Participating Generating Facility or Facilities ______ (xx) Business Days written notice.

4.3.3 The Company may terminate this Agreement after Default pursuant to Article 5.5.

4.3.4 The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

Article 5. Assignment, Liability, Indemnity, Uncontrollable Force, Consequential Damages, and Default

5.1 Assignment

Supplier shall not voluntarily assign its rights nor delegate its duties under this Agreement without the Company's written consent. Any assignment or delegation Supplier makes without the Company's written consent shall not be valid. The Company shall not unreasonably withhold its consent to Supplier's assignment of this Agreement.

5.2 Indemnity

5.2.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement.

5.2.2 The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

5.2.3 If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

5.2.4 If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

5.2.5 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

5.3 Consequential Damages

With the exception of damages (1) arising from, or in connection with, the unlawful or willful misconduct or gross negligence of a Party, (2) that are the subject of Supplier's indemnification pursuant to Article 5.2, (3) arising from, or in connection, with either Party's breach of its obligations under this Agreement with respect to Confidential Information, or (4) arising in connection with Supplier's breach of its obligations under the cybersecurity and privacy procedures set forth in Appendix B, neither Party, its officers, directors, employees, agents, representatives, successors, and assigns, shall be liable to the other Party for any special, indirect, incidental or consequential damages whatsoever, whether in contract (including insurance), or tort (including negligence or strict liability), including loss of use of or under-utilization of labor or facilities, loss of revenue or anticipated profits, or claims from customers, arising out of, in connection with, or relating to the Agreement.

5.4 Uncontrollable Force

5.4.1 As used in this article, an Uncontrollable Force Event shall mean "any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm, flood, earthquake, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond the reasonable control of the Company or Supplier which could not be avoided through the exercise of Good Utility Practice. An Uncontrollable Force Event does not include an act of negligence or intentional wrongdoing by the Party claiming Uncontrollable Force."

5.4.2 If an Uncontrollable Force Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Uncontrollable Force Event (Affected Party) shall promptly notify the other Party, either in writing or via the telephone, of the existence of the Uncontrollable Force Event. The notification must specify in reasonable detail the circumstances of the Uncontrollable Force Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Uncontrollable Force Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Uncontrollable Force Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

5.5 Default

5.5.1 Supplier's failure to provide the communication functions set forth in Article 2.2; failure to maintain the cybersecurity and privacy procedures set forth in Article 2.3 and Appendix B; and/or failure to correct, to the reasonable satisfaction of the Company, problems identified by the Company with the Supplier's communication system, as set forth in Article 3.2, shall constitute a Default on the part of the Supplier, subject to Article 5.5.2. Until the Default is cured, Participating Generating Facility(ies) must be disconnected from the electric system or adjusted to operating conditions set forth by the Company.

5.5.2 No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of an Uncontrollable Force Event as defined in this Agreement or the result of an act or omission of the Company. Upon a Default, the Company shall give written notice of such Default to the Supplier. Except as provided in article 5.5.3, the Supplier shall have _______ (xx) days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within ___________ (xx) days, the Supplier shall commence such cure within ________ (xx) days after notice and continuously and diligently complete such cure within __________ (xx) from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

5.5.3 If a Default is not cured as provided in this article, or if a Default is not capable of being cured within the period provided for herein, the Company shall have the right to terminate this Agreement by written notice at any time until cure occurs, and whether or not the Company terminates this Agreement, to recover from the Supplier any damages and remedies to which it is entitled at law or in equity. The provisions of this Article will survive termination of this Agreement.

Article 6. Insurance Requirements

6.1 General Liability Insurance

6.1.1 In connection with the Supplier's performance of its duties and obligations under this Agreement, the Supplier shall, at its own expense, maintain in force throughout the period of this Agreement, commercial general liability insurance for third-party bodily injury and property damage with a limit of not less than $_________ per occurrence and $_________ in the aggregate. Such general liability insurance shall include coverage for Premises-Operations, Products/Completed Operations, Explosion, Collapse, and Underground, and Contractual Liability.

6.1.2 The commercial general liability insurance required in Article 6.1.1 shall, by endorsement to the policy or policies, (a) include the Company as an additional insured; (b) contain a severability of interest clause or cross-liability clause; and (c) state that coverage provided is primary and is not in excess to or contributing with any insurance or self-insurance maintained by the Company. Supplier shall provide for thirty (30) Calendar Days' written notice to the Company prior to cancellation, termination, alteration, or material change of such insurance.

6.2 Cyber Insurance

Supplier shall, at its own expense, procure and maintain in full force at all time during the term of this Agreement Cyber Insurance covering cyber and network risks. Such insurance shall include, but not be limited to, coverage for: (a) liability arising from theft, dissemination and/or use of Confidential Information stored or transmitted in electronic form; and (b) liability arising from the introduction of a computer virus into, or otherwise causing damage to, a customer's or third person's computer, computer system, network or similar computer related property and the data, software and programs stored thereon. Such insurance will be maintained with limits of no less than $2,000,000 per claim and in the annual aggregate, and may be maintained on a stand-alone basis, or as cyber insurance coverage provided as part of any professional liability insurance policy. This insurance shall have a retroactive date that equals or precedes the effective date of this Agreement. Supplier shall maintain such coverage until the later of: (1) a minimum period of three (3) years following termination or completion this Agreement, or (2) until Supplier has returned or destroyed all Confidential Information in its possession, care, custody or control, including any copies maintained for archival or record-keeping processes.

6.3 Certificate of Insurance

6.3.1 The certificate of insurance provided to the Company shall evidence the insurance required above in Articles 6.1 and 6.2.

6.3.2 Supplier agrees to furnish certificates of insurance and endorsements to the Company prior to the provision of any communication functions under this Agreement. The Company shall have the right to inspect or obtain a copy of the original policy or policies of insurance.

6.4 Self-Insurance

6.4.1 If the Supplier is self-insured with an established record of self-insurance, the Supplier may comply with the following in lieu of Articles 6.1 through 6.3:

6.4.1.1 The Supplier shall provide to the Company, at least thirty (30) Calendar Days prior to the provision of any communication functions under this Agreement, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under Articles 6.1 and 6.2.

6.4.1.2 If the Supplier ceases to self-insure to the level required hereunder, or if the Supplier is unable to provide continuing evidence of the Supplier's ability to self-insure, the Supplier agrees to immediately obtain the coverage required under Articles 6.1 and 6.2.

6.5 Notification

6.5.1 The Supplier agrees to notify the Company whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of the insurance required under Articles 6.1 and 6.2, whether or not such coverage is sought.

6.5.2 All insurance certificates, statements of self-insurance, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

Company:
Attention:
Address:
City: State: Zip:
Phone:
Fax:

Article 7. Confidentiality

7.1 Definition of Confidential Information

The confidentiality provisions applicable to this Agreement are set forth in Rule 21 Section D.7, Confidentiality and in the following provisions included in this Article.

7.1.1 Release of Confidential Information

Neither Party shall release or disclose Confidential Information to any other persons, employees, or consultants, or to parties who may be or are considering providing financing to or equity participation with the Supplier, or to potential purchasers of the Supplier, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this Article and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article.

7.1.2 Rights

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

7.1.3 No Warranties

7.1.3.1 By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

7.1.3.2 Should the Company choose to test and approve Supplier's communication system or offer recommendations to correct any problems identified by the Company, as set forth in Article 3.2, it shall not be construed as endorsing the design thereof, as any warrant of the safety, durability, or reliability of those communications systems, or as a waiver of any of the Company's rights.

7.1.4 Standard of Care

Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination; however, in no case shall a

Party use less than reasonable care, consistent with the nature of the information it has received from the other party, in protecting Confidential Information. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this Agreement or its regulatory requirements. This includes the use or disclosure of Confidential Information of the Company's customers (customer names and other information related to customers, including energy usage and distributed energy resource ("DER") generation data ("Customer Information")) among or between the Company's customers on whose behalf the Supplier is acting.

7.1.5 Order of Disclosure

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

7.1.6 Remedies

The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's breach of its obligations under this Article. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party breaches or threatens to breach its obligations under this Article, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the breach of this Article, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article.

Article 8. Disputes

8.1 Dispute Resolution

Any dispute arising between the Parties regarding a Party's performance of its obligations under this Agreement or requirements related to Section Hh of Rule 21 shall be resolved according to the procedures in Rule 21.

Article 9. Miscellaneous

9.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of California, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

9.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

9.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

9.4 Waiver

9.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

9.4.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Any waiver of this Agreement shall, if requested, be provided in writing.

9.5 Entire Agreement

This Agreement, including all Attachments, and any incorporated tariffs or Rules, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

9.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original, but all constitute one and the same instrument.

9.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

9.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, (3) the remainder of this Agreement shall remain in full force and effect, and (4) notification to Participating Generating Facility(ies) provided that Participating Generating Facility(ies) are required to meet communication requirements set forth in Rule 21 within ________ Business Days of such notice.

9.8.1 Business Continuity Plans

Supplier agrees to implement and maintain during the Term of this Agreement, a business continuity plan, a disaster recovery plan, and an incident response plan (collectively, the "Business Continuity Plans") consistent with the level of risk associated with the provision of communication functions under this Agreement. The Business Continuity Plans shall be provided to Company prior to the provision of any communication functions under this Agreement. Supplier shall update the Business Continuity Plans during the Term to reflect lessons learned from real recovery events and as required due to significant changes in risk or business or regulatory environment. The Company shall have the right to review the Business Continuity Plans at any time during the Term and Supplier shall make such Business Continuity Plans available to Company immediately upon request.

9.9 CPUC Modification

Unless otherwise ordered by the CPUC, this Agreement at all times shall be subject to such modifications as the CPUC may direct from time to time in the exercise of its jurisdiction.

9.10 Review of Records and Data

9.10.1 The Company shall have the right to review and obtain copies of Supplier's operations and maintenance records, logs, or other information relating to communications functions and/or the transmission of information to the Company. The Company shall own any data or information provided to it by the Supplier under the terms of this Agreement.

9.10.2 The Supplier authorizes the Company to release to the California Energy Commission ("CEC"), the CAISO, and/or the CPUC information regarding the Supplier, including its name and location, the number of Participating Generating Facility(ies) it is acting on behalf of and the characteristics of those facilities, and any other relevant operational characteristics as are requested from time to time pursuant to the CEC's, CAISO's, or CPUC's rules and regulations.

Article 10. Notices

10.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Supplier:

Supplier:
Attention:
Address:
City: State: Zip:
Phone:
Fax:

If to the Company:

Company:
Attention:
Address:
City: State: Zip:

Phone:
Fax:

10.2 A Party may change its address for Notices at any time by providing the other Party Notice of the change in accordance with Article 10.1.

10.3 The Parties may also designate operating representatives to conduct the daily communications, which may be necessary or convenient for the administration of this Agreement. Such designations, including names, addresses, and phone numbers may be communicated or revised by one Party's Notice to the other.

Article 11. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

<u>For the Company</u>

Name: ____
[Name]

Title: [Title]

Date: ____________________

<u>For the Supplier</u>

Name: ____
[Name]

Title: [Title]

Date: ____________________

APPENDIX A

GLOSSARY OF TERMS

Aggregator: An entity that provides the communication capability functions required in Section Hh of Rule 21 on behalf of one or more Participating Generating Facilities that utilize inverter-based technologies.

Agreement: Shall have the meaning set forth in the first paragraph of this agreement.

Applicable Laws and Regulations: All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Business Day: Monday through Friday, excluding Federal and State Holidays.

Calendar Day: Any day including Saturday, Sunday or a Federal and State Holiday.

Company: [______________]

Generating Facility: All Generators, electrical wires, equipment, and other facilities, excluding Interconnection Facilities, owned or provided by Producer for the purpose of producing electric power, including storage.

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.

Operating Requirements: Any operating and technical requirements that may be applicable due to Regional Transmission Organization, the CAISO, balancing authority area, or the Company's requirements, including those set forth in the Agreement.

Participating Generating Facility or Facilities: Generating Facility(ies) that have executed a Participating Generating Facility-Aggregation Agreement with the Company, as set forth in Exhibit C.

Participating Generating Facility-Aggregation Agreement: Agreement that has been executed by a Participating Generating Facility with the Company of the Participating Generating Facility's election to utilize Suppler [________] to fulfill its Rule 21 Section Hh requirements.

Party or Parties: The Company, the Supplier, or any combination thereof.

Reasonable Efforts: With respect to an action required to be attempted or taken by a Party under the Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Supplier: [_______________]

APPENDIX B

DESCRIPTION OF CYBERSECURITY AND PRIVACY REQUIREMENTS

Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Supplier shall therefore meet standards for system infrastructure and operational security, including physical, operational, and cyber-security practices, as set forth herein.

APPENDIX C

LIST OF PARTICIPATING GENERATING FACILITIES

The following Generating Facility(ies) have executed a Participating Generating Facility-Aggregation Agreement with the Company:

PARTICIPATING GENERATING FACILITY-AGGREGATION AGREEMENT

BETWEEN

[PARTICIPATING GENERATING FACILITY]

AND

[COMPANY]

This Participating Generating Facility-Aggregation Agreement ("Agreement") is entered into by and between [Participating Generating Facility Name] ("Participating Generating Facility"), a [form of entity and state of registration], and [Company Name] ("Company"), a California Corporation. Participating Generating Facility and Company are sometimes referred to herein individually as "Party" or collectively as the "Parties." In consideration of the mutual promises and obligations stated in this Agreement and its attachments, the Parties agree as follows:

Article 1. Scope, Purpose, and Related Agreement

1.1 Applicability

1.1.1 This Agreement, in conjunction with the Distributed Energy Resource Aggregation Agreement entered into between [Aggregator Name] ("Supplier") and the Company on [date], allows the Company to communicate with the Supplier on the Participating Generating Facility's behalf.

1.1.2 This Agreement incorporates in its entirety the Company's California Public Utilities Commission ("CPUC") approved Electric Rule 21 Tariff ("Rule 21"), subject to any modifications the CPUC may direct in the exercise of its jurisdiction. In the event of inconsistency between this Agreement and the terms of Rule 21, the provisions of the latter shall control.

1.2 Limitations

Nothing in this Agreement is intended to affect any other agreement between: (a) the Participating Generating Facility and the Company, or (b) the Participating Generating Facility and the Supplier.

1.3 Capitalized Terms

Capitalized terms not otherwise defined herein shall have the meanings ascribed to them in Appendix A to the Distributed Energy Resource Aggregation Agreement or Rule 21.

1.4 Summary and Description of the Parties

1.4.1 The Participating Generating Facility is located at:

____

____

____

1.4.2 The Company, to which the Supplier shall provide communication functions on behalf of the Participating Generating Facility under the terms and conditions set forth in the Distributed Energy Resource Aggregation Agreement, is located at:

____

____

____

1.4.3 The Supplier is located at:

____

____

____

Article 2. Participating Generating Facility Acknowledgments and Obligations

2.1 The Participating Generating Facility acknowledges that it has authorized the Supplier to provide the communication functions required under Section Hh of Rule 21 on its behalf. The Participating Generating Facility shall be solely responsible for the terms of any such agreement between it and the Supplier.

2.2 The Participating Generating Facility acknowledges that the Company is allowed to communicate with the Supplier on the Participating Generating Facility's behalf.

2.3 The Participating Generating Facility shall make its communications systems reasonably accessible to the Company's personnel, contractors, or agents if necessary to perform the Company's duties under Rule 21.

2.4 The Participating Generating Facility avers that it has not entered into an agreement with any other Aggregator (besides Supplier) for the provision of those communication functions required under Section Hh of Rule 21 on its behalf.

Article 3. Effective Date, Term, and Termination

3.1 **Effective Date**

This Agreement shall become effective upon execution by the Parties.

3.2 **Term of Agreement**

This Agreement shall become effective on the Effective Date and shall remain in effect for a period of ______ (xx) years from the Effective Date or such other longer period as the Parties may agree and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with Article 2.3 of this Agreement.

3.3 **Termination**

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination.

3.3.1 The Parties may agree in writing to terminate this Agreement.

3.3.2 The Participating Generating Facility may terminate this Agreement at any time by giving both the Company and the Supplier ______ (xx) Business Days written notice.

3.3.3 The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

Article 3. Assignment and Limitation of Liability

3.1 **Assignment**

Participating Generating Facility shall not voluntarily assign its rights nor delegate its duties under this Agreement without the Company's written consent. Any assignment or delegation Participating Generating Facility makes without the Company's written consent shall not be valid. The Company shall not unreasonably withhold its consent to the Participating Generating Facility's assignment of this Agreement.

3.2 **Limitation of Liability**

3.2.1 Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages of any kind whatsoever.

3.2.2 The Company shall not be liable to the Participating Generating Facility in any manner, whether in tort or contract or under any other theory, for loss or damages of any kind sustained by the Participating Generating Facility resulting from termination of the Distributed Energy Resource Aggregation Agreement.

Article 4. Miscellaneous

4.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of California, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

4.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

4.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

4.4 Waiver

4.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

4.4.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Any waiver of this Agreement shall, if requested, be provided in writing.

4.5 Entire Agreement

This Agreement, including any incorporated tariffs or Rules, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

4.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

4.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

4.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

4.9 CPUC Modification

Unless otherwise ordered by the CPUC, this Agreement at all times shall be subject to such modifications as the CPUC may direct from time to time in the exercise of its jurisdiction.

4.10 Release of Data

The Participating Generating Facility authorizes the Company to release to the California Energy Commission ("CEC"), the CAISO, and/or the CPUC information regarding the Participating Generating Facility, including the characteristics of its Generating Facility, and any other relevant operational characteristics as are requested from time to time pursuant to the CEC's, CAISO's, or CPUC's rules and regulations.

Article 5. Notices

5.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Participating Generating Facility:

Participating Generating Facility
Attention:
Address:
City: State: Zip:
Phone:
Fax:

If to the Company:

Company:
Attention:
Address:
City: State: Zip:
Phone:
Fax:

5.2 A Party may change its address for Notices at any time by providing the other Party Notice of the change in accordance with Article 5.1.

5.3 The Parties may also designate operating representatives to conduct the daily communications, which may be necessary or convenient for the administration of this Agreement. Such designations, including names, addresses, and phone numbers may be communicated or revised by one Party's Notice to the other.

Article 6. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Company

Name: ______________________________
[Name]

Title: [Title]

Date: ____________________

For the Participating Generating Facility

Name: ____
[Name]

Title: [Title]

Date: ____________________

ISSUE 8 PROPOSAL

Issue 8 Question: How should the Commission incorporate the results of the Integration Capacity Analysis into Rule 21 to inform interconnection siting decisions, streamline the Fast Track process for projects that are proposed below the integration capacity at a particular point on the system, and facilitate interconnection process automation?

Proposals and Status

The following proposals were developed by stakeholders as part of the Working Group process to address Issue 8. Where a stakeholder's position is partial or qualified, it is labeled "qualified" and additional explanation is provided in subsequent sections where the proposal is detailed. If stakeholders' positions are not specifically noted, they neither "support" nor "oppose."

Proposals to modify the Rule 21 process include:

- **Proposal 8.a:** Remove Existing Fast Track Eligibility Limit
    - Consensus

- **Proposal 8.b:** Modification of Initial Review Process to Include Verification and Explanation of Updated ICA
    - Non-consensus
        - Supported by PG&E, SCE, SDG&E, IREC (qualified), Public Advocates Office (qualified), GPI, TURN, Clean Coalition (qualified), CALSSA (qualified)

- **Proposal 8.c:** Track When ICA Values are Updated Outside of the Required Monthly Update to Inform Future ICA Discussions
    - Non-consensus
        - Supported by SCE, SDG&E, IREC, Public Advocates Office (qualified), GPI, TURN, Clean Coalition, CALSSA
        - Opposed by PG&E

- **Proposal 8.d**: Modification of Projects if ICA Values are Out-of-Date to Stay Under ICA Limit and Maintain Queue Position
    - Non-consensus
        - Supported by CALSSA, GPI, Clean Coalition
        - Opposed by PG&E, SCE, SDG&E, TURN

- **Proposal 8.f1**: Adopt Additional Initial Review Screen F1
    - Consensus

- **Proposals 8.f, 8.g, 8.h, and 8.j:** Apply Screen F, G, H and J only to Projects Larger than 30 kVA; Provide Earliest Available Indication where Screen F and G Failure is Likely
    - Modification 1: Consensus
    - Modification 2: Non-consensus
        - Supported by PG&E (qualified), SDG&E (qualified), IREC (qualified), Public Advocates Office (qualified), CALSSA (qualified), GPI (qualified), Clean Coalition
        - Opposed by: SCE

- **Proposal 8.i:** Consider Applicability of Screen I for Non-exporting Projects Above 30kVA
    - Non-consensus
        - Option A:
            - Supported by PG&E, SCE, SDG&E, TURN
            - Opposed by IREC, Clean Coalition, CALSSA, Stem, GPI, Public Advocates Office
        - Option B:
            - Supported by CALSSA, IREC, GPI, Clean Coalition, Stem, Public Advocates Office
            - Opposed by PG&E, SCE, SDG&E, TURN

- **Proposal 8.k:** Modify Screen L to Include the Transmission Overvoltage and Transmission Anti-islanding Test
    - Non-consensus
        - Option A:
            - Supported by PG&E, SCE, SDG&E
            - Opposed by TURN, CALSSA
        - Option B:
            - Supported by CALSSA
            - Opposed by PG&E, SCE, SDG&E

        - Option C:
            - Supported by IREC, GPI, Clean Coalition
            - Opposed by PG&E, SCE, SDG&E

- **Proposal 8.l**: Provide Earliest Available Indication where Screen L Failure is Likely
    - Non-consensus
        - Supported by PG&E, TURN, Clean Coalition, GPI, IREC
        - Opposed by: SCE, SDG&E

- **Proposal 8.m:** Screen M should be modified to reflect ICA
    - Non-consensus
        - Option A:
            - Supported by PG&E, SCE, SDG&E, TURN
            - Opposed by IREC, GPI, Stem, Clean Coalition, Tesla, Sunrun, CALSSA, Public Advocates Office
        - Option B:
            - Supported by IREC, GPI, Stem, Clean Coalition, Tesla, Sunrun, CALSSA, Public Advocates Office
            - Opposed by PG&E, SCE, SDG&E, TURN
        - Options A or B:
            - Implementation Variation 1
                - Supported by Clean Coalition, IREC, CALSSA, SCE (qualified)
                - Opposed by SDG&E, PG&E
            - Implementation Variation 2
                - Supported by Clean Coalition, IREC, PG&E (qualified), SCE (qualified), CALSSA, SDG&E (qualified)

- **Proposal 8.n:** Update Screen N Methodology
    - Non-consensus
        - Supported by PG&E, SDG&E, SCE, IREC, Public Advocates Office, GPI, Clean Coalition, TURN, CALSSA

- **Proposal 8.q:** Modify Screen P
    - Consensus

- **Proposal 8.r:** The Interconnection Application Should have an Option to Combine Initial Review and Supplemental Review, With Applicants Pre-Paying for Initial Review and Supplemental Review

    - Consensus

- **Proposal 8.s:** Reduce interconnection application fee for non-NEM systems
    - Non-consensus
        - Supported by CALSSA, GPI, Clean Coalition (qualified), IREC (qualified)
        - Opposed by PG&E, SCE, SDG&E, TURN

- **Proposal 8.t:** Queue management
    - Non-consensus
        - Option A:
            - Supported by CALSSA, IREC, Clean Coalition (qualified)
            - Opposed by PG&E, SCE, SDG&E, GPI, TURN
        - Option B:
            - Supported by GPI, Tesla

- **Proposal 8.v:** Additional Automation and Streamlining Opportunities Proposal
    - Non-consensus
        - Supported by GPI, Clean Coalition, Stem
        - Opposed by PG&E, SCE, SDG&E, TURN

Background

Integration Capacity Analysis ("ICA") was developed under the Distribution Resources Plan ("DRP") proceeding (R.14-08-013) of the California Public Utilities Commission ("CPUC"). CPUC Decision ("D.") 17-09-026 adopted the use of ICA for online maps, interconnection streamlining and automation, and distribution planning, and the CPUC authorized system-wide implementation of ICA across the utilities' territories. This Decision reiterated that one of the key purposes of the DRP is to dramatically streamline the interconnection process and that ICA results can help customers design distributed energy resources ("DER") systems by providing accurate information about the amount of DER capacity that can be interconnected at specific locations without significant distribution system upgrades or study.[6]

ICA and Interconnection Overview

ICA provides information on the distribution system's hosting capacity, helping to inform interconnection applicants on project siting and sizing. This information is based on analyses of grid conditions accounting for thermal limitations of distribution components,

[6] D.17-09-026, p.27.

voltage levels, power quality limits, protection, and safety requirements. The Distribution Resources Plan Working Group report described its expectations for using ICA to support interconnection as follows[7]:

> *Developers should be able to submit a Rule 21 Fast Track application for DER interconnection up to the identified ICA value at the proposed point of interconnection, based on ICA figures shown on the map, changes in queued DER since the last map update and the underlying data, and be able to pass those Screens representing criteria the ICA has evaluated…*
>
> *The ICA values identified at a point of interconnection are expected to replace and/or supplement the size limitations in the Fast Track eligibility criteria and will be able to address and/or improve the technical Screens in the Rule 21 Fast Track process which are part of the ICA methodology…. With few exceptions, interconnection customers should be able to use the ICA value at their point of interconnection to know whether a proposed project will pass these Screens in the Fast Track process. In the near-term, there will be additional Screens that still need to be evaluated due to data not currently analyzed in the ICA.*

D.17-09-026 further specified how ICA should be implemented and the specifics of the methodology that should be used but identified Rule 21 as the proceeding to decide how ICA can be incorporated into the Rule 21 tariff. The R.17-07-007 Scoping Memo identified three Phases of the proceeding and scoped issues to be addressed by various Working Groups. Working Group Two is tasked with discussing ICA and streamlining interconnection issues (Issues 8-11).

Threshold Considerations

The Working Group spent much of its effort identifying and developing consensus proposals and exploring issues where consensus may exist. Where consensus could not be reached many parties have offered proactive solutions for the Commission's consideration. In identifying changes to the Rule 21 tariff, members of the Working Group also identified where there are "threshold considerations" to adopting the recommended changes. These threshold considerations include 1) cost considerations, 2) implementation dependencies and 3) ICA validation.

Cost Considerations

The Working Group discussed whether and how to consider the costs of implementing proposals suggested here. While all proposals will come with some expenditure of resources to implement, the question of costs has been of particular concern for certain

[7] ICA Working Group Final Report, p. 8-9 (https://drpWorking Group.org/wp-content/uploads/2016/07/ICA-Working Group-Final-Report.pdf).

proposals. First, the question of cost comes up in Proposals 8.f, 8.g, and 8.l, in which some Working Group members propose the utilities present information related to the likelihood that interconnecting generators could pass Screens F, G, and L. Second, the question of cost comes up in Proposal 8.v, concerning additional automation and streamlining opportunities. As noted throughout, numerous stakeholders qualify their support for proposals on the reasonableness of the costs of implementing them.

The Working Group discussed the potential costs and benefits of each proposal, but did not reach consensus on how to handle determinations of whether potential costs are reasonable. Some proposals include a specified recommendation on how the Commission might consider cost implications, while others do not. As such, the Working Group requests guidance from the Commission on how it can best support the Commission's consideration of potential costs, benefits, and determinations of reasonableness.

Implementation Dependencies

New tools and processes will be needed to implement the Proposals herein. Those include:

1. Tool or process to efficiently reference the ICA values
2. Tool or process to efficiently update the ICA value during the interconnection application review (see Proposal 8.b)
3. Tools to reference external information (e.g., the National Renewable Energy Laboratory's PV watts) for processing of operational profiles
4. Processes related to new interconnection process flow (applications, forms)

This report recognizes the need for these tools and processes to be operational to implement these proposals. Implementation details of readying these tools and processes were beyond the scope of this Working Group report.

Proposed ICA Validation Study

Given the complexity of ICA and that ICA modeling is new, the IOUs are conducting quality control and assurance efforts to ensure the results of the analysis can be used in the ways proposed herein. The Working Group recognized that the quality of the data is essential for expanding the interconnection process while still maintaining safety and reliability of the system. The Utilities will conduct quality control and validation of data prior to the implementation of these proposals. In the event that significant issues are found in the verification process, the utilities will propose a plan to solve issues and will submit a request to the Commission for new implementation dates.

Issue 8 Proposals

Proposal 8.a: Remove Existing Fast Track Size Eligibility Limit

Proposal

Remove the existing Fast Track Eligibility Size Limits in Rule 21 E.2.b.i Fast Track Eligibility.

Status

Consensus

Discussion

Fast Track evaluation allows for rapid review of certain projects to enable them to interconnect without Detailed Study. Fast Track is comprised of an Initial Review and, if required, a Supplemental Review. Because a project's size has been a primary indicator of whether it is likely to be approved for interconnection under Fast Track, eligibility for Fast Track review currently is dependent on the project's size. PG&E and SCE currently use a 3 MW size limit to determine Fast Track eligibility, while SDG&E uses a 1.5 MW size limit.

The ICA provides an estimation about what size project can likely be interconnected at a specific point in a circuit without requiring distribution upgrades. In addition, in some cases projects that are proposed above the ICA limit may be able to be interconnected without study after Supplemental Review is conducted if minor upgrades or system changes are possible to address the limitation. Thus, this proposal will allow any applicant to select Fast Track as their preferred study track regardless of the size of their project.

All Working Group members supported the elimination of Fast Track Eligibility Limits. Three caveats to this proposal were emphasized by the Working Group.

- First, the ICA only evaluated certain technical criteria, and thus even projects that are below the ICA may still be required to go to Supplemental Review or Detailed Study even if they fail the other Screens not evaluated by the ICA.
- Second, elimination of the Fast Track eligibility limit does not increase an interconnecting generator's chances of passing through Initial or Supplemental Review if the project is sized above the ICA. Applicants are therefore encouraged to reference the ICA in determining their preferred study track.
- Third, net-energy metering ("NEM") projects under 30kVA are currently processed as Fast Track projects. The Working Group recommends this practice continue, regardless of the ICA.

Proposal 8.b: Modification of Initial Review Process to Include Verification and Explanation of Updated ICA

Proposal

The IOUs will modify their Initial Review processes to incorporate an additional run of the specific node/feeder ICA where updated ICA values may be required. The IOUs will provide an interconnecting generator with an explanation of the update if necessary. Different approaches to implementing this proposal are suggested by each IOU. If needed, the update will be completed within the Initial Review timeframe.

