Rule 21 Working Group Four
Final Report
Third draft 8/3
Comments due by 8/7

ANNEXES

ACRONYMS

AC	Alternating Current
ADMS	Advanced Distribution Management System
AI	Artificial Intelligence
BDs	Business Days
BTM	Behind-the-Meter
C&I	Commercial and Industrial
CCA	Community Choice Aggregator
CDs	Calendar Days
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CSIP	Common Smart Inverter Profile
DC	Direct Current
DER	Distributed Energy Resource
DERMS	Distributed Energy Resources Management System
DG	Distributed Generation
DIDF	Distribution Investment Deferral Framework
DRP	Distribution Resources Planning (proceeding)
DTT	Direct Transfer Trip
ECTs	Existing and Customer Owned Technologies
EOL	End of Line Fault
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
FAN	Field Area Network
FERC	The Federal Energy Regulatory Commission
GFEMS	Generating Facility Energy Management System.
GIA	Generator Interconnection Agreement
GMPs	Grid Modernization Plans
GMS	Grid Management System
GRC	General Rate Case
HV	High Voltage
HVAC	Heating, Ventilating and Air Conditioning
ICA	integration Capacity Analysis
IDER	Integration of Distributed Energy Resources (proceeding)
IEEE	Institute of Electrical and Electronics Engineers
IOUs	Investor Owned Utility
IT	Information Technology
ITCC	Income Tax Component of Contribution
JEAC	Japan Electric Association Code
kW	Kilowatt
LF	Loading Fractions
LG	Single line-to-ground fault
LL	Line-to-line fault

LLG	Double Line-to-ground fault
LLL	Three-phase short circuit fault
LV	Low Voltage
MV	Medium Voltage
NDZ	Non-detection Zone
NEM	Net Energy Metering
NEM-MT	Net Energy Metering Multiple Tariff
NEMA	Net Energy Metering Aggregated
NRTL	Nationally Recognized Testing Laboratory
OIR	Order Instituting Rulemaking
OpFlex	Operational Flexibility
PCTs	Programable Controllable Thermostats
PEVs	plug-in electric vehicles
PF	Power Factors
PTO	Permission to Operate
PV	Photovoltaic
ROI	Risk of Islanding
ROT	Run-on Time
SB	Senate Bill
SCADA	Supervisory control and data acquisition
SCMU	Separate Smart Inverter Control Unit
SIO	Smart Inverter Operationalization
SIWG	Smart Inverter Working Group
SLCPs	Short-Lived Climate Pollutant
SLDs	Single Line Diagrams
TD	Technical Document
TOU	Time-of-Use Rates
TY	Test Year
UL	Underwriters Laboratories
VNEM	Virtual Net Energy Metering
WAN	Wide Area Network
WDAT	Wholesale Distribution Access Tariff
ZNE	Zero Net Energy

Working Group Four 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 Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E), or the investor-owned utilities (IOUs or utilities), to convene eight working groups to develop proposals to address the issues.[1]

Working Group One submitted its final report on March 15, 2018. Working Group Two submitted its final report on October 31, 2018. Working Group Three submitted its final report on June 14, 2019.[2]

An amended scoping memo issued on November 16, 2018 originally tasked Working Group Four to address four issues (18, 19, 29, and F), commencing on a date to be determined.[3] An Administrative Law Judge's ruling on November 27, 2019 established the commencement of Working Group Four as February 2020.[4] A workshop notice was filed on January 31, 2020[5] announcing the commencement of Working Group Four with a workshop on February 12, 2020. The duration of the Working Group was set at six months from this date.

Working Group Scope

Working Group Four developed proposals addressing four issues (18, 19, 29, and F) from the November 16, 2018 amended scoping memo:

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?

Issue 19. Should the Commission adopt streamlined interconnection procedures (e.g. standard

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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] Rule 21 Interconnection Rulemaking 17-07-007, https://www.cpuc.ca.gov/General.aspx?id=6442455170
[3] R.17-07-007 Amended Scoping Memo and Joint Ruling, November 16, 2018 (http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M241/K155/241155616.pdf)
[4] R.17-07-007 Administrative Law Judge's Ruling Directing Responses to Attached Questions and Revising Schedule, November 19, 2019 (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M320/K710/320710784.PDF)
[5] R.17-07-007 Notice of Workshop (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M326/K281/326281931.PDF)

configurations eligible for expedited review) to facilitate implementation of California Zero Net Energy building codes and, if so, what should those procedures entail?

Issue 29. Should the Commission establish a forum, either within this proceeding or externally, to develop interconnection safety standards to address safety and environmental risks as the interconnection of distributed energy resources devices grows?

Issue F. What interconnection rules should the Commission adopt to account for the ability of Distributed Energy Resource Management Systems (DERMS) and aggregator commands to address operational flexibility need.

Working Group Process

Working Group Four met in-person and virtually a total of 12 times between February 12 and June 23, 2020 to develop proposals to address Issues 18, 19, 29, and F. Seven teleconference calls lasted 2 hours, and five full-day meetings provided 4 hours or more of meeting time. The first two full-day meetings, on February 12 and March 11, were in-person meetings in San Francisco, and all subsequent full-day meetings were via teleconference. There were also three meetings to discuss the Final Report towards the conclusion of the Working Group, from July 7, 2020 to July 28, 2020.

The organization Gridworks was contracted to facilitate Working Group Four, which included:

- Arranging meeting logistics: Maintaining the Working Group participant list, managing the Working Group schedule, setting meeting agendas, preparing meeting slide decks, and issuing meeting notes.
- Framing issues to facilitate productive discussion: Preparing background issue briefs for some of the issues, facilitating the formation of sub-groups led by parties.
- Supporting proposal development and drafting for each issue: Coordinating comments and counter-proposals on proponent proposals and writing issue report drafts for each issue which were each reviewed prior to development of the Final Report.
- Writing the Final Report: Setting the schedule of final report review and revision, providing guidance on the scope of party comments for each revision stage, and soliciting and incorporating party comments on Final Report drafts.

Issues were addressed in parallel and discussed over multiple meetings (Table 1). During the initial discussion of an issue, either Gridworks or a Working Group participant would prepare an initial issue brief. Following the initial discussion of an issue, one or more parties developed proposals for that issue, which were discussed and refined over the course of multiple Working Group meetings. At various stages of the process, parties were requested to comment on proposals by given deadlines and given the opportunity to submit counter-proposals.

By the date of the final discussion for a given issue, proposals and party positions would be finalized. Following the final discussion, an issue proponent would finish writing the final version of their proposal, and Gridworks would then write the first draft of the Issue Report (also called "issue write-up") for that issue, based on the understandings reached in the final discussion and on the final versions of proponent proposals.

Working Group participants reviewed each issue write-up in three review cycles (designated versions v1, v2, v3), with discussion of each draft during Working Group meetings. The process of reviewing and discussing the four issue write-ups started on May 19 and continued through June 23. The third versions of each issue write-up were then consolidated into a first draft of the Final Report issued on July 5. The final three Working Group meetings (July 7, July 28, and August 4) were dedicated to reviewing and discussing the Final Report.

Table 1: Schedule of Working Group Discussions by Issue

Issue(s)	Initial discussion	Final discussion	Number of meetings
18	2/12/20	5/19	7
19	2/12	4/14	6
29	4/21	5/19	3
F	3/11	6/2	7

Consensus and Non-Consensus Proposals

Working Group members made significant efforts to reach consensus on each issue. Each proposal in this report lists which parties indicated support for it and which parties indicated opposition to it. Indicating support or opposition was optional. In addition, the "discussion" section of each proposal provides party positions on the proposal as provided by the parties themselves. A "consensus" proposal is one in which no party indicated opposition.

Of the 20 individual proposals across all four issues, 9 of these were consensus and 11 were non-consensus. Generally, there was enough time over the course of multiple meetings, comment solicitations, and off-line discussions to reach reasonable understanding of whether consensus could be achieved on any given proposal. For proposals where consensus was not reached, parties had fundamentally differing viewpoints that could not be resolved, and more discussion time would likely not have resulted in consensus.

For proposals where consensus was not reached, the Working Group documented diverging viewpoints in the proposal "discussion" sections to provide the Commission with sufficient information to make an informed decision. Substantive areas of non-consensus, with one or more non-consensus proposals developed to address these areas, include:

Issue 18: Generation-to-load calculations, PG&E new anti-islanding screens, an Interconnection Guidebook, least-cost anti-islanding solutions, timelines for determining anti-islanding requirements, and funding demonstrations and guidebook

Issue 19: Single-submission or batch-application for multiple units, development of single-line diagrams, and timelines/streamlining of interconnection application process for ZNE buildings

Issue F: Smart Inverter Operationalization Working Group venue and timing, and addressing SIO as part of grid modernization plans

Working Group Materials

Working materials are available on the Gridworks Working Group Four website: https://gridworks.org/initiatives/rule-21-working-group-4. In addition, the Working Group made active use of a OneDrive shared file space, which contains all the proposals, counter-proposals, party comments on all issues discussed, and a full record of party comments and edits for each of the issue write-ups and Final Report review versions. [LINK]

Working Group Participants

"Working Group Four" (or "the Working Group") references all active parties participating in Working Group Four meetings, which include the utilities, government representatives, developers, nonprofits, and independent advocates and consultants. The final report is the product of written and oral contributions from participants representing the following organizations.

33North Energy
Artwel Electric
Bear Peak Energy Consulting
Bioenergy Association of California (BAC)
Bloom Energy
Calcom Energy
California Energy Commission (CEC)
California Energy Storage Alliance (CESA)
California Independent System Operator (CAISO)
California Public Utilities Commission (CPUC)
California Solar & Storage Association (CALSSA)
Center Point Energy
Clean Coalition
Enphase
ForeFront Power
Foundation Windpower
Fronius
Green Power Institute (GPI)
GridComm
Interstate Renewable Energy Council (IREC)
Kitu Systems
Ningbo Ginlong
Nuvve
OpenEGrid
Pacific Gas & Electric (PG&E)
Public Advocates Office
Small Business Utility Advocates (SBUA)
Southern California Edison (SCE)
San Diego Gas and Electric (SDG&E)
Smarter Grid Solutions
SolarEdge
Sunpower
Sunrun
SunStreet
Sunworks
X-Utiilty

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?

__Proposal Summaries__

Proposal 18-a. Require Protective Equipment for Machine Generators. Any machine generator larger than 40 kW requesting interconnection to the distribution system may be required to install a recloser, or other protective equipment of similar function and cost, under either of two conditions: (1) the utility determines that risk of unintentional islanding is a present concern; in this case, the protective equipment and its interconnection will be at the expense of the interconnection customer. Or (2) it is reasonably anticipated that risk of unintentional islanding is likely to be a concern in the near future; in this case, the protective equipment and its interconnection will be at the expense of the utility. In addition, if Supplemental Review for a proposed inverter-based generator determines that the proposed generator fails the anti-islanding screen due to existing machine generation, the utility will initiate installation of the required recloser and the protective equipment will be at the expense of the utility. This proposal does not include any requirement related to installation of Direct Transfer Trip. And this proposal does not apply to utilities that do not perform enhanced anti-islanding screening based on the Sandia studies referenced in this proposal, which currently includes both SDG&E and SCE.

Initiating proponent: CALSSA
Supported by: BAC, Foundation Windpower, IREC, Tesla, PG&E
Opposed by: <none>
Not applicable to: SCE, SDG&E

Proposal 18-b. Perform Generation to Load Calculations with Hourly Profiles. The generation-to-load calculation should use an hourly load profile similar to that employed in the Integration Capacity Analysis (ICA) methodology. The generation profile for solar should also use 288-hour time periods. Utilities should determine that a project exceeds the screen threshold if the ratio of total generation to load exceeds 50% during any of the 288 hours. This calculation would be performed for specific locations in response to individual interconnection applications. Applications for solar systems larger than 30 kW can be required to submit an hourly generation profile (but not including energy storage operation) with the initial application so that the utility has the data when a calculation is needed. This proposal does not apply to utilities that do not perform enhanced anti-islanding screening based on the Sandia studies referenced in this proposal, which currently includes both SDG&E and SCE.

Initiating proponent: CALSSA
Supported by: Clean Coalition, IREC, Tesla
Opposed by: PG&E
Not applicable to: SCE, SDG&E

Proposal 18-c. Provide interconnection customers with option to hire an independent analyst to perform a risk of unintentional islanding study. If the utility determines that anti-islanding mitigation may be required, the customer should have the option to hire an independent analyst approved by the utility to perform a risk of islanding study. This study would include analysis specific to the proposed installation and the circuit segment. If the risk of islanding study demonstrates that an islanding condition is not possible, the project should be allowed to interconnect with no mitigations for managing islanding beyond the existing UL 1741 certification. In addition to risk of islanding, alternative mitigation methods to Direct Transfer Trip and reclosers should be explored in the study. This should include but not be limited to utilizing a Distributed Energy Resource Management System to mitigate islanding, utilizing additional protective devices and relays at the point of interconnection, and adjusting DER settings. The study should be completed within 40 business days. This proposal would not apply to utilities that do not perform enhanced anti-islanding screening based on the Sandia studies referenced in this proposal, which currently includes both SDG&E and SCE.

Initiating proponent: CALSSA
Supported by: BAC, Clean Coalition, GPI, IREC, Tesla, PG&E
Opposed by: <none>
Not applicable to: SCE, SDG&E

Proposal 18-d. Convene an Unintentional Islanding Working Group on Distribution-System-Level Solutions. The Public Utilities Commission should organize an Unintentional Islanding Working Group to explore distribution-system-level solutions to anti-islanding. The Working Group should evaluate solutions and recommend next steps in the continuance of islanding (or anti-islanding) research and development at both the distribution and transmission system level.

Initiating proponent: IREC
Supported by: BAC, CALSSA, Clean Coalition, GPI, Tesla, PG&E, SDG&E
Opposed by: <none>

Proposal 18-e. PG&E Will Adopt New Anti-Islanding Screens. PG&E will adopt new anti-islanding screens in their Bulletin that considers aggregate generation relative to minimum load, aggregate machine generation or aggregate uncertified distributed generation to total generation ratio, fixed power factor modes, and inverter anti-islanding "types." The proposed screens are used to verify or ensure islands are terminated in two seconds or less in accordance with Rule 21 Section H.1a.iii and section 4.b, whenever there is a question of whether a system configuration may result in an island lasting more than two seconds. The screen will include the option of a Risk of Islanding study upon failure of the screen as specified in Proposal 18-c. This proposal would not apply to utilities that do not perform enhanced anti-islanding screening based on the Sandia studies referenced in this proposal, which currently includes both SDG&E and SCE.

Initiating proponent: PG&E
Supported by: CALSSA, Clean Coalition, IREC, Tesla
Opposed by: GPI
Not applicable to: SCE, SDG&E

Proposal 18-f. Develop an Interconnection Guidebook of Anti-Islanding Options. The CPUC, utilities, and developers should work together to develop a guide that provides anti-islanding options, clearly identifies the cost of each option, and sets out the circumstances when it will be required.

Initiating proponent: BAC
Supported by: GPI, PG&E
Opposed by: SCE, SDG&E

Proposal 18-g. Evaluate and Choose Least-Cost Anti-Islanding Solutions. Utilities should continue to assess and offer new or alternative least-cost anti-islanding solutions that can meet each IOU's anti-islanding requirements. As new technologies or applications are developed and demonstrated, utilities should evaluate those technologies and attempt to choose the lowest cost option that meets the anti-islanding requirements. Similarly, if Risk of Islanding studies show that a less expensive option is adequate to prevent islanding, then the utility should employ the less expensive option.

Initiating proponent: BAC
Supported by: Clean Coalition, GPI, PG&E
Opposed by: SCE, SDG&E

Proposal 18-h. Specify Timelines for Determining Anti-Islanding Requirements. Utilities should agree to a reasonable timeline to conduct Risk of Islanding studies and determine anti-islanding requirements. This is particularly important for Distributed scale Bioenergy Projects Employing Synchronous Generators that are required by the Governor's Emergency Order on Tree Mortality, SB 1122 (the BioMAT program), or to meet the requirements of SB 1383 (California's Short-Lived Climate Pollutant law, which requires policies and incentives to increase biogas and biomethane production). The CPUC should adopt an interconnection study timeline.

Initiating proponent: BAC
Supported by: GPI
Opposed by: PG&E, SCE, SDG&E

Proposal 18-i. Use EPIC Funding for Demonstrations and Guidebook Development. The Commission and CEC should support use of Electric Program Investment Charge funding to identify and demonstrate additional, less expensive options for anti-islanding, help fund development of the Interconnection Guide, and help demonstrate technologies that provide anti-islanding and islanding (microgrid) solutions.

Initiating proponent: BAC
Supported by: Clean Coalition, GPI, PG&E
Opposed by: SCE, SDG&E

Background

If a fault occurs on the distribution system, any Distributed Energy Resource (DER) connected to the system must quickly de-energize (or go off-line) so that there is not an unintentional "island" formed (i.e., a portion of the distribution grid remains energized). Unintentional Islanding, which is defined as an unplanned island that lasts greater than two seconds[6], is a concern for the following reasons:

- A sustained unintended island could result in a safety hazard if personnel are not aware that the DER is energizing a circuit.
- This could result in transient voltages and frequencies to customer equipment. Abnormal voltages on remote line sections may result in customer equipment damage.
- Reduced fault current capability in the islanded section could lead to possible subsequent uncleared or delayed clearing faults. Additionally, unintended islands separate the normal grounding source from the islanding which could result in additional overvoltage conditions.
- Automatic reclosing could result in an out-of-phase condition that would cause high current and mechanical stress to machine-based equipment.