Status

Non-consensus

- Supported by PG&E, SCE, SDG&E, IREC (qualified), Public Advocates Office (qualified), GPI, TURN, Clean Coalition (qualified)

Discussion

Per implementation requirements from D.17-09-026, the ICA is currently updated on a monthly basis on circuits where significant system changes have occurred and those monthly updates are reflected in the ICA maps and public data portals. The Working Group noted that this frequency of updates means that sometimes Interconnection Requests could be sized based upon ICA values that are not up-to-date; that is, the ICA values reflected on the public data portal and online map may not reflect changes which have occurred in the grid (e.g., circuit reconfigurations, load changes, equipment changes, etc.) or changes in the interconnection queue (e.g., new interconnection applications and/or withdrawals) since the ICA was last run.

The following are examples of why the ICA values may have changed from the latest monthly update:

- Significant amount of DER on a distribution circuit: While not all DERs will trigger a verification of ICA values, larger single DER installations and/or the aggregation of small residential DERs will cause the need to validate the ICA value.
- Permanent distribution system modifications: These types of modifications are needed as part of daily grid operations in order to balance loading on circuits or substations.
- Significant modification in load: When it is known that a significant increase or loss in load (e.g., a factory closing) will occur.
- Upgrades to the grid: Such as upgrades in conductor size or installation of protection devices.
- New distribution system energized: Such as energizing new housing tracks or new commercial services.

- Modification to existing device parameters: Such as changes to relay settings and/or changes to voltage regulation settings.

Each of the IOUs have proposed a different process for how they will verify whether the ICA values need to be updated. These are the two IOU proposals with stakeholder modifications or objections noted below each:

- SCE and SDG&E propose to use the Initial Review process to determine if the ICA values at the proposed Point of Interconnection ("POI") need to be updated. If it is determined that the ICA values at the POI need to be updated, SCE and SDG&E will use the ICA tool on the specific electrical node or will run the ICA on all the electrical nodes in the circuit, depending on future ICA tool capabilities.
- PG&E generally agrees with SCE and SDG&E's approach but proposes that verification of the ICA within the Initial Review process may also be accomplished through existing 15% of peak load calculations without rerunning the ICA.
- If 8.f, 8.g, 8.h, and 8.j are adopted, the IOUs will not perform additional analyses of Interconnection Requests with less than 30 kVA nameplate capacity.
- All utilities propose to implement this without changes to the existing timelines for Initial Review.

In addition to these questions of how ICA values would be updated, the Working Group discussed what steps the IOUs should take to share the results of their analysis with the interconnecting generator. Most Working Group participants agree an explanation of the following is warranted:

- Grid condition changes
- Interconnection queue changes

In the event disclosing ICA results fails any confidentiality provision, the IOUs will provide information in aggregation or at a level of granularity that would allow IOUs to continue to comply with the Commission's data redaction policies in place at the time of interconnection.

Finally, SCE agreed to consider future implementation of a system for "flagging" if the ICA values likely need an update. If possible, SCE would attempt this during Q1 2019.

Qualified Positions

The Working Group did not receive an explanation or any opportunity to consider PG&E's approach to verification. Thus, several parties strongly object to PG&E's position. They are concerned interconnection applicants will not understand how the screening limit is derived and applied, and that the backstop position of using the 15% screen would undermine the use of the ICA altogether. They ask instead that the ICA should produce the values used in the screening process.

Clean Coalition notes that any alternate methods used by the IOUs must provide effectively equivalent results to the applicant as an updated ICA value. In those cases where this is not clear, an updated ICA value must be used.

GPI suggests that with ICA updates at a monthly resolution it is likely that "stale" ICA values will be a large problem. GPI's suggested solution for this potential problem is to have the IOUs complete the automated ICA update process in the near-term, as discussed in Proposal 8.v. GPI regards their support for Proposal 8.b as an interim measure until alternatives delineated in 8.v can be adopted.

The Public Advocates Office supports Proposal 8.b, concluding it will help ensure that the online ICA tool is as accurate and as reflective of real-time conditions as possible. However, the Public Advocates Office recommends that, were this proposal to be implemented, the costs to the IOUs of performing these intra-month updates be reviewed as part of the long-term ICA refinements to see if they are placing an undue cost burden on the IOUs and, by extension, the ratepayers.

Proposal 8.c: Track When ICA Values are Updated Outside of the Required Monthly Update to Inform Future ICA Discussions

Proposal

The IOUs will track when the ICA is updated leading to Interconnection Requests failing Initial Review.

Status

Non-consensus

- Supported by SCE, SDG&E, IREC, Public Advocates Office (qualified), GPI, TURN, Clean Coalition
- Opposed by PG&E

Discussion

The Working Group discussed whether tracking of the deviations from the posted ICA values would help inform future discussions on the ICA.

Some Working Group participants suggested that the IOUs should track deviations from the posted ICA values that surface during the implementation of Proposal 8.b to inform future discussions of ICA refinement. Tracking of these deviations will help inform future discussions about how frequently the ICA needs to be updated systemwide and also in what manner and when ICA may need to be updated on a case by case basis for individual applications.

SCE and SDG&E expressed a willingness to track ICA updates for those projects that require Supplemental Review. PG&E opposes this proposal at this time, finding it better related to long-term ICA refinements within the DRP proceeding.

GPI expressed the need for comprehensive data in order to assess the effectiveness of the ICA, and tracking ICA posted value deviations is the first step in collecting the required diagnostic data to improve the system over time.

Qualified Positions
The Public Advocates Office supports Proposal 8.c, concluding it will help ensure that the online ICA tool is as accurate and as reflective of real-time conditions as possible. However, like Proposal 8.b, the Public Advocates Office recommends that, were this proposal to be implemented, the costs to the IOUs of performing these intra-month updates be reviewed as part of the long-term ICA refinements to see if they are placing an undue cost burden on the IOUs and, by extension, the ratepayers.

Proposal 8.d: Modification of Projects if ICA Values are Out-of-Date to Stay Under ICA Limit and Maintain Queue Position

Proposal
Applicants who apply based on the posted ICA should have an opportunity to make modifications to their applications should they fail any Initial Review Screens because the posted ICA values have changed by the time their application was reviewed. Applicants will have ten business days to modify their application or elect to go to Supplemental Review. If they do not respond, the project will proceed to Supplemental Review after ten days.

Status
Non-consensus

- Supported by CALSSA, GPI, Clean Coalition
- Opposed by PG&E, SCE, SDG&E, TURN

Discussion
The Working Group discussed that projects applying to be studied under Fast Track that submit an application based on the posted ICA values may want an opportunity to modify their application request if the ICA values have changed in a way that causes them to fail Fast Track before the time their application is evaluated in the queue.

The current Material Modification rules under Fast Track review do not allow an applicant to reduce the size of a proposed project without resubmittal. Rule 21 Working Group One made a recommendation to allow a size reductions up to 20% if it does not impact another project lower in the queue. That recommendation is pending. This proposal would address situations not contemplated within Working Group One; this proposal is to allow an interconnecting customer to maintain queue position when it would impact another applicant lower in the queue.

CALSSA provides the following example illustrating the impact of this proposal:

> *"Suppose there are published ICA values sufficient to interconnect 2 MW of south-facing solar. After that number is published, Customer A submits an application for a system for 900 kW, leaving approximately 1.1 MW. Without knowing that, Customer B for 1.5 MW based on the published ICA values, then Customer C submits an application for 600 kW. Customer B is informed that there is actually only 1.1 MW of capacity and chooses to downsize. If Customer B is allowed to downsize without resubmitting, Customer C will not be able to interconnect without upgrades. If Customer B is required to resubmit and goes behind Customer C, only 500 kW of capacity will available. This proposal would allow Customer B to interconnect 1.1 MW because that customer was acting on posted ICA data in the initial submittal and should not be punished due to another project that submitted right ahead of them. Customer C would have to pay for upgrades to interconnect, which is what would have happened if all customers had access to up-to-date information."*

CALSSA notes there are disadvantages to this proposal. Specifically, the proposal would add up to ten days to the interconnection process and some applicants would not be able to decide within the ten-day timeframe, which would slow things down without providing a benefit. However, CALSSA believes solar providers will become accustomed to presenting multiple options to customers ahead of time in order to make speedy decisions when these situations arise.

The IOUs take a different position. The IOUs assert this proposal adds complexity and makes the Fast Track process much slower than it is intended to be. It also reflects the challenges of the prior serial study process and why the Independent Study Process was introduced. It begs the question whether the Utilities should receive multiple interconnections requests under the Fast Track process with such interdependencies. Adding provisions to allow size changes that impact others in the queue means that completed interconnection studies would have to be re-done potentially impacting other customers project plans. The IOUs observe there is no data supporting this proposal and thus not prudent to add complex rules on a scenario that may or may not happen frequently. Today, the number of projects that fail the Fast Track process is small.

Further, the IOUs assert CALSSA's scenario is unfair to Customer C who also applied based on the posted information, and based on existing practices it is fair for Customer B to take responsibility of the upgrade. From the IOUs' perspective, the CALSSA proposal would not only create excessive complexities in the Fast Track process but also change the cost responsibility principles that exist in the tariff. Further, besides increasing the complexity of the Fast Track process, this also complicates the monthly updates to the ICA values. For example, if the IOUs allow ten days for a customer to decide if they want to change, then the IOUs will not be able to update the model for that circuit, which means that the IOUs will not be able to post updated monthly values for that circuit if this occurred towards the end of the reporting period.

Proposal 8.f1: Adopt Additional Initial Review Screen F1

Proposal

The proposal is to add Screen F1 to the Initial Review Screens to screen whether the generating system's short circuit contribution exceeds 1.2 per unit.

Status

Consensus

Discussion

Generating systems with 1.2 per unit short circuit contribution can reference the ICA value for meeting the reduction of reach ICA protection Screen. For Generating Facilities with short circuit current contribution greater than 1.2 per unit, the utilities will use the protection ICA value at the point of interconnection in conjunction with the project specific per unit short circuit contribution to determine if they pass Screen F1. If the project Screen fails Screen F1, it must be evaluated under Supplemental Review for impacts to reduction in reach.

The ICA cannot be used to evaluate synchronous or induction generators. The ICA uses 1.2 per unit short circuit duty contribution for inverter-based technology. Thus, an additional screen is proposed to evaluate whether a DER's short circuit duty contribution is under the allowable level; if yes, the Interconnection Request would pass Screen F1; if no, the Interconnection Request would fail Screen F1 and may need to be evaluated under Supplemental Review for impacts to reduction of reach. While the ICA was calculated using 1.2 per unit short circuit contribution, Screen F1 can be passed even when the DER short circuit contribution is greater than 1.2 per unit, so long as the DER nameplate value multiplied by its DER per unit contribution does not exceed the ICA value multiplied by 1.2 per unit. Below is an example to illustrate how the Screen would be applied.

Project MVA (MW) Nameplate capacity = 3 MW

Project Specific Short Circuit Contribution = 2.5 per unit

Updated protection ICA value at the Point of Common Coupling = 5 MW

Calculated project specific protection ICA value = 2.4 MW

Project fails Screen F1 because the project's nameplate capacity is greater than the Project Specific Protection ICA value

Therefore, a DER with a higher level of short circuit duty contribution needs to be adjusted to ensure consistency with ICA calculations.

Proposals 8.f, 8.g, 8.h, and 8.j: Apply Screen F, G, H and J only to Projects Larger than 30 kVA; Provide Earliest Available Indication where Screen F and G Failure is Likely

Proposal

This proposal has two parts:

- Modification 1: Raise the applicability limit for Screen F, G, H, and J from above 11kVA to above 30 kVA
- Modification 2: The IOUs provide earliest available indication where Screen F and G failure is likely, as detailed herein.

Status

Modification 1: Consensus

Modification 2: Non-consensus

- Supported by PG&E (qualified), SDG&E (qualified), IREC (qualified), Public Advocates Office (qualified), GPI (qualified), Clean Coalition, CALSSA (qualified)
- Opposed by: SCE

Discussion

<u>Modification 1</u>

The existing Rule 21 tariff language for Screen F, G, H, and J includes the following language:

> *Note: This Screen does not apply to Generating Facilities with a Gross Rating of 11 kVA or less.*

The Working Group discussed expanding the exemption from 11 kVA to 30 kVA to allow standard NEM and other small projects to easily pass the Screen and maintain the goal of streamlining the interconnection process for small projects. It is not anticipated that projects below 30 kVA would be likely to raise any safety or reliability concerns if they skipped these Screens.

To implement this change, the tariff language could be changed to:

Note: This Screen does not apply to Generating Facilities with a Gross Rating of 30 kVA or less.

All Working Group stakeholders agree the increase from 11 kVA to 30kVA is an improvement. Some Working Group members are concerned the threshold could be larger than 30kVA. The IOUs emphasize the 30kVA is an acceptable number but not derived from technical analysis. Some stakeholders requested additional analysis and reasoning behind the 30kVA threshold, but none was provided. Supporting stakeholders nevertheless support 30kVA at a minimum.

Modification 2

Screen F ("Is the Short Circuit Current Contribution Ratio within acceptable limits?") identifies whether a project may have an impact on the system's short circuit duty, fault detection sensitivity, relay coordination, or fuse-saving schemes. Screen G ("Is the Short Circuit Interrupting Capability Exceeded?") identifies and studies whether a Generating Facility, in aggregate with other Generating Facilities on the distribution circuit, cause disturbances to protective devices and equipment, risking overstressing the equipment. This Screen allows the IOUs to evaluate how a generation project on the distribution system affects interrupting devices on the entire system, including at the distribution substation level, sub-transmission substation level (where applicable), and at the transmission level.

The ICA Working Group report had indicated that the ICA could enable an updated methodology incorporating these Screens; however, this Working Group identified that all elements of the tests conducted under Screens F and G are not actually evaluated within ICA.

Screens F and G require the IOUs to study impacts in aggregate with other Generating Facilities on the circuit. In order to determine if a project fails Screen F or G it is necessary to run short circuit flow models. In sum, the ICA does not provide a complete indication whether a project will pass or fail these Screens.

In the place of the ICA, the IOUs considered whether/how they may provide an early indication of whether a project is likely to face challenges related to Screens F and G. Some Working Group members propose the utilities post information on the ICA maps that indicate whether these Screens are likely to be a problem at that location.

PG&E and SDG&E propose that Screen F results can be provided in the Pre-Application Report, given that CYME and Synergi, distributed generation screening tools, have the capability to analyze Screen F and G quickly. Information can be provided as an additional Screen in the pre-application report once a screening tool is modified to add this new feature.

SCE is evaluating the feasibility of displaying locations where projects would likely fail Screen F or G. If SCE determines it can develop this capability at a reasonable cost, SCE would display this information along with the ICA values in the ICA maps. For now, SCE opposes Modification 2.

Qualified Positions

The Public Advocates Office supports raising the kVA threshold for these four Screens, as it will make the Rule 21 process more efficient by not requiring that the IOUs spend time and resources unnecessarily investigating projects between 11 and 30 kVA that do not impact safety or reliability. The Public Advocates Office also supports IOU efforts to display locations where projects would likely fail Screens F and G and recommends that any standards for displaying this information be applied consistently across all three IOUs.

GPI does not support the Pre-application Report option suggested by PG&E because from their perspective this adds considerable expense and time to determine whether the posted ICA value is likely to be accurate or not, and the Commission's clear direction has been that the posted ICA values be accurate.[8] GPI prefers SCE's flagging solution as a temporary solution until ICA includes Screens F and G, or a better solution is identified. The automation options for Screens F and G discussed Proposal 8.v will likely, when implemented, be a better solution than flagging.

Finally, some stakeholders have reservations about this proposal, noting that a "pass/fail" flag for Screen F and G may have limited value, given that successfully passing these Screens is a function of the project's size. Other stakeholders emphasize that the value of the proposal depends on what exact information the IOU provides and what the information means, both questions which remain unanswered.

In light of these different positions, IREC, CALSSA, and Clean Coalition have proposed that the Commission require the utilities to file an Advice Letter 120 days after the Commission's Order which would set forth their proposed approach to posting or otherwise providing information on likely Screen F, G and L results including any analysis of the costs of providing this information. If parties disagree with the proposals, they can protest the advice letters.

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[8] D.17-09-026 is replete with mentions of the need for accurate ICA results.

Proposal 8.i: Consider Applicability of Screen I for Non-exporting Projects Above 30kVA

Proposal

Option A: Relocate Screen I to the Rule 21 technical framework overview so that non-exporting projects above 30 kVA are reviewed under all Screens.

Option B: Do not relocate Screen I, continue to allow non-exporting projects of all sizes to skip Screens K, L and M. This is status quo, with the expectation that the issue will be reviewed in Phase 2 of this proceeding or through some other docket as appropriate.

Status

Non-consensus

- Option A:
  - Supported by PG&E, SCE, SDG&E, TURN
  - Opposed by IREC, Clean Coalition, CALSSA, Stem, GPI, Public Advocates Office
- Option B:
  - Supported by CALSSA, IREC, GPI, Clean Coalition, Stem, Public Advocates Office
  - Opposed by PG&E, SCE, SDG&E, TURN

Background on responsibility for grid upgrades when load changes

Except for NEM projects below 1 MW, Rule 21 currently holds interconnecting generators responsible for grid upgrades that are necessary to accommodate the interconnecting generator (see Rule 21 Section E.4). In the event load changes (i.e., increases or decreases) subsequent to that interconnection, the utility has several approaches to cost allocation for the associated costs. If the change falls under Rules 15 and 16, which cover new line extensions, cost responsibility is determined by the customer's obligations under the line extension contracts. If the change is not covered by Rule 15 and 16, such as for load increases or decreases that emerge in forecasted load, the utility would plan for necessary upgrades, seek approval of those costs from the Commission through a general rate case during the utilities' filing period, and, if approved, collect the costs of the upgrade from all customers. In the past, DER penetration has been relatively low, so load decreases have not been considered and thus have not triggered the need for upgrades; load increases were handled through overarching grid planning as a normal course of business. This dynamic has been aided by Screen M, which provided a flag that would allow the utility an opportunity to do additional review before the generation on a circuit got too close to the minimum load. However, that Screen currently does not apply to non-exporting generators, which may be offsetting load onsite and therefore reducing the load on the circuit. The Working Group asked, because larger non-exporting systems are expected to become more common, what may be the effect of changing load by non-exporting generators? Would the

Commission's approach to changes in load created by new non-exporting generators differ from its approach to other changes in load? How should these changes be evaluated and how should they be allocated under Rule 21?

The Working Group agreed this issue has broad implications, including some that are more appropriately considered in a ratesetting context where the Commission can make necessary determinations.

Discussion

Screen I ("Will power be exported across the PCC?") asks whether a project is export or non-export. Currently, if a project passes Screen I, it is allowed to bypass Initial Review Screens J, K, L, and M. Consequently, it also is not required to undergo Supplemental Review as long as it also passed Initial Review Screens A-H. The Working Group discussed whether non-export projects, which pass Screen I, should be required to be evaluated under subsequent Screens.

Option A

The IOUs' perspective is that, as levels of DER penetration are increasing in the distribution system, the level of ICA margin at various parts of the distribution system are diminishing to the point at which non-export projects which remove load from the system can potentially adversely affect the safety and reliability of the distribution grid by causing overvoltage conditions and possible overloads. In order to ensure that all DERs are connected to the grid in a safe and reliable manner, an adequate level of technical evaluation needs to be performed for all DER projects, including those that do not export power to the grid. This includes evaluating how non-export projects may affect the ICA parameters, including thermal, voltage, and protection. For these reasons, the IOUs propose to relocate Screen I to the Rule 21 technical framework overview so that non-exporting projects above 30 kVA are reviewed under all Screens.

Option A could result in new costs for interconnecting non-export projects. Option A would observe the existing cost responsibility rules in Rule 21 Section E.4.

Option B

CALSSA, Stem, Clean Coalition, and IREC's perspective is that customers may change the nature and quantity of their demand using a wide variety of tools for many different reasons. The utility proposal to relocate Screen I would cause some applicants to pay fees for Supplemental Review and to pay for distribution upgrades. This would be a major departure from existing cost responsibility and would discriminate between customers on the basis of the method they choose to use to reduce their load—even if the impacts are identical. For example, if a customer decreases their load by 20% via energy efficiency measures they would not be subject to any additional study or upgrade costs, but, by relocating Screen I, a customer reducing their load by 20% through the use of onsite non-exporting DERs would be subject to additional study and upgrade fees.

Furthermore, CALSSA and IREC assert that never in the past have customers been required to guarantee the utility any specific amount of load. Requiring them to pay for upgrades caused by decreases in load amounts to a departing load charge that is a major departure from current practice. It is not the reduced load itself that could cause a reliability concern; it is the fact that the line segment may no longer support the previously interconnected generation on that circuit segment. Thus, if a customer reduces consumption, they should not have cost responsibility for failing to support nearby DERs.

The Public Advocates Office maintains that one of the goals of Working Group 2 is to use the ICA tool to allow certain projects to bypass certain Rule 21 screens to make the Rule 21 process more efficient. This Joint IOUs' Issue 8.i Proposal makes the process less efficient by subjecting non-export projects to additional screens, and it does so with an insufficiently detailed technical justification from the IOUs. Therefore, the Public Advocates Office opposes the proposal and does not recommend subjecting non-export projects that have passed Screen I to additional screens they are not currently subjected to under Rule 21. If the IOUs provide a comprehensive technical assessment of the existing threats posed by non-export projects that pass Screen I that is complete with specific examples, stakeholders, including the staff of the Public Advocates Office, can re-assess the Issue 8.i Proposal in light of that new information.

Finally, CALSSA and IREC emphasize that the utilities have indicated that to-date this situation has never arisen and thus there is likely more time before this reaches the point where it is happening frequently enough to be of concern. In the meantime, the utilities retain the opportunity to review changing grid load conditions and take necessary measures at any time they deem warranted, without changing the processing of interconnection applications, Screens, timelines, or cost allocation principles.

GPI agrees with these concerns and suggests that since the identified issue has never occurred to date the Working Group should flag it as a potential issue and re-visit possible solutions when the projected impacts start to occur.

Proposal 8.k: Modify Screen L to Include the Transmission Overvoltage and Transmission Anti-islanding Test

Proposal

Option A: Screen L should be modified to include a transmission overvoltage and transmission anti-islanding test proposed by PG&E.

Option B: Screen L should be modified to include only a transmission overvoltage test.

Option C: Screen L should be modified to temporarily allow application of anti-islanding tests, as defined in writing by utility guidance documents, until the questions raised in Issue 18 can be addressed more thoroughly.

Status

Non-consensus

- Option A:
  - Supported by PG&E, SCE, SDG&E
  - Opposed by TURN, CALSSA
- Option B:
  - Supported by CALSSA
  - Opposed by PG&E, SCE, SDG&E
- Option C: IREC Proposal
  - Supported by IREC, GPI, Clean Coalition
  - Opposed by PG&E, SCE, SDG&E

Discussion

The existing Screen L (Transmission Dependency and Transmission Stability) tests whether the Interconnection Request is made in an area where there are known or posted transient stability limitations, or the proposed Generating Facility has interdependencies known to the utility with earlier-queued transmission system Interconnection Requests. The ICA does not identify the results of Screen L, because the analysis is not conducted up to the transmission level. However, PG&E contends that there are some areas where utilities have identified known transmission deficiencies that will impact the application of ICA.

Currently, Screen M ("Is nameplate generation > 15% of peak load?") evaluates whether there is a risk that aggregate generation could exceed 15% of peak load and, if so, identifies which projects should proceed to Supplemental Review. 15% of peak load is designed to approximate when generation on a circuit segment exceeds 50% of minimum load. PG&E has been using the 15% of peak load in Initial Review and 50% of minimum load calculations in Supplemental Review in conjunction with data on the presence of synchronous generators and substation grounding to identify when projects should undergo more detailed protection tests which are currently performed in Detailed Study such as traditional anti-islanding and transmission overvoltage.

SDG&E and SCE do not currently conduct this screening but have indicated a potential desire to do so in the future. PG&E identified that these transmission protection screens are not incorporated into ICA and therefore making Screen M less conservative by changing the current 15% of peak load methodology to the ICA means that these Screens need to be captured elsewhere. As detailed below, PG&E proposes that these screens be conducted in Screen L because Screen L is also evaluating transmission impacts.

It is noted that there is some overlap in this topic with Issue 18 ("should the Commission adopt changes to anti-islanding Screen parameters to reflect research on islanding risks when using UL 1741-certified inverters in order to avoid unnecessary mitigations? If yes, what should those changes entail?"). Working Group Four, tasked with Issue 18, is scoped to consider changes to the existing anti-islanding test while PG&E's Issue 8 proposal would move the screening from Screen M to L in the Initial Review.

Option A

PG&E proposes that the anti-islanding and over voltage evaluation screen be transitioned to Screen L from the current Screen M. Screen L will test for 15% of peak load for those circuits (based on proposal 8.l) that have a risk of anti-islanding and transmission overvoltage.

The proposal could be implemented with the following change to the tariff language (emphasis added):

> Is the Interconnection Request for an area where: (i) there are known, or posted, transient/dynamic stability limitations, or (ii) the proposed Generating Facility has interdependencies, known to Distribution Provider, with earlier queued Transmission System Interconnection Requests, or (iii<u>) islanding conditions are possible based on [PG&E, SDG&E or SCE's] currently adopted and published screening policies with respect to anti-islanding screening</u>. Where (i), (ii) or (iii) above are met, the impacts of this Interconnection Request to the Transmission System may require Detailed Study further study.
>
> - If Yes (fail), Supplemental Review is required.
> - If No (pass), continue to Screen M.

Initial Review's 15% of peak load and Supplemental Review's 50% of minimum load calculations are used in conjunction with data on the presence of synchronous generators and substation grounding to identify when projects should undergo more detailed protection tests that are currently performed in Detailed Study.

The detailed evaluation of anti-islanding and transmission overvoltage for those projects that fail Supplemental Review is conducted pursuant to the current PG&E standard.9 No

[9] The current standard for anti-islanding tests can be found here: https://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/TD-2306B-002.pdf.

changes to the technical evaluation is proposed at this time but the technical evaluation is in scope in Issue 18 in the proceeding.

Below is some additional detail on islanding and transmission overvoltage:

- Islanding is generally considered possible when the ratio of machine-based synchronous generation to inverter-based generation is over 40% and aggregate generation is greater than 50% of min load. 15% of peak load is used as the initial screen or filter to conduct additional screening on projects that exceed 15% of peak load.
- Transmission overvoltage is generally considered possible when a transmission breaker opens on a substation that has an ungrounded high side and aggregate generation is greater than 50% of min load. 15% of peak load is used as the initial screen or filter to conduct additional screening on projects that exceed 15% of peak load.

Option B

CALSSA contends that PG&E is misinterpreting the risk of anti-islanding failing to work. For Issue 8, CALSSA opposes PG&E's proposal not to use ICA values on circuits with machine-based synchronous generation. CALSSA does not oppose the addition of the transmission overvoltage screen. The reasoning for this position follows.

Anti-islanding is an essential function that requires DERs to shut down during a grid failure. It prevents DERs from operating as an unintentional "island" of generation that could pose a safety risk to utility personnel repairing equipment that they expect to be de-energized. Anti-islanding functionality is required by UL 1741. For years, the UL 1741 committee, which includes utility and non-utility representation, has thoroughly addressed this important issue.

The overarching policy proposed as part of 8.k. is being driven by PG&E's protection engineering department based on several studies conducted by Northern Plains Power Technology in cooperation with Sandia National Laboratories. These studies are:

1. "Unintentional Islanding Detection Performance with Mixed DER Types", Ropp Ellis, July 2018.
2. "Risk of Unintentional Islanding in The Presences of Multiple Inverters or Mixed Generation Types", Northern Plains Power Technologies, May 2015
3. "Suggested Guidelines for Assessment of DG Unintentional Islanding Risk", Ropp Ellis, November 2012

In addition, PG&E has engaged Northern Plains Power Technology to conduct its own internal study surrounding the impact of synchronous generators combined with UL 1741 certified inverters. This PG&E-funded study has been completed but the results have not been published.

All four of these studies were conducted using computer modeling programs, and their applicability is limited due to the lack of substantive real-world testing data. CALSSA takes no exception to the methods employed in the study process, but as with any study, the theory should be proven before it is incorporated into wider policy.

One independent study that reviewed real world UL 1741 inverter testing and grid conditions was conducted by General Electric in cooperation with PG&E for the Commission and is titled "Quantification of Risk of Unintended Islanding and Re-Assessment of Interconnection Requirements in High Penetration of Customer Sited PV Generation", Bebic – 2016, (the "GE Study"). Within this study, much of the anti-islanding theory proposed by Northern Plains Power Technology's first two studies (1&2 above) was proven to be inaccurate. PG&E used the results of this study to relax some of their islanding review requirements. However, on a broader scale, the discrepancy highlights an inherent inconstancy between computer models and real-world testing. In addition, PG&E's current review standards omit some of the recommendations proposed in the report.

PG&E's policy document on anti-islanding screening stipulates that islanding becomes a concern when the ratio of machine-based synchronous generation to inverter-based generation is over 40% and generation is more than 50% of minimum load. Breaking down the criteria in PG&E's policy, we note the following:

1. <u>50% minimum load</u> – The GE report states, "Power factor of the circuit has significant impact on island duration." The proposed 50% of minimum load check in 8.k. completely omits any check of reactive power matching possibility. The GE report goes on to recommend the following changes to the review process to more accurately assess the risk of islanding. Note the use of the term *simultaneous* load, not minimum loading.
    a. **In initial review**: raise the Screening limit from 15% peak load to 60% of estimated simultaneous load; the estimated simultaneous load will be based on conversion factors as was defined and implemented in [3].

    b. **In supplemental review**: Keep the existing minimum daytime load Screen when SCADA data is available and allow 80% of estimated simultaneous load by maintaining the power factor of the section below 0.98 inductive.

    c. **In detailed review**: Allow up to 105% of simultaneous load by de-tuning circuits to maintain the power factor between 0.95 and 0.98 inductive, to address islanding concern if needed.

Based on the recommendations in this report, CALSSA proposes adding a and b to replace the 50% minimum loading condition. In addition, we propose that c be allowed in circumstances that meet the defined criteria.

2. 40% Synchronous Generator Mix – This component of proposal 8.k is unproven. Adding it to Screen L as part of this Working Group is premature. No field testing has been conducted to verify the applicability of the research conducted by NPPT. Questions exist surrounding the field conditions that produce an extended run-on and whether the computer simulated grid are feasible in practice.

From a policy perspective, the intent of Issue 8 is to coordinate the implementation of the ICA, not to add in an unsubstantiated technical review measure. The question of anti-islanding review is going to be addressed by Issue 18 in this proceeding. From a policy perspective, Issue 18 is the more appropriate venue to address adding additional review points to the Rule 21 process.