A distributed generator that is inverter-based could normally detect a voltage sag during fault conditions and trip offline, thus avoiding creating an island. However, particular types of faults (e.g., high impedance faults) may prevent the voltage reduction required for a timely trip of the inverter. This is more likely for transmission line faults and substation transformer faults that do not generate much DER fault current. Thus, inverters are required to have additional anti-islanding protection beyond the simple detection of voltage sag. Underwriters Laboratory (UL) 1741 testing standard requires strict testing to ensure that inverters shut down production

[6] IEEE 1547-2003, Standard for Interconnecting Distributed Resources with Electric Power Systems, section 4.4.1 Unintentional Islanding Requirement, "For an unintentional island in which the DR energizes a portion of the Area EPS through the PCC, the DR interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island."

within two seconds of a grid outage. All inverters that are interconnected in California must be certified to UL 1741/UL 1741SA.

However, even with UL 1741/UL 1741SA certification, there are two concerns about inverter anti-islanding performance.

First, there is concern that inverters with different "types" or methods of anti-islanding protection may interact with each other in ways that compromise their anti-islanding effectiveness. Inverter manufacturers have developed multiple types of anti-islanding protection, and testing according to UL 1741SA and Institute of Electrical and Electronics Engineers (IEEE) 1547.1 does not specify that the type of anti-islanding employed must be identified. Since current testing methodology per IEEE 1547.1 and UL 1741SA tests each DER as a standalone unit, the aggregate and interactive effect of multiple inverters with different anti-islanding types during an unintended island are not tested by these standards.

Second, two research reports by Sandia National Lab—SAND2012-1365[7] and SAND2018-8431[8]—and referenced by the Electric Power Research Institute (EPRI)[9] have shown in lab studies and simulations that inverter anti-islanding protection can fail in certain conditions, which include: (1) proximity to large non-inverter-based machine generators, (2) high power factor, (3) high level of generation compared to load, or (4) load closely matches generation.

This first condition, the presence of machine generators on a circuit, means that inverter-based DERs being added to a circuit on which machine generators already exist can potentially fail to properly anti-island – but only if the existing machine generators do not themselves have anti-islanding protection. That is, in a circuit that has both inverter-based and non-inverter-based generation, laboratory and simulation studies have indicated that machine generators without additional anti-islanding mitigation may cause proximate DER inverters to fail to properly anti-island even if those inverters are properly certified to UL 1741/UL 1741SA, leading to an island continuing greater than two seconds.

One solution to prevent such failures of inverter-based anti-islanding is to add mitigation to the machine generators, such as either Direct Transfer Trip (DTT) and/or reclosers. Grid operators can manually use a SCADA-equipped recloser to shut down the machine generator or line section if they detect a sustained island during a grid fault. This would not happen within the two-second standard but is a backstop measure.

SCE: Comment regarding recloser mitigation - If an inverter cannot see the issue then how will the recloser see it since they are the same location and sensing the same grid condition?

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[7] *Suggested Guidelines for Assessment of DG Unintentional Islanding Risk,* M. Ropp, A. Ellis, Sandia National Laboratories, SAND2012-1365. Printed February 2012, Revised November 2012

[8] *Unintentional Islanding Detection Performance with Mixed DER Types*, M. Ropp, A. Ellis, Sandia National Laboratories, Unintentional Islanding Detection Performance with Mixed DER Types, Printed July 2018

[9] Reference Section 7 pages 4 and 17 EPRI Final Report "Performance and assessment of Inverter On-Board Islanding Detection with multiple testing platforms." 3002014051, T Key, April 2020.

PG&E Response: The majority of the recent DTT schemes are initiated from the transmission system in which automatic island termination is required. In order to minimize the amount of DTT's required to a given station the receiver is located at the substation, and trips the feeder breaker or breakers with the affected generation or generators. This allows for quick generation isolation from the substation and transmission system without having to install a DTT scheme for each generator. The installation of a SCADA equipped recloser is a compromise to allow manual tripping for the distribution line section unintended islanding.

At low levels of DER penetration, failure of the anti-islanding protection provided by the DER inverters is not a concern since a high level of load cannot be supported by the DERs and the DERs quickly trip in any case. A potential risk occurs with higher levels of distributed generation penetration that become able to support the load on a circuit, which could lead to delayed tripping of generators during an unintended island event and an island continuing greater than two seconds.

There is dispute among parties on the extent to which such failures of anti-islanding protection can occur in real world conditions. Utilities in other areas of the country assess the likelihood of such failures very differently and accordingly have developed different levels of screening based upon their relative assessment of the likelihood and their risk tolerance thresholds. There are other utilities that screen based on SAND2012-1365, including National Grid, Joint NY Utilities and Emera Maine.[10] [11] [12] Added by PG&E, reworded by Gridworks

The utilities in California currently take different approaches with respect to how they assess and manage the potential risks of unintentional island formation. PG&E conducts additional screening of DERs for the risk of islanding, and when DERs fail those screens they may be required to implement mitigation measures. The mitigation measures currently used by PG&E are typically reclosers on machine generators and/or DTT installed at the substation so that they can be shut down or separated from the transmission system during a grid outage.

A crucial point is that although the mitigation measures are applied to machine generators, the need for such measures is triggered by new DERs. For example, a new distributed generation project can make the generation-to-load ratio on a circuit segment exceed the specific threshold causing concern and triggering mitigation. Under current practice, if the utility determines mitigation is needed in response to an interconnection application for a new inverter-based generator, the new interconnection customer has been required to pay for a recloser and/or DTT on the existing machine generator. This can add additional costs to the development of DER for the interconnection customer (unless the DER is a NEM project smaller

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[10] Page 34, New York State Standardized Interconnection Requirements and Application Process For New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems. December 2019.

[11] National Grid Specification for Electrical Installations, Electrical Systems Bulletin, ESB 756 December 2019 Version 5, 12/04/2019, Append D pages 31-33.

[12] EPRI Technical Brief June 2019, Utility Direct Transfer Trip Survey Results

than 1 MW, in which case the upgrade is funded by ratepayers). The time required to add a recloser and/or DTT also can delay DER development, as the upgrade must be completed before the system is given Permission to Operate.

The cost of installing DTT is significant and, in some cases, the single largest cost of new machine generation projects. PG&E's Unit Cost Guide states that the base cost of a single DTT scheme, including paired transmitter and receiver, is $600,000, and the base cost of a recloser is $80,000.[13] Multiple DTT units can be required, increasing the base cost accordingly. If related costs, such as Cost of Ownership (COO) and Income Tax Component of Contribution (ITCC) are included, the all-inclusive cost to the developer for DTT and reclosers is roughly double the base cost. The costs of DTT can exceed the cost of the generator itself, and in all cases become a substantial part of overall costs and can affect project viability. Other related costs such as leased line communications infrastructure can be particularly expensive in less-urban areas. The costs of DTT are particularly relevant in more rural areas of the State where the grid is radial and DTT is applied to numerous substations.

These upgrades frequently force renewable DER projects to withdraw interconnection applications due to their high interconnection costs and/or long implementation timelines. Installation of DTT can take up to 18-24 months to complete. Installation of a recloser can take up to 6-12 months to complete.

There are differences between the three utilities' systems which make islanding more of a concern for PG&E due to the configuration of the distribution and transmission system and the use of communication-aided protection schemes (see Annex 1). Interconnection review by SCE and SDG&E does not employ the type of screen used by PG&E:

- SDG&E has not experienced unintentional islanding and also has a different system configuration, therefore is not using or proposing to develop an enhanced "Anti-Islanding Screen" based on the Sandia Studies. SDG&E requires that inverters to be certified to UL 1741/UL 1741SA.
- SCE requires inverters to be certified to the most current approved testing standards, and requires project-specific protection for non-inverter-based technology in satisfaction of anti-islanding requirements (DTT is not required). When both inverter-based and non-inverter-based systems are together on the same circuit, each perform its own function to ensure that the systems as a whole does not create an unintentional island. SCE notes however, that anti-islanding is under review through a current EPIC project, which along with the proposed Unintentional Islanding Working Group as discussed within Proposal 18-d, may further refine SCE's anti-islanding project screens and supporting facility requirements.

However, some DER developers disagree with PG&E on the level of concern. The main source of contention is the two studies by Sandia National Lab referenced above that model how

[13] Unit Cost Guide dated April 1, 2019.

inverters would respond to certain grid conditions. This is not a phenomenon that has been observed in practice. The difference in opinion on this issue stems from differences in interpretation of those lab-based studies. Because the potential harm caused by a sustained island during a grid fault is so high, PG&E considers it necessary to require mitigations in some circumstances. Because the chances are so small that all of the factors considered in the report ever align in real-world conditions, other parties do not agree that mitigations are necessary at this time.

Some DER developers take the position that UL 1741 is a strict standard that has been carefully developed over many years, and that requiring all inverters installed in California to be certified to that standard is a strong protection.

As a result of the cost and timing impact that the screening and mitigation has on DER development, there is a desire to ensure that (1) the risk of islanding is being assessed appropriately, (2) that the methods for screening for that risk are reflective of the latest and most credible research on island formation, (3) that the mitigations implemented (if necessary) are both effective and cost conscious, and (4) that the costs of the mitigations are assessed on the appropriate party(ies). Within each of these categories there are a set of questions that need to be explored and policy choices that the Commission may want to make to ensure appropriate treatment of islanding risk under Rule 21 and underlying utility guidance.

Proposals 18-a, 18-b-, and 18-c only apply to PG&E currently, and all three proposals state that "this proposal does not apply to utilities that do not perform enhanced anti-islanding screening based on the Sandia studies referenced in this proposal, which currently includes both SDG&E and SCE."[14]

PG&E Anti-islanding Screens

PG&E interconnection review contains screens that identify conditions that may lead to anti-islanding failure, in accordance with PG&E Technical Document TD-2306B-002.[15] Depending on

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[14] There are a number of reasons why SCE and SDG&E do not currently perform enhanced anti-islanding screening based on the Sandia studies. In addition to the differences in system configuration (see Annex 1), which has a large impact, some philosophies and operating history may be different, along with the fact that neither SCE or SDG&E has had an extended islanding event (this could also be due to penetration levels). PG&E has more machine-based generation within the system, (approximately 723 MW of distribution machine generation), additionally PG&E has a significant amount of machine generation installed prior to adoption of Rule 21, in which the voltage, frequency and operating mode may not be per current Rule 21 requirements, therefore more exposure. PG&E says it performs screening and Risk of Islanding studies as a prudent method to ensure unintended islanding and extended fault clearing is not an issue going forward rather than waiting for an adverse event and then reacting. The Risk of Islanding studies also ensure mitigation is applied appropriately.

[15] PG&E, "Distributed Generation Protection Requirements," 11/15/2017; https://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/TD-2306B-002.pdf

the circumstances, PG&E requires one of two different types of equipment to manage the risk of islanding: reclosers on machine generators for distribution level impacts and direct transfer trip (DTT) at substations for transmission level impacts. These mitigations ensure that the machine generators do not run past two seconds after a grid fault or unscheduled de-energization resulting in an unintended island on the transmission system and distribution transformer.

PG&E's current review methodology is based on the two Sandia National Lab primary research reports referenced above: SAND2012-1365[16] and SAND2018-8431.[17] SAND2012-1365 provides guidance on how to assess the potential for unintended islanding, and SAND2018-8341 expands on the interactions between multiple types of DER on a circuit and the impact on islanding.

The Sandia studies consider four main elements that determine the level of risk on a circuit segment:[18]

A. The ratio of total generation to minimum load
B. The ratio of machine generation to total generation
C. The ratio of reactive power to active power
D. The anti-islanding type of the inverter

A project currently fails PG&E's anti-islanding screen if Element A is greater than 50% and Element B is greater than 40%. The screen does not account for Elements C or D.

Currently, minimum load and total generation are calculated in Element A as annual values as currently specified in Rule 21 Screen N, and Screen N Note 2: in which the absolute minimum load is taken into account over a 12-month period. For solar generation, load and generation outside of 10 am – 4 pm is not considered, but one value is produced for load and generation during those hours for the entire year. The minimum load and some generating resources are not consistent throughout the year. For example, if the minimum daytime load is in December at 10:00 am and the maximum DER output is in June at 1:00 pm, those two values are used in the ratio even when the maximum DER output is far lower in December. This is the basis of Proposal 18-b.

SAND2018-8431 is the main reference since it includes the newer voltage and frequency ride-through settings as specified in Rule 21 Table Hh. This table includes the latest inverter anti-islanding methods, and provides run-out times for various configurations, including mixed inverter anti-islanding types and inverter-machine mixtures, hence it is more representative of the present system.

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[16] *Suggested Guidelines for Assessment of DG Unintentional Islanding Risk,* M. Ropp, A. Ellis, Sandia National Laboratories, SAND2012-1365. Printed February 2012, Revised November 2012

[17] *Unintentional Islanding Detection Performance with Mixed DER Types*, M. Ropp, A. Ellis, Sandia National Laboratories, Unintentional Islanding Detection Performance with Mixed DER Types, Printed July 2018

[18] Op Cit., Footnote 15

While PG&E is using some of the prescribed methods in both reports, it does not use reactive power matching (ratio C above). That is, TD-2306B-002 does not check for reactive power matching. SAND2012-1365, at page 8, states, "Cases in which it is not possible to balance reactive power supply and demand within the potential island. In order for an island to be sustained, both the real and reactive power demand of the load and power system components must be satisfied. Since most loads and power system components absorb VARs, there must be a source of VARs in the potential island in order for islanding to be sustained."

There is conflicting guidance about whether a reactive power mismatch overrides the presence of machine-based generation, and thus the extent to which the normal presence of reactive power mismatch reduces the risk of anti-islanding failure.[19] SAND2012-1365 on page 8 states a reactive power mismatch will not allow an island to sustain itself, but on page 11 it states that the presence of rotating machines can lead to greatly increased run-on times for the island and is a basis for further study. Also, in the screening section (pages 12 and 13) the machine-based generation to total DER ratio is screened (Screen 3) even if the reactive power match (previous Screen 2) is satisfied. The variable nature of reactive power loading at the time of the island is very difficult and time consuming to quantify, especially with the existing inverter grid support Volt/Var function currently utilized.[20]

Per EPRI[21], utilities have not been performing SAND2012 1365 reactive power matching screening methodology due to the difficulty in performing the screening criteria.

As mentioned above, reactive power matching is an element identified in SAND2012-1365 as necessary for a sustained unintentional island. This is a major factor in giving some stakeholders confidence that sustained islands are not actually happening. The report states, "To emphasize, the guidelines provided in this document lead to reasonable conclusions about the risk of unintentional islanding only if it is applied in its entirety."[22] PG&E does not consider the ratio of reactive power to active power. This is partially due to the increasing difficulty of accurately measuring the ratio. PG&E notes that SAND2012-1365 was developed prior to the newly required ride-through and grid support functions.

With advanced inverter functionality that is designed to stabilize grid voltage, it is very difficult to predict power factor on a circuit segment. Therefore, even though the risk of a sustained island is extremely low due to the improbability of matching both real and reactive power, it

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[19] It should be noted SAND2012-1365 was developed prior to the newly required ride-through and grid support functions. Recent EPRI research has indicated an extended island with non-ride-through or grid support functions can occur with up to 7% Var mismatch. In addition, SAND2012-1365 at page 12 states, "To emphasize, the guidelines provided in this document lead to reasonable conclusions about the risk of unintentional islanding only if it is applied in its entirety."

[20] SAND2012-1365 was developed before grid support functions or extended ride-through requirements were available.

[21] Reference Section 7 Recommendations for Islanding Screening Risk Assessment, page 4, Exert from EPRI Final Report "Performance and assessment of Inverter On-Board Islanding Detection with multiple testing platforms." 3002014051, T Key, April 2020.

[22] SAND2012-1365, p. 12.

may be difficult to measure the exact extent of that risk without doing a study that is beyond the normal scope of Rule 21 engineering review. This is the basis of Proposal 18-c.

Future Distribution-System-Level Approaches to Anti-Islanding

Further efforts are needed to explore ways to resolve concerns about unintentional island formation more efficiently and effectively at the distribution system level. This is the basis for Proposal 18-d on forming an Anti-Islanding Working Group.

Anti-islanding capability has always been tested on the individual inverter level per the test procedures of IEEE 1547.1. Recent research[23] has shown that there may be distribution system concerns that affect the ability of an individual inverter to successfully detect an island. For instance, it has been shown that interactions between inverters and rotating machines can decrease anti-islanding effectiveness. It has also been shown that some anti-islanding algorithms may be more effective than others, and different algorithms may not interact well.[24] It is now understood that the risks of unintentional island formation has less to do with any individual inverter (since all are certified to have adequate individual anti-islanding capabilities) and more to do with a variety of different types of interactions between equipment on the distribution system. As a result, it is becoming clear that unintentional islanding is a distribution system issue, and yet individual inverters are being called on to address the issue.

Bioenergy Machine Generator Projects

The high all-inclusive costs of DTT, which often exceed the generator costs, coupled with lack of clear guidance about when and where DTT will be required, have resulted in some proposed bioenergy machine generator projects being cancelled, some delayed, and significantly increased costs for most of the remainder. In several cases, after review by the Governor's Office, PG&E, and others, the requirements for DTT and related equipment turned out not to be necessary in several projects, increasing uncertainty and risks for bioenergy project developers.[25]

Proponent Bioenergy Association of California (BAC) remains concerned that the Issue 18 proposals included here do not go far enough to reduce costs and uncertainty for machine generation projects such as the small-scale bioenergy projects required by SB 1122[26] and the

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[23] Gonzalez, A. Ellis, M. Ropp, C. Mouw, D Schutz and S. Perlenfein, "Unintentional Islanding Detection Performance with Mixed DER Types," Sandia National Laboratories report SAND2018-8431, July 2018, https://www.osti.gov/servlets/purl/1463446M.
[24] Ibid.
[25] See, *Bioenergy Association of California's Comments on the OIR To Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21*, Attachment A, filed August 2, 2017 in Rulemaking 17-07-007.
[26] Senate Bill 1122 (Rubio, 2012), adding Public Utilities Code 399.20(f)(2), now known as the BioMAT program.

Governor's Emergency Order on Tree Mortality.[27] That emergency order and the *California Forest Carbon Plan* also call on the CPUC to accelerate interconnection for new forest BioMAT projects that are required by SB 1122, in order to reduce wildfire hazards and air pollution from open burning of forest waste.

Despite repeated calls to remove interconnection barriers, the Governor's Tree Mortality Task Force found that multiple distributed bioenergy projects face unnecessarily high interconnection costs. As part of the Task Force, the Governor's Office, CPUC, PG&E, and BioMAT project developers reviewed the interconnection project costs for six projects. Working together with senior PG&E engineers, the group was able to reduce interconnection costs by an average of $1 million per project. PG&E's senior engineer helped identify a total of $5.6 million in interconnection cost savings for the six projects.

This Task Force review of interconnection costs highlights the uncertainty and variability that developers face when it comes to interconnection requirements and costs. Providing clear, reliable guidance on which technologies will be required under what circumstances is critical to help small-scale bioenergy projects determine where to site projects to minimize interconnection costs and what costs to expect.

The high costs and unpredictable requirements for bioenergy interconnection are hampering the state's climate change and wildfire reduction policies. California is relying heavily on new bioenergy projects to meet the state's climate goals. California's *Short-Lived Climate Pollutant Reduction Strategy* calls for more bioenergy production to reduce these pollutants and states that California must remove barriers to interconnection of bioenergy projects to meet the state's climate goals. [28]

Proposals Discussion

Proposal 18-a. Require Protective Equipment for Machine Generators. Any machine generator larger than 40 kW requesting interconnection to the distribution system may be required to install a recloser, or other protective equipment of similar function and cost, under either of two conditions: (1) the utility determines that risk of unintentional islanding is a present concern; in this case, the protective equipment and its interconnection will be at the expense of the interconnection customer. Or (2) it is reasonably anticipated that risk of unintentional islanding is likely to be a concern in the near future; in this case, the protective equipment and its interconnection will be at the expense of the utility. In addition, if Supplemental Review for a proposed inverter-based generator determines that the proposed

[27] Governor Brown's Emergency Proclamation on Tree Mortality, Paragraphs 9 and 10, https://www.gov.ca.gov/docs/10.30.15_Tree_Mortality_State_of_Emergency.pdf.
[28] *Short-Lived Climate Pollution Reduction Strategy,* adopted by the California Air Resources Board in March 2017, at pages 3, 4, and 29.

generator fails the anti-islanding screen due to existing machine generation, the utility will initiate installation of the required recloser and the protective equipment will be at the expense of the utility. This proposal does not include any requirement related to installation of Direct Transfer Trip. And this proposal does not apply to utilities that do not perform enhanced anti-islanding screening based on the Sandia studies referenced in this proposal, which currently includes both SDG&E and SCE.

Initiating proponent: CALSSA
Supported by: BAC, Foundation Windpower, IREC, Tesla, PG&E
Opposed by: <none>
Not applicable to: SCE, SDG&E

While all UL 1741 tested inverter-based generators utilize acceptable anti-islanding methods, it is when rotating machines are present on a circuit that risks of unintentional islands arise. Rotating machines are not currently required within Rule 21 to have UL 1741 active anti-islanding protections.

In the absence of this proposal, if a machine generator is not required to install protective equipment at the time it is approved for interconnection on the distribution system, and it later needs protection due to increased generation on the circuit, another customer will have to pay for the protection even though it is the machine generator that needs to be controlled.

This proposal clarifies that machine generators are responsible for the cost of mitigation required at the time of their interconnection, and would ensure that distributed generators subsequently connecting are not bearing the burden of unintended island risk created by the combination of rotating machines and inverter-based machines on the same circuit.

The requirements in this proposal should be revisited after three years if other mitigation options with equal protection have become viable.

Party Positions on Proposal 18-a:

PG&E supports the proposal however a blanket installation of equipment may result in mitigation that will not be required therefore the utility would prefer an option of not installing mitigation in some cases and instead initiate a process that proactively installs mitigation during the study process for follow-on generation. The intent is to not hold up subsequent interconnections while mitigation equipment is installed. In these cases, the cost burden would be placed on the utility.

Proposal 18-b. Perform Generation to Load Calculations with Hourly Profiles. The generation-to-load calculation should use an hourly load profile similar to that employed in the

Integration Capacity Analysis (ICA) methodology. The generation profile for solar should also use 288-hour time periods. Utilities should determine that a project exceeds the screen threshold if the ratio of total generation to load exceeds 50% during any of the 288 hours. This calculation would be performed for specific locations in response to individual interconnection applications. Applications for solar systems larger than 30 kW can be required to submit an hourly generation profile (but not including energy storage operation) with the initial application so that the utility has the data when a calculation is needed. This proposal does not apply to utilities that do not perform enhanced anti-islanding screening based on the Sandia studies referenced in this proposal, which currently includes both SDG&E and SCE.

Initiating proponent: CALSSA
Supported by: Clean Coalition, IREC, Tesla
Opposed by: PG&E
Not applicable to: SCE, SDG&E

This proposal creates a more accurate calculation of generation-to-load that could result in fewer unnecessary anti-islanding mitigations being required. This proposal changes the generation-to-load calculation to reflect solar power generation variation over the course of the year without changing the ratio thresholds in the two criteria in the current PG&E screen.

Currently, PG&E's calculation of generation to load for use with its anti-islanding screen is based on absolute minimum load and generation nameplate, which may not be reflective of all months of the year, particularly for solar generation.

Applications for systems larger than 30 kW can be required to submit an hourly generation profile with the initial application so that the utility has the data when a calculation is needed. Customers will not submit energy storage operating data because hourly data will only be relevant for PV.

Party Positions on Proposal 18-b:

Tesla:

Tesla supports this proposal provided that the use of a more granular approach to determining the generation to load ratio and the associated requirement to submit an operational profile at the utilities' request is **optional**. While developing the load profile for solar is straightforward for standalone solar projects, it is less so for storage or solar + storage projects. In these circumstances it would be better to allow a developer to rely on the current, albeit more conservative approach.

For those circumstances where a developer can provide the hourly load profile, Tesla agrees that PG&E's approach is overly conservative insofar as it results in the methodology yielding the highest generation to load ratio, and thus increases the likelihood of a project failing the screen despite the fact actual experience suggests that the ratio so calculated never occurs in any given hour.

PG&E:

This proposal specifies using hourly load and generation data instead of the minimum load for the calendar year. Currently the available hourly data consists of "Net Load" which is equal to the load minus existing generation. There is no separate hourly load or generation data available. In order to derive hourly load data, the hourly generation data needs to be added back into the "Net Load." While hourly generation data would be available for the proposed generation, the same level of data is not available for the existing generation, of which there may be hundreds of units for a given substation. In order to use the hourly net load data, a methodology will have to be developed to derive hourly generation or hourly minimum load data. Such methodology presently does not exist.

Additionally, while there will be seasonal variability in generation output and load, the low generation output could coincide with the low load such that the minimum load to generation ratio exceeds 50%. It should be noted this is a subsection of a screen and does not necessarily result in a failure, but rather moves to the next step in the screening process. Use of the lower generation data in conjunction with the 50% screen may result in less PV generation such that 'the greater than 40% DG ratio' could be reached more often, thus proceeding to the next screen and further study.

Proposal 18-c. Provide Interconnection Customers with Option to Hire an Independent Analyst to Perform a Risk of Unintentional Islanding Study. If the utility determines that anti-islanding mitigation is required, the customer should have the option to hire an independent analyst approved by the utility to perform a risk of islanding study. This study would include analysis specific to the proposed installation and the circuit segment. If the risk of islanding study demonstrates that an islanding condition is not possible, the project should be allowed to interconnect with no mitigations for managing islanding beyond the existing UL 1741 certification. In addition to risk of islanding, alternative mitigation methods to Direct Transfer Trip and reclosers should be explored in the study. This should include but not be limited to utilizing a Distributed Energy Resource Management System to mitigate islanding, utilizing additional protective devices and relays at the point of interconnection, and adjusting DER settings. This proposal would not apply to utilities that do not perform enhanced anti-islanding screening based on the Sandia studies referenced in this proposal, which currently includes both SDG&E and SCE.

Initiating proponent: CALSSA
Supported by: BAC, Clean Coalition, GPI, IREC, Tesla, PG&E
Opposed by: <none>

Not applicable to: SCE, SDG&E

This proposal addresses the problem that the current anti-islanding screen is less accurate than an in-depth study, and thus the anti-islanding screen sometimes results in unnecessary mitigations. This proposal creates the means for an interconnection customer to independently verify that mitigation is actually required, at their own cost. The customer, in deciding to perform an independent risk of islanding study, would have to weigh the cost of the independent study against the likelihood that the anti-islanding screen is requiring a mitigation that may not be necessary.

The Risk of Islanding study will be performed an analyst deemed qualified by the utility, and the analyst performing the study will be selected by the developer among qualified analysts and paid by the developer. The utilities can maintain a list of analysts they deem qualified to perform these risk of islanding studies. Utilities must establish transparent criteria for inclusion on the list and maintain a process for analysts to request to be added to the list. The study should include the elements described in Annex 2.

As proposed, the Risk of Islanding study will add a new study option to the study phase after a System Impact Study (where an islanding mitigation would be identified), but before the Interconnection Agreement phase, as shown in the diagram below. The current options after a System Impact Study Results Meeting are to (a) forgo a Facilities Study and proceed to Interconnection Agreement; or (b) proceed to a Facilities Study and then determine whether to proceed to an Interconnection Agreement (also in the diagram below). Since the proposed Risk of Islanding study option would be added to the Rule 21 study process, like any other Rule 21 study phase process, a timeline is needed for the customer to complete this action to ensure projects pass through the study process. The timeframe for the customer to have the study performed should be 40 business days.

Without a timeline, projects could stay within the study phase indefinitely, causing later queued projects to fail Screen R ("Is the Interconnection Request independent of other earlier queued and yet to be studied interconnection requests interconnecting to the Distribution System?") and be forced into the Distribution Group Study Process (DGSP), adding an unnecessary cost to the interconnection.

PG&E notes that a discussion on the Risk of Islanding study timeline is needed to prevent the creation of a pause point within the study phase.

Figure 1 provides a diagram of what the Risk of Islanding study option would look like in the study process and why a timeline is needed for this step.

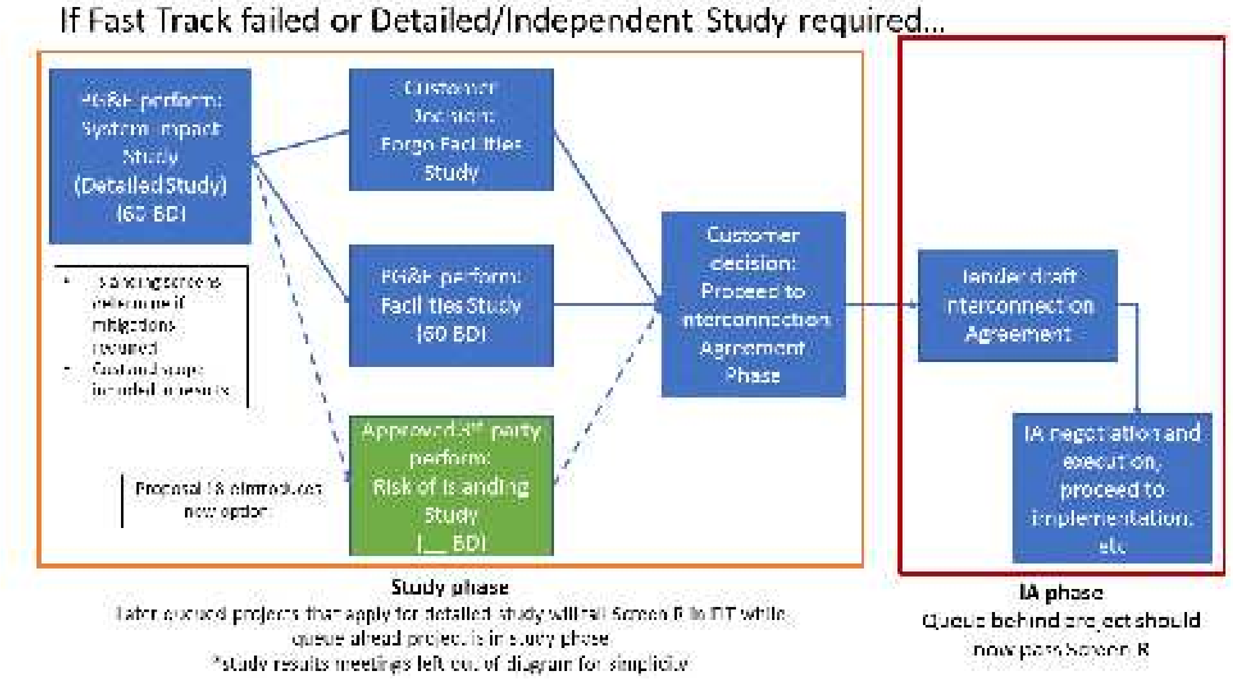

Figure 1: Risk of Islanding Study Option in the Study Process

Party Positions on Proposal 18-c:

Tesla supports this proposal as a common sense means of vetting the need for DTT or other costly mitigations. Given the costs involved, which for many projects, will render them economical non-viable, providing this option is reasonable and appropriate.

PG&E supports this proposal in that it could provide an evaluation methodology to verify the need for anti-islanding mitigation. However, PG&E points out that an risk-of-islanding study timeline is needed to ensure projects move through the study process and don’t remain indefinitely. All other Rule 21 study tasks are governed by a timeline either for the customer or IOU to complete a task within a specific time and this should be no exception.

GPI supports this proposal but hopes that significantly less costly solutions may be developed that will avoid the need for DTTs in the future. We also urge PG&E to reasonably weigh the risk of actual islanding occurrences (given that there has only been one documented case so far) against the costs of protection.

Proposal 18-d. Convene an Unintentional Islanding Working Group on Distribution-System-Level Solutions. The Public Utilities Commission should organize an Unintentional Islanding Working Group to explore distribution-system-level solutions to anti-islanding. The Working Group should evaluate solutions and recommend next steps in the continuance of islanding (or anti-islanding) research and development at both the distribution and transmission system level.

Initiating proponent: IREC
Supported by: CALSSA, Clean Coalition, GPI, Tesla, PG&E, SDG&E
Opposed by: <none>

Anti-islanding capability has always been tested on the individual inverter level per the test procedures of IEEE 1547.1. Recent research has shown that there may be distribution system concerns that affect the ability of an individual inverter to successfully detect an island. For instance, modeling from Sandia National Lab has demonstrated the possibility that interactions between inverters and rotating machines can decrease anti-islanding effectiveness.[29] The modeling also suggests that some anti-islanding algorithms may be more effective than others, and different algorithms may not interact well. It is now understood that the risks of unintentional island formation have less to do with any individual inverter (since all are certified to have adequate individual anti-islanding capabilities) and more to do with a variety of different types of interactions between equipment on the distribution system. As a result, it is becoming clear that unintentional islanding is a distribution system issue, and yet individual inverters are being called on to address the issue. This proposal seeks to explore ways to resolve concerns about unintentional island formation more efficiently and effectively at the distribution system level. Gridworks: CALSSA significantly re-wrote this paragraph, but the changes are too significant in terms of meaning to be able to make and achieve agreement in the time remaining, so have not been made

As DER penetrations have risen, so too have more diligent reviews of islanding risk. Today, utilities such as PG&E apply additional screening in supplemental review, per Rule 21 Screen M and P, in order to determine whether or not it is likely that a circuit or transmission line may be at risk of islanding with the addition of a new DER. If this becomes more prevalent, risk of islanding screens or assessments may over time move developers to adopt inverters with specific anti-islanding algorithms that have been shown to be more effective and will pass the screens or assessments. For example, Proposal 18-e would create a potentially faster review process for inverters with Group 1 or 2A anti-islanding methods. (SAND2018-8431 defines eight different anti-islanding types or methods. Group 1 is defined as a method that uses positive feedback error on a frequency or phase pulse creating instability when an island forms up to the frequency trip limits. The output perturbation may be continuous or pulsed. Group 2A is similar to Group 1 with the exception that the signal is not continuous and may be

[29] S. Gonzalez, A. Ellis, M. Ropp, C. Mouw, D Schutz and S. Perlenfein, "Unintentional Islanding Detection Performance with Mixed DER Types," Sandia National Laboratories report SAND2018-8431, July 2018, https://www.osti.gov/servlets/purl/1463446M.

stepped or discontinuous.) SAND2018-8431 concludes that Group 1 and 2A have been shown to be effective even when paired with fairly high proportions of rotating machines or when grouped with other less effective anti-islanding methods. Such a screening process could provide impetus for developers to prefer those inverters, and thus create a market incentive for inverter manufacturers to utilize those methods.