PG&E has stated that the current approximate percentage of circuits impacted by the PG&E anti-islanding standard is approximately 7%.[10] This appears to be understated based on customer experience. Stakeholders should have the opportunity to independently verify this data point before any additional criteria are added to the anti-islanding standard. In addition, PG&E has implemented only one mechanism to address anti-islanding and that is to install Direct Transfer Trip at the substation level. Direct Transfer Trip results in typical costs above $1 million (either customer or ratepayer borne) and delays to interconnecting generation of up to 24 months. These results commonly cause projects to be withdrawn from the interconnection process.

Based on the impact of PG&E's anti-islanding policies and the fact that the results are still unproven, there should be no changes to the Rule 21 anti-islanding policy at this time. Stakeholders should have an opportunity to challenge the theoretical data and propose alternative, more cost- and time- effective measures to manage islanding.

Option C

Increasing the transparency and predictability of the Rule 21 interconnection process has been a fundamental principle that the Commission has been working towards since at least 2011, and the creation of the ICA was intended to significantly advance this goal in a transformative way. Throughout this Working Group report, nearly all of the proposals are intended, in one way or another, to enable interconnection customers to be able to identify particular locations for projects where interconnection hurdles would be minimal and to predict with greater certainty whether they will pass the Fast Track Screens and be able to interconnect swiftly and at a low cost. In addition, the ICA was a necessary step forward to

[10] PG&E discussion slides for May 16, 2018 Working Group meeting, slide 7, which can be found at https://gridworks.org/initiatives/rule-21-working-group-2/.

enable the state to move away from the use of the 15% of peak load Screen, which is quite conservative and has become, by a wide margin, the most commonly failed Screen. This will only become more common as penetration increases in the state. The other proposals in this report advance this goal, but the original IOU proposal to insert a layer of specific screens for anti-islanding that have not been vetted by stakeholders and researchers could dramatically and almost entirely undermine this goal.

The extent to which UL 1741-certified inverter-based systems create a risk that unintentional islands will be created is an area of significant dispute. PG&E currently has assessed that risk to be significant enough that it actively screens for the risk. SCE and SDG&E currently do not screen for this but have indicated that there is a possibility that they could do so in the future. The risk of a generation to load match that could create the potential for an island, while somewhat challenging to characterize, has been shown to be very low (e.g., 10-5 /second – see IEA PVPS task 5 report). In order for stable islands to occur, a close match in active and reactive power must also be present at the moment an interrupting device opens. For this reason, some Working Group members are skeptical about whether screening is really needed, and if so, whether the Screens currently used by PG&E (via their protection handbook) are sufficiently narrow as to target the real risks.

Currently, the consequences of determining that a project could create the risk of an unintentional island forming are significant. PG&E requires that a project install Direct Transfer Trip, which is both very costly (for ratepayers in the case of NEM projects, or developers/customers in the case of non-NEM projects) and can extend the timeframe for interconnection by 18 months or more.

After some discussion, PG&E modified its proposal and rather than defining the screens in Initial Review (as part of Screen L), and they then proposed to have projects fail Screen L where: "(iii) islanding conditions are possible based on currently accepted conditions and standards," which is highly problematic in two ways. First, rather than defining what the actual screen for anti-islanding or transmission overvoltage is, the proposed language vaguely referred to "accepted conditions and standards." This would have created a completely open-ended screen that would not specify what test will be used to screen the projects, undermining both the transparency and predictability concerns.

Second, there are no "accepted conditions and standards." Indeed, as noted above, there is considerable dispute about what is the "acceptable" way to screen for anti-islanding conditions, and there are not any nationally accepted standards that fully address this. This is evidenced by the fact that the three IOUs engaged here currently take very different approaches when it comes to screening for anti-islanding. The approach used by PG&E is accepted by them but not by others.

That said, IREC understand that a more thorough discussion of whether a screen for anti-islanding is necessary, and if so, what the screen will be, will happen when the Working Group gets to Issue 18, as outlined in the Scoping Memo. While IREC has significant concerns that the approach currently utilized by PG&E is unduly conservative, we recognize that use of the ICA for Screen M will impair their ability to apply their current screening method. Thus, in the interim, IREC recommends that the Commission adopt a more specific but temporary language in Screen L that would allow current Screening practices to continue until the Working Group reaches Issue 18.

Rather than referring vaguely to "accepted conditions and standards", the Commission should adopt the following language in Screen L:

> Is the Interconnection Request for an area where: (i) there are known, or posted, transient/dynamic stability limitations, or (ii) the proposed Generating Facility has interdependencies, known to Distribution Provider, with earlier queued Transmission System Interconnection Requests, or (iii) islanding conditions are possible based on [PG&E, SDG&E or SCE's] currently adopted and published screening policies with respect to anti-islanding screening. Where (i), (ii) or (iii) above are met, the impacts of this Interconnection Request to the Transmission System may require ~~Detailed Study~~ further study.
>
> - If Yes (fail), Supplemental Review is required.
> - If No (pass), continue to Screen M.

This proposed language would allow PG&E to utilize their current screening practices, as identified above, that look at whether a project has failed 50% of minimum load AND where 40% or more of the generation on the substation comes from rotating machines. SCE and SDG&E currently do not screen for anti-islanding, but should they determine that it is necessary in their opinion to do so prior to the Issue 18 discussion, this proposal would allow this so long as they publish a guidance document, similar to PG&E's, that identifies the specific screening approach they intend to use.

This is a subtle but important change to some of the Working Group members because it enables the customer to identify the specific screening approach that will apply to them and it does not memorialize any particular screening approach prior to the Issue 18 discussion. It is important that the Commission recognize that by allowing PG&E to screen using its current approach a significant number of projects that are proposed within the ICA limits are likely to fail Initial Review. Thus, it is important to ensure a thorough and fair discussion of this topic in Issue 18 and to only adopt this change on a temporary basis at this time. We have significant concerns that overly broad anti-islanding screening will undermine the progress on the ICA and result in unnecessary upgrade costs in some cases.

PG&E has modified their proposed language to mimic IREC's proposal which is appreciated, but IREC wants to make clear that our support for this change is temporary and must be followed with a rigorous discussion in Issue 18 of whether these screening methods are indeed appropriate.

Proposal 8.l: Provide Earliest Available Indication Where Screen L Failure is Likely

Proposal

The IOUs will post an indication of potential Screen L results on ICA maps.

Status

Non-consensus

- Supported by PG&E, TURN, Clean Coalition, GPI, IREC
- Opposed by: SCE, SDG&E

Discussion

The Working Group discussed how identifying locations where certain pre-existing grid conditions exist would be useful for developers in understanding where they may fail Screen L. These conditions are:

- fused high side of substation transformer;
- existing direct transfer trip or hard wire tripping scheme;
- synchronous generators present; and
- known transmission constraint areas.

Identifying where projects are "likely to fail" upfront will facilitate the transparency, predictability and streamlining of the interconnection process by allowing developers to make informed development choices. Thus, this proposal would provide more information for developers but is not an "actionable" number.

PG&E proposes to list this data with other feeder-summarized data (e.g., feeder name, circuit voltage, customer counts, generation totals, etc.). PG&E proposes two fields to help identify locations that could be of concern for Screen L:

- Substation High Side Fuse: Y/N
- Substation Direct Transfer Trip/Hard Wire Trip Installed: Y/N

As part of a potential future enhancement to SCE's ICA map, SCE is evaluating the feasibility of displaying locations where projects would likely fail Screen L. If and when this capability and information is available, SCE would display this information along with the ICA values in the ICA maps. SCE notes that what PG&E proposes as new fields are not applicable to SCE because SCE currently does not apply Screen L in the same way as PG&E. Instead of the two PG&E proposed fields, SCE would publish an additional notice in the ICA information field that would read:

> *Studies have shown that this area has transmission stability issues or dependencies which may cause the failure of Screen L.*

SDG&E does not support this proposal. IREC, Clean Coalition, and GPI support requiring all three IOUs to post information on their maps that helps to flag known conditions that might indicate whether a project may fail Screen L. CALSSA notes that circuits will not need to be highlighted for potential to fail the anti-islanding Screen if the anti-islanding Screen is not adopted in Proposal 8.k.

Proposal 8.m: Screen M should be modified to reflect ICA

Proposal
Screen M should be modified to reflect ICA

Status
Non-Consensus

- Option A:
  - Supported by PG&E, SCE, SDG&E, TURN
  - Opposed by IREC, GPI, Stem, Clean Coalition, Tesla, Sunrun, CALSSA, Public Advocates Office
- Option B:
  - Supported by IREC, GPI, Stem, Clean Coalition, Tesla, Sunrun, CALSSA, Public Advocates Office
  - Opposed by PG&E, SCE, SDG&E, TURN
- Options A or B:
  - Implementation Variation 1
    - Supported by Clean Coalition, IREC, CALSSA, SCE (qualified)
    - Opposed by SDG&E, PG&E
  - Implementation Variation 2
    - Supported by Clean Coalition, IREC, PG&E (qualified), SCE (qualified), CALSSA, SDG&E (qualified)

Discussion
There are five key limiting factors to whether a new DER can be integrated without impacting safe and reliable service and without requiring additional grid upgrades: thermal, voltage, power quality, protection and safety (i.e., operational flexibility). The ICA

is a methodology to assess the system's hosting capacity reflecting these limits, with each assessed independently.

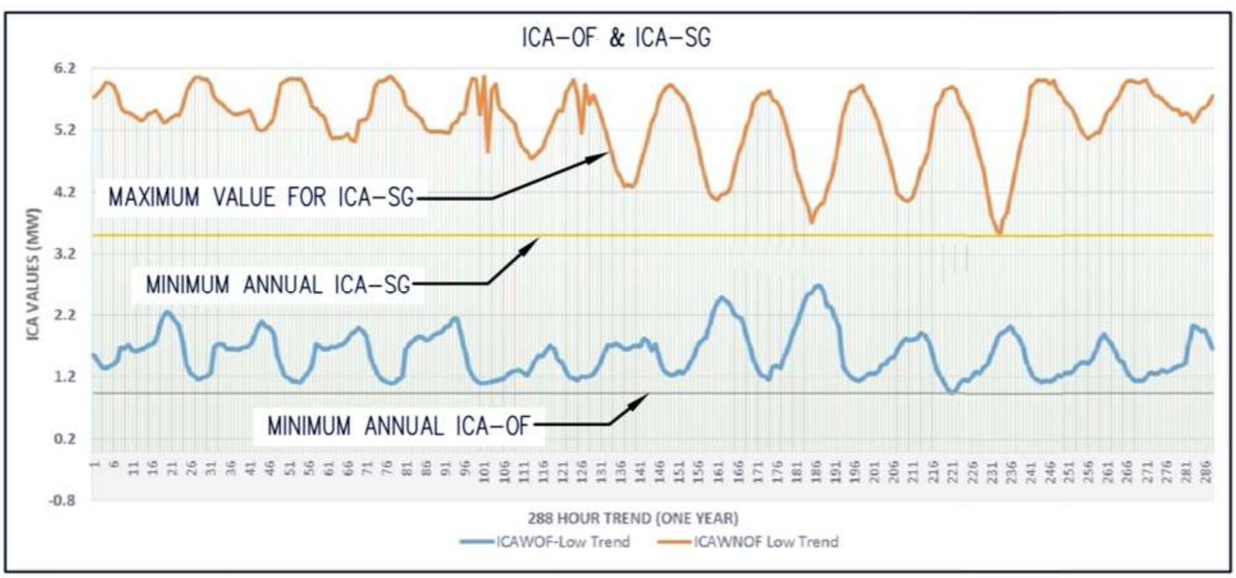
There are two types of ICA profiles being developed by the IOUs under direction from the Commission.

- ICA-Static Grid ("ICA-SG") 576 profile: This profile is the minimum ICA values at each of the 576 hours for the most limiting of these categories: thermal, voltage, power quality and protection.
- ICA-Operational Flexibility ("ICA-OF") 576 profile: This profile is the minimum ICA values at each of the 576 hours for the most limiting of these categories: thermal, voltage, power quality, protection *and safety*.

Where the safety ICA is not the lowest of all the categories, ICA-OF and ICA-SG are the same.

The ICA produces 576 values, a minimum and maximum load day for every month, for 12 months. Several points within the 576 values warrant emphasis, as illustrated in the following figure:

- The minimum annual ICA-OF value is the ICA's most conservative assessment of the system's ability to interconnect new DER.
- The maximum value for ICA-SG is the least conservative scenario.
- In between lies another operative value, the minimum annual ICA-SG



How the ICA impacts a DER interconnection depends on which of these limits constrains the hosting capacity at the Point of Interconnection and what DER generation profile you compare against that constraint. Different scenarios require different procedures. The scenarios considered by the Working Group are as follows:

- Scenario 1: A request to interconnect a generator at a point of interconnection constrained by the safety (or operational flexibility) criterion (ICA-OF).
- Scenario 2: A request to interconnect a generator at a point of interconnection constrained by either thermal, voltage, power quality, or protection criteria (ICAW-SG).
- Scenario 3: A request to interconnect a generator at a point of interconnection where an ICA value cannot be determined.

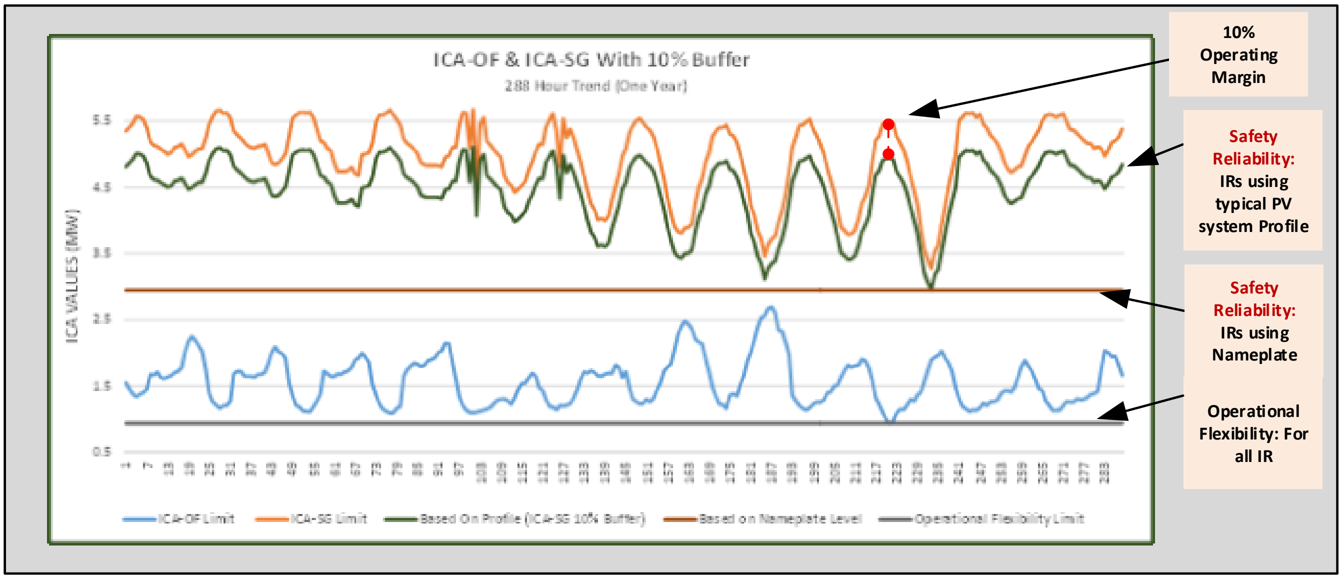
For all proposals under Issue 8, it is assumed that the generator has a fixed PV generation profile. Issue 9 considers these scenarios with a Limited Generation Profile.

When projects interconnect up to or near the point where generation and minimum load meet (i.e., 100% of minimum load), there is a risk that the load on a circuit may change after the project is interconnected, which can lead to safety and reliability issues without an opportunity to remedy the condition. If generation exceeds load, certain types of technical impacts could emerge. When interconnecting projects using the Initial Review Screens, the IOUs do not have a chance to verify the potential risks of load changes, and thus, the Working Group proposes to integrate a buffer into Screen M, effectively leaving space between the amount of expected interconnecting generation and the ICA value. As detailed in each of the following proposals, the applicability of the buffer varies by proposal.

Option A

The IOUs suggest a hybrid approach, applying a 10% buffer to the ICA-SG and no buffer to ICA-OF. Under this proposal, when the ICA-SG and ICA-OF are separated at each hour by more than 10%, (as depicted in the figure below) the following would occur:

- Safety (i.e., operational flexibility) would be evaluated with the ICA-OF. If the Interconnection Request is greater than ICA-OF, it would be sent to Supplemental Review for further evaluation.
- Thermal, voltage, power quality and protection would be evaluated against the ICA-SG with 10% buffer curve. If the Interconnection Request crosses this 10% buffer, then the necessary upgrades would be implemented to maintain the 10% buffer at minimum. Cost responsibility would apply per existing rules.



The IOUs propose the following language for Screen M:

- For Interconnection Request Based on Nameplate –
  a. Is the Interconnection Request aggregate nameplate capacity greater than 90% of the lowest value in the ICA-SG 576 profile; or
  b. Is the Interconnection Request aggregate nameplate capacity greater than 100% of lowest value in the ICA-OF 576 profile?

  If the response is "yes" to either (a) or (b), project must be evaluated under Supplemental Review or Detailed Study to determine mitigation requirements

- For Interconnection Request Based on Typical PV Output Profile –
  c. Is the PV Interconnection Request real power production based on PV Watts® or equivalent greater than 90% of the ICA-SG 576 value in any hour; or
  d. Is the PV Interconnection Request real power production based on PV Watts® or equivalent greater than 100% of the lowest value in the ICA-OF 576 profile?

  If the response is "yes" to either (c) or (d) project must be evaluated under Supplemental Review or Detailed Study to determine mitigation requirements

- ICA information not available – Use current Screen M.

Further, the IOUs propose if a project is interconnecting to an area of the system without ICA, the project is evaluated against 15% peak load using the current process. If ICA is not available due to customer confidentiality, ICA will still be used, with certain details withheld, consistent with current Commission data confidentiality rules for aggregating customer data.

If a project fails Screen M, it is sent to Supplemental Review to further study the project, which may include evaluating the impact on the operational flexibility of the system, thermal, protection, and power quality, including studying probable switching configurations in order to determine mitigation requirements

<u>Application Submittal Process</u>
For Interconnection Request Based on Typical PV Output Profile, CALSSA and SCE propose customers specify the incremental equipment details necessary for PV Watts or equivalent to generate project hourly output. This information should provide sufficient detail on the proposed equipment along with basic information about the configuration. This information can be used to calculate location specific generation capacity to be compared to hourly ICA values. Uniform generation will also be compared to the hourly ICA values, but there will be no need to create an hourly production profile for that comparison.

Note that this revision to the application submittal process will require an adjustment to the PV Watts tool to generate best-case generation capability data and integration of this tool to each of the IOU's application portals.

The exceedance of an ICA value during any hour evaluated will constitute a failure of Screen M. Further investigation in Supplemental Review will determine whether there are simple ways to address this failure.

<u>Option B</u>
IREC, Clean Coalition, Stem, CALSSA, Tesla, Sunrun, and the Public Advocates Office support a counter proposal, which aligns with the Option A except for the treatment of the ICA-OF.

These stakeholders object to the enormous buffer proposed by the utilities for review against the ICA-OF for Interconnection Requests based on a typical PV profile. They note that it is incorrect to view the IOU proposal as having a buffer on ICA-SG and no buffer on ICA-OF. 100% of the lowest value is much more conservative than 90% of hourly values. In D.17-09-026, the Commission set the ICA as having 576 data points. The IOUs have agreed to evaluate proposals against that hourly and seasonal data for ICA-SG but are proposing not to use hourly and seasonal data for ICA-OF.

The Public Advocates Office argues that the ICA is a tool that is being invested in by the IOUs and it should be used as much as possible to derive maximum efficiency for Rule 21. This option will get the most value out of ICA while maintaining grid safety and reliability.

Proponents of Option B propose that section (d) of the utilities' proposed language for Screen M be changed to:

Is the PV Interconnection Request real power production based on PV Watts® or equivalent greater than 100% of the ICA-OF 576 values in any hour?

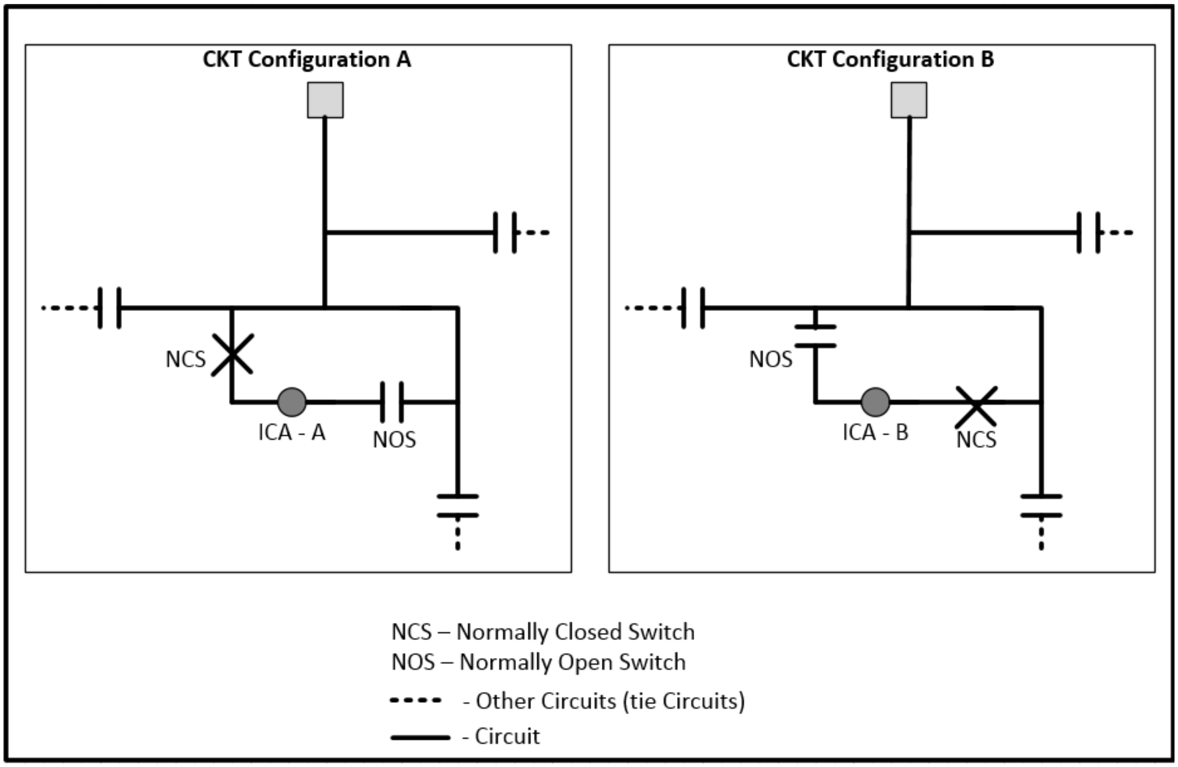
IOU Response

The ICA methodology accounted for operational flexibility between multiple circuits where minimum load at SCADA devices is used to determine the ICA-OF. However, the ICA methodology did not account for operational flexibility within a single individual circuit.

In many cases, distribution feeders have internal loops, which if modified could reduce the ICA values because of the way the circuit itself has been reconfigured. In the figure below, the ICA value is for the same electrical three phase node. However, if there is a need to internally reconfigure the feeder (e.g., for maintenance or operations) then the ICA values from configuration A and the ICA values for configuration B will be different even though the circuit has not been reconfigured with other circuits as intended for ICA-OF. Not accounting for this internal reconfiguration can lead to reliability and safety issues during normal operation of the grid.

Therefore, the IOU's reinforce that using the lowest value of ICA-OF is essential to ensure that the internal system can be reviewed as part of the interconnection process to ensure the safety and reliability for the DER connection up to ICA-OF can be maintained during normal operations of the grid.

The IOU's propose that this limitation to lowest value of ICA-OF would only be a condition to allow Supplemental Review to conduct review of the feeders' potential reconfiguration that could lead to grid reliability and safety issues.



In addition, having interconnection limits not based on a flat line would require a system to track those limitations and control a DER to prevent it from exceeding the limitations. This is subcomponent of Issue 9. With that, the IOUs are providing the same concerns here under this alternate proposal as it does for Issue 9:

- Error in forecasting of generation: uncertainty as to whether an actual generator profile may be faithfully represented by the forecasted Limited Generation Profile;
- ICA vs Operational Values: uncertainty as to whether the ICA-SG, the least conservative output of the ICA process, which is based on a forecast, will reflect actual grid conditions.
- Lack of experiences and infrastructure to work with generator controls: uncertainty as to whether the inverter and Data Acquisition System controls will meet expectations and consequent need for a utility system to supervise site controller.
- Lack of infrastructure to realized needed generation reductions: recognize grid operations happen in real-time, whether and how the IOU would know with certainty if/when the generator's output needed to be reduced, whether the IOU could effectively communicate the needed change to the DER, and whether the DER would respond in a timely and accurate manner.
- Questions about impact on subsequent interconnections: if an upgrade is avoided due to an operational constraint but the next customer elects to upgrade, does the operational constraint remain? Do utilities set rules that states that this line is now an operational constraint line and no upgrades will be allowed even if customer funded? What systems would be needed to operationalize such rules?

- Modeling Challenges: currently modeling of future planning and generation assume a typical PV output. Limited Generation Profiles adds new complexity to modeling.
- Applicability not well understood: do all customers need this option? Projects of all sizes and asset types?

The Joint IOUs note that an ongoing PG&E Distributed Energy Resource Management System ("DERMS") 2.0 pilot under the Electric Program Investment Charge ("EPIC") is actively exploring both how Limited Generation Profiles could be defined and enforced. This experimentation may lead to integration of solutions like the one being proposed here, but rigorous study is needed before that is possible.

<u>Options A or B</u>

Implementation Variation 1

CALSSA, IREC, and Clean Coalition oppose applying the buffer to the protection constraint. The ratio of load to generation does not determine whether a protection issue will arise, thus the reasoning behind the need for a buffer does not apply to protection. This variation would change the Screen to the following:

> *If the aggregate Generating Facility capacity on the line section is less in each hour evaluated than the lowest of 90% of the thermal ICA value, 90% of the voltage ICA values, 90% of the power quality ICA value, 100% of the protection ICA value, and 100% of the safety ICA value for that hour the Screen passes. If Screen fails, project is further evaluated under the Supplemental Review*

Implementation Variation 2

CALSSA and IREC believe the ICA would be much more user-friendly if the buffer were incorporated into the ICA values on the back end. If the thermal and voltage ICA values are de-rated by 10% before posting, it would be much more straightforward for the Screen to simply follow the adjusted ICA values. The ICA values could be posted in the adjusted form such that customers can use them without adding an additional buffer.

Utilities have expressed concern over their ability to include this before mapping ICA. If that is the case, the scripts can be adjusted at a later date. However, because there is still plenty of time before the ICA is put into practice, CALSSA and IREC suggest that this change can happen at some point before full implementation. If Implementation Variation 1 is adopted, PG&E and SCE are supportive of Implementation Variation 2 as well since it will better reflect where the buffer is required in the analysis and be less complicated for customers.

Proposal 8.n: Update Screen N Methodology

Proposal

Update Screen N to allow the evaluation of thermal overload, steady state voltage deviation, and protection reduction-of-reach when the Interconnection Request fails Initial Review due to exceeding the ICA values or Screen F1. This evaluation will also account for the default Volt-Var settings for inverter-based Generating Facilities.

Status

Non-consensus

- Supported by PG&E, SDG&E, SCE, IREC, Public Advocates Office, GPI, Clean Coalition, TURN, CALSSA

Discussion

Background

Screen N is a test of DER penetration. The Screen asks:

> *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.*

If the failure cannot be addressed through this review, Electrical Independence Tests and Detailed Studies are required. 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.

The significance of the Screen is that 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.

Tesla Perspective

Tesla would like to see this approach expanded to include profiles that are dictated by software controls as opposed to limiting the evaluation to "natural" profiles, like the standard solar profile.

Reasons for updating screen

Like the Screen M penetration test, the Screen N penetration test needs to be updated from its current methodology to a methodology based on ICA. In Screen N, projects that exceed ICA values will be evaluated to determine if there is indeed an impact on the distribution system and, if so, whether there are simple mitigations that can be identified without Detailed Study.

Screen N was originally designed to provide a method of determining possible negative impacts (e.g., thermal overloads and overvoltage) by verifying whether flow of electrical power from the distribution circuit to the low side bus of the substation would occur under typical DER operating conditions (i.e., 10am to 4pm for fixed panel solar Generating Facilities and 8am to 6pm for solar Generating Facilities utilizing tracking systems). This reverse power flow would not occur as long as the verifiable minimum load was greater than the DER real power output, thus maintaining this level of aggregate DER would insure that no electrical distribution systems would become overloaded and/or no overvoltage in the distribution circuit would occur. When the aggregated DERs exceed the minimum load, then the IOUs could perform additional analysis under Supplemental Review or Detailed Study, depending on the complexity of the distribution system and Interconnection Request.

Voltage conditions are a particular concern for solar interconnections because solar can cause voltage on the line segment to increase slightly. If a circuit segment already has voltage near the high end of the acceptable range and a new solar system is proposed, the proposed system must be studied carefully to make sure it does not push the voltage out of range. However, Rule 21 Section Hh now contains requirements that all new interconnections have certain smart inverter functions enabled. Among these is the Volt-Var function, which is designed to force each solar system to mitigate its own voltage impacts.

The voltage constraint may cause the application to fail Initial Review, but in Supplemental Review, the utility will consider the impact of Volt-Var and may conclude that there is no negative impact on voltage. Alternatively, the utility may find that an adjustment to the standard Volt-Var settings is needed due to the electrical characteristics of the specific line segment.

As part of the long-term refinements to the ICA methodology, the utilities are working with software vendors to incorporate Volt-Var and other smart inverter functions into the calculation of ICA values. Until that time, this impact can be considered in Supplemental Review.

With the implementation of ICA values that account for thermal overload, overvoltage conditions, and protection, Screen N needs to be adjusted for each of following scenarios that an Interconnection Request falls into relative to ICA:

1. When the Interconnection Request is below the updated ICA value and passes Screen F1: a new condition needs to be added in Screen N that states that Screen N can be bypassed if the Interconnection Request is below the updated ICA and has passed Screen F1.
2. When the Interconnection Request is above the updated ICA value or fails Screen F1: a new condition needs to be added to Rule 21 to address Interconnection Requests that are above the updated ICA or fail Screen F1. The IOU will determine if a quick review of the Interconnection Request may determine the requirements of interconnecting. If a quick review cannot determine the requirements to interconnect, then Electrical Independence Tests and Detailed Studies are required If voltage is a prevailing constraint, then the smart inverter default volt/var function will be used in power flow analysis for the evaluation of the proposed project. This will reveal if the proposed project causes any voltage impacts of concern. If concerns related to steady state voltage, thermal, or protection exist and the utility can identify simple upgrades through power flow analysis (e.g., installation of voltage regulator devices or protection devices to mitigate reduction of reach), then the Interconnection Request will use screen N to determine the mitigation requirements. When larger upgrades or complex protection evaluation is required, Screen N will fail and the technical evaluation will be conducted under the Detailed Study process.
3. When ICA information is not available: no changes to the existing process and Rule 21 are required. The utility will utilize the existing tariff language.

Proposal 8.q: Modify Screen P

Proposal

Update Screen P to account for new smart inverter capabilities.

To account for new smart inverter capabilities, the Working Group proposes to add the following item to the list of factors in Rule 21 Section G.2.c which may affect the nature and performance of an interconnection:

- Advanced inverter functionality and settings.

The following would be added to Rule 21 Section G.2.c as example of an item that may be considered under this Screen P:

- Will the proposed system cause any voltage impacts considering the settings of the Volt-Var function and the characteristics of the circuit segment?

Status

Consensus

Discussion
Screen P in Supplemental Review is used to determine if there are mitigations that can avoid having the project move to Detailed Study. The Working Group recommends the list of issue types that are considered be expanded to include advanced smart inverter functionality.

Voltage conditions are a particular concern for solar interconnections because solar can cause voltage on the line segment to increase slightly. If a circuit segment already has voltage near the high end of the acceptable range and a new solar system is proposed, the proposed system must be studied carefully to make sure it does not push the voltage out of range. However, Rule 21 Section Hh now contains requirements that all new interconnections must have certain smart inverter functions enabled. Among these is the Volt-Var function, which is designed to force each solar system to mitigate its own voltage impacts.

The voltage constraint may cause the application to fail Initial Review, but in Supplemental Review, the utility will consider the impact of Volt-Var and may conclude that there is no negative impact on voltage. Alternatively, the utility may find that an adjustment to the standard Volt-Var settings is needed due to the electrical characteristics of the specific line segment. The proposal made here allows the IOUs to account for such changes in its determination under Screen P whether Detailed Study is needed.

As part of the long-term refinements to ICA methodology, the utilities are working with software vendors to incorporate Volt-Var and other smart inverter functions into the calculation of ICA values. Until that time, this impact can be considered in Supplemental Review.

Proposal 8.r: The Interconnection Application Should Have an Option to Combine Initial Review and Supplemental Review, With Applicants Pre-Paying for Initial Review and Supplemental Review

Proposal
With the publication of the ICA results, which customers may use to size their projects, and the additional transparency elements discussed in this Working Group report, customers will have additional information to help determine if their projects may fail certain Initial Review Screens. Thus, it is proposed that customers can opt to combine the Initial Review and Supplemental Review processes to skip to and increase the efficiency of the overall process.

Status
Consensus

Discussion
This proposal is to add an upfront option on the interconnection application to allow a customer to pre-pay for Supplemental Review, alongside paying for Initial Review, and opt to proceed straight to Supplemental Review without the optional Initial Results meeting. The utility would then be authorized to combine the Initial and Supplemental Reviews into one analysis and to skip the time and steps that normally occur between those reviews. Applicants and the utility would benefit from additional time savings by opting to skip the Initial Results meeting. The applicant would still need to pay both fees for Initial Review and Supplemental Review, and the utility would still review the project under both the Initial Review and Supplemental Review Screens, except for the Initial Review Screens made redundant by the Supplemental Review. For example, Screen M is made redundant by Screen N.

In discussing this proposal, project developers were asked how often they take the option to review the Initial Review results report and schedule an Initial Review results meeting with the IOU engineers. A number of developers, including Sunworks, Sunpower, Tesla and CalCom Energy responded, giving a range anywhere from 0-50% of projects electing to take the Initial Review results meeting before heading to Supplemental Review. Even when they decline the meeting, there is a time lag which could be avoided by customers who elect to combine both processes without the need to have an Initial Results meeting.

Proposal 8.s: Reduce Interconnection Application Fee for Non-NEM Systems

Proposal
Option A: Change the application fee for non-NEM systems smaller than 1 MW to match the application fee for NEM systems.

Option B: Review actual costs and determine whether a $300 fee is appropriate for significant application categories.

Status
Non-consensus

- Supported by CALSSA, GPI, Clean Coalition (qualified), IREC (qualified)
- Opposed by PG&E, SCE, SDG&E, TURN

Discussion

Option A

An $800 application fee applies to non-NEM systems of any size. This includes relatively small non-export storage systems along with large wholesale systems. Until recently, most projects were either NEM solar systems smaller than 1 MW or solar systems larger than 1 MW that were not eligible for NEM. As energy storage has become more common, some of which is not paired with solar, there are applications for non-NEM systems far smaller than 1 MW that are proposing to interconnect. These small-scale projects bear more resemblance to small solar projects than large wholesale projects.

With implementation of the NEM successor tariff, NEM systems pay an application fee that is based on actual utility costs to process applications. Because applications for non-NEM systems smaller than 1 MW require roughly the same amount of work to process as NEM systems, they should pay application fees at the new NEM level rather than the full $800.

The IOUs disagree with CALSSA's characterizations. IOUs assert their data does not support these statements because for NEM projects, the overall average cost is based on thousands of residential NEM systems that average about 8 kW. The nearly 100,000 per year of small residential systems cause the average cost to be much lower for all NEM applicants. For these residential NEM projects, most of the complicated Initial Review Screens (e.g., Screens F, G, H, and E) are not evaluated for individual projects, which makes the overall technical study simple, fast and cost effective. This NEM-style technical review cannot be compared to non-export storage projects up to 1 MW because non-export storage projects require an evaluation of Screens F, G, H, and E and potentially an evaluation of loading profiles, which are all bypassed for small residential NEM projects. Therefore, is not appropriate to compare small NEM projects to large non-export projects up to 1 MW.

CALSSA further suggests that through the use of ICA data and other efficiency measures, it may be determined that smaller non-NEM applications result in average costs of less than half the standard $800 fee. CALSSA concludes that, because the fee is disproportionately burdensome on small projects, it should not be set significantly higher than the average cost for applicants in this category. The IOUs disagree with this statement as ICA does not evaluate all the Screens that require evaluation under the $800 fee. None of the Initial Review Screens, including Screens F, G, H, and E, are evaluated by ICA, and thus, the $800 application cost is appropriate to evaluate non-export project.

Option B

Clean Coalition and IREC support an alternative to the CALSSA proposal. Clean Coalition asserts that the current $145 fee for NEM systems is based on an average of all NEM applications, the vast majority of which are <30 kW. Initial Review of smaller non-NEM project applications are likely less costly to review than larger project applications and may warrant a lower fee, however it is not clear that a fee based on systems <30 kW is reflective of projects of all sizes up to 1 MW. In addition, any reduction in the $800 fee would be more meaningful to smaller projects than those closer to 1 MW.

Clean Coalition believes that the fee should reflect actual average costs, and these costs should be determined. Clean Coalition suggests that implementing a separate lower fee category would only be warranted where it is a significant reduction. Therefore, if it is determined that a defined class of applicants has substantially (>50%) lower average actual costs for Initial Review, then these applicants should be subject to a lower fee. Project review cost data is needed to establish whether this class includes all applicants <1 MW or only a subset (e.g., applicants <200 kW).

The IOUs oppose the Clean Coalition's inclusion of this proposal in the report, finding their opportunity to review the proposal was insufficient.

Gridworks determined inclusion of both Option A and B in the report was prudent, but agrees consideration of the proposal was limited. Gridworks suggests the Commission consider further input from parties on Proposal 8.s through comments on the record where supporting data can be gathered and analyzed.

Proposal 8.t: Queue Management

Proposal

Option A: Require justification for extending Commercial Operation Date; tighten deadlines; and allow small projects to interconnect if they do not impact larger projects that are in front of them in the queue.

Option B: Modified Option A with alternative approach to extending Commercial Operation Date.

Status

Non-consensus

- Option A:
  - Supported by CALSSA, IREC, Clean Coalition (qualified)
  - Opposed by PG&E, SCE, SDG&E, GPI, TURN
- Option B:
  - Supported by GPI, Tesla

Discussion

Developers of wholesale, front-of-the-meter DER projects must normally apply for interconnection before they have a counterparty to buy the energy or have a clear sense of whether they can obtain financing, secure environmental permits and satisfy other relevant factors that may affect a project's viability. This is the case whether the power is sold to the distribution utility under Rule 21 or to a different buyer under the Wholesale Distribution [Access] Tariff ("WD[A]T"). It has been necessary for wholesale developers to invest the resources to take these steps because the Commission's IOU procurement programs, as well as other energy purchasers, such as Community Choice Aggregators or direct access customers, have requirements for participants in their solicitations to have an interconnection agreement or at least have completed a phase 2 interconnection study or its equivalent. Those purchasers want to have confidence that a winning bidder has determined interconnection constraints and that any costs are reflected in the bids, such that the proposed project is financially viable. As such, completing interconnection studies is the first major development step after securing site control.

A downside of this situation is that until a developer wins a contract in a solicitation, they have a project with no buyer and are motivated to hold the reserved grid capacity for as long as it takes to find a buyer. This "queue sitting" impacts customers that want to invest in behind-the-meter DERs, as well as later queued wholesale projects, in locations where there is not enough existing capacity for their projects in addition to previously queued projects. Developers of behind-the-meter systems sized to serve onsite load always have a counterparty buyer because they are designing a system for the customer at that site.

Different stakeholders hold differing opinions on the current magnitude of this problem, but stakeholders agree it may worsen with the advent of the ICA. If a developer knows how much solar can be interconnected at a location without upgrade costs, they will be motivated to lock it in.

Currently developers expect there will be upgrade costs for large projects, so even though acting sooner will create a higher likelihood that there will be some amount of existing hosting capacity, the existing hosting capacity is not a known value and is expected to be low. As soon as the developer knows there is, for example, exactly 2.2 MW of hosting capacity at a location, there will be a lot of motivation to quickly design a system of that size and to worry about market opportunities later.

As noted, some stakeholders, including the Clean Coalition and GPI, disagree that the problem seeking to be addressed is yet a problem and are less concerned that the introduction of the ICA will make much difference. This opinion is based on their experience with earlier iterations of hosting capacity, expectations for whether ICA values will be up-to-date or stale (see Proposal 8.b), and their review of interconnection queues to date. Clean Coalition and GPI therefore oppose Part 1 of Option A, as detailed below.

<u>Option A</u>

The Commission should take steps to make sure the rollout of ICA does not result in a "land grab" of available hosting capacity. The proposals below are mild, in recognition that wholesale developers do need a lot of flexibility, but they head in the direction of addressing the problem.

1. Require justification for extending Commercial Operation Date

A developer with an approved project but no power purchase agreement should not be allowed to extend the Commercial Operation Date without having made real progress in construction or making clear efforts to find a buyer. If the developer is actively moving the project forward, they should have to resubmit and lose queue position.

Rule 21 currently states the following (PG&E Rule 21 Section F.3.e.iii) [**emphasis added**]:

> *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 agreement terms.*

CALSSA proposes the following changes:

- Commercial Operation Date must be set by mutual agreement, considering the intended counterparty, reasonable construction time, and grid upgrades. The developer must demonstrate progress in construction and in securing a power purchase agreement when requesting an extension. The utility will grant extensions of up to a year at a time due to construction delays, failure to secure a buyer despite good faith efforts, or circumstances outside of the control of the developer.
- If the Commercial Operation Date is more than two years in the future, developers should be required to submit an annual Summary of Activity beginning two years after the results of Initial Review or Detailed Study. Utilities will undertake an Activity Review of that summary. The utility will notify the developer that the application is deemed withdrawn if the developer does not demonstrate evidence of activity toward securing a buyer and constructing the project. Evidence of attempting to secure a buyer includes recently submitted bids and specific bids under development. Evidence of progress in constructing the project includes obtaining permits, securing financing, and actual construction. Failure to make progress toward construction should not lead to application withdrawal if it is due

to circumstances outside of the control of the developer, such as waiting for the utility to make distribution system upgrades.

2. Tighten deadlines

The current interconnection milestones for wholesale projects in Rule 21 include the following.

- Developer must have “site exclusivity” – own or lease the land or have an agreement for such – at the time of application.
- Developer must pay a deposit for the interconnection study.
- Developers must pay a financial security posting within 60 business days of signing the Generator Interconnection Agreement, per language that the utilities include in the Generator Interconnection Agreement, or lose their queue position. After ICA is made available, there may be very large projects that go through Fast Track and thus are not required to put down study deposits, which would greatly diminish the significance of this step.
- After agreeing to pay upgrade costs, if any, the utility sends a draft interconnection agreement to the developer within 15 business days and the developer has 90 calendar days to negotiate changes and sign the agreement. The agreement includes schedules for work to be completed by the developer and the utility associated with the distribution upgrades and interconnection facilities.
- Developer must make good faith efforts to meet the schedules in the interconnection agreement.
- If a project fails Screen R, developer has 40 business days to indicate whether they intend to be included in a Distribution Group Study. If a study window closes during that time, the project will be studied approximately six months later in the next Distribution Group Study.
- Applicant has 30 business days to agree to scope of study.
- Developer has 60 calendar days to post initial financial security for grid upgrades and interconnection facilities.
- Developer proposes a Commercial Operation Date and can request extensions of that date without restriction. Utility is obligated to approve extensions as long as the developer has paid the required deposits.

All of these steps add up to a very long timeline, especially when developers are intentionally moving slowly. CALSSA proposes the following changes to these milestones.

- Developers must pay the Detailed Study deposit within ten business days.
- Timeline for negotiating an interconnection application should be reduced from 90 calendar days to 60 calendar days.
- After failing Screen R, a developer has 20 business days to decide whether to enter the Group Study process with extension for an additional 20 days.
- Agreement on the scope of the Detailed Study should be completed within 20 business days rather than 30.

3. Allow small projects to interconnect if they do not impact larger projects that are in front of them in the queue

Large projects that take years to study can hold up small projects that would not impact the results of the study of the larger project. If there is 1.5 MW of hosting capacity at a location and a 5 MW proposed project is undergoing detailed study to identify needed upgrades, a 1 MW project behind the larger project in the queue should be allowed to move forward if it would not impact the extent of the upgrades needed for the larger project, or if the associated cost responsibility will follow the tariff obligations of the project with the later queue position.

Qualified Support

While supporting the proposals to enable later queued projects to advance, some Working Group members, including the Clean Coalition, have expressed concern that the proposed new annual proof of progress requirement may impose a reporting and enforcement burden which is not currently warranted. A review of the interconnection queues indicates a relatively small number of Rule 21 projects currently exceeding planned Commercial Operation Date, and no evidence of either increasing delay or a "land rush" associated with the ICA exists. Clean Coalition supports the approach but recommends development of evidence that the measure is warranted prior to implementation of this component of the proposal.

IOU Perspective

The IOUs oppose these proposals. PG&E finds there are aspects which may be beneficial, but the topic needs further discussion. PG&E highlights an upcoming surge in Zero Net Energy homes and potentially Rule 21 applications being submitted before construction begins on new home constructions. It is unclear whether timelines proposed here would work for majority of applications. PG&E does, however, support better queue management.

SCE notes the proposal refers to aspects of the Wholesale Distributed [Access] Tariff, a Federal Energy Regulatory Commission regulated tariff similar to Rule 21. SCE notes any recommendations relying on changes to the Wholesale Distributed [Access] Tariff are misplaced.

SCE also would modify Part 1 of Option A to set a firm deadline—a maximum extension of 18 months from the original Commercial Operation Date would be allowed—which would be enforceable regardless of construction status. SCE suggests extension requests greater than 18 months would require a reapplication and new queued position. This position, which is supported by PG&E and SDG&E, is designed to eliminate the need for subjective assessments of a project's progress which the IOUs contend will lead to contentious disputes with their customers.

With regard to Part 2 of Option A, the IOUs are reluctant to alter timelines as suggested.

With regard to Part 3, SCE opposes this proposal. While this sounds simple, it is not. In the scenario described above, it necessary to first determine what type of mitigation the 5 MW project is required to implement in order to determine if the 1 MW project can be interconnected without additional upgrades. Using the example above, because the 5 MW project came into the queue prior to the 1 MW project, the 5 MW project has the right to use the 1.5 MW of ICA-identified capacity first and its only required to pay for mitigation for the additional 3.5 MW of generation. In this scenario it is unlikely that the 5 MW project will install upgrades that would allow the 1 MW project to also interconnect without additional upgrades. For example, the 5 MW project may cause some sections of the circuit to get close to thermal overload, but the 1 MW project would cause those sections to be over the thermal limits, making the 1 MW project responsible for the upgrades. This type of analysis cannot be performed until the utility fully studies the 5 MW project.

If both projects have received their full studies and the 5 MW project takes longer to complete construction then the 1MW project, then SCE believes that it is reasonable to allow the 1 MW project to be interconnected ahead of the 5 MW project, as long as the 1 MW project pays for the upgrades identified in its study.

Option B

GPI's Option B is identical to Option A, except for one deviation on Part 1 of the CALSSA proposal.

Instead of Option A's suggested approach to continuations of a project's Commercial Operation Date, GPI suggests the utilities continue to rely on the negotiation phase of the interconnection process, which takes place before finalizing the Generator Interconnection Agreement. GPI notes that the milestones negotiated within that process can be numerous and detailed. As such, there is already a process in place that holds wholesale interconnection customers accountable for moving ahead judiciously, with the risk of being removed from the queue if these milestones are not met and not cured within the time allotted.

Tesla supports GPI's proposal.

Proposal 8.v: Additional Automation and Streamlining Opportunities

Proposal

The Commission should consider the Interconnection Automation and Streamlining Opportunities report (attached as Appendix A) and provide guidance on further action within this proceeding regarding:

1) how future Working Group schedules can include additional discussion of the automation opportunities identified;

2) review of the likely costs and benefits of implementing automated data processes to reduce costs and streamline interconnection processes and schedules;

3) coordination of related IOU investments in line with the Commission's Distribution Resources Plan precedent, the DER Action Plan, and the merits of including automation goals in the DER Action Plan or a separate automation roadmap.

Status

Non-consensus

- Supported by GPI, Clean Coalition, Stem
- Opposed by PG&E, SCE, SDG&E, TURN

Discussion

In discussing Issue 8, the Working Group identified that certain actions that facilitate automation are not necessarily related to integration of ICA, but are part of the Working Group 2 scope.

GPI and Clean Coalition led the development of recommendations and identified additional automation and streamlining opportunities for the Rule 21 process, beyond the automation of ICA that is already taking place. The intent of the draft Interconnection Automation and Streamlining Opportunities report included in Appendix A is to form the starting point for an actionable "roadmap" for further automation and streamlining of the interconnection process for adoption by the CPUC, after additional discussion in this proceeding.

GPI and Clean Coalition, with support from Smarter Grid Solutions as engineering consultants, took the lead in drafting the report and solicited input from stakeholders, including IOU and non-IOU Working Group members, to refine the understanding of opportunities and develop recommendations. GPI and Clean Coalition had several opportunities to present their research and recommendations to the larger Working Group and circulated the report for written comment during the course of Working Group 2. The result is a GPI and Clean Coalition proposal informed by other stakeholders. It is not a comprehensive reflection of input received, and it is only representative of the views of stakeholders identified as "supporters."

The Working Group has several discussions of the potential cost implications of this proposal. TURN repeatedly and clearly expressed the need for a high-level cost estimate of these automation opportunities before a roadmap should be developed. As the Report shows, to date only a *relative* cost-benefit analysis has been provided. GPI and Clean

Coalition identify cost estimates as a topic worthy of further discussion and invite utility proposals of those potential costs.

A summary of the most promising opportunities identified by the GPI/Clean Coalition draft report and resulting discussions are as follows:

1. Automating the application process and completeness review
    a. Reduce review time from 1-40 business days to as little as 1 day for projects that don't require corrections
    b. Reduce turnaround time for corrections from 10 business days for each round of corrections to 1-2 days with automated interconnection portals
    c. Issue 22 has already scoped potential revisions to the interconnection portals, and this contributes to that work
2. Automating (at least partially) Initial Review
    a. Automating analysis of refined Screens toward reducing time from 15-17 business days to 1 day <u>for eligible projects</u>
    b. Further evaluation of costs and benefits is required
3. Automating (at least partially) Supplemental Review
    a. Reduce time from 20-22 business days or inclusion of the Supplemental Review Screens in Initial Review (no additional time required for Initial Review) <u>for eligible projects</u>
    b. Screens N and O have been automated as part of ICA, leaving the catchall Screen P for engineering review
4. Frontloading and automating the Generator Interconnection Agreement drafting process
    a. Provide template Generator Interconnection Agreement to customer after application deemed complete, in order to frontload customer review of GIA terms
    b. Automated population of template Generator Interconnection Agreement with Initial Review/Supplemental Review results so that draft Generator Interconnection Agreement can be generated in 1 day rather than 15 business days
    - Work to identify additional automation and streamlining items

Opposing Parties' Perspectives

TURN opposes the inclusion of the report from Smarter Grid Solutions. TURN's perspective is that the proposal needed to be supported by a high-level cost estimate of automation opportunities. The report instead provided arelative cost-benefit analysis. TURN concludes these materials are interesting but insufficient. TURN reasons that just because Proposal A is worse than Proposal B doesn't make B a good proposal. In addition, the IOUs have not indicated that they agree with the analysis conducted by Smarter Grid Solutions on behalf of GPI and Clean Coalition. Thus, TURN opposes the inclusion of the report by Smarter Grid Solutions. Furthermore, TURN recommends that the Commission not treat GPI's proposal as a roadmap. Rather, GPI's proposal should be seen as identification of potential opportunities to be analyzed later, including conducting a cost-benefit analysis, identifying stakeholders that benefit from the proposals, and discussing the proper cost allocation for these costs.

SCE appreciates GPI's and Clean Coalition's efforts to identify aspects of the interconnection process that could be streamlined through changes to relevant IT tools. However, SCE cautions that scoping, development and implementation of such IT tools will require time and cost. CPUC authorization for additional funding will be required to accomplish many of the aspects of the GPI and Clean Coalition "report." Such funding approval is typically addressed in a utility's General Rate Case.

SCE points to a few areas in the report that are especially concerning to SCE.

- **Automation of completeness review:** The proposal to automate the completeness review does not account that verification of PDF Single Line Diagrams requires engineers to physically verify details that cannot be done by an automated system. For example, the engineer needs to verify connection points for current transformers, potential transformers, metering, and other devices. It necessary to verify this information to prevent safety issues and costly modification. In many cases, these Single Line Diagrams need corrections by the customer as part of the application review process.
- **Automation of Initial Review Screens:** Several of the screens (e.g., Screens F and G) require significant work to prepare and maintain very complex databases that are continually changing. Even the ICA work did not include these Screens due to their complexity and thus automation of these screens should be a long-term goal.
    - GPI response**:** our report identifies how Screens F and G could be automated with existing tools and databases.
- **Automation of Supplemental Review:** The Screens in Supplemental Review are complex to automate as proposed:
    - Screens N and O requires power flow analysis to be completed. This means that the automation tool would have to call a power flow tool (e.g., CYME) and automatically update network models with the right point of interconnection and the correct DER level. This level of automation is, at this point, not available and should be a long-term goal
        - GPI response: Screens N and O are already automated as part of ICA, including map integration.
    - Screen P cannot be evaluated by a power flow tool as this Screen evaluates safety issues that cannot be evaluated by the other Screens. To perform this evaluation, the engineers need to look at characteristics of the overall system in conjunction with proposed and existing Interconnection Requests.

    - GPI response: we are not proposing at this time that Screen P be automated, and the report states as such.
- The report confuses the automation being done as part of the ICA development process with automation for the Rule 21 interconnection process. It is correct that the ICA working group final report mentions automation multiple times, but, the context of the automation in the ICA report in development of monthly ICA values not automation of the Rule 21 interconnection process.
    - GPI response: our report does not confuse or conflate automation of ICA with automation of Rule 21 more generally; we are clear in distinguishing these two issues. We also note that Issue 8 specifically scopes "interconnection process automation" and how ICA can facilitate such automation.

PG&E's perspectives:

- In general, PG&E supports improving automation and IT systems, but we have to make sure we do it properly and that Rule 21 timelines remain what they are now. There are times when systems fail and manual workarounds have to be engaged, so compliance timelines should reflect the manual process
    - GPI response: our report discusses the need to phase in automation for most projects, but not all projects; so projects that still need to go through manual review can do so under existing timelines, but most projects should be automatable and subject to much faster timelines.
- Since this recommendation involves consideration of costs, if supported by the Commission, it should be considered as an element of funding approval which is typically addressed in a utility's General Rate Case. Consideration of any IOU expenditures should not be addressed in the Rule 21 proceeding. Such funding approval is typically addressed in a utility's General Rate Case.
    - GPI response: many tasks utilities are assigned from legislation or the Commission do not require General Rate Case funding approval, including the ICA itself; our view is that much of the automation and streamlining work can be funded outside of the General Rate Case process.
- Note that IT costs were covered in the IOU responses to the ALJ's August 15th Ruling question 5 under Issue 3. (If the Commission orders development of Process Options 2 and/or 3, should the Utilities recover their costs through the General Rate Cases, balancing accounts, or increasing the interconnection application fees? Explain the reasoning for your preferred approach.) Cost treatment to the extent appropriate should be consistent.
- It is important to note that these timeline reductions should not be carried over into Rule 21 itself. Efficiency gains and automation are what we should be striving for, but they are not infallible solutions. As such, Rule 21 compliance timelines should reflect what the manual process of performing the task entails, keeping in mind the volume of projects that the IOUs are experiencing.

- GPI response: our report discusses the need to phase in automation for most projects, but not all projects; so projects that still need to go through manual review can do so under existing timelines, but most projects should be automatable and subject to much faster timelines.

Issue 8 APPENDIX

Interconnection Automation and Streamlining Opportunities:
Preliminary findings and recommendations

Tam Hunt, GPI

Sahm White, Clean Coalition

With review and assistance by Smarter Grid Solutions, Inc.

This document was drafted as part of the R.17-07-007 Working Group 2, to be included as an appendix to the Working Group's final report. GPI and Clean Coalition intend that this document, with further deliberation and cost-benefit analysis, be used as guidance in consideration of an actionable "roadmap" for adoption by the Commission in a later phase of the current proceeding.

This document is representative of the authors' perspectives with various rounds of input from working group members received as of Oct 3, 2018. Due to differences in party opinions the document as a whole does not necessarily reflect the perspective of any individual Rule 21 Working Group member.

Table of Contents

Proposal 8.v for Commission action in relation to this report:

That the Commission review this document and provide guidance on further action within this proceeding regarding:

1) how the Working Group can best schedule additional discussion of the automation and streamlining opportunities identified;

2) review of the likely costs and benefits of implementing the Working Group's automation and streamlining recommendations;

3) coordination of IOU automation investments in line with the Commission's Distribution Resources Plan (DRP) precedent, the DER Action Plan, and consideration of including automation goals in a new DER Action Plan or a separate automation "roadmap."

I. Summary of recommendations and background

The Green Power Institute and the Clean Coalition presented, on April 25, 2018, to Working Group 2 a preliminary review of opportunities for either full or partial automation of the various aspects of the Rule 21 interconnection process in support of the Commission's goal of dramatic interconnection streamlining. After significant dialogue between various Working Group parties, this report describes the initial findings and recommendations for the most promising automation and streamlining opportunities.

The automation engineering firm Smarter Grid Solutions was engaged by GPI to provide feedback to the working group on the proposed recommendations included, and provided broad cost-benefit review of the report's key recommendations.

<u>Most of the recommendations in this report are intended to apply to behind-the-meter projects over 500 kW as well as front-of-meter projects of any size, because these projects don't currently enjoy the benefits of automation or low/no-cost interconnection that small behind-the-meter projects do enjoy.</u>

In terms of the benefits of the recommendations below, the authors of this report see three major time savings opportunities, as follows: 1) saving as much as 10-40 business days in the application and completeness review stage; 2) saving as much as 10-30 business days in the Initial Review and Supplemental Review; 3) saving as much as 30-60 calendar days in the GIA review and negotiation process. These potential savings add up to as much as six months savings for each Fast Track interconnection application.

Time savings are significant wherever projects are operating under a restricted schedule, such as in solicitations for DER to meet location-specific needs, compliance mandates, or funding opportunities. These savings can also be substantial because many developers, particularly for front-of-meter projects, must go through an interconnection process multiple times before a viable location is found. While ICA and Pre-application Reports (PAR) help with this, the ICA only addresses some factors, and the PAR require $1,100 and 40 days each for detailed information, and PAR information is not definitive (only interconnection studies are definitive). As such, time savings for going through the interconnection process each time can add up quickly and lead to substantially reduced overall development timelines and related costs. These cost savings will be passed on to ratepayers.

It is also important to note the distinction between behind-the-meter and front-of-meter projects in terms of development timelines and prioritization. For front-of-meter projects, completing interconnection studies early in the development process is imperative, in order to test project viability in light of the expected interconnection costs. Smaller wholesale projects (ReMAT and RAM, for example) are particularly sensitive to project costs because profit margins are thin. Moreover, utilities are increasingly requiring Fast Track studies (phase 2 studies or their equivalent like Fast Track) to be completed before bids may be submitted into RFPs.

A summary of key opportunities for automation and streamlining follows, with information about each utility's status with respect to each automation:

- **Automating the application process and completeness review**. Utilities must inform the applicant whether the application is deemed complete, or must be corrected, within 10 business days (BDs) after receipt of the Interconnection Request (E.5.a). In practice, this step can take two months or longer if multiple corrections are required (as is common for larger projects). Automation of the interconnection portal and application processing could reduce this step to one day for those projects that don't need corrections, as well as dramatically reduce the time required for each round of corrections, and can build upon existing on-line application portals for net-metered projects, which already significantly reduce application processing times through partial automation. PG&E states that it has already planned for the work required to automate the application portal and its small NEM application review is already automated. SCE has gone out to bid for similar work to update and partially automate its interconnection portal, but the full extent of this effort is not known at this time. SDG&E's DIIS portal is already partially automated but SDG&E has no plans to further automate its portal.