Due to the fact that the preferred anti-islanding method attempts to actively perturb the voltage and frequency of the system in the same way, there is a concern the combined effects may begin to introduce unwanted power quality issues at high penetration levels. Indeed, Japan instituted a standardized anti-islanding algorithm for all inverters (through standard JEAC 9701), which worked well for island detection but introduced flicker issues.[30]

While mitigations for unintentional island formation have focused on the single DER/inverter up until now, mitigating island formation may also be done at the transmission or distribution system level (e.g. through the use of voltage reclose blocking, high-speed grounding switches, or a power line carrier heartbeat signal)[31] and could apply to all DER on the circuit. Given that cost-causation rules dictate that a single DER or group of DERs pay for mitigation solutions, it is challenging to adopt system-level architectures through individual Rule 21 applications that would benefit all DER now and in the future. Some aspects of potential solutions could benefit non-DER ratepayers or grid reliability in general and yet individual interconnection applications drive the implementation of today's mitigation techniques.[32] Developing the right solution for the future may involve evaluating infrastructure upgrades that potentially affect many customers, so it is challenging to evaluate or implement them without raising capital expenditure and ratepayer concerns. Nor is it easy to evaluate these solutions in this docket if the focus of the Rule 21 process is on screening for particular interconnection applications. Inverter manufacturers generally meet the requirements of existing standards and market needs. Today's standards do not address system-level approaches (IEEE 1547 is focused on the individual interconnection) and a market cannot be established without coordinating utilities and PUCs to ensure that system-level approaches would be accepted.

Utilities have safety and power quality concerns about allowing unintended islands to remain energized for more than two seconds. If an unintentional island is formed, the utility can no longer control power quality and thus wants to ensure that unintentional islands do not occur in the first place. However, it is generally not questioned what legal or technical mechanisms could allow islands, even unintentional ones, to continue energizing the circuit if power quality could be assured. On the technical side, reclosing into an energized island is one major risk

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[30] K. Otani, "Japanese test bed of renewable integration – Challenges of high penetration of renewable DERs into existing grids" [PowerPoint slides], 8th International Conference on Integration of Renewable and Distributed Energy Resources, 2018, retrieved from http://www.ired2018.at/Sessions/5.5%20IRED2018_Otani.pdf.

[31] B. York, T. key and A. Huque, "Are Current Unintentional Islanding Prevention Practices Sufficient for Future Needs?" EPRI, February 2015.

[32] It is our understanding that PG&E has charged interconnection customers for some of the mitigations necessary, but has also found that other mitigations are not the responsibility of the customers. However, the cost of the screening, study and time delays fall on the individual projects regardless of who pays for the upgrade cost.

since it can damage loads if done significantly out of phase. However, there are technical solutions such as synchronized reclosing or reclose blocking. When exploring system-level approaches to dealing with island risk, it may pay to question the assumptions that lead to mitigation in the first place.

Circuit-level microgrids could eventually serve a resiliency role on feeders or substations with high DER penetration and coordination. Thus, it may not always be in the best interest of ratepayers to require DER to shut down when disconnected from the bulk grid. Preparing for that future would mean reframing the discussion from anti-islanding to intentional islanding, and ensuring that DER equipment could eventually be integrated into a microgrid.

The role of microgrids in mitigating unintentional islands represents the intersection of the present Issue 18 anti-islanding mitigation scope under Rule 21 with other potential scoping under the Commission's current microgrid proceeding and other proceedings. In scoping the proposed Unintentional Islanding Working Group under Rule 21, the Commission would need to determine how to address this intersection. For example, the Track 2 Staff Proposal[33] issued under the microgrid proceeding provides for proposals in support of PUC 8371(c) (Impact Studies), to develop guidelines that determine what impact studies are required for microgrids. There would need to be alignment of scoping of such impact studies with the proposed Unintentional Islanding Working Group. Unintentional islanding should only be scoped within the impact studies of the microgrid proceeding or within the Unintentional Islanding Working Group, but not both. Added by SCE, edited by Gridworks

Further, the Unintentional Islanding Working Group would not attempt to set microgrid design standards, which are being addressed in the microgrid proceeding.

For example, today's DER equipment, with the focus on avoiding islands, may not be able to be integrated into a future microgrid. This may mean that alternative anti-islanding means should be used today, or that the algorithms in the inverters be able to be turned off in the future. Additionally, "microgrid-ready" inverters may need a means to adjust functional parameters when entering microgrid mode. Generally, there needs to be some coordination of DER within a microgrid and distribution system-level equipment could play that role. For example, reclosers may act as the microgrid isolation device ("intentional island interconnection device" in IEEE 1547-2018) and distribution system communications equipment may serve the coordinating role.

While there are a number of potential solutions to mitigate the risks of unintentional islanding at the distribution-level or transmission-level existing today, as well as to be developed, there is no clear answer as to how inverter manufacturers should continue development or which of these solutions should be further evaluated. There is a need to coordinate the evaluation of

[33] Administrative Law Judge's Ruling Requesting Comment on the Track 2 Microgrid and Resiliency Strategies Staff Proposal, Facilitating the Commercialization of Microgrids Pursuant to Pursuant to Senate Bill 1338 dated July 23, 2020

such solutions at the state and/or national level. California, as a leader in high-penetration DER, could play a role in being the first to address this issue, likely bringing national attention and experts to the table.

As the combination of generator types and technologies grows on the distribution system it is becoming clear that mitigating risk of islanding on a project-by-project basis may be both inefficient and ineffective. Thus, we propose to form a Working Group to explore whether distribution system level solutions to anti-islanding should be adopted.

Questions to be answered by the Working Group could include but not be limited to the following:

- What type of technical evaluations/studies need to be conducted to determine what system conditions would drive the need for additional mitigation?
- What information would be necessary from DERs (such as anti-islanding algorithms) in order to perform technical evaluation?
- What mitigations would be available for resolving the identified issues?
- What would be the anti-islanding evaluation process?
- At high levels of penetration, are the power quality issues driven by anti-islanding algorithms in need of mitigation?
- What reclosing and system-level unintentional island mitigation solutions exist or are feasible today (e.g. reclose blocking, extending anti-islanding response time, grounding switches)?
    - What are typical costs associated with those solutions?
    - Do power quality concerns within an unintentional island need to be addressed if the system-level approach is used?
- What system-level anti-islanding enabling solutions exist or are feasible today (e.g. grounding switches, power line carrier heartbeat, communications)?
    - What are typical costs associated with those solutions?
    - Do power quality concerns within an unintentional island need to be addressed if the system-level approach is used?
- ~~What system-level intentional island enabling solutions exist or are feasible today (e.g. communications, power line carrier heartbeat)?~~
    - ~~What are typical costs associated with those solutions?~~
    - ~~Do power quality concerns within an intentional island need to be addressed if the system-level approach is used?~~ SCE: included in final scoping of Microgrid Working Group
- What potential unintentional island mitigation solutions that do not yet exist need further evaluation and/or testing?
- What unintentional island mitigation solutions are ripe for pilot projects and/or additional testing to ensure feasibility?
- What coordination and cost allocation issues need to be surmounted in order to deploy the most effective/feasible/least cost unintentional island mitigation solutions?

To the extent that other OIRs (such as MG OIR) are addressing similar questions to this list, this Working Group shall manage the discussion and development on those topics in coordination with those OIRs such that efforts are not duplicated, and are harmonized to the extent possible.

The Working Group would draw on existing research and experience, identify gaps in research and experience, and recommend further research and experience (e.g. pilot projects).

The Smart Inverter Working Group is a potentially good model for this type of work, as it successfully brought parties to the table to identify inverter capability needs, implement the capabilities in California, and jumpstart national standards work to further address those needs. We suggest that a similar framework of recommendation reports could be created by an Islanding Working Group, with the focus on research, capability development and pilot project needs. The Commission should direct the Energy Division staff to lead and facilitate the working group or appoint an outside neutral third-party facilitator.

The IOUs support the proposal to form the Anti-Islanding Working Group and are willing to participate. The utilities do not, however, want to be responsible for leading the group or funding a facilitator as that might divert resources from their interconnection processing and review efforts.

The Commission should convene an Anti-Islanding Working Group within four months of the Commission's Order. The Working Group should meet once a month for 18 months to develop an initial report that examines the potential approaches to distribution system solutions for anti-islanding and makes recommendations to the Commission for next steps. Those recommendations may include proposals for concrete pilot projects to test different solutions, proposals for immediate investment in particular techniques, or proposals to continue with the current approach to anti-islanding. The Commission shall ensure that outside experts on anti-islanding are invited and encouraged to participate (including appropriate representatives of EPRI, Sandia and the National Renewable Energy Laboratory (NREL) or other research groups or national labs). The Anti-Islanding Working Group shall submit a report to the Commission within two months of the conclusion of the Anti-Islanding Working Group meetings or provide an update to the Commission if additional time is necessary based upon Working Group activities.

Party Positions on Proposal 18-d:

> Tesla supports this proposal. Given the evolving nature of the collective understanding of this issue, its highly technical nature, and the very high costs of addressing unintentional islanding formation, it seems like the kind of issue that would be well suited for a technical working group.
>
> SDG&E supports this proposal on the condition that any facilitation, including funding for a third-party facilitator, should not be required of SDG&E. SDG&E would participate

in and support the Working Group with technical expertise as resources allow. However, because this issue is not applicable to SDG&E, since it does not perform enhanced anti-islanding screening based on the Sandia studies, SDG&E does not support diverting resources from interconnection processing and review, nor should SDG&E customers be required to fund any facilitation.

Proposal 18-e. PG&E Will Adopt New Anti-Islanding Screens. PG&E will adopt new anti-islanding screens in their Bulletin that considers aggregate generation relative to minimum load, aggregate machine generation or aggregate uncertified distributed generation to total generation ratio, fixed power factor modes, and inverter anti-islanding "types." The proposed screens are used to verify or ensure islands are terminated in two seconds or less in accordance with Rule 21 Section H.1a.iii and section 4.b, whenever there is a question of whether a system configuration may result in an island lasting more than two seconds. The screen will include the option of a Risk of Islanding study upon failure of the screen as specified in Proposal 18-c. This proposal would not apply to utilities that do not perform enhanced anti-islanding screening based on the Sandia studies referenced in this proposal, which currently includes both SDG&E and SCE.

Initiating proponent: PG&E
Supported by: CALSSA, Clean Coalition, IREC, Tesla
Opposed by: GPI
Not applicable to: SCE, SDG&E

PG&E proposes to adjust its enhanced anti-islanding screens to determine whether the majority of inverters in a circuit segment use the anti-islanding methods that have lower risk of failure in proximity to machine generators. It is used to verify or ensure islands are terminated in two seconds or less in accordance with Rule 21 Section H.1a.iii and section 4.b, when there is a question of whether a system configuration may result in an island lasting more than two seconds.

The proposed PG&E screen provides anti-islanding protection requirements for the interconnection of inverter-based DER when it connects to a circuit that includes machine-based generation. The machine-based generation screens will be modified to include a Risk of Islanding study if the load screen has failed (Aggregated DG > 50% of minimum load).
The Risk of Islanding study will be performed by entities selected by the utility, and the study will be funded by the developer. The Risk of Islanding study requirements (see Annex 2) will be developed and based upon the studies performed by Northern Plains Power Technologies, which is the industry benchmark for Risk of Islanding studies.[34]

[34] Risk of Islanding Study on Old River Substation, 70kV Level. Norther Plains Power Technology, June 23, 2017 (version 2).

The proposed screen is not binding on the other IOU's. Proposal 18-e only applies to PG&E.

For all utilities, no more than three years CALSSA prefers two years after publication of this Working Group report, any utility that does enhanced anti-islanding screening will hold a minimum of one workshop with inverter manufacturers and other interested stakeholders to consider whether changes are warranted to the definition of preferred anti-islanding methods. If warranted, the utility shall file an advice letter recommending changes to the definition of preferred anti-islanding types or a process for developing changes to the definition.

In addition, no more than three years after publication of this Working Group report, any utility that does enhanced anti-islanding screening will hold a minimum of one workshop with inverter manufacturers and other interested stakeholders to consider whether the threshold in Screen 5 below should be increased from 70% to 100% or some value in between.

The functional descriptions of Inverter Groups 1 and 2A are given in SAND2018-8431 (see also Proposal 18-d discussion). If inverter manufactures develop alternative active anti-islanding methods that meet the functional requirements it should be communicated to the IOUs for evaluation to ensure it does not adversely affect the aggregate generation anti-islanding capability. If the utility wants to functionally modify the screens there should first be a workshop involving the Commission and industry representatives.

Currently PG&E does not require mitigation if all the islanded DER consists of certified inverter-based generation. However, if there is machine-based or uncertified generation within the circuit segment, mitigation may be required. It should be pointed out that as more certified inverters are added to the grid the less likely islanding mitigation will be required. This is due to the active anti-islanding capability of the inverters which act to destabilize the island; however, the active anti-island type must be of the most effective type and of sufficient aggregate size to push the islanded system to a voltage or frequency trip setpoint. Review of the recent studies mentioned above have resulted in the proposal below. They take advantage of the non-ride through voltage and frequency elements for machine-based generation, the fact they are in P-Q mode, and the presence of anti-islanding types 1 and 2A which significantly reduces the chances of a run-on island.[35] The screens also acknowledge that a Risk of Islanding study should be performed before hardware mitigation is specified.

Proposed PG&E Screens

The new UL1741/1741SA anti-Islanding screening proposal is illustrated by the flow chart in Figure 1 and contains the following elements.

[35] SAND2018-8431 describes eight different anti-islanding types. Type 1 is defined as a method that uses positive feedback error on a frequency or phase pulse creating instability when an island forms up to the frequency trip limits. The output perturbation may be continuous or pulsed. Group 2A is similar to Group-1 with the exception that the signal is not continuous and may be stepped or discontinuous. Sandia has determined that these two types are the most reliable for terminating unintended islands.

1. Is aggregated DG greater than 50% of minimum load?
    a. If no, no further review is required.

    b. If yes, continue to Screen 2.

2. Is the ratio of unprotected[36] aggregate machines and/or uncertified DG to total DG greater than 40%?
    a. If no, then no further review is required. *Note: As more certified inverters are added to the system, it will become more likely that projects will pass this screen and therefore not be required to install mitigations for islanding.*

    b. If yes, continue to Screen 3.

3. Are the unprotected machines and/or uncertified DG (e.g., wind) operated in fixed power-factor mode AND are the voltage and frequency elements set per Rule 21 Table H[37]?

    a. If yes to both, skip Screen 4 and continue directly to Screen 5.

    b. If no, proceed to Screen 4.

4. Can the DG be placed in fixed power-factor mode AND the voltage and frequency elements be set per Rule 21 Table H?

    a. If yes to both, then continue to Screen 5.

    b. If no, then a Risk of Islanding Study must be performed to determine whether mitigation is required. If the Risk of Islanding Study determines there is a risk of an island forming after more than two seconds then mitigation will be required. If the applicant does not want to proceed to a Risk of Islanding Study, then mitigation will be required or the application must be withdrawn.

5. Are more than 50% of the inverters using a type 1 or 2A[38] anti-islanding method AND is the ratio of unprotected aggregate machines and/or uncertified DG to total DG less than 70%?

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[36] Unprotected – if an existing machine/uncertified DG already has DTT or a recloser installed for this islanding condition the DG would not count towards the ratio limit.

[37] Rule 21 Table H settings are specified in PG&E Electric Rule No. 21 Sheets 173, and 176.

[38] Inverter Group 1/2A is referenced to SANDIA defined Active Islanding methods. Group 1 is defined as a method that uses positive feedback error on a frequency or phase pulse creating instability when an island forms up to the frequency trip limits. The output perturbation may be continuous or pulsed. Group 2A is similar to Goup-1 with the exception that the signal is not continuous and may be stepped or discontinuous.

a. If yes to both, then no further review is required.

b. If no to either or both, then a Risk of Islanding Study must be performed to determine whether mitigation is required. If the Risk of Islanding Study determines there is a risk of and island forming after more than two seconds then mitigation will be required. If the applicant does not want to proceed to a Risk of Islanding Study, then mitigation will be required or the application must be withdrawn.

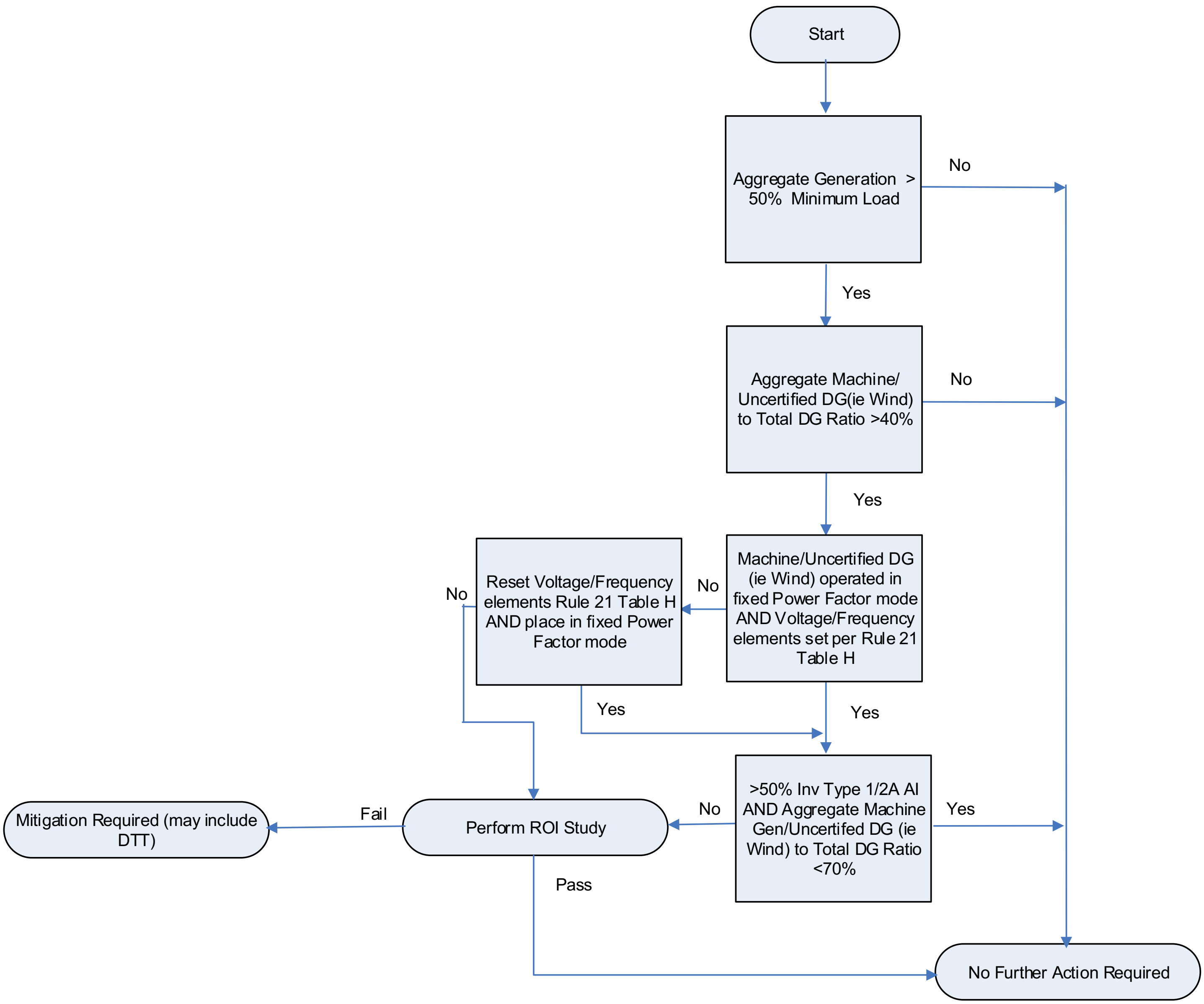

Figure-1 Certified Inverter Screen

Referring to Figure 1, the first screen is to check for minimum loading, this check is intended to screen out interconnections requiring mitigation based on the load to generation ratio. The load data is based upon the minimum load for the calendar year.

The new machine uncertified anti-Islanding screening proposal is illustrated by the flow chart in Figure 2 and contains the following elements.

Note -1 Machine/Uncertified DG (i.e., wind) shall be operated in fixed Power Factor mode AND Voltage/Frequency elements set per Rule 21 Table H.

1. Is aggregated Machine DG greater than 50% of the 24hr minimum load?

    a. If no, no further review is required.

    b. If yes, continue to Screen 2.

2. Are more than 50% of the inverters using a type 1 or 2A[39] anti-islanding method AND is the ratio of unprotected aggregate machines and/or uncertified DG to total DG less than 70%?

    c. If yes to both, then no further review is required.

    d. If no to either or both, then a Risk of Islanding Study must be performed to determine whether mitigation is required. If the Risk of Islanding Study determines there is a risk of and island forming after more than 2 seconds then mitigation will be required. If the applicant does not want to proceed to a Risk of Islanding Study, then mitigation will be required or the application must be withdrawn.

[39] Inverter Group 1/2A is referenced to SANDIA defined Active Islanding methods. Group 1 is defined as a method that uses positive feedback error on a frequency or phase pulse creating instability when an island forms up to the frequency trip limits. The output perturbation may be continuous or pulsed. Group 2A is similar to Goup-1 with the exception that the signal is not continuous and may be stepped or discontinuous.

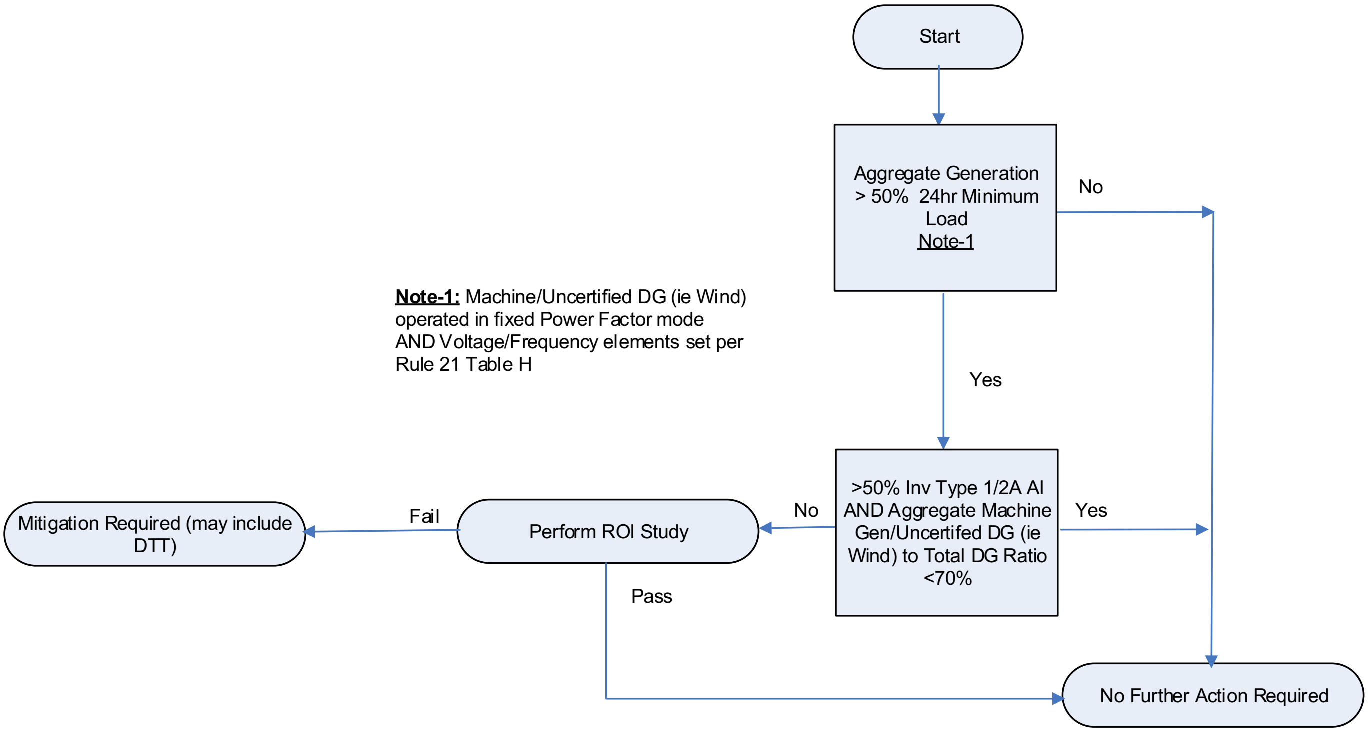

Figure-2 Machine Generator Screen

Referring to Figure 2, the first screen is to check for minimum loading, this check is intended to screen out interconnections requiring mitigation based on the load to generation ratio. The load data is based upon the 24-hour minimum load for the calendar year.

Party Positions on Proposal 18-e:

Tesla:

Tesla generally supports the concept behind PG&E's proposal, which would add several additional screens to its existing study process to more narrowly apply a requirement to deploy direct transfer trip or other mitigations to those circumstances where the risk of anti-islanding failure is more likely.

Tesla does have some questions regarding the practical ability to implement PG&E's proposal. Specifically, it seems that implementing PG&E's approach would require knowing the anti-islanding detection algorithm that is employed by all of the existing inverters interconnected to a given circuit. The proposed screen would require that Group 1 and 2A detection types make up > 70% of the inverter population by nameplate on a given circuit to avoid a risk of islanding study. It's unclear from PG&E's proposal how they would acquire this information and, if they are unable to obtain it, how that would impact how this would change their proposed screens.

In addition, Tesla sees the technical/empirical underpinnings of the specific thresholds that PG&E proposes as an evolving area of research, and while Tesla appreciates the reliance on sources like the Sandia to inform these thresholds, it is not clear if the thresholds incorporated into these screens, such as the > 70% of Group 1 and Group 2A anti-islanding detection algorithm, are set at the appropriate level. As discussed below, the forum proposed by IREC would appear to be a good venue to continue to vet the risk of islanding and ensure that the approach taken to evaluate and mitigate that risk reasonably reflects the latest research and is adjusted as additional research in this area sheds further light on this topic.

GPI:

GPI agrees with Tesla and IREC that a forum to vet the risk of islanding is warranted before this new screening process is approved. During the course of this Working Group it has come to light that just one islanding incident has been documented, ever, for the types of generators that PG&E seeks to include in the new anti-islanding screening process. No data was provided as to the likely prevalence of such incidents in the future, or projected growth curves of such incidents over time of such incidents. As such, it seems to GPI that adding these screens is premature, particularly considering the additional costs and timelines required for building the reclosers or DTTs that may be required. Even if these costs are rate-based, as was suggested by PG&E, this is still a cost to ratepayers, and the extended timelines from requiring additional protective equipment, plus the uncertainty that such additional screens may result in, seems unwarranted given the very rare incidence of actual harm from islanding.

PG&E (responding to Tesla):

PG&E has a list of all inverter types and manufacturers. In the near future PG&E will be contacting the manufacturers with the highest number of installations within the PG&E system to determine the type of anti-islanding methodology applied. From this information a reasonable assumption can be made on the types of anti-islanding installed in a given location.

PG&E (responding to GPI):

The lack of islanding events should correspond with the success of existing PG&E unintended islanding methods. To ensure mitigation is applied efficiently, the proposed screening process vets interconnections that are in need of further study. Mitigation is only required if an ROI study indicates a run-on island is possible. The propose IREC forum could take years to determine a screening process, in the meantime distributed generation continues to be installed with extended voltage and frequency ride though with various forms of anti-islanding that are not tested as an aggregate system. Performing the screening and study process in the interim is a prudent step to ensure unintended islanding is not an issue while further research is being performed.

Proposal 18-f. Develop an Interconnection Guidebook of Anti-Islanding Options. The CPUC, utilities, and developers should work together to develop a guide that provides anti-islanding options, clearly identifies the cost of each option, and sets out the circumstances when it will be required.

Initiating proponent: BAC
Supported by: Clean Coalition, GPI, PG&E
Opposed by: SCE, SDG&E

Costs in this "Interconnection Guidebook" should be all-inclusive. The Guidebook, while not a binding regulatory document, should provide clear guidance to project developers so that they know exactly what circumstances will trigger a requirement for DTT and what circumstances or steps can be taken to avoid DTT. There should be clear metrics and examples provided so that developers do not have to guess about potential requirements.

Utilities should not be allowed to require more than what is in the Guidebook unless they demonstrate the need for additional measures in a timely manner. For instance, if the Guidebook says that DTT is not required if an end of line fault (EOL) can be seen and the generator tripped in 120 cycles (two seconds), then the utility should not be able to deviate from that without a clear written explanation as to why something more than the Guidebook recommendation is needed.

The Guidebook could also provide explanations of the different utility interconnection systems and requirements (e.g., why PG&E's system is different from the other utilities and what that means in practice), and many of the other issues covered in the Background Section of this report to provide context to developers and others, as well as much more clear guidance on likely requirements and options to prevent unintended islanding.

Party Positions on Proposal 18-f:

SCE:

It is unclear if the proposal is only targeting installation requirements of DTT and/or utilities that person enhanced anti-islanding screening based on the Sandia studies, in either case this proposal would not be applicable to SCE since SCE currently does not require the installation of DTT for DERs interconnecting on distribution voltage or perform ant-islanding screening based on Sandia studies. However, because the proposal includes the term "all-inclusive," it appears to apply to all the elements that would be applicable to anti-islanding, such as the utilization of customer relays and SCE ground detection equipment to support anti-islanding. To the extent the proposed Guidebook is intended to include these elements, SCE already publishes non-binding cost information in its Rule 21 Unit Cost Guide[40] for equipment that is used to support anti-islanding. A second publication would therefore be duplicative.

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[40] https://www.sce.com/sites/default/files/inline-files/Attachment_A-Unit_Cost_Guide_2020_Final.pdf

Moreover, requiring SCE to demonstrate why a particular system mitigation infringes on SCE's ability to operate its electrical grid in a safe, reliable, efficient and cost-effective manner. The current interconnection process provides ample opportunities for an interconnection customer to discuss the study results and alternative to solve any technical issues including anti-islanding, and, if necessary, to dispute specific results through the use of the existing Section K process or pending interconnection dispute resolution process. Finally, it is unclear within Proposal 18-f to whom the utilities would need to justify their decisions, in what forum, and who would be the arbiter of whether a system solution is justified or not.

SDG&E:

Because the SDG&E does not perform enhanced anti-islanding screening based on the Sandia studies, this proposal should not be applicable to SDG&E. While SDG&E understands the challenges and issue, it is simply not appropriate for SDG&E ratepayers to fund the development of this guide and for SDG&E resources to be diverted from interconnection processing and review. SDG&E is already supportive of Proposal 18d to organize an Islanding Working Group to explore and provide further next steps in continuance of islanding (or anti-islanding) research that would support further development of anti-islanding solutions and believes that is the appropriate venue for further discussion. Furthermore, Rule 21 Section H and Hh already provide protection requirements that SDG&E follows to develop anti-islanding system mitigations. As an electrical corporation, SDG&E is required to operate its electrical grid in a safe, reliable, efficient, and cost-effective manner. The current interconnection process provides ample opportunities for an interconnection customer to discuss the study results, and, if necessary, to dispute specific results through the use of the existing Section K process and pending interconnection dispute resolution process. Finally, it is unclear within BAC's proposal to whom the utilities would need to justify their decisions, in what forum, and who would be the arbiter of whether a system solution is justified or not.

PG&E:

Support this in principal, however Rule 21 already provides a cost envelope guide that is available it all interconnection entities. Additional requirements are not specified outside of Rule 21. The intent of the non-binding guidebook is as a reference for developers to know conditions and configurations that may result in DTT mitigation. This could be used to set expectations for a given interconnections or to select another interconnection before time and money spent on project.

Provided response to the questions as noted at the beginning of the write-up. The Guidebook in this case is Rule 21, this is not in excess of what is specified in Rule 21. PG&E supports an informal guide that outlines common configurations which initiate anti-islanding upgrades, this could be an informative annex to the Distribution or Transmission interconnection handbook as appropriate.

Proposal 18-g. Evaluate and Choose Least-Cost Anti-Islanding Solutions. Utilities should continue to assess and offer new or alternative least-cost anti-islanding solutions that can meet each IOU's anti-islanding requirements. As new technologies or applications are developed and demonstrated, utilities should evaluate those technologies and attempt to choose the lowest cost option that meets the anti-islanding requirements. Similarly, if Risk of Islanding studies show that a less expensive option is adequate to prevent islanding, then the utility should employ the less expensive option.

Initiating proponent: BAC
Supported by: Clean Coalition, GPI, PG&E
Opposed by: SCE, SDG&E

This proposal sets explicit policy to encourage utilities to continue to seek the lowest cost solutions to protect against unintended islanding. It is in ratepayers' interest to ensure that the least expensive options are used to prevent anti-islanding.

The experience with the Governor's Tree Mortality Task Force (as referenced in the Background section) supports this proposal. That Task Force reviewed seven separate BioMAT projects and found an average savings of $1 million in unnecessary or overly costly interconnection requirements, many of which were related to anti-islanding measures. The Task Force found a wide variation in project requirements. As a result of the review, PG&E agreed to remove DTT and relays on several projects, including Burney Hat Creek, North Fork, and the Pitt Power House, where less expensive options were adequate to protect against anti-islanding.

The experience with the Task Force demonstrates that it may be necessary for a secondary review to ensure that only necessary costs are imposed on projects. This may be as simple as having a higher-level engineer within the utility review interconnection studies and requirements, as PG&E did during the Tree Mortality Task Force Review. While utilities may intend to employ least-cost solutions, this does not always happen in practice. Making this policy explicit helps to underscore the need for continued diligence in providing least-cost solutions.