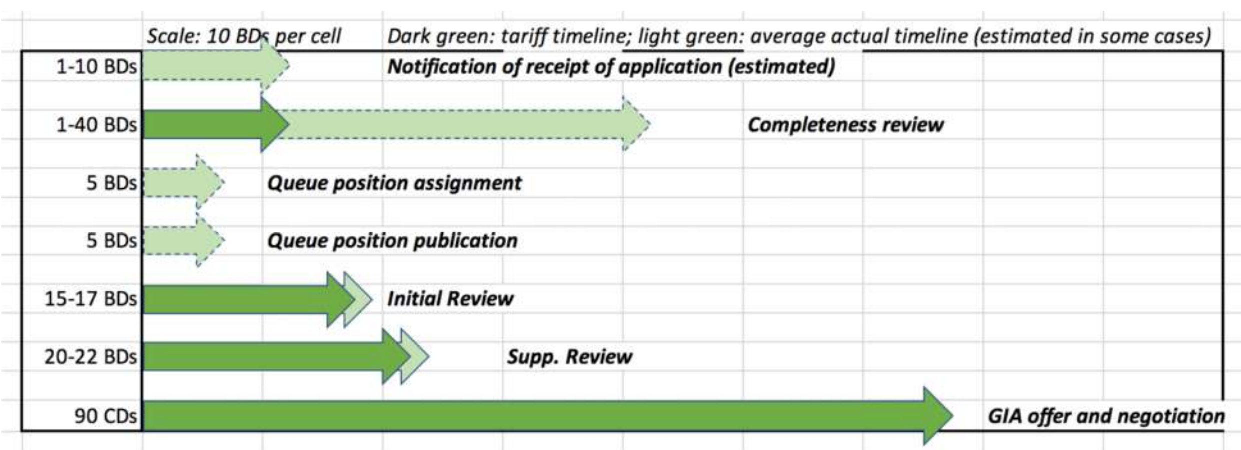
- **Automating (at least partially) Initial Review**. Initial Review must be delivered within 15 BDs of the application being deemed complete (F.2.a). If applicable Screens can be cleared automatically through use of data from the online application inputs and ICA data, it may be feasible to reduce the Initial Review to 1 BD. This report identifies feasible ways for achieving this level of automation. PG&E agrees with the merits of automating IR, and notes that all Screens except F and G are already automated, but considers it necessary to maintain the 15 BD review in order to allow engineers to study mitigation options for projects that fail IR.[11]
- **Automating (at least partially) Supplemental Review**. Supplemental Review must be completed within 20 BDs (F.2.c). Parts of SR may already be automated with the existing ICA (Screens N and O are already automated with the current ICA). Under the currently-defined SR Screens, this leaves only Screen P, a "catch all" safety and reliability Screen, to be completed in SR. PG&E agrees that parts of SR can be automated but note that a cost/benefit analysis should be completed before a decision on full automation is made by the Commission.
- **Frontloading Supplemental Review Screens N and O into Initial Review.** Projects that are less than or equal to displayed ICA value, or otherwise expect to interconnect without need for Supplemental Review, may be susceptible to largely automated initial review. Frontloading Screens N and O into IR will allow an easier automation of Initial Review because Screen N makes Screen M redundant and Screen O renders some IR Screens, or at least part of those Screens, redundant. (This recommendation may be mooted by changes contemplated in the Issue 8 draft proposal for changes to Screens M and N)
- **Combining Initial Review and Supplemental Review**. Only applies to projects that select this option, which will generally be 500 kW and larger behind-the-meter and front-of-meter projects of any size. Combined review could either be a serial study process, skipping the IR results meeting, or a concurrent study process. Revised timelines and fees for the combined IR/SR to be determined as part of the working group process.

[11] GPI notes that the utilities don't generally offer mitigation options until Supplemental Review is completed, so it is not clear that a 15 BD timeline for IR is necessary if this is the case, even for projects that fail IR. In GPI's experience, IR results in a short report stating which Screens, if any, are failed, with information about the applicant's choices for how to proceed.

- **Frontloading and automating the Generator Interconnection Agreement** (GIA) generation and offer process. A GIA currently must be offered to most applicants within 15 BDs of passing Initial Review or 15 BDs of applicant's request after passing Supplemental Review (F.2.c.iv). This step could be "frontloaded" by offering a fully or partially populated provisional GIA once an application is deemed complete, allowing the applicant to begin detailed review of the draft GIA much earlier than under the existing process. Execution of the final GIA may be streamlined by such frontloading and also by including the key IR or SR results in a second, automatically-generated, GIA, such that the fully populated draft GIA generation process takes only 1 BD for the large majority of projects instead of the 15 BDs currently allowed in the tariff. Frontloading of the initial GIA should also reduce the 90 CD negotiation period. PG&E is already planning this work but notes that it will be difficult to automate inclusion of mitigation options into the GIA. SCE has recently completed a behind-the-meter energy storage interconnection pilot that included frontloading the GIA; SCE has no plans currently to expand this pilot approach to additional technologies.

Figure 1 illustrates the Rule 21 Fast Track tariff-specified timelines (darker green arrows) and average actual timelines (lighter green arrows), with estimates in dashed arrows, for projects over 500 kW. Where there is no dark arrow there is no tariff-specified timeline.[12]

Figure 1. *Fast Track timelines under Rule 21.*



[12] Sources: IREC R.17-07-007 2018 data requests and responses from PG&E and SCE (SDG&E is excluded because data set was so small); interconnection experience by GPI attorney Tam Hunt working with his private clients over the last decade; and other developers such as Tesla working with thousands of C&I solar projects.

The utilities have already significantly and effectively leveraged automation to streamline the application submission process and some additional aspects of application management and review, as described below. Existing utility automation efforts have, however, focused on smaller net-metered systems, but those existing efforts can in many cases be expanded to include over 500 kW behind-the-meter and front-of-meter projects of any size seeking to interconnect under Rule 21. Costs and benefits of expanding these existing procedures is discussed at the end of this report.

There are also a number of pilot projects that will be useful for automation and streamlining efforts in this proceeding, including the DOE and CEC-funded EASE pilot project that is hosted by SCE, and the Interconnection Online Application Portal (IOAP) pilot being developed by AVANGRID in New York. These efforts are described further below.

We describe below how many aspects of the interconnection process could be automated for the large majority of projects. While achieving such automation sounds ambitious, we want to stress the phrase "for the large majority of projects." Reaching full automation of interconnection for all projects is a longer-term goal that may not be warranted given the costs of achieving such wide-scale automation—if, for example, only a small number of projects per year would benefit from these improvements. But increasingly robust automation, or even full automation of review for the large majority of projects, is an attainable and probably cost-effective task (more work will be required in examining costs for some aspects of automation)[13] at this time.

We must also consider the intent of AB 327 and the Commission to encourage DER, rather than only reacting to DER interconnection issues, by proactively creating a dramatically streamlined interconnection process.[14]

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[13] We include some considerations on cost-effectiveness at the end of this report.

[14] D.17-09-026 in the DRP proceeding, created by AB 327, echoes the DRP's Final Guidance document in calling for "dramatic streamlining" of the interconnection process as a key step for helping DERs (p. 26)."

II. How does the existing Rule 21 interconnection process work?

It is helpful to consider the following Figures 2 and 3 showing the full timeline for Fast Track interconnection for both front-of-meter projects and a 1 MW behind-the-meter project, including pre-application items and post Interconnection Agreement items.

Figure 2. *Interconnection costs and timelines for Rule 21 Fast Track 1 MW front-of-meter.*[15] [16]

Wholesale DG timelines and costs — Clean Coalition

WDG Rooftop 1 MW Fast Track Project Development (Project where ICA map indicates sufficient capacity)	Timeframe (BD) Max	Timeframe (BD) Min	Timeframe (BD) Typical	Fees Max	Fees Min	Fees Typical	Costs Max	Costs Min	Costs Typical
PRELIMINARY WORK AND SITE CONTROL	371	113	218						
Site Selection	2	1	1	$-	$-	$-	$600	$200	$300
Preliminary site evaluation and project screening	2	1	2	$-	$-	$-	$600	$150	$300
Preliminary layouts and performance models	7	1	3	$-	$-	$-	$4,000	$1,000	$2,000
Site control (Lease Option Agreeement)	180	60	100	$-	$-	$-	$40,000	$15,000	$25,000
Preapplication reports	60	30	35	$600	$300	$600	$1,500	$500	$1,000
Other site research and selection	120	20	75	$5,000	$500	$1,500	$15,000	$3,000	$9,000
INTERCONNECTION REQUEST AND INITIAL REVIEW	50	23	37						
Prepare and submit interconnection application	10	3	5	$800	$800	$800	$20,000	$5,000	$10,000
Utility deems application complete	10	5	7	$0	$0	$0	$0	$0	$0
Initial review results	15	15	15	$0	$0	$0	$4,000	$2,000	$3,000
Developer requests initial review results meeting or proceeds to supplemental review	10	0	5	$0	$0	$0	$0	$0	$0
Initial review results meeting (if clear, go to GIA cost estimate or GIA)	5	0	5	$0	$0	$0	$1,000	$500	$750
INTERCONNECTION SUPPLEMENTAL REVIEW	110	50	70						
Decide to proceed to Supplemental Review	15	0	5	$2,500	$2,500	$2,500	$600	$150	$300
Supplemental review results	60	20	30	$0	$0	$0	$4,500	$2,100	$3,300
Developer requests supplemental review results meeting	15	0	5	$0	$0	$0	$0	$0	$0
Supplemental review results meeting	5	0	5	$0	$0	$0	$1,000	$300	$500
Decide to proceed to GIA draft	30	30	30	$0	$0	$0	$0	$0	$0
POWER SALES CONTRACT	340	100	180						
Review power sales options	100	20	60	$0	$0	$0	$5,000	$2,000	$3,500
Obtain Power Purchase Agreement	240	80	120	$2,000	$0	$1,000	$20,000	$5,000	$12,500
Negotiate GC/EPC and engineering contracts	30	10	20	$-	$-	$-	$10,000	$1,000	$5,000
GENERATOR INTERCONNECTION AGREEMENT (GIA)	60	1	30						
GIA negotiations and signatures (90 Calendar Day max time allowed)	60	1	30	$0	$0	$0	$5,000	$2,000	$3,500
GRID UPGRADES CONSTRUCTION**	250	0	100						
Grid upgrade costs				$0	$0	$0	$300,000	$0	$150,000
O&M costs (Cost of Ownership or COO)***				$0	$0	$0	$150,000	$0	$75,000
Coordinate upgrade construction with utility, deed transfers				$0	$0	$0	$10,000	$2,000	$6,000
PTO				$0	$0	$0	$1,000	$500	$750
COD				$0	$0	$0	$1,000	$500	$750
Totals (accounting for overlapping times)	1181	287	723	$10,900	$4,100	$6,400	$594,800	**$42,900**	$312,450
"Typical" Totals			**723**			**$6,400**			**$312,450**

[15] These charts are meant to show comparison data for real-world experience developing front-of-meter and behind-the-meter projects, not idealized timelines based only on tariff-required timelines. For example, PAR costs and timelines cover 1-2 PARs per project b/c it's almost never "one and done" in terms of finding a site that works.

[16] Tesla offers the following comments on Figure 2:

> Timelines can be longer if there is a line-side tap or AC Disconnect variance review is required, or non-standard equipment is utilized for the functionality of the design. Extensive NEM-A arrangement causes longer than normal land review (sometimes this can take 20 to 40 business days). Additional delays in timelines are incurred when PV is paired with battery energy storage systems (BESS).

Figure 3. *Interconnection costs and timelines for 1 MW NEM projects.*

Net Energy Metering (NEM) timelines and costs — Clean Coalition

NEM Rooftop 1 MW Project Development (TPO)	Timeframe (BD)			Fees			Costs		
	Max	Min	Typical	Max	Min	Typical	Max	Min	Typical
PRELIMINARY WORK	245	30	45						
Customer acquisition and site selection	75	5	20	$-	$-	$-	$10,000	$2,500	$5,000
Preliminary site evaluation, Preapplication Reports, and project screening	60	5	10	$2,500	$600	$1,500	$10,000	$2,500	$5,000
Preliminary layouts and performance models	30	5	5	$-	$-	$-	$4,000	$1,000	$2,000
Avoided cost and project models	20	5	5	$-	$-	$-	$3,000	$1,000	$1,000
Proposal and LOI	60	10	5	$-	$-	$-	$3,000	$1,000	$1,000
POWER SALES CONTRACT	140	40	50						
PPA/lease negotiation	60	10	20	$-	$-	$-	$3,000	$1,000	$1,000
Site due diligence (structural, roof condition, soils, electrical/services, etc)	50	20	20	$-	$-	$-	$10,000	$1,000	$5,000
Negotiate GC/EPC and engineering contracts	30	10	10	$-	$-	$-	$10,000	$1,000	$5,000
INTERCONNECTION REQUEST AND GENERATOR INTERCONNECTION AGREEMENT	150	50	105						
Prepare and submit interconnection application; receive response from IOU	90	20	60	$145	$145	$145	$20,000	$5,000	$10,000
Negotiate NEMEXP IA (Form 79-978, for 1,000 watts or less)	60	30	45	$-	$-	$-	$3,000	$250	$500
GRID UPGRADES CONSTRUCTION**	200	0	180						
Grid upgrade costs				$0	$0	$0	$0	$0	$0
Coordinate upgrade construction with utility				$0	$0	$0	$5,000	$500	$1,000
PTO				$0	$0	$0	$1,000	$250	$500
COD				$0	$0	$0	$1,000	$250	$500
Totals (accounting for overlapping times)	590	75	302.5	$2,745	$745	$1,745	$83,000	$17,250	$37,500
"Typical" Totals			**302.5**			**$1,745**			**$37,500**

III. What is automation?

For the purposes of this report, partial automation is defined as follows:

> Partial automation of the Rule 21 interconnection process constitutes automation of various sub-components of the process in the near-term (1-2 years) and mid-term (3-4 years).

Full automation is defined as follows:

> Full automation of the Rule 21 interconnection process would be a procedure that requires *de minimis* human intervention for the large majority of applications from receipt of application through final review and draft Interconnection Agreement (for Fast Track).

It should be stressed that full automation efforts will likely apply to the "large majority" of projects, not all projects, since issues will very likely arise for some projects that may always require some human intervention.

Our intention is not to pursue automation and streamlining for its own sake but in order to improve rates, to increase the delivery of renewable energy, and to help the state meet its energy and climate change goals. Accordingly, this document outlines efforts that will help to meet these objectives.

IV. The DRP and automation: DRP ICA Working Group Final Report

The DRP's ICA Working Group Final Report (R.14-08-013) adopted a number of recommendations with respect to automation. Perhaps the key passage states, with respect to automation:

> As a long-term vision, and not part of the ACR's [six-month] scope, some members of the WG envision that the ICA should be updated on a real-time or daily basis to the extent possible to allow the reflecting values to be used in **an automated interconnection process**. Future enhancement should work towards this goal, while considering issues such as the following in coordination with the Rule 21 proceeding:
>
> - **Development of automated interconnection studies which considers specific application information that cannot be known ahead of time to be reflected in ICA**. Generation queuing, commercial operation dates, and planned work/transfers can all have a unique impact on certain locations in the system and currently must be considered application-by-application with manual engineering review.

Automation is mentioned over 20 times in the Final Report; some examples are as follows:

- "PG&E notes that if full automation is desired, then focus must shift to automating more of the interconnection process versus the proactive ICA, which can only improve portions of the interconnection review."
- "SCE reiterates that it would incorporate significant changes to new circuit models on a monthly basis. SCE is currently developing automated processes to maintain the accuracy of network models and data as changes on the distribution system occur, as part of full system-wide deployment of ICA."
- "SDG&E currently automatically updates its models daily, but those are not currently validated for ICA purposes. SDG&E would need to validate those models that have monthly changes for the ICA update."

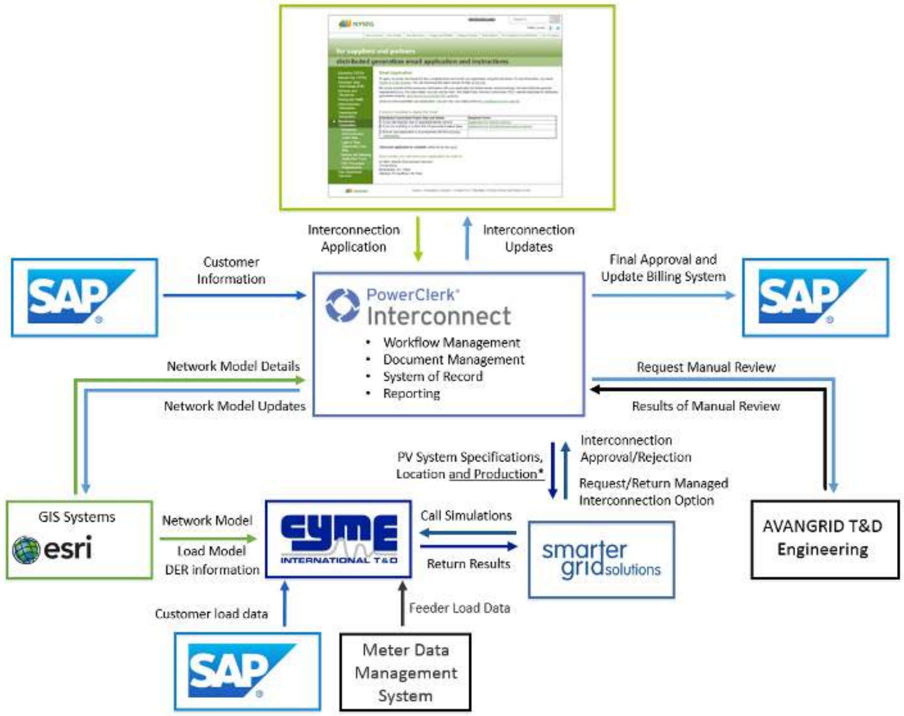
The DRP proceeding (R.14-08-013) Track 1 decision (D.17-09-026) adopts the Final Report and also the DRP Final Guidance language with respect to the need to "dramatically streamline" interconnection (p. 26): "[O]ne of the key purposes of the DRP is to dramatically streamline the interconnection process."

V. Similar automation efforts

There are a number of similar efforts that we can look to for guidance in this proceeding. Specifically, the following efforts are helpful as guidance (arranged chronologically):

- EnergyNet 2011 and 2013 (final report) >> this is a precursor to the ICA; funded by CEC
- SP Energy Networks in the UK "Utility Map Viewer" (the model for IOAP)
- AVANGRID's (NY) Interconnection Online Application Portal (IOAP), is a partnership between Clean Power Research, Eaton (provider of the distribution simulation software CYME), and Smarter Grid Solutions. The proof of concept is finalized, with final product rollout expected in 2018/2019, pending regulatory approvals and funding. Relevant program details are as follows:
    - Clean Power Research to automate the administrative side of the interconnection process
    - CYME to automate the technical Screening/power flow analysis

- Smarter Grid Solutions (SGS) to automate its Flexible Interconnection analysis
- Objectives:
    - Fully-automated interconnection processes
    - Hosting capacity maps – Static and Flexible hosting capacity
    - Data transparency for developers
- IOAP intends to automate the full range of Screens within the NY Standard Interconnection Requirements in the final product rollout, and has successfully demonstrated automation for a number of Screens within the proof of concept:
    - Screen A: Anti-Islanding
    - Screen B: Fault Duty Contribution
    - Screen C: Primary Distribution Interconnection
    - Screen D: Transmission Interconnection Adjudication
    - Screen H: Distribution Equipment
    - Screen K: Voltage Rise
    - Screen L: Voltage
- The schematic for the IOAP automation effort is as follows:



- New York State has created functional requirements for an Interconnection Online Application Portal. Each of the utilities in the state must submit plans for its implementation as part of their distribution system integration plan (DSIP) filings.

- DOE/CEC-funded EASE project, hosted by SCE
    - This is a broad-ranging effort to automate much of the interconnection process for all DER, as well as a management system (DERMS) for interconnected projects
    - EASE is focused on, *inter alia*, reducing interconnection time for >100 kW DER to five days or less (as described by the Smarter Grid Solutions program brochure)
    - This effort is also underway in 2018, with the project design basically complete, according to Smarter Grid Solutions, and testing set to begin in 2019, with field trial beginning in late 2019

VI. What is already automated in Rule 21?

A number of different aspects of Rule 21 have already been automated to varying degrees, including the following:

- NEM application acceptance and review for projects under 30 kW is partially automated for some utilities, starting in 2013 for PG&E and 2012 for SDG&E
- SCE, e.g., has at least partially automated the following:
  - Power Clerk Interconnect (PCI) for Online Application for NEM and Rule 21-non-export projects
    - While the intake process is through PCI, several internal handoffs are still required to process certain type of projects (New services NEM-aggregation, Meter adopters, NGO, etc.)
  - Customers are able to see the project status and can provide documents via the tool until PTO is issued
    - Limited integration with back-office systems which requires data from multiples sources gathered for technical review
    - Not all projects go through PCI, requiring additional handoffs and thus delays
    - Tesla notes that C&I projects have 3-5 changes to applications over their lifespan. This results in 4-12 weeks of avoidable delay on average per project when waiting for a simple update in the portal to resubmit and/or submittal of documentation in a timely manner
- Planned future efforts for SCE:
  - PCI or a similar tool is envisioned to support all projects seeking to interconnect to the distribution grid
  - Envisioned to integrate with existing and future back-office systems
  - Envisioned to streamline the DER Interconnection process through business process Optimization and Automation

- Funding review is underway and although initial funding for limited scope was authorized, additional funding may be required at a future date and functionality may be contingent on funding allowances
- Final scoping and related timelines remain under review

- PG&E has also automated standard NEM under 30 kW
  - PG&E is also undertaking several initiatives to further enhance its automation. This would include expanding its online invoicing, to projects submitted through the ACE-IT portal greater than 30 kW and less than 1 MW.
  - PG&E has partially automated the Preapplication Report process
  - Has already partially automated a number of Initial Review Screens: A, B, F, G, J, K, M
- The ICA value generation process is automated and the final ICA is to be completed by late 2018 (pushed back from July 2018)

VII. How can Rule 21 interconnection be automated?

This section looks at the various aspects of the Rule 21 interconnection process and identifies opportunities, at a high level, for partial or full automation.

A. Automating the application portals

- IOUs already have online portals for submitting NEM solar interconnection applications, representing partial automation of this aspect of the interconnection process. Much more can be done, however, to further automate these portals, particularly expanding the automated process above the 30 kW limit to all distribution-connected DERs (behind-the-meter and front-of-meter)
  - E.g. PG&E "standard NEM interconnection" is mostly automated
  - SCE here
  - SDG&E here

- Potential revisions to utility interconnection portals is scoped as Issue 22 in the R.17-07-007 Scoping Memo, but this scoping item does not specify automation or "dramatic streamlining," which is the focus of the present report.

- Automation of front-of-meter DER and over 500 kW behind-the-meter should be map-interactive, with ICA values displayed on the interconnection maps plus a link to the application portal

    - This is the beginning of the "Click n Claim" process that GPI has advocated in the present proceeding

- NY's IOAP (Interconnection Online Application Portal) is a good model to emulate for the "nuts and bolts" of a comprehensive automated application portal, as discussed above. The IOAP will be a fully automated application portal and interconnection process, similar to the Click n Claim proposal, once completed

B. Automating application processing and the "deemed complete" determination

- An application must be processed by the utility within 10 Business Days (BDs), applicant notified of receipt, and if the Interconnection Request is deemed complete or not (E.5)

- If the online portal application is populated correctly, this is automatable in two different ways:

    1. Provide template single-line diagrams (SLDs), that can be modified as required, for simpler projects. SDG&E's DIIS system has largely automated this process for NEM projects, including an automated SLD process template that applies to many straightforward projects by allowing the customer to select a generic generator configuration from the DIIS tool instead of supplying a project-specific SLD, and that generic configuration then serves as the SLD
    2. Larger behind-the-meter and front-of-meter projects require more complex SLDs and for this type of project dialogue windows should specify the needed information in order to safely interconnect such projects without requiring individualized SLD review

- If deemed complete, applicant is notified automatically by email that Initial Review will be completed within 15 BDs (E.5.a, F.2.a)

- If not deemed complete, applicant is notified automatically of the deficiencies and that it will have 10 BDs (per the tariff) to cure (E.5.b). Deficiencies will often result in multiple rounds of corrections, with each round requiring 10 BDs by the IOU. With an automated application portal, the need for corrections should be significantly diminished and the turnaround time for notifying applicants of deficiencies may also be significantly diminished.

C. Automating the queue position assignment

- Applies to all front-of-meter applicants; queue position assigned based on date application received if no deficiencies were found, but otherwise assigned when “deemed complete” (E.5.c)
- This can be automated by linking the required databases

D. Automating queue publication

- Queue is published monthly by each utility (E.5.d)
- Updates to the queue can be automated by linking databases, and then published in real-time or defined time periods
- Should be linked to ICA updates, eventually in real-time. Tesla and GPI note that “the key word here is actionability.” That is, ICA results should not be stale and developers should be able to consider ICA figures to be reliable.

E. Automating ICA

- ICA was intended to be a highly automated process from the outset.
- SCE, for example, describes their process for automating ICA: “Three software suites are being developed to support the ICA system-wide implementation. The Grid Connectivity Model (GCM) develops and orchestrates interfaces to provide various data (e.g., substation capacity results, fault duty calculation, circuit configuration, load profiles, line regulator settings, etc.) to the System Modeling Tool (SMT) which utilizes the data from GCM to automate the ICA calculations. The scope of SMT also includes license fees for software like the Power System Analysis Tool. The Distribution Resources Plan External Portal (DRPEP) integrates with modeling and calculation tools that provide ICA results and publishes those results externally on the web map interface known as DERiM.” (SCE ICA Interim Report Jan. 2018)
- Final ICA results are set to be produced in late 2018 (originally set for mid-2018 but delayed)

F. Automating ICA updates

- The frequency of updates to the grid-wide ICA has been set by the Commission as monthly for now, but with the admonition that the frequency of such updates will be improved once the utilities gain some experience with monthly updates (D.17-09-026, pp. 29-30). In order to ensure actionability (and avoid stale ICA values), IOUs will need to move quickly to real-time automated ICA value updates

- ICA updates should occur in real-time, as new applications are submitted and processed, in order to eliminate stale data issues. Computational resource issues are implicated with real-time updates, but it is our view that updating the model in real-time, based on automatic inclusion of new interconnection applications, should be automatable with the use of CYME or other power flow software that is already being integrated by IOUs. As discussed below, there are questions about timing and costs that need to be addressed before automated queue updates can occur.

- IOUs are already planning to automate ICA updates, however, as described in the DRP ICA Working Group Final Report (emphases added):

    - "PG&E has a gateway tool for incorporating circuit updates into its circuit models <u>on a weekly basis</u>. PG&E also creates yearly planning models from a snapshot of the gateway model which contains specific modifications and planned worked on the circuits. Recommendations from the WG would require additional work to merge the planning models with the gateway models." PG&E reiterated in response to the present report that automating ICA updates is already planned work.

    - "SCE reiterates that it would incorporate significant changes to new circuit models on a monthly basis. <u>SCE is currently developing automated processes</u> to maintain the accuracy of network models and data as changes on the distribution system occur, as part of full system-wide deployment of ICA."

    - "SDG&E <u>currently automatically updates its models daily</u>, but those are not currently validated for ICA purposes. SDG&E would need to validate those models that have monthly changes for the ICA update."

G. Automating Screens not included in ICA

The Fast Track review Screens are divided into Initial Review (A through M) and Supplemental Review (N, O, P)

IREC provided comments on the potential for automation the Fast Track Screens in informal comments to the working group on March 26, 2018. IREC identified possible software automation for Screens A, B, H, J, K, and L, and also identified ways in which Screens other than the ICA Screens could be deemed inapplicable or otherwise resolved. We include IREC's full comments on the Fast Track Screens as Attachment A. GPI and Clean Coalition comments below, with additional suggestions from SGS, consulting engineers retained by GPI for this purpose, reflect and incorporate IREC's comments on potential automation and streamlining.

This section reviews the potential for automation of the Screens but doesn't include any cost-benefit analysis of doing so. The authors of this report have made clear that our High-level cost-benefit considerations are included in the last section of this report.

The following abbreviations are used in the below discussion:

- **OK/NA**: automation already completed or not applicable for inverter-based systems
- **ST**: Short Term (1-3 years)
- **MT**: Medium Term (3-5 years)
- **LT**: Long Term (>5 years)

Power simulation software providers are beginning to incorporate automated Screen functionality (e.g. Eaton – CYME). The application processing software should be designed to connect easily to the specific power simulation software package to access this functionality. Triggering the updates for projects based upon relevant changes should also be relatively easy to incorporate within the application processing software.