Initiating proponent Bioenergy Association of California also believes that many transfer trips could be achieved with an inexpensive SCADA system and a phone line or appropriate protective relays. A T1 communication link[41] with a $1,000,000 DTT transmitter/receiver setup is often not necessary nor preferred. Utilities should continue to assess and offer options that are less expensive and require less upkeep than DTT. The Interconnection Guidebook described

[41] T1 is a multiplexed communication path containing 24 individual DS0 channels. Digital Signal 0 (DS0) is a basic digital signaling rate of 64 Kbit/s, corresponding to the capacity of one voice-frequency-equivalent channel. The DS0 rate forms the basis for the digital multiplex transmission hierarchy in telecommunications systems used in North America.

in Proposal 18-f could provide the basis (criteria) for deciding when less expensive options are sufficient.

Party Positions on Proposal 18-g:

SCE:

SCE does not perform enhanced anti-islanding screening based on the Sandia studies, so this proposal should not be applicable to SCE.

SCE opposes this proposal on the grounds that it is unclear. Specifically, it is unclear if the proposal is exclusively targeted at the installation of DTT after Risk of Islanding studies are completed, and SCE does not currently require DTT or perform enhanced anti-islanding screening based on Sandia studies Further, SCE already works to identify the best fit/least cost system and is concerned that Proposal 18-g intrudes on the utilities' system judgement without justification. SCE agrees with IREC's observation that there can be a considerable amount of nuance and disagreement when determining what is truly "best fit." Moreover, the current interconnection process provides ample opportunities for an interconnection customer to discuss system study results and, if necessary, to dispute specific results through the use of the existing Section K process along with the pending interconnection dispute resolution process. Finally, Rule 21 Sections H and HH already provide protection interconnection requirements that SCE follows to develop anti-islanding system mitigations.

SDG&E:

Because the SDG&E does not perform enhanced anti-islanding screening based on the Sandia studies, this proposal should not be applicable to SDG&E. While SDG&E understands the challenges and issue, it is simply not appropriate for SDG&E ratepayers to fund the development of this guide and for SDG&E resources to be diverted from interconnection processing and review. SDG&E already works to identify the best-fit, least-cost system. SDG&E is concerned that this proposal intrudes on the utilities' system judgment without justification. In addition, the current interconnection process provides ample opportunities for an interconnection customer to discuss system study results and, if necessary, to dispute specific results through the use of the existing Section K process along with the pending interconnection dispute resolution process. Finally, Rule 21 Sections H and Hh already provide protection interconnection requirements that SDG&E follows to develop anti-islanding system mitigations.

PG&E:

Support in principal. PG&E already installs the least cost alternative based on the safest existing technology; however, application of the existing technology is becoming cost prohibitive and complex. This proposal could be expanded to include evaluation of new technology, or Risk of Islanding studies. It should be noted application of this technology should remove 70% limit depending on the technology.

IREC:

IREC supports the utilities always being required to offer the least-cost-best-fit mitigations. We recognize, however, that there can be a considerable amount of nuance and disagreement when determining what is truly "best fit."

Proposal 18-h. Specify Timelines for Determining Anti-Islanding Requirements. Utilities should agree to a reasonable timeline to conduct Risk of Islanding studies and determine anti-islanding requirements. This is particularly important for Distributed scale Bioenergy Projects Employing Synchronous Generators that are required by the Governor's Emergency Order on Tree Mortality, SB 1122 (the BioMAT program), or to meet the requirements of SB 1383 (California's Short-Lived Climate Pollutant law, which requires policies and incentives to increase biogas and biomethane production). The CPUC should adopt an interconnection study timeline.

Initiating proponent: BAC
Supported by: GPI
Opposed by: PG&E, SCE, SDG&E

Rule 21 gives utilities 80 business days to complete Risk of Islanding and interconnection studies, but recent projects have experienced a series of 5-day delays that can add up to months longer. This is especially problematic for forest BioMAT projects called for by the Governor's Emergency Order (which calls on the CPUC to facilitate interconnection for these projects), where delays mean missing an entire fire season. Often, the 5-day delays are generated by auto-messages without any explanation and there is currently no limit in how many times the utilities use these delays. Initiating proponent Bioenergy Association of California believes the timeline for Risk of Islanding and interconnection studies generally should be shortened and delays should only be allowed when justified (not as a result of auto-messages).

Party Positions on Proposal 18-h:

IREC:

IREC supports more compliance with interconnection timelines for all projects. This has been addressed more comprehensively in the Working Group 3 Report, Issue 12.

PG&E:

As proposed, the Risk of Islanding studies would be funded by the developer and performed by a third-party entity chosen by the developer, so PG&E's position is that the Risk of Islanding study timeline be determined between the third-party studier and the developer. By design, the utility has no control over the study, so the utility should not be held to a timeline for its completion.

In addition, the process of determining the interconnection mitigations, such as anti-Islanding requirements, takes place during the interconnection study process and the interconnection studies are already subject to Rule 21 timelines.

SCE:

SCE does not conduct Risk of Islanding studies to determine anti-islanding requirements; therefore, to the extent this Proposal 18-h purports to require SCE to perform Risk of Islanding studies, it is not appropriate.

SCE supports Proposal 18-h with modifications and, if adopted, the proposed Anti-Islanding Working Group may develop additional Risk of Islanding studies and potential timelines for those studies. Requiring Risk of Islanding studies is inappropriate without technical clarification on issues such as the need for Risk of Islanding studies, when and under what conditions a Risk of Islanding study would be required, and what would be evaluated as part of the Risk of Islanding study.

Proposal 18-h would also call for a specific timeline preference that would not be available to other interconnecting parties. As previously discussed within SCE's positions on Proposals 18-g and 18-f, there are pending and existing venues to dispute or raise project-specific concerns, including regarding system project timelines.

SDG&E:

Construction durations are influenced by factors that are outside the utilities' direct control. One example of this challenge is that both project permitting and local jurisdiction's final approvals are a shared responsibility of both the interconnection customer and local agency. Other causes of potential delays can also range from outage coordination through environmental permitting approvals. As a matter of best practice, SDG&E encourages the interconnection customer to engage and work with SDG&E as early as possible to minimize construction delays. For more complex cases, SDG&E develops a proposed milestone schedule to highlight key activities supporting a project's operating date. Finally, as discussed during the Working Group, there are pending and existing venues to dispute or raise project-specific concerns.

Proposal 18-i. Use EPIC Funding for Demonstrations and Guidebook Development. The Commission and CEC should support use of Electric Program Investment Charge funding to identify and demonstrate additional, less expensive options for anti-islanding, help fund development of the Interconnection Guide, and help demonstrate technologies that provide anti-islanding and islanding (microgrid) solutions.

Initiating proponent: BAC
Supported by: Clean Coalition, GPI, PG&E
Opposed by: SCE, SDG&E

Party Positions on Proposal 18-i:

IREC:

IREC supports exploring the use of EPIC funding to support the work of the Islanding Working Group in Proposal 18-d but does not think we can bind the Working Group at this time.

SCE:

As EPIC projects are reviewed and governed through a process outside of the interconnection rulemaking, SCE believes it would be more appropriate for stakeholders to work through the EPIC process directly and develop proposed projects through the EPIC project review and related workstream. In addition, it would be inappropriate to evaluate and prioritize projects outside the EPIC progress and related reviews as stakeholders should develop and propose projects directly through the EPIC funding program and related processes.

SDG&E:

SDG&E's position and comments on the proposed Working Group are provided in response to Proposal 18-d above. With respect to EPIC funding, SDG&E is not opposed to use of EPIC funding as long it fulfills the EPIC requirements and gains EPIC approval in a future cycle. Typically, one utility will take the lead with the other utilities collaborating on the same EPIC project to avoid overlapping the same study. While SDG&E would not support leading such an EPIC project, SDG&E neither supports nor opposes use of EPIC funding to identify and demonstrate additional options for anti-islanding.

PG&E:

PG&E supports the used of EPIC funding to determine effective and cost efficient, localized machine-based generation anti-islanding methods that do not require external commination methods. The determination of such methodology should allow for less complex and expensive mitigation, which in turn would ease interconnection requirements.

Issue 19

Should the Commission adopt streamlined interconnection procedures (e.g. standard configurations eligible for expedited review) to facilitate implementation of California Zero Net Energy building codes and, if so, what should those procedures entail?

Proposals Summaries

Proposal 19-a. Enable residential home builders to submit interconnection applications based on street address. A residential home builder should be able to submit an interconnection application in their name based on a street address. A meter number should not be required for an interconnection application for new construction. Because SDG&E has already built out their system using account IDs with a reasonable way to get account IDs based on addresses, this two-step process can continue for SDG&E.

Initiating proponent: CALSSA
Supported by: Clean Coalition, GPI, SBUA, Tesla, PG&E, SCE, SDG&E
Opposed by: <none>

Proposal 19-b. Enable residential home builders to submit applications for multiple units via single submission or via batch process. Builders of residential home developments with multiple units should be able to either submit a single application for all of the units or submit multiple units via a batch application process.

Initiating proponent: CALSSA
Supported by: Clean Coalition, GPI, SBUA, Tesla, PG&E, SCE
Opposed by: SDG&E

Proposal 19-c. Utilities should allow template single-line drawings for small solar and small solar-plus-storage. All three IOUs should allow template single-line drawings for small solar and small solar-plus-storage in new ZNE residential construction, as ordered in the microgrid proceeding, R.19-09-009.

Initiating proponent: CALSSA
Supported by: Clean Coalition, GPI, SBUA, Tesla, PG&E, SCE, SDG&E
Opposed by: <none>

Proposal 19-d. Expand utility development of single-line diagrams. All three IOUs should be required to publish standard proposed facility configuration designs and single line diagrams for use in new ZNE residential construction interconnection applications.

Initiating proponent: Clean Coalition

Supported by: GPI, SBUA
Opposed by: PG&E, SCE, SDG&E

Proposal 19-e. Utilities Should Consider Expedited Processing for ZNE Projects. Utilities should fully consider and provide responses on the degree to which ZNE interconnection applications (both residential and commercial) may enjoy the same or similar benefits as NEM projects under 30 kW currently enjoy in terms of rapid processing. Utilities should consider and provide responses on which of the expedited processing tools applicable to projects 30 kW and below may be extended to ZNE projects over 30 kW.

Initiating proponent: GPI
Supported by: Clean Coalition, SBUA
Opposed by: PG&E, SCE, SDG&E

Background

In order to meet its greenhouse gas emissions reduction goals, California has set ambitious requirements for the development of "zero-net-energy (ZNE) buildings." One important step towards these goals was taken when the CEC adopted the 2019 update to Title 24 (California building energy efficiency standards), which went into effect on January 1, 2020.[42] As updated, Title 24 now requires solar energy systems on all new residential construction up to three stories.

This solar requirement was a further step towards California's ZNE goals. The 2008 California Long Term Energy Efficiency Strategic Plan[43] called for all new residential construction, including high-rise buildings, to be ZNE by 2030, half of new major renovations of state buildings to be ZNE by 2025, half of all commercial buildings to be retrofit to ZNE by 2030, and all new commercial construction to be ZNE starting from 2030.

A ZNE building is an energy-efficient building where, on a source energy basis, the actual annual consumed energy is less than or equal to the renewable energy produced onsite. In a ZNE building, energy efficiency measures can directly impact the electric and thermal profiles and requirements. Solar or other onsite generation may offset only electricity consumption, or both electricity and gas. Energy storage technologies may be incorporated into ZNE residential buildings. These storage technologies could be either non-exporting, only used for load reduction and peak shaving, or could be exporting, providing opportunities for system benefits with direct or indirect approaches, under both NEM and other tariffs as these evolve over time. ZNE may result in solar and storage projects in both multi-family and community level development, and coordination with a developing micro-grid design at various scales.

[42] Title 24; https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards
[43] https://www.cpuc.ca.gov/General.aspx?id=4125

Changes to Rule 21 in the current round of the Rule 21 proceeding should reflect these goals and mandates over the next decade, recognizing that durations of the past two Rule 21 proceeding cycles have taken multiple years.

The proposals put forth by the Working Group for Issue 19 are all intended to streamline interconnection procedures and timelines to facilitate implementation of California ZNE energy efficiency building codes. (Note: the terminology as used here, "ZNE building," "new ZNE construction," "ZNE projects," "ZNE building codes," and "energy efficiency building codes" all refer to Title 24 energy efficiency building codes and buildings that meet Title 24 requirements.)

Although ZNE building codes now require solar generating systems for new residential home construction, solar projects have interconnected using the Net Energy Metering program for several years and have already influenced utilities' new construction practices now applicable to projects developed to meet ZNE building codes. Now that there is a state requirement that all new homes contain solar, it is important to review new construction practices for solar installations.

However, it is also important to highlight that projects developed to meet ZNE building codes are no different than any other interconnection projects from the perspective of the interconnection application process, engineering requirements, and evaluating potential grid impacts.

The proposals put forth address streamlining the procedures for interconnection reviews, the use of single-line diagrams (SLDs), and interconnection timelines for ZNE new construction.

<u>Proposals Discussion</u>

Proposal 19-a. Enable residential home builders to submit interconnection applications based on street address. A residential home builder should be able to submit an interconnection application in their name based on a street address. A meter number should not be required for an interconnection application for new construction. Because SDG&E has already built out their system using account IDs with a reasonable way to get account IDs based on addresses, this two-step process can continue for SDG&E.

Initiating proponent: CALSSA
Supported by: Clean Coalition, GPI, SBUA, Tesla, PG&E, SCE, SDG&E
Opposed by: <none>

This proposal establishes more consistent and appropriate interconnection processing procedures for new ZNE construction. Waiting to submit an interconnection application until the homebuyer has established a service account is out of sync with ZNE new home construction schedules, in which it is known prior to construction that all homes will require interconnection.

The current interconnection review process presents challenges for new home construction. Most notably, interconnection applications have traditionally been identified by meter number and service account number by some utilities. A house under construction does not have a homeowner service account or meter. And installing solar on new construction should be part of the overall construction schedule. The wiring should be completed when the main electrical work is being done. The roof attachments should be installed before the roof is finished. The interconnection request should be submitted at the same time that the builder is seeking other regulatory approvals.

Further, builders and homebuyers have experienced two common processing challenges. First, for some utilities, if a homebuyer requests electrical service while the interconnection application is still pending, the application from the builder gets cancelled and the homebuyer is required to submit a new application. (Note that SCE and SDG&E do not use this practice within their service territories.) Second, if the system is not given permission to operate before the homebuyer moves in, the solar system cannot be used, which greatly upsets the customer, and the process is complicated because the builder is out of the picture. (This is also not an issue within SDG&E's and SCE's service territories.)

From the utility perspective, generation interconnection should be considered at the same time as the new load. When it is certain that the house will have solar, it does not make sense to study the load first and the generation later.

SCE and SDG&E are already compliant with this proposal. For SCE, it is possible for the builder to submit an interconnection application using the address. SDG&E requires builders to submit addresses and request that the utility assign account numbers. After receiving the account numbers, the builder submits interconnection applications. For both SCE and SDG&E, if the homebuyer sets up an account before the utility issues permission to operate the system, it does not disrupt the application. Permission to operate is granted to the builder, and it seamlessly transfers to the homebuyer just as it would transfer from one homeowner to the next.

PG&E continues to require a homeowner account number and meter number in the interconnection application. PG&E should implement this proposal before December 31, 2021. Because SDG&E has already built out itsr system using account IDs with a reasonable way to get account IDs based on addresses, this two-step process can continue for SDG&E but should not be replicated for PG&E. As an interim measure before the proposal can be implemented, PG&E is encouraged to implement a two-step process that allows for application submittal prior to installation of a customer meter or establishing a service account for the homebuyer.

This proposal also calls for utilities to maintain a goal of issuing permission to operate before the homebuyer moves in, provided that a complete interconnection application, including final release from the local authority having jurisdiction is submitted early enough in the construction process. However, in the event that a customer does set up service before the utility grants permission to operate the system, this should not impact the application that was signed by the builder before the transfer of ownership. That is, it is disruptive to the process to change the interconnection application midstream if a homebuyer creates a service account before PTO.

Party Positions:

PG&E supports developing this functionality and has funded IT work into 2021 that will enable customer ability to submit interconnection application based on project address. A background of the plan was provided to the Working Group.

SCE already allows for residential home builders to submit an interconnection application in their name based on street address.

SDG&E's interconnection portal has been designed to use account numbers and/or meter numbers. Modifying SDG&E's information technology (IT) systems to enable a customer to submit an interconnection application using only an address would require significant capital investment to redesign the systems. Instead, SDG&E has developed a simple and effective process for builders and solar providers to acquire account numbers for new construction accounts. Therefore, SDG&E does not support a requirement to modify its online portal to accomplish the goals of this proposal. Additionally, SDG&E's process does not require the homebuyer to submit a new application if the customer signs for electric service under its name prior to permission to operate (PTO). In the event the customer signs for electric service under its name prior to PTO, upon completion of the application, PTO will be issued to the current customer of record. Notification of PTO will also be sent the home builder and the authorized solar provider. This process provides a seamless transfer and avoids the issues raised in this proposal.

Proposal 19-b. Enable residential home builders to submit applications for multiple units via single submission or via batch process. Builders of residential home developments with multiple units should be able to either submit a single application for all of the units or submit multiple units via a batch application process.

Initiating proponent: CALSSA
Supported by: Clean Coalition, GPI, SBUA, Tesla, PG&E, SCE
Opposed by: SDG&E

This proposal will reduce administrative overhead for both home builders and utilities. This will be more efficient for applicants and utilities, and will provide utilities with information near the beginning of the construction process that is useful to their planning. It is inefficient to submit and review individual interconnection applications when an entire subdivision is under development. Under the new California ZNE standards, new subdivisions will always require interconnection of multiple residential buildings. Submitting applications piecemeal hinders the utility's ability to plan for the entire community.

The proposed implementation date is December 31, 2021.

Both SCE and PG&E have or are planning to have processes for submitting multiple applications together. For SCE, these are the batch processing highlights:

- Applicant can submit a group of NEM projects in one request using one excel worksheet format that is transferred to SCE via an application program interface
- Each NEM project submitted within the batch application continues to have the 1-to-1 relationship consistent with existing SCE processing practices further highlighted below:
    - Each project in the batch represents one specific Point of Interconnection and will be assigned an individual NEM Project Number
    - After submittal of the batch application, the project's workflow will progress individually, just like any other NEM project
- Batch application process is currently designed for new construction, single-family residential projects

PG&E's current application process requires a developer to submit a single application for each unit within a development. Each application is studied and managed independently. However, PG&E is planning to enhance the current application process by eliminating the need to submit individual applications for each metered unit, making it easier for the developer to apply and enabling PG&E to study and manage the interconnections collectively as a single project. The enhanced process would apply to residential home developments, which is defined by PG&E as two or more residential units constructed by the same developer as a single project (e.g., subdivisions, townhomes, condos, apartment complexes, and duplexes).

Although there would be a single application per residential development, it will still be necessary for the developer to submit detailed technical information for each individual unit, such as but not limited to:

- Generating Facility Operational Details
- Equipment Details
    - AC Disconnect Switch
    - Generator
    - Inverter
    - Energy Storage (e.g., Battery)
- Solar Statistics Data
    - Customer Sector
    - Performance Monitoring and Reporting Services

- PEVs
- System Ownership and Financing
- Additional PV Facility Information

Party Positions:

PG&E:

PG&E supports developing this functionality and has funded IT work into 2021 that will enable developer ability to submit a single interconnection application for residential home developments with multiple units. A background of the plan was provided to the Working Group.

SCE:

SCE supports Proposal 19-b as it allows for use of a batch application process as this type of process allows SCE to maintain individual applications. Maintaining individual applications is important to ensure accurate billing and allow for project system studies based on each project's unique characteristics (e.g., PV size and storage size).

SCE also believes, based on previous conversations with homebuilders, that a batch application (e.g., the ability to submit multiple applications at once) is what home developers are actually seeking. SCE is already in the process of developing batch application functionality expected to be in place by the end of 2020. The batch process would allow the homebuilder to submit information for multiple homes at the same time while providing specific information for each home in terms of PV size and storage, which would not be possible if a single application was used for multiple home units.

SDG&E:

SDG&E does not support this proposal. First, SDG&E's online interconnection portal is currently not set up to receive a single application in lieu of multiple applications with different points of interconnection. Secondly, the cost to modify SDG&E's portal would exceed any material benefits that may accrue to a relatively small subset of interconnection applicants in SDG&E's service territory. In 2019, interconnection applications for new home construction projects made up approximately two percent of the total interconnection applications received by SDG&E during the year (approximately 680 out of 33,205 applications processed by SDG&E in 2019 were for new construction). SDG&E anticipates that ZNE building codes will not have a significant impact to the overall average annual interconnection requests it has received during the last several years. This proposal would require a significant system redesign, including integrating the new service application system with the interconnection application portal, that may provide a benefit to a very limited number of interconnection applicants. Likewise, because SDG&E designs its distribution system based on load projections, a process that combines new service applications and interconnection requests provides no benefits to SDG&E. More importantly, the portal improvements associated with this proposal would add substantial IT capital costs that must be incurred by all interconnection applicants, while the potential benefit is enjoyed only by a small subset of applicants developing new home construction projects.

SDG&E notes that any modifications to its IT system are limited by the Commission-approved modification freeze that SDG&E is currently experiencing, and it will not be possible for SDG&E to implement changes to the online interconnection portal until sometime after the second quarter of 2021.

Tesla:

Tesla generally supports this proposal. Tesla further agrees with those stakeholders that note that for a batch process to yield meaningful value it will require investments in an API to facilitate project specific data transfers from developers regarding individual project details to the utility application processing system. Such a system would substantially reduce data entry requirements by allowing the use of project reference numbers to pull data and information regarding a particular project or projects directly from a developer's project database rather than requiring that information to manually input into the utilities' systems via the utilities' application portals.

Proposal 19-c. Utilities should allow template single-line drawings for small solar and small solar-plus-storage. All three IOUs should allow template single-line drawings for small solar and small solar-plus-storage in new ZNE residential construction, as ordered in the microgrid proceeding, R.19-09-009.

Initiating proponent: CALSSA
Supported by: Clean Coalition, GPI, SBUA, Tesla, PG&E, SCE, SDG&E
Opposed by: <none>

This proposal will streamline the interconnection process by expediting utility review of single line diagrams (SLDs) for systems associated with new ZNE residential construction that have standard designs. For many projects, a great amount of time is consumed before an application is deemed complete in correcting inconsequential issues with the single line diagram. A common error is a slight difference in the model number between the SLD and the application form. Inverter model numbers typically include many digits and dashes. Not including the full number on the diagram is not consequential but leads to delays and multiple reviews of an application.

Utilities and local building departments look at different aspects of a single line diagram. One is reviewing compliance with building codes such as setback requirements and the other is considering grid safety and reliability. Even though an SLD is created for the permit application, problems may arise in utility review of the SLD within the interconnection application that would not matter to the building department.

Template SLDs for new ZNE residential construction will reduce the average time required for the deemed-complete process.

PG&E and SDG&E already allow template single line drawings for small solar-only projects.

This proposal was developed concurrently with equivalent activity in the microgrid proceeding, R.19-09-009, and the recent decision in that proceeding, D.20-06-017, fully adopts this proposal. The proposal is not deleted from this report simply because template single-line diagrams are specifically mentioned in the scoping of this issue. However, parties believe that Proposal 19-c is sufficiently addressed by D.20-06-017, and no further action is required in the Rule 21 proceeding with respect to this specific proposal.

In accordance with Decision 20-06-017 in the Microgrid OIR, the utilities have now posted additional SLDs on their respective websites that customers can use to guide their custom electrical designs or upload to the online interconnection application portals. These SLDs cover the following behind-the-meter project types:

- Rule 21 non-export storage <10 kilowatts ("kW");
- Net Energy Metering ("NEM") solar <30 kW; and
- NEM paired storage for both AC- and DC-coupled systems with solar <30 kW and storage <10 kW

For the purposes of this proposal, "small solar" is defined as standard NEM, solar 30-kW or less; and "small solar plus storage" is defined as standard NEM Paired Storage, solar 30-kW or less plus battery 10-kW or less.

Party Positions:

PG&E:

As stated in the Microgrid proceeding, PG&E offers template single line diagrams for Rule 21 non-export storage (<10 kW), NEM Paired storage (AC Coupled and DC coupled) (with <30 kW solar and <10 kW storage), and NEM Solar (<30 kW) as these projects will address 95% of all interconnection applications received. This will allow PG&E to automate and accelerate the study process for these project types. In turn, this will allow engineering personnel to focus on larger and more complex interconnection projects, including Zero Net Energy buildings, thereby reducing study process timelines for all interconnection projects.

SCE**:** On June 17, 2020, the Commission issued a Final Decision (D.20-06-017) (Decision) within the Microgrid rulemaking (R.19-09-009) requesting the IOUs to prepare standardized SLDs for the following three Rule 21 project types: 1) Non-Exporting; 2) Net Energy Metering and 3) Net Energy Metering Paired Storage. SCE is supportive of the Commission's directive for SLDs and has already commenced developing Non-

Exporting SLDs with the other two project types to follow. (Advice Letters have already been filed microgrid in support of template SLDs for Rule 21 non-export, NEM solar and NEM paired storage projects.) To this end, SCE is supportive of CALSSA's proposal that calls for SLDs for small solar and small solar plus storage and supports CALSSA's view that this proposal should be folded into the Microgrid proceeding.

SDG&E:

SDG&E supports this proposal to the extent that no additional template SLDs would be required beyond those ordered within the Microgrid OIR's Track 1 Decision, D.20-06-017. However, a single-line diagram for a ZNE project is no different than any other project. For example, a SLD for a NEM-Paired Storage system installed under a ZNE project would look no different than a SLD for a similarly situated non-ZNE project. It is important to emphasize that an interconnection application for a ZNE project looks no different than an interconnection application for a non-ZNE project and therefore, ZNE projects inherently enjoy all of the expedited processing currently enjoyed by non-ZNE projects. Providing preferential treatment to ZNE projects would jeopardize the high level of service provided to all interconnection applicants. If a standardized SLD is useful for a particular type of generating facility, there is no reason to create one template for ZNE and another identical template for a non-ZNE project. Therefore, given that this topic has already been addressed in the Microgrids and Resiliency proceeding, there is no need to duplicate review and efforts to relitigate it within this proceeding.

Tesla:

Although Tesla supports this proposal, it is not clear what, if any, incremental action is required by the Commission beyond the current directives to the utilities to develop single line diagram templates for specific solar, storage and solar + storage projects. There does not appear to be anything that would distinguish these projects deployed in the ZNE context from projects deployed in other contexts and as such the templates the utilities have been directed to develop already should be equally beneficial to project applications associated with ZNE buildings. Given this, while again, we do support the proposal it's not clear if it is actually needed to the degree it is already being implemented. ~~It would helpful for the proponents of this proposal to more clearly articulate the specific deficiency this proposal would address given the existing, Commission-directed effort to establish single line diagram templates.~~

Proposal 19-d. Expand Utility Development of Single-Line Diagrams. All three IOUs should be required to publish standard proposed facility configuration designs and single line diagrams for use in new ZNE residential construction interconnection applications.

Initiating proponent: Clean Coalition
Supported by: GPI, SBUA
Opposed by: PG&E, SCE, SDG&E

There are additional requirements in this proposal that go beyond Proposal 19-c. These additional requirements are recommended to address any current or future configurations beyond the several identified and ordered in the Microgrid proceeding Decision 20-06-017. In that Decision the Commission states "While we adopt the single line diagrams for these particular behind-the-meter projects, we recognize that …. greater than 10 kW storage must be considered. These considerations may be addressed in subsequent tracks of this proceeding." (at page 24).

The configurations and single line diagrams (SLDs) addressed in that proceeding focus specifically on microgrid applications. While there can be substantial overlap between configurations designed for microgrids and those used in ZNE and other Rule 21 related applications, addressing these in this interconnection proceeding will be more inclusive, more comprehensive, and more appropriately aligned with the technical requirements and assessment of customer interest across all ZNE and related applications.

As detailed in Annex 3, D. 20-06-017 and the related Proposal 19-c do not address SLDs in a wide range of applications, including nearly all outside of the Net Energy Metering (NEM) tariff or those under NEM that are most applicable to disadvantaged communities such as Solar on Multi-family Affordable Housing, Virtual NEM and Aggregated NEM, including any application in which energy storage output is >10 kW. Additionally, no provision is made for retrofit applications or modifications of existing systems, such as when a customer simply wishes to add storage, and no provision is made to require future updates as needs change.

1. The need for development of an additional SLD ZNE standard template not covered by existing ZNE applicable templates would be triggered upon satisfaction of the following conditions:
    a) Proposed template SLD would be applicable to a category or sub-category of projects built under ZNE building codes
    b) Following receipt of an estimated 50 applications within the previous calendar year for which the utility has received functionally equivalent ZNE project built specific SLDs, the need for template SLD would be evaluated and discussed with DER industry stakeholders via a stakeholder call coordinated by the utility within 90 days (Q1) (Energy Division staff supporting interconnection would be invited to DER industry stakeholder discussions). Stakeholder feedback provides support that the expected pace of applications for the identified ZNE project template will continue and that the identified ZNE project type would be supported by development of an additional standard SLD template
    c) A standard SLD design template shall be published within 120 days after conclusion of the stakeholder discussions. (Only a single standard design example is required for each functionally distinct configuration.)

2. The template SLD shall be published in one or more formats (ex: a PDF form or a web interface) as determined by the IOU after considering industry feedback. Formats shown below would be expected to satisfy format requirements:
    - A protected static PDF where content cannot be modified by applicant (to ensure proper use of document)
    - Formats that provide the ability to enter information digitally such that it can be submitted in a machine-readable format

3. Where applicable, utilities are encouraged to minimize duplication or inconsistency.

Publication means in electronic format or via link on utility and/or Commission interconnection related website(s).

For the “50 applications received” threshold, IOUs may exercise a standard of reasonable utility discretion regarding similarity, subject to direction from Energy Division. The intent is to capture only critical required features and allow discretionary elements flexibility within the format of the template. The aim is to differentiate functionally distinct templates, not every possible variation that meets the same utility requirements.

The justification for this proposal is similar to Proposal 19-c. Most new residential construction and increasing levels of other new and retrofitted construction aims to meet ZNE standards -- the interconnection process for this construction will similarly benefit from the availability and use of standard design and configuration templates. Coordination of interconnection related matters is appropriately managed within this proceeding. In addition, as discussed previously, projects developed to meet ZNE building codes are a subset of interconnection projects that are not inherently different in electrical characteristics than other interconnection projects.

In most cases, an interconnection application involves submitting detailed, site-specific diagrams depicting system design. In contrast, a template-based interconnection application process allows developers to select their design from a clear set of options, including pre-established single line diagrams and pre-approved inverters and other equipment. The use of a template-based approach for various project types could simplify the overall interconnection application process, including the submission and review processes.

Having a published set of SLDs for those projects that do not typically have project-specific requirements will expedite the interconnection process. Only a limited set of SLDs are required -- all projects within each project category may follow the same SLDs, and only a single standard design example is required for each functionally distinct configuration, which will reduce the total number of SLDs required. For simplicity, if individual developers were to submit their own SLDs, the IOUs may end up with a wide range of SLDs making the near-term solution for expedited interconnection burdensome.

Standardized digital formats have well established advantages over paper or digitized image scans, especially as we take steps toward automated application review where it may prove useful in the future, as well as ease of data entry, analysis and reporting. Current utility processes may not be positioned to offer or take full advantage of digital formats, and IT integration may not currently be available or warranted, but may be scoped for future modernization planning.

While Issue 19 proposals are scoped to ZNE development, we should appreciate that such improvements could also be broadly applicable beyond just ZNE facilities, in line with the overarching goals and scoping of this proceeding. Much new housing will be multi-family, and the metering and configurations are likely similar for some commercial applications and can be addressed with no additional work, helping us get a head start on commercial ZNE. Although non-residential ZNE is not currently required until 2030, it is important to support early adoption and retrofit in order to meet broad statewide policy goals and coordination.

In Working Group discussions, stakeholders have noted:

- Any template will help reduce the percentage of applications that are found deficient and kicked back to a developer for correction and resubmission.
- Design Templates assist applicants not only in the development of SLDs, but in understanding appropriate design factors, such as variations in meter or relay placement to comply with tariff requirements
- Tesla believes that on average, shifting to a template-based approach would reduce the interconnection timeline by five to ten days. Benefits would accrue to virtually all project types with the biggest beneficiaries likely being solar plus storage projects given the significant and increasing volume of projects that are deploying these technologies together.
- IOUs have raised concern that an overabundance of different SLDs may lead to more confusion to applicants, rather than simplification. Applicants will need to understand the various nuances of the SLDs in order to select the correct one.
    - Stakeholders note: Agreed, and recommend a simple check list or decision tree that would provide the applicant with the correct template.
    - The number of different SLDs will be limited to those meeting specific adopted criteria or as otherwise warranted as determined by IOUs or Energy Division.

Among the IOUs, PG&E already deploys a standard SLD for NEM Photovoltaic (PV) applications less than or equal to 30 kW. SDG&E’s SLD templates for stand-alone PV systems are embedded within the online interconnection application portal for customers to select. And SCE uses six template SLDs for Rule 21 non-export and NEM solar and NEM paired storage.

As discussed previously, in accordance with Decision 20-06-017 in the Microgrid OIR, the utilities have now posted additional SLDs on their respective websites that customers can use to guide their custom electrical designs or upload to the online interconnection application portals. These SLDs cover the following behind-the-meter project types:

- Rule 21 non-export storage <10 kilowatts (“kW”);
- Net Energy Metering (“NEM”) solar <30 kW; and
- NEM paired storage for both AC- and DC-coupled systems with solar <30 kW and storage <10 kW

Additional template SLDs are being developed to expedite microgrid development in accordance with the Commission’s Decision 20-06-107. Annex 3 provides a comparison list which SLDs are included or partially included in the decision. However, the microgrid proceeding addresses microgrids, not ZNE. Annex 3 delineates the limited applicability of the microgrid proceeding to the full range of ZNE. While it is not disputed that the single customer NEM and non-export storage examples in the microgrid proceeding may constitute 80% of current applications, that may leave out 20,000 out of every 100,000 applications, including those most benefiting disadvantaged communities including multifamily, aggregated and virtual NEM installations and almost all non-NEM installations currently received or arising from changes in NEM resulting from the forthcoming proceeding.