Suggestions for automation or streamlining of each of the Screens follows below. The net result of the recommendations is at least a partial, and potentially a fully, automated Initial Review and Supplemental Review process, if the identified issues can be resolved for each Screen:

- **Screen A: Networked Secondary**
    - This is a Screen that should be automatable through software as it only requires verification of whether the applicant's POI is on a Networked Secondary System. These networks should be clearly mapped and also indicated on the ICA maps. (ST)
- **Screen B: Certified Equipment**
    - This only requires verification against a database and could be automated through the application process, no engineering time should be required. (ST)
- **Screen C: Voltage Drop**
    - This only applies to motoring generators and thus will be automatically passed by most DERs today. (OK/NA)
- **Screen D: Transformer Rating**
    - Projects with a primary connection are covered by ICA. (OK/NA)
    - Since the secondaries were not included in the ICA this Screen will still require verification for projects connecting to a secondary (which isn't the case for 500 kW and over behind-the-meter or for front-of-meter projects). (MT)
- **Screen E: Does the Single-Phase Generator Cause Unacceptable Imbalance?**
    - Projects with a three-phase connection will not go through this Screen. (OK/NA)
    - Projects with inverters connect across 240V will require some verification but this will rarely be associated with the larger behind-the-meter/front-of-meter customers targeted in this roadmap, which will tend to be connected to three-phase. (MT)
    - Since single-phase secondaries were not included in the ICA this Screen will still require verification for projects connecting to a single phase secondary. (MT)
- **Screen F: Is the Short Circuit Current Contribution Ratio w/in Acceptable Limits?**
    - As long as the generator model is added correctly, fault simulation functionality already exists in the distribution simulation software (ST)
    - Protection is analyzed in the ICA. Coordination is not modeled in the ICA currently, but may be able to ID the substations where this is an issue.
- **Screen G: Is the Short Circuit Interrupting Capability Exceeded?**
    - As long as the generator model is added correctly, fault simulation functionality already exists in the distribution simulation software. Substantial database development and maintenance may be required. (MT)
    - ICA partially covers, substation needs to be reviewed. <1 MW may pass, or can utilities use a modified version of the PG&E automated Screening tool?
- **Screen H: Line Configuration**

- Should be able to be addressed quickly through software or manual verification if the information about wire configurations on the system is available. (MT)
- **Screen I: Will Power Be Exported Across the PCC?**
  - This is allowed to fail for larger projects which will be analyzed further in Screens N and O.
  - This Screen should be automated through the export/non-export selection on the IOU application portals– Filtering Screen only (ST)
- **Screen J: Is the Gross Rating of the Generating Facility 11 kVA or less?**
  - Not applicable to the larger projects considered here
  - This Screen can be automated – Filtering Screen only (ST)
- **Screen K: Is the Generating Facility a NEM Generating Facility with nameplate capacity less than or equal to 500 kW?**
  - Not applicable to the larger projects considered here
  - This Screen can be automated – Filtering Screen only (ST)
- **Screen L: Transmission Dependency and Transmission Stability Test**
  - This may require IOUs to ID and flag those substations with either transient stability limitations or interdependencies with earlier queued generation. (ST)
- **Screen M: Aggregate Generation ≤15% of Line Section Peak Load**
  - Uses available data automated as part of ICA for existing and proposed modified Screen M as part of Working Group 2 Issue 8 proposals. (ST)
- **Screen N: Penetration Test (100% of Min. Load)**
  - Pass if within ICA value; readily automatable if over ICA value or ICA not available (OK/ST)
- **Screen O: Power Quality and Voltage Fluctuation**
  - Pass if within ICA value; readily automatable if over ICA value or ICA not available (OK/ST)
- **Screen P: Safety and Reliability Test**
  - Used in Supplemental Review as a "catch all" applied only when one of the earlier Initial Review Screens is failed, so we are not proposing at this time to automate Screen P. (LT/NA, "safety valve")

We summarize in the below chart SGS' conclusions with respect to the feasibility of automating the Fast Track Screens, as described above. Power simulation software providers are beginning to incorporate this functionality (e.g. Eaton – CYME). The application processing software should be able to connect easily to the power simulation software and access this functionality.

As mentioned previously for the ICA and initially discussed in the application processing automation section, relevant changes to projects could automatically trigger updates to projects lower in the queue. Relevant changes to all projects affected could trigger automated communication of the changes with the applicant.

Assumptions:

- Applies mostly to behind-the-meter over 500 kW and front-of-meter projects of any size
- Online interconnection portals supported by business administration process software are being used.
- The interconnection portals contain the automation functionality required as described in relevant 'Required Effort(s)' in the table below, or a separate software application is developed that integrates the interconnection portals with the required utility systems and databases.
- The circuit model has been updated to include the application of interest. If it is too difficult for the POI to be automated for inclusion in the circuit model, the operator would need to perform this task manually after successful application submission through the online interconnection portals.

Screen	*Required Effort(s)*	*Automation Feasibility*
A – Networked Secondary	POI links to utility system with GPS to identify if it is a networked secondary.	High -- if this attribute exists in utility database
B – Certified Equipment	Can be incorporated into Interconnection Portal with list of certified equipment types when specifying system details.	Very High – already demonstrated in other tools
C – Voltage Drop	Only applies to motoring generators. Can be skipped for solar PV applications.	N/A -- only applies to motoring generators
D- Transformer Rating	Interface with appropriate utility database. Large projects will only connect to the primary, so irrelevant to this study case.	N/A – large projects would have their own dedicated voltage transformation
E – Single-Phase Generator Causing Unacceptable Imbalance?	Large projects will only connect to the primary, so irrelevant to this study case.	N/A – same as above
F – Short Circuit Current Contribution Ratio within Acceptable Limits?	Requires integration with the utility distribution simulation software. Easily automated using fault simulation.	Medium – As long as the generator model is added correctly, fault simulation functionality already exists in the distribution simulation software
G – Short Circuit Interrupting Capability Exceeded?	Requires integration with the utility distribution simulation software. Easily automated using fault simulation.	Medium – similar to Screen F
H –Line Configuration	Reference appropriate database indicating type of line at the POI.	High – assumes the database for line types and parameters exists.
I – Will Power be Exported Across PCC?	This is allowed to fail for larger projects which will be analyzed further in N and O.	N/A -- for larger and wholesale projects
J – Gross Rating of the Generating Facility 11 kVA or less?	This is allowed to fail for larger projects which will be analyzed further in N and O.	N/A -- for larger and wholesale projects
K – Is the Generating Facility a NEM Generating Facility with Nameplate Capacity less than or equal to 500 kW?	Not applicable to the application types being considered (larger and exporting projects), but easily referenced with the application data within the interconnection portal.	N/A -- for larger and wholesale projects
L – Transmission Dependency and Transmission Stability Test	Based on the Rule 21 description, this would probably require IOUs to flag those substations with either transient stability limitations or interdependencies with earlier queued generation.	Low – variability associated with the analysis used to support this screen makes it difficult to automate the exact efforts on an individual case basis.
M – Aggregate Generation <u>≤15% of Line Section Peak Load</u>	Could be difficult if CIM not included in modelling software – i.e. need to detect if there is a switch upstream of PCC. Or, a database kept of data on all line sections.	Easy if IR/SR are combined. Medium to Low if not combined – automating the detection of relevant line sectionalizers simple with CIM, otherwise a database identifying line sections is required.
N – Penetration Test (100% of Min Load)	Automated as part of ICA, rendering screen M redundant for combined IR/SR	Already completed
O – Power Quality and Voltage Fluctuation	Automated as part of ICA	Already completed

H. *Frontloading Supplemental Review Screens N and O into Initial Review*

- Projects that are less than or equal to the displayed ICA value, or otherwise expect to interconnect without need for Supplemental Review, may be susceptible to largely automated review. Frontloading Screens N and O into IR will allow an easier automation of Initial Review because Screen N makes Screen M redundant and Screen O may render some IR Screens at least partially redundant.
- Given the automation of Screen N and Screen O as part of the ICA tool and the ability to apply this functionality to meet the analysis requirements for a specific project, minimal effort would be required to assess the complete fast track potential for a given application that passes all IR Screens.
- Moving all automatable Screens to the IR would be beneficial as a whole while providing as much information as possible up front to the customer with minimal effort.
- A single review from the utility engineer and reduced communication requirement to the customer offer significant process time and reduced fee improvements.

I. *Frontloading and automating offer of Generator Interconnection Agreement*

- A standard Generator Interconnection Agreement (GIA) must be offered within 15 BDs of passing Initial Review (F.2.a), or 15 BDs from applicant's request after passing Supp. Review (F.2.e)[17]
- 90 Calendar Days are allowed for negotiation and signing of the GIA (F.2.e)
- Utilities could instead "frontload" a partially populated draft GIA offer immediately after the application is deemed complete, allowing the agreement to be reviewed by the applicant before IR and SR are complete
- Or utilities could offer the option to generate this document auto-filled from the application portals, as is currently available with the SCE Power Clerk portal.

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[17] Tesla notes that PG&E is inconsistent with when it provides this form and how complete it is when received. Some utility reps fill it out and some leave it blank and request that the contractor fill it out. There are also inconsistent practices in how this form is prepped by specific utility reps. For SDG&E, depending on the type of agreement needed for the application Tesla is sometimes required to fill out a template rather than have a filled out agreement drafted and provided for customer signature by the u

tility rep.

- Once Fast Track Review is completed, the draft GIA will be fully populated with the relevant results and this second draft will be sent automatically to the applicant, within one BD

VIII. Cost/benefit analysis initial considerations

This section offers preliminary cost-benefit analysis of the top recommendations from this report, as described in the summary above, along with related considerations about costs and benefits more generally. Most of this section was provided by SGS, automation engineers retained by the Green Power Institute to assist with this report.

TURN stressed the need for cost-benefit analysis prior to further action on automation opportunities. Parties generally agreed that cost-benefit analysis is important but that the Commission regularly conducts analysis of opportunities for policy improvements, prior to any cost-benefit analysis. The middle ground in this case was for GPI to retain SGS as consulting engineers to both vet this report's analysis and recommendations and to complete a preliminary cost-benefit analysis, which is described below.

PG&E notes with respect to costs and benefits: "We continue to support automation and note the importance to highlight the cost benefit analysis on all automation efforts. Ratepayer funding should focus on benefitting the largest populations and then move into targeting smaller areas, with the benefit to rate payers as the deciding factor. Efficiency gains and automation are what we strive for but not infallible solutions, and Rule 21 Compliance timelines should reflect the manual process of performing the task, as needed, until the benefits of automation are determined."

A. General cost-benefit considerations

The general cost and benefit elements associated with implementing the various automation options are as follows:

Utility Perspective (in the experience of SGS):

- Single source of interconnection information provides greater internal efficiencies.
- Significantly reduces manual effort (see above timeline reductions) both for initial project Screening and updates based upon changes to applications ahead in the queue. This includes automated communication with the applicant.
- Power system simulation software, such as CYME, already demonstrate functionality for the automation of relevant Screens. Further messaging to CYME, Synergi around what Screens are required would ensure that functionality finds its way into the software.
- Integration of systems requires effort where needed.
- If administrative software, e.g. Power Clerk, does not possess the functionality to access required systems and process information accessed for Screens, some form of custom software wrapper must be developed to do so; this may or may not include results from the power simulation software.
- Interconnection application processes can be modified to leverage automation efforts to significantly reduce processing times and required customer interaction.
- Maintaining an up-to-date published ICA map will greatly reduce the number of nonviable interconnection applications and consequently the processing time for those that are feasible. Once automation is developed for the Screening, keeping maps up-to-date simply requires translation to a map service assuming that the processing of hosting capacity across the nodes on the network does not require significant processing requirements (e.g. this is not possible with flexible hosting capacity). The benefit of directing developers towards circuits with greater headroom has already been witnessed in SP Networks pilot, avoiding applications with a low probability of going to construction.
- Accurate positioning of generation within the associated power simulation model could be difficult and require engineer confirmation (as noted during conversations with AVANGRID).
- Scoping, development and implementation of such IT tools will require time and funding. CPUC authorization for additional funding will be required to accomplish many of the aspects of the Report. Such funding approval is typically addressed in a utility's General Rate Case but may be addressed in this case independently.

Developer Perspective (in the experience of SGS):

- Lower project development costs means lower barriers to entry
- Reduced application time means realizing project revenue sooner – time value of money
- Increased automation should also lead to significantly lower application and study costs
- Lower risk of losing project funding, land rights, etc.
- Lower project risk can be passed on to ratepayers due to lower project cost and thus lower bids for front-of-meter/wholesale RFPs
- Can survey best opportunities for project development at very low cost

B. Cost-benefit considerations specific to top automation recommendations

The following sections discuss how these benefits relate to the automation efforts listed above:

a. Automating the Application Portals and Application Processing with Queue Management and Updating Publicly Available Interconnection Queue

This is the first task that should be accomplished while offering the best returns and providing the basis for other automation efforts to grow upon. Instead of having multiple resources in separate locations, there is a single "one-stop shop" for interconnection applications.

Interconnection portal software should be able to be modified to handle alterations to a given application, while also being the resource that maintains the interconnection queue.

It should be easy to implement alerts that indicate those projects affected by a change to a project ahead in the interconnection queue. The automatic updating of Screens to accommodate the project change, including those projects affected, is discussed later on.

b. High-level cost-benefit considerations for opportunities identified in this report

SGS developed the following information for Working Group discussion and to provide a basis for identifying the best near-term automation and streamlining opportunities. Again, this analysis <u>applies mostly to behind-the-meter projects over 500 kW and front-of-meter projects of any size</u>. Costs are evaluated on a per project basis, considering a <u>default 1 MW project size</u>.

Automation Action	Estimated process streamlining (days)[1]	Utility savings (person days)[2]	Type of investment needed (labor, license, other)	Relative cost / complexity	Relative benefit-cost ratio
Application Portal, Queue Mgmt, Queue publishing	5+	5+	• SaaS license • IT (labor) • Design of UI (labor)	Medium	High
ICA and ICA updates	n/a	5+	• Power system analysis tool license (toolbox) • Dist Planning (labor) • IT (labor)	Medium to Hard	Medium
Automating Screens not in ICA	2-5 days	2-5 days	• Dist. Planning (labor) • IT (labor)	Medium	Medium
Frontloading SR Screens N and O into IR[3]	5+	1-2 days	• Process design (labor)	Easy but contingent of previous steps	High but depends on stakeholder
Frontloading and automation of GIA	5+	n/a	Process design (labor)	Easy once process management tool implemented	High, particularly for projects w/o upgrades

1- Here we estimate savings as being 1-2 days, 2-5, or greater than 5 days.
2- Savings here reflect the reduction in time due to meetings, analysis, and administration (emails, documentation, other)
3- Assumes that Screens N and O have been automated, whether through ICA (as is currently planned) or independently.

IREC informal comments on Working Group 2 Issue 8, May 26, 2018, on automation and streamlining of Rule 21 Fast Track Screens

- Evaluate Initial and Supplemental Review Screens and determine which Screens are addressed directly by the ICA results and which may further be streamlined using software or other methods.
  - The ICA Working Group report found that the ICA results would be able to replace or make the determinations for Screens F, G, M, N & O.[18] An initial assessment of the Screens and the discussion of them follows:

    Initial Review

    - Screen A: Networked Secondary – This is a Screen that should be able to be addressed automatically through software as it just requires verification of whether the applicants POI is on a Networked Secondary System. These networks should be clearly mapped and also be able to be indicated on an ICA map at some point.
    - Screen B: Certified Equipment – This is also something that requires verification but could be automated through software potentially, no engineering time should be required.
    - Screen C: Voltage Drop – This only applies to motoring generators and thus will be skipped by most DERs today.
    - Screen D: Transformer Rating – Since the secondaries were not included in the ICA this Screen will still require verification for projects connecting to a secondary. Projects with a primary connection do not go through this Screen however.
    - Screen E: Does the Single-Phase Generator Cause Unacceptable Imbalance – Since single-phase secondaries were not included in the ICA this Screen will still require verification for projects connecting to a single phase secondary. Projects with a connection to a three phase primary should not go through this Screen however.
    - Screen F: Is the Short Circuit Current Contribution Ration w/in Acceptable Limits? – Per the WG report this Screen should be addressed by the ICA.
    - Screen G: Is the Short Circuit Interrupting Capability Exceeded? – Per the WG report this Screen should be addressed by the ICA.
    - Screen H: Line Configuration – This Screen was not directly addressed by the ICA but should be able to be addressed automatically through software/ manual verification if the information about wire configurations on the system is available.
    - Screen I: Will Power Be Exported Across the PCC? – This Screen is not addressed by the ICA. It is essentially a yes or no question based upon information provided in the application form, however, it likely requires utility verification

[18] There was an oversight on this in the final report as the approved ICA methodology does not fully account for Screens F & G, as came to light early in the Working Group 2 process in the first half of 2018.

(automatic or manual tbd) to make sure the facility correctly meets one of the non-export configurations. *However, for purposes of expediting review it is not clear whether this question retains its importance in the review process if the ICA results are in place.*

- Screen J: Is the Gross Rating of the Generating Facility 11 KVA or less? – This Screen can be automated and is likely no longer relevant with the ICA in place.
- Screen K: Is the Generating Facility a behind-the-meter Generating Facility with nameplate capacity less than or equal to 500 kW? – This Screen can be automated and is likely no longer relevant with the ICA in place.
- Screen L: Transmission Dependency and Transmission Stability Test – It is possible that this Screen may be able to be automated. We should have a thorough discussion of how this Screen is really being used (if at all) and what information is required to apply it.
- Screen M: Aggregate Generation ≤15% of Line Section Peak Load – This Screen is addressed by the ICA.

Supplemental Review

- Screen N: Penetration Test (100% of Min. Load) – This Screen is addressed by the ICA
- Screen O: Power Quality and Voltage Fluctuation – This Screen is addressed by the ICA
- Screen P: Safety and Reliability Test – This Screen is not directly addressed by the ICA, however it is also used in Supplemental Review as a "catch all" that should only be applied when one of the earlier Initial Review Screens is applied. It may make sense to discuss how it will be used and structured with the ICA in place and what evaluation will be done under this Screen.

Issue 9 Proposal

Issue 9 Question: What conditions of operations should the Commission adopt in interconnection applications and agreements to allow distributed energy resources ("DER") to perform within existing hosting capacity constraints and avoid triggering upgrades?

Proposal: Allow Interconnecting DER to Be Evaluated and Operate Under Limited Generation Profile

This proposal would Modify interconnection procedures to allow a DER customer to submit a "Limited Generation Profile" as part of their Interconnection Application, require that customer to enable generation profile limiting functionality, and allow utility limited future opportunity to alter that profile if circumstances warrant.

Status

Non-consensus

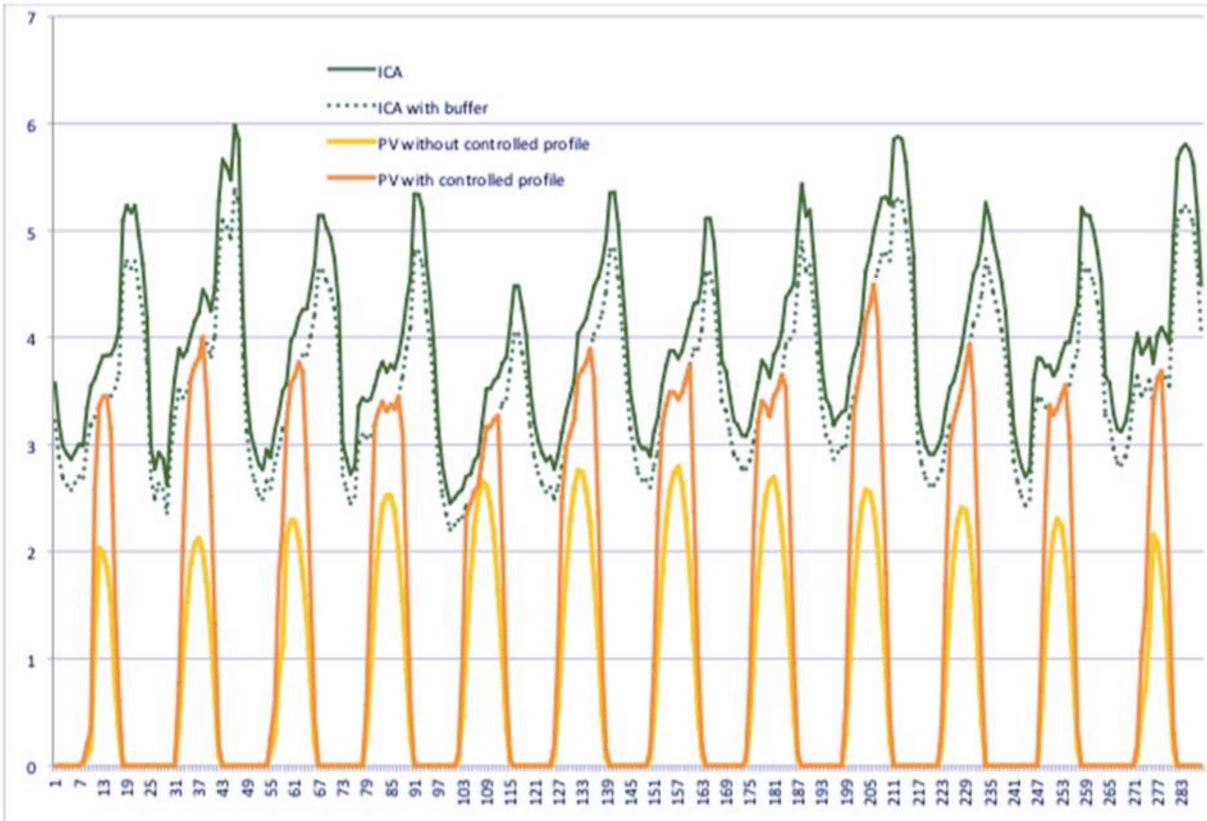
- Supported by CalCom, CALSSA, TURN (qualified), Public Advocates Office (qualified), Clean Coalition (qualified)
- Opposed by Joint IOUs
- Counter-proposal by Joint IOUs[19] in Issue 9 Appendix

Discussion

Proposal 9 builds on Proposal 8.m and applies to DER which would accept certain conditions of operation, as detailed below.

The purpose of the proposal is to consider whether and how a generator may be allowed to interconnect generation capacity which exceeds the minimum annual Interconnection Capacity Analysis-Static Grid ("ICA-SG") value while remaining below the maximum ICA-SG at any given time. This scenario is illustrated in the following figure:

[19] This proposal was introduced following the conclusion of stakeholder discussions. As such, no stakeholder positions on the proposal were collected. Energy Division representatives indicated party positions may be considered through comments on the Working Group Report.



The proposal has three parts:

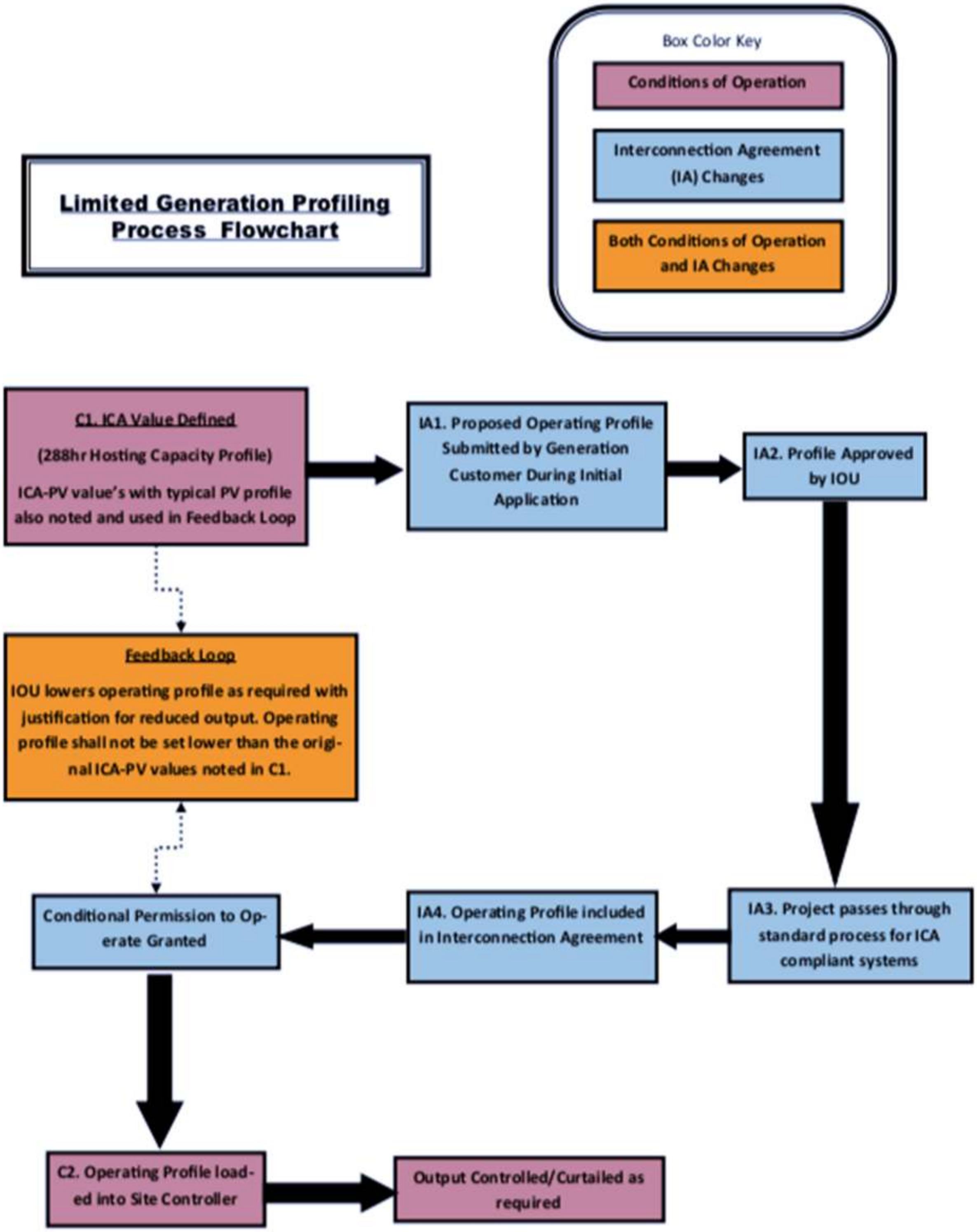
- Part 1: A DER customer submits a "Limited Generation Profile" as part of their Interconnection Application. The Limited Generation Profile may include generation up to the ICA-SG value published by the IOU at the time of the application and would be submitted in a standard 288-hour format so that it can be easily superimposed on the ICA results.
    - The submission of the Limited Generation Profile would be an option for all customers pursuing interconnection where ICA values have been published.
    - The proposal acknowledges the need for a buffer between the published maximum ICA-SG and the corresponding output in the Limited Generation Profile. A final determination on the size of the buffer has not been made.
    - The source of the 288-hour format generation profile can be produced using PV-watts with Clear Skies data with the addition of operational limitations.

- Part 2: The DER customer agrees to enable smart inverter functionality and local controls capable of ensuring actual operations conform with the submitted Limited Generation Profile.
    - The Working Group generally agreed that the technology needed for a DER facility to implement a scheduled generation profile is already available. These technologies include smart inverter communications protocols, which

allow for a standardized bridge between a localized DER controller (typically a Data Acquisition System ("DAS")) and smart inverters. The generation profile could be uploaded to the Data Acquisition System, which would then send a communications signal to the inverters to adjust production based on the pre-defined schedule. This would conform with the technical specifications for Function 8 in Phase Three of the approved smart inverter standards.

- Part 3: DER customer agrees to allow future reductions to generation profile up to the minimum ICA-SG typical PV profile published by the IOU at the time of the application. Determination of such reductions would be made by IOUs under defined circumstances.
    - The proposal acknowledges future grid conditions could result in actual hosting capacity being below the published ICA-SG. Under such circumstances, the utility may need to reduce generation to ensure safe and reliable service without grid upgrades. Anticipating this possibility, the proposal suggests the interconnecting generator would agree to generation reductions down to a pre-defined static level. This level would be set as the lowest ICA typical PV profile value identified at the time of the Interconnection Application.
    - Whether and how the IOUs make the determination that reductions are necessary has not yet been determined.

The following diagram illustrates how this proposal would be implemented.



Proponents of this change assert this proposal has the potential to increase hosting capacity, thereby reducing interconnection challenges and cost. Further, the proposal should reduce the need for grid upgrades which are triggered by un-limited generation profiles. Proponents also find the proposal to be consistent with longstanding discussions and expectations from the ICA Working Group and the Smart Inverter Working Group.

<u>IOU Perspective</u>
IOUs raised several concerns in response to this proposal, including:

- Error in forecasting of generation: uncertainty as to whether an actual generator profile may be faithfully represented by the forecasted Limited Generation Profile.
- ICA vs Operational Values: uncertainty as to whether the ICA-SG, the least conservative output of the ICA process, which is based on a forecast, will reflect actual grid conditions.
- Lack of experiences and infrastructure to work with generator controls: uncertainty as to whether the inverter and Data Acquisition SYstem controls will meet expectations and consequent need for a utility system to supervise site controller.
- Lack of infrastructure to realize needed generation reductions: recognize grid operations happen in real-time, whether and how the IOU would know with certainty if/when the generator's output needed to be reduced, whether the IOU could effectively communicate the needed change to the DER, and whether the DER would respond in a timely and accurate manner.
- Questions about impact on subsequent interconnections: if an upgrade is avoided due to an operational constraint but the next customer elects to upgrade, does the operational constraint remain? Do utilities set rules that states that this line is now an operational constraint line and no upgrades will be allowed even if customer funded? What systems would be needed to operationalize such rules?
- Modeling Challenges: currently modeling of future planning and generation assume a typical PV output. Limited Generation Profiles adds new complexity to modeling.
- Applicability not well understood: do all customers need this option? Projects of all sizes and asset types?

The Joint IOUs note that an ongoing PG&E DERMS 2.0 pilot under EPIC is actively exploring both how Limited Generation Profiles could be defined and enforced. This experimentation may lead to integration of solutions like the one being proposed here, but rigorous study is needed before that is possible.

<u>TURN Perspective</u>
TURN's support for the proposal is contingent on the Commission taking some action to address these concerns. Specifically, TURN asks:

- That the Commission order the smart inverters relied on by this proposal to be tested and added to a list of certified inverters that are deemed able to effectively and reliably limit output;
- That generation be monitored and measured in real-time. Any measurement of generation cap (whether it's ICA-SG or something else) has to be able to measure

instant generation instead of over a period of time, such as an hour. A measurement over a period of time would likely lead to underestimates.

Public Advocates Office and Clean Coalition Perspective

Based on the Public Advocates Office's assessment, the Issue 9 proposal fits squarely within the ICA uses cases identified in the ICA Working Group's Final Report. The Public Advocates Office finds the proposal makes the interconnection process less costly and allows for more sophisticated, potentially less expensive distribution planning on the part of the IOUs. It has the potential to avoid certain rate-based distribution upgrades. The Public Advocates Office supports the proposal while recognizing that there are numerous challenges facing its implementation.

Below are suggestions the Public Advocates Office would like to advocate for to address such challenges in future fora.

1. Incorporate the findings of the Smart Inverter Working Group. The IOUs have stated that grid operators would need real-time data from and potentially control over DERs for this proposal to be implemented. The Smart Inverter Working Group ("SWIG"), part of Rulemaking (R.) 14-08-013, has defined protocols to communicate with smart inverters, along with monitoring and control functions that should be able to support the Issue 9 proposal. Related reports, decisions and resolutions issued to date should be taken into account to ensure that any research and analysis is not duplicated.

2. Encourage the IOUs to develop verification processes for generator profiles. This proposal hinges on the ability of the IOUs to verify and have operational confidence in the generation profiles submitted by DERs. The Public Advocates Office recognizes that the IOUs will be, at times, forced to rely on these profiles when ensuring safety and reliability. Any verification processes would need to be developed by the IOUs to be effective. The Public Advocates Office encourages the IOUs to engage with the proposal and develop a draft generation profile verification process that would give them confidence implementing the proposal.

Issue 9 APPENDIX

Joint-IOU Proposal: Allow Interconnecting DER to Be Evaluated and Operate Under Limited Generation Operation Limits Leveraging Smart Inverter Phase III Function 3 (Limit Maximum Real Power Mode)

Summary

Update the interconnection procedures to allow customers which have certified Phase III inverters to use Phase III Function 3 (Limit Maximum Real Power Mode) in order to limit maximum power output based on seasons of the year. This functionality must account for future changes in load profiles, which may require the Function 3 limits to be updated in order to prevent distribution safety and reliability issues.

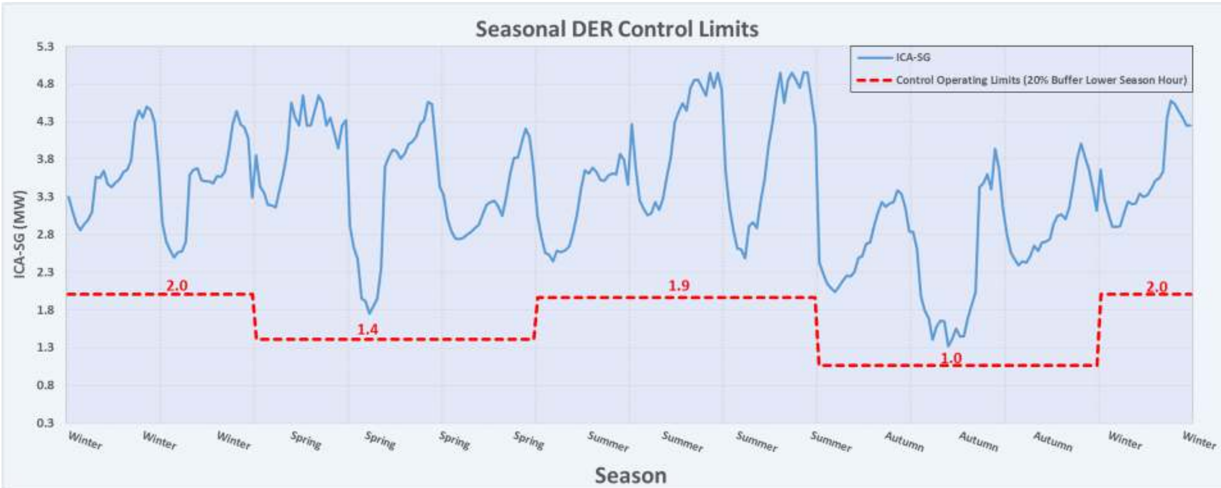
Status

Non-Consensus

Discussion

The joint-IOU proposal applies the work from Smart Inverter Working Group ("SWIG") and its recommendation to include a Real Power Limiting Function on Smart Inverters (Function 3). As mandated in Resolution E-4898, this function will be required for new inverters by December 2019 at the latest. Inverter manufacturers may be able to certify their inverters prior to December 2019 and activate a Phase II communication option in order to take advantage of this function.

This proposal would allow DER customers to utilize a smart inverter's ability to increase its output during seasons of the year where a higher level of ICA is available, while still operating in a manner that maintains safety and reliability of grid operations. The figure below depicts a control limitation based on seasons of the year (winter, spring, summer, & autumn). The seasonal real power limit would include a 20% buffer as depicted in the figure below.



- Part 1: A DER customer submits a "Limited Generation Profile" as part of their Interconnection Application. The Limited Generation Profile may include generation up to the 80% ICAW-SG value published by the IOU at the time of the application and would be submitted in a standard 288-hour format so that it can be easily superimposed on the ICA results.
    - The submission of the Limited Generation Profile would be an option for certain customers pursuing interconnection where an ICA has been published.

- Part 2: A DER customer agrees to enable smart inverter functionality (i.e., Phase II communications requirements and Phase III Function 3: Limit Maximum Real Power Mode) in order to ensure actual operations conform to the submitted Limited Generation Profile.

- Part 3: A DER customer agrees to allow future reductions to generation profile. Determination of such reductions would be made by IOUs under defined circumstances.
    - The proposal acknowledges future grid conditions could result in actual hosting capacity being below the published ICAW-SG. Under such circumstances, the utility may need to reduce generation to ensure safe and reliable service without grid upgrades.

ISSUE 10 PROPOSAL

Issue 10 Question: How can the Commission coordinate the Integration Capacity Analysis and each Utility's Rule 21 processes with the Rule 2, Rule 15, and Rule 16 processes in order to improve efficiency of the overall interconnection process?

Proposal

CALSSA proposes to standardize utility processes and timelines for interconnection applications which must be reviewed under Rule 2, Rule 15 and Rule 16. CALSSA's proposal includes 8 parts, including:

> **Proposal 1:** Assign a project manager for interconnection requests greater than 100KW
> **Proposal 2:** Use of a single Project Identification Number
> **Proposal 3:** For a project studied under Rules 2, 15 and 16, the customer shall be informed of the start date of that study.
> **Proposal 4:** Engineering advance or the facility costs process
> **Proposal 5**: Schedule a mitigation work scoping meeting process
> **Proposal 6:** Design and cost estimation must be completed within 60 business days
> **Proposal 7:** Construction of interconnection completed within 60 business days
> **Proposal 8:** The utility shall send a detailed reconciliation of the costs of interconnection facilities and distribution upgrades, with refund of any amount paid in excess of actual costs, within 20 business days of project completion

Status

- **Proposal 1:** Assign a Project Manager for Interconnection Requests greater than 100KW
  - Non-consensus
    - Supported by: CALSSA, Clean Coalition (qualified), TURN (qualified)
    - Opposed by: SCE, PG&E, SDG&E

- **Proposal 2:** Use of a Single Project Identification Number
  - Consensus

- **Proposal 3:** For a project studied under Rules 2, 15 and 16, the customer shall be informed of the start date of that study.
  - Consensus

- **Proposal 4:** Engineering advance or the facility costs process

- Non-consensus
    - Supported by: CALSSA, Clean Coalition (qualified), TURN (qualified), SCE (qualified)
    - Opposed by: SDG&E, PG&E (qualified)

- **Proposal 5**: Schedule a mitigation work scoping meeting process
  - Non-consensus
    - Supported by: CALSSA, SCE (qualified), Clean Coalition (qualified), TURN (qualified), PG&E (qualified)
    - Opposed by: SDG&E

- **Proposal 6:** Design and cost estimation must be completed within 60 business days
  - Non-consensus
    - Supported by: CALSSA, SCE (qualified), Clean Coalition (qualified), TURN (qualified)
    - Opposed by: SDG&E, PG&E

- **Proposal 7:** Construction of interconnection completed within 60 business days
  - Non-consensus
    - Supported by: CALSSA, SCE (qualified), Clean Coalition (qualified), TURN (qualified), SCE (qualified)
    - Opposed by: PG&E (qualified), SDG&E

- **Proposal 8:** The utility shall send a detailed reconciliation of the costs of interconnection facilities and distribution upgrades, with a refund of any amount paid in excess of actual costs, within 6 months of project completion
  - Non-consensus
    - Supported by: CALSSA, Clean Coalition, TURN (qualified)
    - Opposed by: SCE, SDG&E, PG&E (qualified)

Discussion

Background

If a generator is pursuing interconnection under Rule 21, the utility may require a new service account, a service upgrade under Rule 2, 15 or 16, or may require modifications to the distribution system to facilitate the interconnection.

- Rule 2 covers special facilities (e.g., transformers, new substation banks, or direct transfer trips) which may be installed, owned and maintained or allocated by a utility as an accommodation to the applicant.
- Rule 15 covers new distribution facilities which are a continuation of, or branch from, the nearest available existing permanent Distribution Line (including any facility rearrangements and relocations necessary to accommodate the extension) to the point of connection of the last service.
- Rule 16 covers the overhead and underground primary or secondary facilities (including but not limited to Utility Owned Service Facilities and Applicant owned

service facilities) extending from the point of connection at the Distribution Line to the Service Delivery Point.[20]

When a new service is requested at the same time as a Rule 21 generator, the current process entails the review of the retail load elements eligible for Rule 2, 15, or 16 first to determine the scope and cost related to the new service and load request. The Rule 21 generator scope and cost is then evaluated after the evaluation of the load is completed.

For projects that require work to be performed by the utility, the interconnection process takes on new complexity, and those complexities differ by utility, including how the utility manages the end-to-end design, estimation, construction, and reconciliation process across different groups of utility personnel.

In working group discussions solar providers contend that the transition from Rule 21 to the other rules has often not been smooth and that there is very little visibility into the status of a project outside of the interconnection review under Rule 21. Solar providers report several concerns, including:

- Project Identification Numbers may change;
- Timelines - Unlike Rule 21, which has details and timelines for the different steps of project review, Rules 2, 15 and 16 lack information about the study process relied on by utilities;
- Process related to invoicing - SCE, when presenting the results of interconnection review, includes an invoice for work to be done. PG&E and SDG&E do not require payment before construction and instead require payment of an engineering advance;
- General inquiries go unanswered; and
- Difficulty making contact with a utility representative who can answer questions.

Unlike Rule 21, which has details and timelines for the different steps of project review, Rules 2, 15 and 16 lack information about the study process relied on by utilities. Further, utility processes also differ from one another. SCE, when presenting the results of interconnection review, includes an invoice for work to be done. PG&E and SDG&E do not require payment before construction and instead require payment of an engineering advance.

For context: SCE and SDG&E report that the number of projects which must be reviewed across Rule 21 AND either Rule 2, 15, or 15 is limited. The number of projects going through this review in PG&E's service territory is greater.

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[20] More complete explanations and diagrams can be reviewed at https://gridworks.org/wp-content/uploads/2018/08/Rule-21-Working-Group-2-8.1.18.pdf, slides 5-7.

The following proposals are intended to ensure that projects are managed smoothly, that customers are able to track progress, and that utility work is done within a reasonable timeline.

CALSSA Proposals and Utility Perspectives

Proposal 1: The utility shall assign a project manager to all projects larger than 100 kW. In addition to managing the project through interconnection review, the project manager shall manage the transition to study under Rule 2, 15 or 16 and be available to get responses to questions related to construction of interconnection facilities and distribution upgrades.

Status: Non-consensus

- Supported by: CALSSA, Clean Coalition (qualified), TURN (qualified)
- Opposed by: SCE, PG&E, SDG&E

  Utility Perspective:

  - While SCE and SDG&E agree that this may be a good practice, the CPUC should not mandate how we may effectively manage the interconnection process to meet our customer needs. Project management personnel needs is a function of the needs for such a position. What is important is that the utility provides adequate management of projects and contact information, but the utility should not be required to have a project manager.
  - For PG&E, current practice depends on the nature of the project. For the more complex interconnection projects (i.e., multi-tariff, etc.) greater than 100 kW, a project manager is assigned to manage the transition to study under Rules 2, 15, or 16, and this project manager is available to respond to questions related to construction of interconnection facilities and distribution upgrades.
    - For the basic expanded net energy metering interconnection projects between 100 kW and 1 MW, PG&E has a dedicated team of four project managers assigned to collectively manage the interconnection process and be on point for responding to questions related to construction of interconnection facilities and distribution upgrades.
    - For the basic expanded net energy metering interconnection projects, PG&E will be assigning 1 of the 4 project managers to each project between 100 kW and 1MW effective mid-October.
    - PG&E is also considering identifying a dedicated team of project job owners that will provide the project manager more visibility and support on Rules 2, 15, and 16 project work.
  - While complying with its tariffs, each utility should be afforded the latitude to manage its responsibilities and assign the appropriate number of resources necessary to efficiently interconnect the projects. Rule 21, Section E.2.a, further discusses this point: "…Distribution Provider will establish an individual representative as the single point of contact for Applicant, *but may*

allocate responsibilities among its staff to best coordinate the Interconnection of an Applicant's Generating Facility." (emphasis added)

Proposal 2: There shall be a single Project Identification Number from the receipt of an interconnection application through permission to operate. This number shall be the identifier used for interconnection review under Rule 21 and study under Rules 2, 15 and 16.

Status: Consensus

Utility Perspective: All utilities agree to this suggestion. PG&E notes that in some cases, such as when a customer applies for a panel upgrade or other requested work prior to interconnection, that is considered a separate application, and, as such, will have its own application ID. Also, such a Project Identification Number is only for the project, would be distinct from, and would not replace the meter number or service account number.

PG&E notes that the issue of multiple Project Identification Numbers has limited certain PG&E personnel from being able to access project history and background when responding to customer inquiries. PG&E has developed a solution that would provide full project history to all parties that are involved in the interconnection process. PG&E believes that this solution will address the challenges that PG&E customers have been experiencing.

Proposal 3: When a project is studied under Rules 2, 15 and 16, the customer shall be informed of the start date of that study.

Status: Consensus

Utility Perspective:

- SCE informs the customer as part of the Rule 21 process as the engineer evaluating the generation also evaluates load impacts. SCE notes, however, that Rule 2/15/16 evaluation is only for storage systems that do not want charging restrictions, for which SCE has only received two requests., Most storage requests do not propose an increase in customer's peak demand and do not require a Rule 2/15/16 evaluation.
- SDG&E reports this practice is already in place in their service territory. SDG&E establishes what it calls the "applicant's final submittal" date, which records the date on which all information necessary has been received and sets the date for the applicable tariff. This date serves as the base date for time measurement.
- PG&E reports they recently implemented notifications informing the customer when design work is initiated.

Proposal 4: The utility must send an invoice for the engineering advance or the facility costs within five business days of execution of the Interconnection Agreement, unless the request for payment is contained within the Interconnection Agreement.

Status: Non-consensus

- Supported by: CALSSA, Clean Coalition (qualified), TURN (qualified), SCE (qualified)
- Opposed by: PG&E, SDG&E

Utility Perspective:

- SCE expressed concerns with this suggestion for two reasons. First, their current process is working well for customers, an observation that was generally agreed to within the working group. Second, SCE uses the cost in the Fast Track or Independent Study Process to include in the Generator Interconnection Agreement. Once the customer executes the Generator Interconnection Agreement and provides the funds then SCE commences the design and construction of the facilities. SCE has not collected engineering advances for interconnection work. Instead, SCE relies on executed agreements with costs from the study process (i.e., Fast Track, Independent Study Process), and this process has worked well for SCE and its customers.
- SDG&E asserts if they were to allow customers to complete the design themselves, SDG&E would still need to collect these fees. A hard date doesn't work well for SDG&E either.
- PG&E agrees in principle that the invoice should be sent to the applicant as soon as practical; however, an executed agreement should be in place prior to invoicing for capital work. Please note that this timeline will not affect projects that utilize the Financial Security provisions and will only apply to projects using the Special Facilities Agreement process.

Proposal 5: Within five business days of receiving payment for the engineering advance or upgrade costs, the utility must attempt to contact the customer's representative, or the customer if there is no customer representative, to schedule a mitigation work scoping meeting. The utility shall make a good faith effort to coordinate a site visit early in the design phase at the request of the customer or the customer's representative.

Status: Non-consensus

- Supported by: CALSSA, SCE (qualified), Clean Coalition (qualified), TURN (qualified), PG&E (qualified)
- Opposed by: SDG&E

Utility Perspective:

- SCE hosts a scoping meeting after the Generator Interconnection Agreement is executed and payment is received from the customer. In their experience, 10 business days would be a more realistic expectation for customer contact. Finally, SCE reiterates that its current process for the scoping meeting seems to be working, and therefore the change envisioned here is not necessary.

- PG&E will contact the customer's representative or customer within 5 business days of receiving payment to schedule a work scope meeting; however, it should be mutually agreed upon between the customer and PG&E whether the meeting should take place in person, at the point of interconnection, or via telephone.

Proposal 6: Design and cost estimation (if not previously provided) for interconnection facilities and minor distribution upgrades must be completed within 60 business days of: 1) receipt of funds for the engineering advance or upgrade costs, or 2) receipt of the IOU approved necessary customer site information as required for the design of the facilities (such as underground base-maps, switchgear drawing, etc.) that meets the IOU technical requirements, whichever occurs later. Parties may also agree upon a different timeline by mutual consent. If the utility will exceed this timeline, it must inform CPUC Energy Division and the customer's representative, or the customer if there is no customer representative, with an explanation of the reason for the need to exceed the timeline.

Status: Non-consensus

- Supported by: CALSSA, SCE (qualified), Clean Coalition (qualified), TURN (qualified), PG&E (qualified)
- Opposed by: SDG&E

Utility Perspective:

- For SCE, the cost estimation is done in Fast Track or the Independent Study Process, and those costs are collected as part of Generator Interconnection Agreement and then trued up when the project is completed. SCE reiterates that its process has worked well, and it should not be required to change its process. For SCE, a design completion milestone is part of the Generator Interconnection Agreement, where, depending on the scope of the work, SCE has used a term of 60 business days from the time the interconnection customer provides the required design information (facility base maps, underground facilities, etc.). SCE notes that at this point in the interconnection process both SCE and the customer must be working together on milestones that affect each other. For example, SCE cannot commence its design work if a customer does not provide the required design information. Therefore, a firm 60 business days does not work if it's only imposed on the utility, as there are many contingencies which may affect the completion of the design. SCE has used 60 business days for design work as described above for projects that require only interconnection facilities or simple upgrades. For larger projects requiring substation work or large upgrades, the design timeline is based on the scope of what is being designed.

- For SDG&E, fixing a 60-day business schedule does not work. SDG&E believes that customers should get in line with other applicants requesting utility work, and that the interconnection applicant should have the option of doing the distribution design and installation themselves much like an extension. That makes design and construction scheduling competitive in the marketplace.
- PG&E should not be held to the 60 business day requirement for design and cost estimation because the nature of the design and estimation work involves such variability in scope, often involving third parties outside the utilities control (e.g., whether it is for new or existing facilities, account for environmental permitting, allow for FAA review, obtain permitting, perform mapping verification, perform Environmental Impact Review, resolve land right-of-ways issues, etc.).

  In addition, PG&E must balance storm work, fire related support, and work following other natural disasters, all of which may detract from our finite design and estimation team's resources and ability to meet a strict design and estimation timeline.

  Instead, PG&E:
    - Agrees to provide written information to the customer or customer's representative regarding the design and cost timeline and will inform the customer or customer's representative if this design and estimation timeline cannot be met.
    - Proposes to issue quarterly reports for one year to CPUC Energy Division on the performance relative to the estimation and design timelines provided to the customer or customer's representative. Following the year, an assessment can be made to understand what the root causes of the significant delays are, and PG&E can use targeting measures to solve them specifically.

  Note that start of the clock for design and estimation should begin when we have all information required from the customer to complete the design (i.e., Site Plans, Building Elevations, Improvement Plans, Environmental Conditions, Site Photos, Load Data, Generation Data, Meter Equipment Rating, Meter Locations, Design Option, Construction Option).

Proposal 7: Construction of interconnection facilities and minor distribution upgrades must be completed within 60 business days of: 1) a customer's election to proceed after facility design, or 2) after the customer has completed their portion of civil work (if any), whichever occurs later. Parties may also agree upon a different timeline by mutual consent. If the utility will exceed this timeline, it must inform CPUC Energy Division and the customer's representative, or the customer if there is no customer representative, with an explanation of the reason for the need to exceed the timeline.

Status: Non-consensus

- Supported by: CALSSA, SCE (qualified), Clean Coalition (qualified), TURN (qualified), SCE (qualified)
- Opposed by: PG&E (qualified), SDG&E

    Utility Perspective:

    - For SDG&E, fixing a 60-day business schedule does not work. If the applicants wish to move more quickly than the utility's construction schedule, they should be free to go to the market to have a contractor construct the agreed upon facilities to utility standards.
    - PG&E, similar to design and cost estimation, should not be held to the 60 business day requirement for construction because the nature of the construction work involves variability in scope, often with site-specific or time-specific factors outside of PG&E's control (e.g. whether it is for new or existing facilities, actual site conditions, weather, emergencies, archeological studies, joint utility/joint poles consideration, equipment procurement such as transformers, etc.).

        In addition, PG&E has to balance storm work, fire related support, and work following other natural disasters, all of which may detract from our finite construction team's resources and ability to meet a strict design and estimation timeline.

        Instead PG&E:

        - Agrees to provide written information to the customer or customer's representative regarding the construction timeline and will inform the customer or customer's representative if this design and estimation timeline cannot be met.
        - Proposes to issue quarterly reports for one year to CPUC Energy Division on the performance relative to the estimated construction timelines provided to the customer or customer's representative. Following the year, an assessment can be made to understand what the root causes of the significant delays are, and PG&E can use targeting measures to solve them specifically.

Proposal 8: The utility shall send a detailed reconciliation of the costs of interconnection facilities and distribution upgrades, with a refund of any amount paid in excess of actual costs, within 6 months of project completion.

Status: Non-consensus

- Supported by: CALSSA, Clean Coalition, TURN (qualified)
- Opposed by: SCE, SDG&E, PG&E (qualified)

Utility Perspective:

- SCE advocates for a 12-month deadline for final invoicing similar to projects under Federal Energy Regulatory Commission jurisdiction (i.e., Wholesale Distribution Access Tariff and transmission Owner Tariff). For SCE, it typically takes 170 days to get all related costs and documents received and confirmed (e.g., material tracking sheets, As-Built maps, contractor invoices) before beginning reconciliation. The reconciliation and invoicing process, including management review and approval, takes another 60 days. More complex projects can easily extend these timelines. SCE's goal is to produce accurate invoices in the timeliest manner possible, and rushing the reconciliation process is not in our customers' best interest. SCE is continuously exploring ways to improve our reconciliation and invoicing processes.
- For SDG&E, it typically takes 90 days to get all necessary invoices before beginning reconciliation. This process can sometimes require 180 days.
- For PG&E, it currently only reconciles the costs of interconnection facilities and distribution upgrades for net energy metering projects greater than 1 MW and export projects. These reconciliations are typically completed within 12 months of project completion. If PG&E is to provide reconciliation for all other project types, PG&E would need a similar timeline to complete them.

Stakeholder Comments:

- TURN's support for the entire proposal is contingent upon IOUs' determination of additional expenses that would be incurred as a result of this proposal (including costs for project managers, engineering resources, and others, in addition to upgrade costs). TURN also requests that a fee be assessed for projects greater than 100kw that receive these services.
- Clean Coalition offers qualified support. The issues raised are appropriate and proposed solutions are aimed correctly but warrant some modification in line with IOU feedback, which should be taken into account as consistent best practices are implemented. It is important to establish reasonable target timelines and track compliance while allowing for extenuating circumstances - no penalties have been proposed.
- PG&E, SCE, and SDG&E position for proposals 4, 5, 6, 7, and 8 is qualified on the IOUs' opposition to the addition of timelines to Rule 21.
    - PG&E's business practice may support the requested timeline (proposals 4 and 5); however, the addition of such timelines in Rule 21 is not supported. PG&E agrees to provide written information to the customer or customer's representative regarding the timelines and will inform them if estimated timelines cannot be met.
    - SCE does not support the addition of timelines into Rule 21 as outlined in proposals 4, 5, 6, 7, and 8. Instead, SCE argues that its current process uses the interconnection agreement to outline the milestones that are applicable for the customer and SCE. SCE is then supportive of what is in proposals 4, 5,

6, and 7, as long as the timelines are part of the interconnection agreement and not part of the actual tariff.

- SDG&E does not support addition of timelines into Rule 21 as outlined in proposals 4, 5, 6, 7, and 8. Instead, SDG&E argues that its current process uses the interconnection agreement to outline the milestones that are applicable for the customer and SDG&E.

ISSUE 11 PROPOSAL

Issue 11 Question: Should the Commission adopt a notification-based approach in lieu of an interconnection application for non-exporting storage systems that have a negligible impact on the distribution system? If so, what should the approach entail?

Proposal

Expedite interconnection applications for non-export storage systems as detailed herein.

Status

Non-consensus

- Supported by: Stem, GPI, Clean Coalition, CALSSA, IREC, SDG&E, SCE, and PG&E, except where specifically noted otherwise

Discussion

Issue 11 concerns customers seeking to interconnect storage to the grid, where no export or only de minimis inadvertent exports to the distribution grid occur. Historically, Rule 21 concentrated on generating facilities with either no export (e.g., serving on-site load) or distributed energy resources interconnecting for the express purpose of export (e.g., Net Energy Metering generating facilities). This trend has begun to change as more customers are choosing to mix export with non-export, especially in the configuration where battery energy storage systems is added (non-export) to Net Energy Metering. Additionally, non-export stand-alone storage interconnections are becoming more common. As an increasing number of customers elect a storage solution, new questions about interconnection under Net Energy Metering and outside of Net Energy Metering have emerged. Recognizing this trend and the need to consider how Rule 21 may be adapted to accommodate customer and grid needs, R.17-07-007 posed the following question to the Working Group:

> *Should the Commission adopt a notification-based approach in lieu of an interconnection application for non-exporting storage systems that have a negligible impact on the distribution system? If so, what should the approach entail?*

In considering this question, the Working Group began with fundamental questions of definition, including whether the meaning of "notification-based", "non-exporting", and "negligible" were shared. As a part of this threshold discussion, the Working Group explored what criteria would be used to determine which projects would be eligible for a notification only or other expedited process for non-exporting storage systems.

Building on the Working Group's consideration of Proposal 8.i, Working Group One's discussion of Issue 3,[21] and recently completed IOU Non-Exporting Storage Facilities Pilot Programs, the Working Group discussed the potential advantages and disadvantages of a notification-only system for non-exporting storage projects, barriers in the current interconnection application process that proposals to this Issue are intended to address, and how many projects are likely to benefit from addressing identified barriers.

Questions raised by the Working Group in considering Issue 11, included:

- Which Initial Review screens would non-export systems definitely pass and/or which screens are not relevant for non-export systems (possibly below a specific size threshold)?
  - Which would they likely pass?
  - Are there special conditions or caveats to recognize?
- Could we pre-study certain parts of the grid to know ahead of time whether a project would pass Screens F and G?
  - Would certain conditions be needed? If so, how can those conditions be met?
- Can we set a system-wide threshold for F and G? Or set a threshold percent of ICA value at the point of interconnection?
- Does the same approach work for "charging" as "discharging"? Charging from the grid vs. on-site generation?
- Building on the Working Group's definition of non-export, what projects would qualify as non-export?
  - Would any inadvertent export be eligible for the expedited process?
- What timelines and fees would apply to projects eligible for a notification-only interconnection agreement?
- What changes to the interconnection agreement or other documents are needed to support this approach?
- How could forthcoming reports from the Non-Exporting Storage Facilities Pilot Programs support the proposal?
- Is there a reason to limit process improvements to just non-exporting storage, or can they be extended to any small inverter-based project?

The following proposals address many of these questions; however, full coverage of this scope will require further effort.

The Working Group also noted that while Issue 11 was framed to focus on creating a more efficient process for non-exporting storage systems, Issue 25 expressly indicated that the Working Group should consider whether any revisions to the expedited process for non-exporting storage systems could be revised to "support tariff principles of technological neutrality and consistency across the Utilities." Since there is considerable overlap between the processes proposed herein and Issue 25, the Working Group also discussed how to make this process as technology neutral and consistent as possible.

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[21] See Working Group One Report at page 41 (http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M215/K187/215187299.PDF).

Based on the Working Group's discussion, there was no consensus on whether the Commission should adopt a notification-based approach in lieu of an interconnection application at this time. On this question there was a breadth of perspective, substantial differences of opinion, and many unanswered questions which would need to be properly considered to resolve differences. As such, the Working Group took the position that in the immediate and near terms, the focus should be on how the interconnection application could be expedited in order to reduce the time and costs of interconnecting non-export storage systems—with a commitment to identifying the criteria, system conditions/circumstances, and the configurations and/or other technical specifications that could potentially support a notification only approach in the future. The following proposals delineate the potential paths toward that end suggested by the Working Group, including qualifications and caveats from some stakeholders.

Proposals

The following proposals would expedite interconnection applications for non-export storage systems.

As a threshold matter, these proposals are limited to interconnection of *standalone storage systems* (not including new or retrofit to on-site generator) that will be non-exporting under one of the Rule 21 Screen I Options identified in the Working Group's Issue 8, Proposal 8.i. This perspective was not, however, unanimous.

When the Commission adopted the pilots for the non-exporting storage expedited review process, one intent of the pilots was to evaluate whether the efficiencies created through that process could be extended to other projects in a more technology neutral manner. As noted above, this issue has been queued up for evaluation in Issue 25, but through the discussions of the streamlining steps outlined below for a "Lightning Review" process it has become clear to some stakeholders that this process need not be limited just to non-exporting storage projects. This is because the technical characteristics that enable the streamlining proposed herein are not specific to non-export or storage projects. In light of this, IREC, CALSSA, Tesla, and the Clean Coalition believe that the scope of the "Lightning Review" process discussed below should be expanded to include all generating facility aggregate nameplate inverter rating under 30 kVA, regardless of whether those systems are exporting or non-exporting.

These parties believe that none of the steps outlined herein need to be limited to storage projects. And the only area of difference between non-exporting and exporting systems is whether the utilities would apply certain of the screens (namely, screen D). However, since the utilities currently apply those screens for NEM projects under 30 kVA and are able to do so in a very expedited manner, this can also be done for any inverter-based export project below 30 kVA as well. From a technical review standpoint, a non-NEM, inverter based system of 30 kVA would have effectively the same potential impacts as an identically sized NEM-system. Both would be evaluated based on an assumed export potential of 30 kVA. To the degree that the utilities are currently comfortable with and apply an expedited review process for NEM projects of 30 kVA and under, there is no technical basis not to apply that same process to non-NEM inverter-based projects below this same size threshold. These parties believe expanding the scope in this manner would ensure that a much broader set of systems can avail themselves of a faster review process as well as render moot some of the more technically challenging issues associated with having to define what constitutes "non-exporting". In addition, if the Commission adopts these efficiencies now it will not need to address those exact same questions again under Issue 25. In light of the number of important issues scoped into this proceeding, Tesla, IREC, CALSSA, Stem and the Clean Coalition believe it makes sense to take this step now.

Tesla noted it considers there to also be a need for an expedited process for storage retrofits, which may be a significant market and thus will be a significant source of interconnection application volume.

IOU Response: The IOUs provide the following comments on expanding this proposal from 30kVA or less non-export storage systems to non-NEM 30kVA or less exporting inverter-based systems:

- Jurisdiction: Exporting systems can interconnect under Rule 21 if the Interconnection Customer is a Qualifying Facility ("QF") and will sell all of its exports to the grid to the Distribution Provider under a power purchase agreement ("PPA") entered into pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA").
- Transfer to Wholesale Distribution [Access] Tariff: Some exporting systems move to the Wholesale Distribution [Access] Tariff process and have the option to execute a Rule 21 exporting agreement.
- Queue Position: Exporting systems are assigned queue positions.
- Forms and Agreements: Exporting Systems have separate applications and agreements from non-exporting systems.
- Certificate of Insurance: non-NEM systems are required to provide a certificate of insurance.

Exporting systems that are not participating in NEM were not discussed in Issue 11, and these types of inverter-based systems have process and contractual steps that a NEM system does not have. The Joint IOUs oppose the recommendations identified in Issue 11 being applied to any interconnection request types that were not scoped into Issue 11, especially exporting systems because that introduces some key interconnection program differences.

Proposal A: The Commission directs each utility to formally implement all successful process improvements that were tested in the non-exporting energy storage pilots in the standard Fast Track process flow for all storage applications that fit the pilot criteria.

PG&E's Advice Letter 4941-E-A[22] noted, "*PG&E's focus in making this proposal is to continue to build on significant process improvements underway, specifically the building of the modular tool to streamline interconnection application submission. As noted, the scope of the software platform effort embraces everything from collecting equipment descriptions from Applicants to acceptance of online payments and leveraging other PG&E data bases. In this way, PG&E anticipated that the average timeline a given applicant experiences for a storage interconnection will continue to decrease as each new component comes online.*

In fact, significant interconnection time reductions were reported in PG&E's AL 5371-E[23]—in the range of 30-40% for the one-year pilot period—with the expectation that trends would continue to show further improvements. Given the lower volume of the non-export storage project (the pilot included 79 projects), as compared with NEM projects (which would have covered around 60,000 projects in the same time frame), this would be the most cost-effective approach.

Proposal B: The Commission does the following with respect to the Lightning Review concept described herein:

Proposal B1: Direct the IOUs to implement Lightning Review Phase 1 (Standard NEM parity), as detailed below.

Proposal B2: Direct the IOUs to undertake study and design of Lightning Review Phase 2 (Increased size eligibility).

Proposal B3: Scope the study and design of Lightning Review Phase 3 (Pre-studied locations) into the proceeding or Working Group that will address the next set of ICA-related Rule 21 improvements beyond the current Working Group 2.

PG&E Perspective: First, PG&E does not recommend expanding the scope of the current Rule 21 proceeding. There is already enough in scope to make it a challenge to properly address and complete the given tasks. Second, for these three proposals (B1-B3), as stated above, PG&E believes is it more cost effective to pursue a general program of expediting all interconnections, especially given the volumes are still low for these. Upgrading the standard portals is an expensive proposition, and it adds more complexity to the existing portals to include additional options, potentially slowing down the process for all interconnections.

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[22] AL 4941-E was submitted by PG&E on February 1, 2017. Quote at Page 8.

[23] AL: 5371-E was submitted by PG&E on August 31, 2018. Interconnection time reductions listed on Page 6.

Proposal C: In lieu of addressing Issue 25,[24] the scope of Working Group 4 is amended to research and report what circumstances, configurations, lessons and changes would need to be adopted in Rule 21 to effectuate a notification-based approach.

PG&E, SCE, SDG&E do not support Proposal C.

Within this proposal, the Working Group provides high-level impressions of the resources required to implement each recommendation but does not opine on whether the benefits would be worth the investment. All proposals are subject to the Commission's determination that cost, resources, and timelines are reasonable.

The Lightning Review concept is premised on the vision of an interconnection review process that has been streamlined to the maximum extent possible for the broadest range of interconnection applications for non-exporting energy storage installations. The concept originates with the successful streamlining of the Standard NEM processes at the California utilities, and the proposed design and implementation plan is organized into three Phases.

> **Phase 1 (Proposal B1):** Making all non-exporting storage less than or equal to 30 kVA Generating Facility aggregate nameplate rating eligible for effectively the same process that Standard NEM <30 kVA applications go through, subject to fees commensurate with those processes. Additionally, projects that qualify for this process should be exempt from the queueing procedures that non-NEM and NEM > 1 MW projects experience.
>
> **Phase 2 (Proposal B2):** Increasing the project size eligibility for the Lightning Review process to a single number greater than 30 kVA as the new standard that applies to most areas of the grid. Below 30 kVA would still be eligible anywhere on the grid.
>
> **Phase 3 (Proposal B3)**: Utilities implement a process, similar to the ICA, where the grid is pre-studied and the results are published such that eligibility for the Lightning Review process becomes location specific and presumably available to a larger range of projects than met the Phase 2 criteria.

Proponents emphasize that nothing in this schedule and plan should delay the implementation of beneficial process changes for non-exporting storage over 30 kVA (i.e., a known improvement for projects > 30 kVA should not be delayed due to Phase 2 of the Lightning Review implementation).

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[24] Issue 25 at page 6: "Should the Commission make any revisions to the expedited process for eligible non-exporting storage facilities in response to pilot program data collected by the Utilitie3s between July 1, 2017 and June 30, 2018, in order to support tariff principles of technology neutrality and consistency across the Utilities?" from the Scoping Memo of Assigned Commissioner and Administrative Law Judge, dated August 15, 2018.

Lightning Review Process

The Lightning Review Process details are organized into four main areas of process improvement opportunities and the corresponding vision from the proponent's perspective. Each vision statement is the non-IOU framing of the eventual future goal of process streamlining efforts and is not intended to be adopted as official policy:

1. Application submittal to Deemed Complete:
   Non-IOU Vision: Applications are deemed complete within a few days of initial submission without requiring corrections from applicant. This can be accomplished by using as much Front End Error Checking as possible to reduce incoming errors.

2. Fully Frontloading an Executable Generator Interconnection Agreement:
   Non-IOU Vision: The applicant submits a customer-executed Interconnection Agreement with the application; it needs no correction; the utility executes it; and delivery to applicants serves as the Permission To Operate authorization—Front End Error checking and perhaps electronic signature to facilitate this.

3. Technical Screens Review:
   Non-IOU Vision: Technical review is automated or performed by utility staff, and all threshold/lookup values are available per location prior to application submission—Initial Review performed automatically. For projects that fail Initial Review screens or are above certain thresholds, an engineer reviews before delivering results to the customer.

4. Inspection/testing for Permission to Operate :
   Non-IOU Vision: Inspection does not require on-site review by utility staff and is instead completed either through remote review or through self-certification by applicant-hired licensed engineer. Waiving inspections may depend on size, what non-export provision is used to prevent export, and the specific manufacturer and model numbers for the equipment being used.

The major principles for streamlining in each area include:

- Design for the most common cases, where the exceptions can move an application out of Lightning Review.
- Minimize roundtrips between utility and applicant by frontloading information exchange as much as possible and automatically checking for common errors before the applicant submits documents.
- Remove the need for engineering technical review for a review action, by having "checkbox" or simple lookup verification. Ultimately, checkbox and lookup values can be published such that applicant can verify these fields before submitting an application.
- Wherever possible, create standard templates for required documents, so that an application can be checked against a template rather than require technical review.

The following sections identify proposed enhancements in each area of process improvement for Phase 1 of the Lightning Review Process. Process improvement ideas for Phase 2 and Phase 3 are described in the Issue 11 Appendix.

1. Application submittal to Deemed Complete

This section of the Lightning Review assumes that eligible projects will apply using the utility's online interconnection application portal, maps and other documents with known interconnection related information.

Process Idea	Phase 1
Technical criteria published	Equivalent to standard NEM
Eligibility validated by Web Portal	Same as standard NEM
Auto-validation of required fields	Adapt NEM forms
Simplify application form questions	Adapt NEM forms
Web portal should reject application errors	Adapt NEM forms
Electronic application fee payment	Existing NEM process?
Explore basic single line drawing and potential use in this area	Adapt NEM single line diagram processes
Exemption from Queue	

The Phase 1 description of each "process idea" of the application review is discussed further below. Further steps beyond Phase 1 are described in the Appendix.

<u>Technical Criteria Published</u>
The technical criteria required for Lightning Review eligibility is published by each utility for applicant review prior to application submission. This minimizes applications for Lightning Review that are not eligible and reduces costs by allowing developers to plan for interconnection costs and timelines.

Utility Perspective:

- PG&E believes this is not necessary. The application portal should be made simple and provide results as quickly as possible. Having various technical criteria and various flavors of the interconnection programs is confusing and will not be used. PG&E has published best practices and common mistakes which some developers use but most do not. The best practice is to make the interconnection portal process user friendly and simple which is a guiding principle for PG&E.
- SDG&E concurs with PG&E that publishing a separate list of criteria for eligibility for lightning review is not necessary. A straight-forward easy to understand application will communicate effectively the IOU requirements for expeditious review.

<u>Eligibility Validated by Web Portal</u>
Technical eligibility criteria are checked by the portal and prevents submission to Lightning Review process if criteria are not met. The Standard NEM portal only allows applications that meet the criteria for Standard NEM. Eligibility should be built as logic within the web portals.

Utility perspective:

- PG&E and SDG&E have deployed this feature and continue to refine it to prevent the submission of incomplete applications.

<u>Auto-validation of Required Fields</u>

For all other required application fields, intake personnel use standard forms to validate that field has been filled with information in the correct format.

Utility Perspective:

- PG&E and SDG&E have deployed this feature and use their records to auto-populate relevant information associated with the customer once validated.

<u>Simplify Application form questions</u>

Forms should be pared down to only request necessary information. IOUs can use experience from non-exporting storage pilots to determine which fields are unnecessary.

Utility Perspective:

- PG&E and SDG&E limit the fields to what is required for the interconnection program and remove unnecessary fields to make the process streamlined for customers. In the near future however, the number of fields will be growing to support the Phase 2 and Phase 3 features of Smart Inverters in 2019.

<u>Web Portal should reject application errors</u>

Adapt NEM forms to include flags for common mistakes in non-exporting storage applications and reject application errors to assist applicants in ensuring form completion on the first try.

Utility Perspective:

- PG&E has published[25] a Frequently Asked Questions document which provide tips on how to submit an interconnection application for standard NEM and the portal support document[26] for applications for other programs. PG&E continues to monitor issues that customers raise and makes regular updates and enhancements to continue to improve the interconnection process.
- SDG&E agrees with the concept; however, scope and cost to implement flagging of mistakes still needs to be determined.

<u>Electronic Application Fee Payment</u>

Payment of application fee is done with application submittal.

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[25] https://pge.com/includes/docs/pdfs/b2b/interconnections/NEM_FAQs.pdf.

[26] https://s3.amazonaws.com/qado-prod/pge/webassets/ACEITOverview.pdf.

Utility Perspective:

- SCE and PG&E are supportive of collecting application fees electronically. This will require CPUC approval to migrate from the current electronic wires to integrating electronic payments into the interconnection portal.
- SDG&E receives payment with application submittal of NEM projects. Scope and cost to develop and apply upfront payment with application submittal for ≤30 kVA non-exporting energy storage projects has not been determined. The quantity of potential projects should also be considered before committing to incur the costs to implement upfront payments with application.

Single Line Diagrams Verification

Currently, utility intake teams check whether Single Line Diagrams have all the required information. This proposal would order utilities to create a standard set of Single Line Diagram templates for non-exporting storage under 30 kVA .

Utility Perspective:

- PG&E has been working with storage vendors to understand the standard solution set that each particular vendor uses for NEM Paired Storage projects. PG&E has been exploring pre-approving a solution set and its certification to make the review of each transaction quicker.
- SDG&E currently employs standard Single Line Diagram templates for NEM projects. This approach could be extended to non-exporting storage under 30 kVA, although the scope and cost have not been determined.

The proponents of this proposal envision a majority of applications will fit in to standard templates. As such, applicants should understand that Single Line Diagrams that do not fit into a standard template may not remain in the Lightning Review process flow and thus should not expect the Lightning Review timelines.

Exemption from Queue

Propose that projects that qualify for this process be exempt from the queueing procedures that non-NEM and NEM > 1 MW projects experience.

Application to Deemed Complete Summary

Using the online forms to ensure submitted information is as complete and correct as possible should mostly eliminate roundtrips during this section of the process, saving days to weeks in the overall timeline and reducing time for utility intake staff.

Utility Perspective:

- PG&E supports automation efforts to streamline the interconnection process as long as:
    - The automation is designed to support our highest application volume programs first and is not targeted at small particular subsets of the total portfolio; and
    - The cost/benefit ratio is reasonable and cost recovery is clear.

- SDG&E would require a Certificate of Insurance and non-export Interconnection Agreement as part of the application package in order for the application to be deemed complete. Standardized Generator Interconnection Agreements are currently used for NEM projects and could be developed for non-exporting energy storage projects. Standard Certificate of Insurance forms are not currently utilized for NEM projects, and would have to be developed. The scope and cost to develop and implement standard Certificate of Insurance forms has not been identified.

2. Frontloading Generator Interconnection Agreement

Currently for Standard NEM, the Generator Interconnection Agreement is provided up front and the customer submits the signed agreement with the interconnection application.

For the Lightning Review, the conceptual process flow:

- Online form requires applicant to fill in all required fields to generate a Generator Interconnection Agreement
- Online portal generates a complete Generator Interconnection Agreement, assuming that projects meeting Lightning Review criteria passes technical screens with no required upgrades
    - Common mistakes are flagged up front (e.g., business name does not match service account customer name)
    - The Generator Interconnection Agreement specifies the authority level of the person signing the Generator Interconnection Agreement on behalf of the customer
- Customer signs the Generator Interconnection Agreement as part of submitting application
- At any point in Lightning Review, if the Generator Interconnection Agreement information needs to change, the initial signed the Generator Interconnection Agreement is deleted and a new one is issued back to the customer. This may remove the application from the Lightning Review process flow, and the applicant understands that Lightning Review timeline expectations may no longer apply

Utility Perspective:

- As noted, PG&E has implemented the process to obtain customer signature of the agreement as part of the application process for standard NEM. There is an existing workflow that facilitates the existing automation. SCE and PG&E are supportive of expanding the usage of the workflow to non-export storage. Similar to Standard NEM, this will require CPUC approval of forms and agreements modifications.
- SDG&E currently facilitates submittal of standard IA's for NEM projects, and this could be expanded to non-export storage projects.

Frontloading Generator Interconnection Agreement Summary

The benefits of this Proposal, which may accrue to as many as 90% of applications, is that the Interconnection Agreement can be automatically populated and signed and will not require amendments, eliminating roundtrips between developer and IOU as well as minimizing requests to the host customer.

Utility Perspective:

- PG&E supports automation efforts to streamline the interconnection process as long as:
    - The automation is designed to support our highest application volume programs first and is not targeted at small particular subsets of the total portfolio; and
    - The cost/benefit ratio is reasonable and cost recovery is clear.
- SDG&E, as stated above, the scope and cost for a number of Option A improvements have not been determined. This needs to be done, along with an assessment of the quantity of likely projects in order to conclude whether the benefits justify the costs for each improvement.

3. Technical Screens Review

Currently, for standard NEM, either a technical screen already does not apply or non-technical staff has the tools to check the screen using threshold values and comparisons to database information without involving engineering staff.

Phase 1 would allow non-exporting storage under 30 kVA to use the same technical review process with the addition of verification of the chosen Screen I option.

If, at any point, the technical review requires engineering staff, the application exits the Lightning Review process and enters the standard process. If the application exits Lightning Review, the signed the Generator Interconnection Agreement remains valid unless standard review requires a change to the Generator Interconnection Agreement. Of course, if technical review shows that the project triggers a grid upgrade, the application exits Lightning Review and the new Generator Interconnection Agreement will need to be issued.

Throughout the technical screens, the Lightning Review assumes an energy storage device will never charge at a time when the customer's peak demand is increased. The customer will commit to this operational restriction in the Generator Interconnection Agreement.

Screen	Phase 1
A – Network Secondary	Database lookup
B – Certified Equipment	Check against IOU list List published online
C- Voltage Drop	N/A
D – Transformer & Conductor Ratings	N/A for non-export
E- Single phase generator	N/A for NEM, TBD for storage charging
F – Short Circuit Contribution	Checkbox for under 30 kVA
G – Short Circuit Interrupting	Checkbox for under 30 kVA
H – Line Configuration	Checkbox for under 30 kVA
I – Export across PCC	Options 3&4

Technical Screens Discussion

A. <u>Network Secondary</u>

Currently, intake staff can look up network type in a database. In Phase 1, intake staff can do the same for non-exporting storage. Ideally, the application form can do this check automatically, so status is flagged before submission.

IOU comment: Database lookup for verification of point of interconnection is already done today.

B. <u>Certified Equipment</u>

Each IOU maintains a list of certified equipment and makes this list available online. If an applicant's equipment is not on the list, then engineering staff may need to review.

To the extent that projects choose a non-export Screen I option that involves additional hardware (e.g., non-export relay), Phase 1 could include the creation of an additional certified equipment list.

After Phase 1, the Commission directs the IOUs to establish a consistent list across the state with a frequent, regular update process.

IOU comment:

- PG&E and SDG&E have a list of certified equipment that populates the equipment list in the application portals. The IOUs do work together and collaborate in reviewing non-certified equipment.
- Inverter must be listed as being certified and existing in IOU databases. Unlike NEM projects where the CEC has the list of certified equipment, the utility will have to request certification information for storage inverters and will have to maintain a

database of approved certified storage inverters which the utilities will post in the online portals.

C. Voltage Drop – N/A. Only applies to motor generators

Screen C only applies to Generating Facilities that start by motoring the Generator(s).

D. Transformer or conductor Rating

Non-Export Option 3 and 4 projects can bypass this screen on the premise that the customer acknowledges that the generating facility would not increase the host facility peak demand.

Note that if this proposal was expanded to include all inverter-based systems below 30 kVA, then the utilities would still need to apply this screen as they do for standard NEM systems.

E. Single-Phase generator

Currently, Screen E does not apply to standard NEM systems. In the Working Group discussion, it was noted that this could apply to the charging activity of storage.

Single Phase Generator-Customer acknowledges when connection to a single-phase transformer with 120/240 V secondary voltage must be installed such that the aggregated gross output is as balanced as practicable between the two phases of the 240 Volt Service.

F. Short Circuit Current Contribution

Bypass Screen F per Issue 8 Proposal for projects less than or equal to 30 kVA.

G. Short Circuit Interrupting Capability

Bypass Screen G per Issue 8 Proposal for projects less than or equal to 30 kVA.

Screens F&G are the critical screens by which project size affects technical review, and thus eligibility for Lightning Review. Currently, standard NEM projects under 10 kW pass these screens without engineering review. As such, non-exporting storage under 10 kVA or the proposed 30 kVA limit proposed in Issue 8 should also pass these screens.

H. Line configuration

Bypass Screen per Issue 8 Proposal for projects less than or equal to 30 to kVA.

I. Export across the PCC

Customer must choose and qualify for protection option 3 or 4., per Rule 21 Section G.1.I.

Option 3—Database calculation and verification needs to be created for evaluation of the requirements for conditions be met:

a) The total Gross Capacity of the generating Facility must be no more than 25% of the nominal ampere rating of produces service equipment; b) the total Gross Capacity of the generating facility must be no more than 50% of produces service transformer capacity rating c) the generating facility must be certified as non-Islanding

Option 4—Database calculation and verification of the requirements for conditions be met:

This option, when used, requires the generating facility capacity to be no greater than 50% of producers verifiable minimum Host Load over the past 12 months.

Technical Review Summary

Non-exporting storage under 30 kVA should be able to fly through technical review at the same speed as standard NEM. This proposal also increases the chances that front-loaded executable Generator Interconnection Agreement will not need to be changed.

The technical requirements for Phase 1 Lightning review eligibility would include:

- Documentation was complete (e.g., a Single Line Diagram or a Description of Operations) from the application package (SDG&E will also require a Certificate of Insurance and Non-export Interconnection Agreement.)
- The inverter is 1741 SA certified
- The application indicates that the storage device will not increase the host facility's peak load demand
- The application indicates that the installed equipment meets the Electrical Service Requirements
- The Cost Envelope Option was not selected
- The facility is not requesting new retail service
- A Net Generation Output Meter has not been requested on the application
- Interconnection not on the line-side of the customer's main breaker
- No upgrades triggered by this request
- Technology type is comprised solely of non-exporting inverter-based energy storage
- Generating Facility aggregate nameplate is equal or less than 30kVA
- Facility is behind a single, clearly marked and accessible disconnect, as shown on the Single Line Diagram, or has a self-contained meter as means to disconnect the project
- There is no other existing generation (which is not isolated) at the location

- Protection option 3 or 4 were selected in the Interconnection Application
- A single or coordinated control system was is identified in the application

Utility Perspective

- PG&E and SDG&E support automation efforts to streamline the interconnection process as long as:
    - The automation is designed to support our highest application volume programs first and is not targeted at small particular subsets of the total portfolio; and
    - The cost/benefit ratio is reasonable and cost recovery is clear.

4. Inspection / Testing for Permission to Operate

In the Lightning Review process, inspection and testing for issuing Permission to Operate can be completed without requiring a utility employee to visit the project site. When the on-site inspection is avoided, the delivery of the Permission to Operate authorization is streamlined. Non-exporting storage under 30kVA is afforded the same options that Standard NEM applications use.

In their non-exporting storage pilot, SCE has successfully completed several "remote inspections" for qualifying projects. Phase 1 could also involve the formalization of the qualifying criteria and documentation across the IOUs so the applicant could know ahead of time whether or not their project will qualify for remote inspection. The applicant would then submit the required documentation (e.g., photos of installation) as early in the process as possible.

Utility Perspective:

- PG&E supports streamlining the process and avoiding in-person commissioning and testing to the extent possible. However, the option to conduct tests needs to remain as these generating facilities are operating in parallel with the distribution system that PG&E is responsible for maintaining safely and reliably.
- SDG&E currently facilitates remote inspection allowing Interconnection Customers to submit a photo of the meter and plaque.

Inspection / Testing for Permission to Operate Summary

The benefits include any application that can do remote inspection or self-certification can save weeks in the overall timeline. Also reduces utility costs by eliminating a truck-roll. Each IOU establishes formal criteria for eligibility and trains staff to review documentation to sign off

Issue 11 APPENDIX

This Appendix documents the interconnection process improvement ideas that were categorized as belonging to Phase 2 or 3 of the Lightning Review concept. Working Group members did not evaluate or take positions on these ideas and thus, these ideas are not included in the Working Group's formal proposal to the Commission. Working Group members felt that documenting the ideas here will help put the Phase 1 proposal in context of the eventual goals and will help future deliberations if/when Phase 2 and 3 are considered.

This Appendix is organized to mirror the structure of the main body of the proposal.

1. **Application submittal to Deemed Complete**

Process Idea	Phase 1	Phase 2	Phase 3
Technical criteria published	Equivalent to standard NEM	Areas where higher size threshold applies	Maps provide criteria values per location
Eligibility validated by Web Portal	Same as standard NEM	Checks higher size in designated areas	Checks against database per location
Auto-validation of required fields	Adapt NEM forms	Add area ID field	Add map data date stamp
Simplify application form questions	Adapt NEM forms	Add area ID field	Add map data date stamp
Web portal rejects application errors	Adapt NEM forms		
Electronic application fee payment	Existing NEM process		
Explore basic single line drawing use	Adapt NEM single line diagram process		

__Technical Criteria Published__

The technical criteria required for Lightning Review eligibility is published by each utility for applicant review prior to application submission

Phase 2 would add a designation of grid areas for Lightning Review eligibility to the current online interconnection maps

Phase 3 would provide location specific criteria values (such as size thresholds) on the maps

Eligibility Validated by Web Portal

Technical eligibility criteria are checked by the Form and prevents submission to Lightning Review process if criteria are not met.

Phase 2: Only addition would be verification that project is located in an area that's designated to have a higher eligibility threshold
Phase 3: Verification that eligibility threshold at project location is above project size

Auto-validation of Required Fields

For all other required application fields, intake personnel use standard forms to validate that field has been filled with information in the correct format.

Phase 2: Validate that grid area ID is a valid number
Phase 3: New field – applicant provides date when map information was retrieved

Single Line Diagrams Verification
Currently, utility intake teams check whether Single Line Diagrams (SLD) have all the required information

Phase 1: Utilities create a standard set of SLD templates for non-exporting storage under 30 kW
Phase 2: Expand the set of standard templates for larger systems

2. Frontloading Generator Interconnection Agreement

Independent of the Lightning Review Phases, in order to increase the success rate of frontloading the IA, the Commission should consider resolving or expediting the processes for the following common issues:

- Name mismatch: For commercial installations, the mismatch between business name on service account and the business name that is applying for interconnection has been a major time consuming problem for interconnection. The Commission should examine ways to resolve this without requiring an expensive, time consuming service account change, e.g. DBA affidavit or a quick, free way to change the service account name
- IA signing authority level: The required authority level of the person signing the IA has also been an unreasonable barrier in the interconnection process. For large corporations, staff at the required level are not onsite.
- Electronic Signatures: Electronic signatures should be allowed for all IAs. This will make frontloading the IA much easier

3. Technical Screens Review

Phase 1 would allow non-exporting storage under 30 kVA to use the same technical review process with the addition of verification of the chosen Screen I option.

Phase 2 would establish a higher standard size threshold for designated areas of the grid such that projects in those designated areas are eligible for the Lightning Review process.

Phase 3 would establish location specific screen thresholds based on a pre-study of the grid and regular updates akin to the process established for ICA values. Lightning Review eligibility will depend on whether the screen thresholds have changed since the applicant retrieved the numbers for their application.

Screen	Phase 1	Phase 2	Phase 3
A – Network Secondary	Database lookup	Secondary networks marked on maps	Automated form lookup
B – Certified Equipment	Check against IOU list List published online	Consistency across IOUs	
C- Voltage Drop	N/A		
D – Transformer & Conductor Ratings	N/A for non-export		
E- Single phase generator	N/A for NEM, TBD for storage charging		
F – Short Circuit Contribution	Checkbox for under 30 kW	TBD on pre-study for higher values; tools exist	TBD on location-specific pre-study values; tools exist
G – Short Circuit Interrupting	Checkbox for under 30 kW	TBD on pre-study; Harder than F; tools exist	TBD on location-specific pre-study values; tools exist
H – Line Configuration	Checkbox for under 30 kW	Lookup if grid is single or 3-phase with meter number?	
I – Export across PCC	Options 3, 4	Options 3,4 for over 30 kW Pre-approved configurations for other Options?	

A. Network Secondary

Currently, intake staff can look up network type in a database. In Phase 1, intake staff can do the same for non-exporting storage. In Phase 2, the utility's secondary networks could be marked on the online maps. Ideally, the application form can do this check automatically, so status is flagged before submission.

B. Certified Equipment

Each IOU maintains a list of certified equipment and makes this list available online. If an applicant's equipment is not on the list, then engineering staff may need to review.

To the extent that the projects chooses a non-export Screen I option that involves additional hardware (e.g. non-export relay), Phase 1 could include the creation of an additional certified equipment list.

After Phase 1, the Commission direct the IOUs to establish a consistent list across the state with a frequent, regular update process.

C. Voltage Drop – N/A. Only applies to motor generators

D. Transformer or conductor Rating

For non-exporting storage that has committed to never increasing the customer's peak demand, this screen is not applicable. After Phase 1, the IOUs should consider how this screen applies to inadvertent export systems (Screen I Options 5 or 6) and if so, whether this screen can be quickly assessed

E. Single-Phase generator – nothing new after Phase 1

F. Short Circuit Current Contribution

G. Short Circuit Interrupting Capability

Screens F&G are the critical screens by which project size affects technical review and thus eligibility for Lightning Review. Currently, standard NEM projects under 30 kW pass these screens without engineering review.

In the Working Group discussion, it was established that there is no formulaic basis for why the threshold is 30kW versus a higher number, such as 50 kW. Thus, Phase 2 of the Lightning Review implementation would involve developing a methodology by which areas of the grid which fit specific criteria could be designated with a higher standard threshold number.

However, PG&E noted that their non-technical staff has existing tools to check Screens F&G for projects above 30kW. So, another alternative for Phase 2 could be that instead of pre-studying the grid:

- Upfront eligibility for Lightning Review is set at a size higher than 30 kW
    - Higher threshold set at a number utility feels still unlikely to fail F or G for most of their territory
- All IOUs have the tools for intake staff to check Screens F&G

- Applicants understand that projects under the higher threshold may still fail F&G which would cause the application to exit Lightning Review
- This would open Lightning Review to a much larger number of projects while still following an 80/20 rule of benefiting the vast majority of applications

Ultimately, in Phase 3, the IOUs could conduct an "ICA-like" pre-study of their grids to establish "F&G values" in areas of the grid and publish those values on the maps. All of the above suggestions for pre-study acknowledge that such study is more difficult for Screen G than for Screen F but the primary challenges are essentially the same.

This Issue 11 discussion also acknowledges that there is an Issue 8 proposal to publish Screen F&G information on the online maps without a project size threshold. While such information would help an applicant know where Lightning Review is unlikely to succeed, this would provide little to no help in establishing size thresholds under which projects could apply for Lightning Review.

H. Line configuration

In the Working Group discussion regarding Screen H, the IOUs stated that this screen rarely applies to standard NEM since those projects usually seek a single phase interconnection on a single-phase segment of the grid. In Phase 2 or 3, the utilities should consider how this screen applies to non-NEM projects greater than 30 KVa

I. Export across the PCC

In Phase 1, customer must choose and qualify for protection option 3 or 4. Per Rule 21 Section G.1.I.

In Phase 2, for projects larger than 30 kW, eligibility for Lightning Review will depend on the non-export Option that the applicant chooses. The IOUs state that under current review procedures

- Option 1: not eligible
- Option 2: not eligible because engineering review of SLD is required. Phase 2 implementation could require establishing template configurations by which non-technical staff could validate this Option.
- Option 3: eligible
- Option 4: eligible
- Option 5: not eligible – similar reasoning to Option 2
- Option 6: not eligible

Additionally, for Options 1, 2, 5 and 6, Phase 2 could require each IOU to maintain a list of approved non-export configurations from each developer. Then, subsequent projects using an already approved configuration would be eligible for Lightning Review since non-technical staff could just verify that the proposed configuration had already been approved.

Technical Review Summary

For Phase 2, all the Phase 1 Technical Requirements would apply except:

- Technology type is comprised solely of non-exporting inverter-based energy storage: Phase 2 would include any inverter-based technology (not just storage).
- Protection option 3 or 4 were selected in the Interconnection Application: Phase 2 would include mechanisms for choosing Options 2, 5 and 6, potentially with approved software controls to satisfy requirements

Phase 2 Benefits: To the extent that 30 kW threshold can be raised for large areas of the grid, a much larger percentage of applications will be eligible for Lightning Review. This will also enable developers to size storage installations larger, increasing the value those installations can provide to the grid

4. Inspection / Testing for Permission to Operate

Phase 2 would involve expanding the range of projects that were eligible for remote inspection or self-certification.