Party Positions:

PG&E:

PG&E has carefully considered this proposal and determined that this would present significant safety concerns. Specifically, projects larger and/or more complex than those identified tend to have a greater impact on the grid and require detailed technical information to complete a safe and reliable interconnection study. Generation technology detail and configuration, facility detail, such as load and electrical plan, and protective equipment location and configuration are just some of the project specific information that would be impossible to capture in a template-based format.

As stated above, template diagrams for less complex projects will allow engineering personnel to focus on larger and more complex interconnection projects, including Zero Net Energy buildings, thereby reducing study process timelines for all interconnection projects.

PG&E understands that Clean Coalition is requesting an SLD that incorporates all of PG&E’s interconnection and service design requirements, however, these are already publicly available on PG&E’s website under the Distribution Interconnection Handbook and Greenbook, so creating an SLD on top of what is already published is redundant.

Link to DIH: pge.com/dih

Link to Greenbook: https://www.pge.com/en_US/small-medium-business/building-and-property/building-and-maintenance/building-and-renovation/electric-and-gas-service-requirements.page

SCE:

As discussed within both Working Group Four meetings and SCE's written comments on Proposal 19-c, SCE is supportive of developing template SLDs that cover a majority of interconnection requests, including projects developed to meet ZNE building codes consistent with the recent Decision. SCE supports the Commission's Decision direction for SLDs for the following three project types as set forth in the Decision that are now available to project developers:

:

1. BTM Rule 21 non-export storage projects;
2. NEM with paired storage (with one for AC-coupled systems and a separate template for DC-coupled systems); and
3. NEM solar projects.

As the Decision directed the utilities to develop "templates that address 80 percent or more of potential interconnection projects," the template SLDs will cover projects developed in support of Title 24 energy efficiency standards. For example, a SLD for a NEM-Paired Storage system built in accordance with Title 24 energy efficiency standards would look no different than a SLD for a similarly situated non-ZNE project.

While SCE anticipates that recently published template SLD will support more than 80% of the interconnection applications, SCE is supportive of continue to work with industry on development and publication of template SLDs that may be useful to industry stakeholders. However, SCE views that this discussion can be supported without the need for a formal requirement that SCE believes may create increased work for the SCE/utilities, particularly with the potential administrative burden imposed by tracking the number of projects to get to 50. These tracking efforts would take time from SCE personnel already dedicated to interconnection processing as compared to an approach based upon stakeholder feedback.

SDG&E:

The Microgrid OIR (R.19-09-009) Track 1 decision, D.20-06-017, orders the IOUs to develop and implement standardized templates for single-line diagrams. The scope of Working Group 4's review of standardized SLDs must therefore be limited to ZNE projects. However, a SLD for a ZNE project is no different than any other similarly situated project. For example, a SLD for a NEM-Paired Storage system installed under ZNE would look no different than a SLD for a similarly situated non-ZNE project. If a standardized SLD is useful for a particular type of generating facility, there is no reason to create one template for ZNE and another identical template for a non-ZNE project. Therefore, given that this topic has been addressed in the Microgrids and Resiliency proceeding, there is no need to duplicate review and efforts to relitigate it within this proceeding. SDG&E understands the purpose of this proposal is to respond to the issue scoped into this proceeding, which specifically identifies single-line diagrams, but supports the proposal to the extent that no additional work is required beyond the template SLDs already being developed in response to D.20-06-017.

Tesla:

Tesla supports expanding the number of SLD templates offered by the utilities that developers may select from if experience suggests that a certain project configuration is occurring in sufficient volumes to make the availability of a template helpful. However, we generally think this should be true regardless of whether the candidate configuration is deployed in a ZNE or non-ZNE context. While we understand that the proposal here would not preclude expanding the number of templates offered outside of the ZNE context, we are somewhat uncomfortable with the notion that ZNE buildings should take priority over efforts more generally to streamline the interconnection process for solar and storage solutions regardless of context. Furthermore, and consistent with the views Tesla provided regarding Proposal 19-c, it is not clear to us how deployments in the ZNE context would be systematically different from those in the non-ZNE context and thus require a set of ZNE-specific templates.

Clean Coalition:

This proposal does not require utilities to produce template SLDs where they are not warranted, it only creates a standard by which the need for a new template SLD would be evaluated and discussed with DER industry stakeholders. It also does not instruct utilities to change review processes, only to make clear via a published standard design example what features and protection standards are required, and only to do so when an established threshold of comparable applications is reached.

Proponents agree that some method of tracking will be needed, and defers to IOUs to implement the most reasonable and cost-effective approach. This is why language was included, in consultation with SCE, to minimize any burden, stating that "IOUs may exercise a standard of reasonable utility discretion regarding similarity." It is reasonable to expect IOU interconnection departments to be cognizant of whether they are processing numerous functionally similar applications - IOUs have claimed that 80% of applications will be covered by the microgrid standard SLDs, which is only possible to assert if there is already awareness of whether or not applications fit these defined categories and are similar enough to benefit from standard designs. IOUs already track projects by various criteria and after completing the existing application review process they may be reasonably expected to be aware of whether or not an application represents a configuration that is familiar or unfamiliar to their staff. All applications for which a standard template is already offered do not require any tracking, nor do applications that appear unfamiliar as these are by definition unlikely to reach the threshold criteria warranting a standard design template. This proposal offers guidance to interconnection staff, and as no formal audit nor penalty is proposed, a good faith effort is anticipated to have a truly de minimis impact of resources.

Nothing in this proposal requires duplication of effort or review. Proponents agree that only a single standard design example is required for each functionally distinct configuration, and defer to IOU judgement on similarity. However, as clearly outlined in Annex 3, the microgrid proceeding does not address a variety of ZNE categories or configurations, and this proposal merely establishes threshold criteria to determine when these additional configurations warrant attention.

In Advice Letter 4256-E issued July 17, 2020, SCE states that it "commenced the development of template SLDs in late 2019, in response to the recommendations made by participants in the Interconnection Discussion Forum (IDF). The IDF participants, including SCE, agreed that the use of template SLDs could help streamline the interconnection application process 1) by reducing errors on SLDs; thereby 2) reducing the number of deficiencies in the interconnection application, which in turn can; 3) reduce delays in achieving "deemed complete" status for the interconnection application. SCE believes that any effort which reduces errors, deficiencies, and minimizes the resultant delays is a process improvement."

GPI:

GPI mirrors the Clean Coalition comments and note also that the Clean Coalition has carefully delineated in Annex 3, with color coding, where its proposal goes further than the Microgrids Track 1 decision, judiciously proposing that certain types of projects that are commonly seen by each utility should get a template SLD option.

Proposal 19-e. Utilities Should Consider Expedited Processing for ZNE Projects. Utilities should fully consider and provide responses on the degree to which ZNE interconnection applications (both residential and commercial) may enjoy the same or similar benefits as NEM projects under 30 kW currently enjoy in terms of rapid processing. Utilities should consider and provide responses on which of the expedited processing tools applicable to projects 30 kW and below may be extended to ZNE projects over 30 kW.

Initiating proponent: GPI
Supported by: Clean Coalition, SBUA
Opposed by: PG&E, SCE, SDG&E

This proposal is important to ZNE interconnection because, with new building code requirements for residential and commercial buildings to be ZNE, streamlining and automation options now present a more favorable cost/benefit ratio, favoring action on further automation options in the near-term. Streamlining and automation have been discussed previously in Working Groups Two and Three, but the new policy focus on ZNE creates a stronger and more urgent rationale than was the case in those Working Groups.

In order to distinguish ZNE interconnection applications, ZNE applicants shall check the appropriate box on the interconnection application, indicating that they are ZNE applications. Certification of ZNE eligibility from the applicant will be required prior to PTO. Such certification procedures for ZNE buildings are described in Title 24.

Streamlining and automation has been a significant topic in Rule 21 Working Groups Two and Three. The Working Group Two Final Report ("WG2 report") includes an Appendix to Issue 8, authored by GPI and Clean Coalition, that provides a semi-comprehensive overview of streamlining and automation options for the Rule 21 process. Many of these options are applicable to ZNE home interconnections, as described in Table 1 below.

Table 1 shows the overlap and differences between NEM, ZNE and microgrids. Table 2 suggests the most promising near-term options for specific streamlining measures (with "near-term" defined as implementable in the next two years) and explains how these options are applicable and specific to ZNE interconnection. These options are meant to illustrate potential improvements that utilities could implement to streamline ZNE project interconnection, as part of the more general GPI proposal that utilities fully consider how ZNE project interconnection could be streamlined, per the Commission's direction in the Rule 21 Working Groups Scoping Memo.

Table 1: Comparing NEM, ZNE and microgrid project interconnection procedures.

	NEM 2.0 ()	ZNE (Various)	Microgrid (R.19-09-009)
Rule 21 implications?	Y	Y	Y
Scale of interconnection types	1 kW and up, with 1 MW max for NEM portion, for fee purposes, but unlimited for rest of system	No limits, scaled to facility size	No limits, multi-family, critical facility and commercial microgrids commonly 100-999kW, community sizes are in MWs
Standardized SLD considerations?	SDG&E currently allows for up to 30 kW solar; PG&E already uses them for NEM (PV only) up to 30 kW; SCE has none yet.	Proposed by Clean Coalition to cover solar and solar+storage for single family, multi-family, and commercial	Proposed by ED staff for NEM solar, non-export storage, and NEM solar plus storage
Automated interconnection process?	All IOUs have mostly automated Rule 21 interconnection for 30 kW and below	30 kW and below NEM process will apply to many but not all ZNE b/c many commercial ZNE will be over 30 kW.	Existing automation applies only for NEM <30kW.

Table 2: Near-Term Options for ZNE Interconnection Streamlining Measures

Option	Current Situation	Recommendation
Streamline/automate the application process and completeness review for ZNE interconnection applications	• Utilities must under current rules inform the applicant whether the application is deemed complete, or must be corrected, within 10 business days (BDs) after receipt of the Interconnection Request (Rule 21 sec. E.5.a). • In practice, this step can take two months or longer if multiple corrections are required (as is common for larger or more complex projects), each round of which also takes up to 10 BDs • All IOUs have already at least partially automated these steps but much work can be done toward further automation and	For ZNE projects, use streamlining and automation tools to reduce application processing and completeness review to 3 business days (BDs), for those projects that don't need corrections, as well as reduce the time required for utilities to respond to each round of corrections to 3 BDs.

	reducing, in particular, the time required for completeness review.	
Automating (at least partially) Initial Review	• Under current rules, Initial Review must be delivered within 15 BDs of the application being deemed complete (Rule 21 F.2.a). • The WG2 report identifies feasible ways for automating Initial Review. As with completeness review and the application process, Initial Review is already partially automated by all IOUs, but additional automation may still be achieved.	For ZNE applications, where IR screens can be cleared automatically through use of data from the online application inputs and available ICA (Integration Capacity Analysis maps) data, reduce the Initial Review to 3 BD.
Automating (at least partially) Supplemental Review	• Applications failing IR must go through Supplemental Review, which is another set of screens that provide more flexibility to the IOU to pass a project. Supplemental Review must be completed within 20 BDs (Rule 21 F.2.c). • Parts of SR are already automated with the existing Integration Capacity Analysis (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. • To date, stakeholders have generally agreed that SR can be automated in most cases but debates have occurred with respect to the cost/benefit analysis of doing so. The new policy focus on PSPS and ZNE should shift this debate toward taking action in the near-term.	For ZNE applications, utilize existing automation of SR screens N and O (not screen P), reducing current 20 BD timeline to 5 BDs.
Frontloading and automating the Generator Interconnection Agreement (GIA) generation and offer process	• A standard Generator Interconnection Agreement (GIA) must be offered within 15 BDs of passing Initial Review (Rule 21 F.2.a), or 15 BDs from applicant's request after passing Supp. Review (F.2.e) • 90 Calendar Days are allowed for negotiation and signing of the GIA (F.2.e)	For ZNE applications, deliver draft GIA to applicant the same day as the application being deemed complete, allowing applicant to review the GIA concurrently with the study process. Then, auto-populate the draft GIA with study results, allowing reduction of time for negotiating the final GIA to 45 Calendar Days (down from 90 CDs from provision of the GIA under current rules). Utilities could frontload delivery of 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 was previously available with the SCE Power Clerk portal. Once Fast Track Review is completed, the draft GIA can be auto-populated with the relevant results and sent automatically to the applicant.

Party Positions:

PG&E:

PG&E supports Proposal 19-a in lieu of Proposal 19-e because the months of streamlining introduced by allowing application submittal based on project address will outweigh the days of timeline adjustments proposed here. Proposal 19-e requires significant process and technology improvement in each of the steps and only potentially results in days of timeline difference.

PG&E currently has three interconnection portals: Customer Connections Online (CCO) for Rule 21 Export and Wholesale Distribution Tariff, ACE-IT for all non-Standard NEM Rule 21 projects and Standard NEM. These portals were developed at different times due to program volume increase requiring new technologies that older portals like CCO were not able to provide. PG&E is actively working toward a single portal with increased functionality for all project types by 2021 (as stated in Proposal 19-a).

Until the single portal project is completed, queueing must be equitable across PG&E's portals until all portals are combined. If automated application review and queueing was implemented in ACE-IT, CCO would also need it in order to maintain equitability and that would not be feasible nor a prudent investment right now because CCO will be retired by 2021.

Projects under 30 kW like Standard NEM and Standard NEM Paired Storage are far less complex than projects above this size. These projects require more detailed review that cannot currently be automated to the same level. An important distinction is ZNE projects are greenfield, while Standard NEM are installed on existing PG&E services. PG&E's SNEM study automation relies on the existing service being mapped to a specific node in our GIS and utilizes the system information at that node, which greenfield projects do not have. The smaller size projects automatically pass screens in the Initial Review, while larger projects do not consistently pass these screens and need an engineer review.

Allowing applications based on project address is already planned for completion in December 2021 and will streamline the process for all ZNE projects, regardless of size, by allowing the submission of an interconnection application months earlier in the project lifecycle.

Regarding study automation using the ICA, the ICA results are not real time and only maps the primary voltage system. It does not take into account secondary voltage characteristics like transformer size, which are critical to SNEM's automation as stated above.

There is no need to adjust the interconnection agreement negotiation timeline from 90 to 45 CD. Actual interconnection experience indicates that typically, negotiation takes far less than 90 CD and customers typically need much longer to review internally with their managers and legal teams than PG&E does. When PG&E delivers a GIA, it is very close to the final version because all PG&E aspects are pro forma language or directly inserted from the study results. Adjusting the allowed negotiation timeline doesn't actually make the interconnection go faster.

PG&E is focused on maximizing the effects of its technology enhancement projects by streamlining and automating the phases of interconnection that all Interconnection Requests go through such as application submittal and application review, where possible. While frontloading the GIA and auto-populating the GIA with study results would be a helpful automation for both PG&E and customers, not all interconnection requests make it to the GIA phase, so only a portion of projects would benefit from this enhancement.

SCE:

As discussed within the Working Group meetings and further discussed here, projects developed in support of Title 24 energy efficiency standards are inherently no different electrically than any other interconnection project. Projects developed in compliance with these standards send electrical power to the grid just like any other generation project and can create safety and reliability system concerns just like any other generation project. Thus, it is not appropriate to distinguish projects developed under Title 24 energy efficiency standards from any other interconnection project and they should be subject to the same system reviews so as to ensure grid safety and reliability.

It is not possible or practicable to implement a separate and distinct technical evaluation process for projects designed to meet ZNE building code requirements.

In order to ensure that an automation tool (or automated process) adequately evaluates safety and reliability issues such as thermal overloads, voltage control, and protection, it is necessary to evaluate all generation projects regardless of their classification (NEM, Rule 21, WDAT). Attempting to require specialized automation schemes for projects developed to meet ZNE building codes is therefore inappropriate.

As acknowledged in Proposal 19-e, interconnection streamlining and system automation have both been discussed within Working Groups Two *and* Three with a Commission decision anticipated shortly (for example, Working Group Three resulted in a detailed automation proposal as developed by GPI with input by other parties). Since projects developed under Title 24 energy efficiency standards are no different than any other interconnection project, Commission decisions issued addressing automation and interconnection streamlining review will directly impact projects developed under ZNE building codes. Therefore, SCE views this proposal as duplicative. Furthermore, SCE already processes paired storage projects (Title 24 akin projects) between 10kW and 30kW within an average of 18 calendar days from Complete Package Date to Permission to Operate, with projects less than 10kW achieving an average of 16 calendar days.

SCE highlights that projects developed in compliance to Title 24 energy efficiency standards already receive NEM project processing as long as they are NEM eligible, including SCE's anticipated batch application process as discussed within SCE's response to CALSSA's Proposal 19-b that was highlighted by home developers as providing a clear processing benefit. In addition, projects developed to meet ZNE building codes below 30kW would be expected to go through an expedited system review consistent with projects currently processed under the NEM program. For larger sized projects (ex: >30kW) developed to meet ZNE building codes, additional system review would be expected consistent with interconnections processed through the NEM program. SCE disagrees with GPI's characterization of the discussion regarding size limits (for example, 30kW limit) as size limits were extensively discussed within Working Group Two Issue Eight. Through these discussions, several Rule 21 screens were refined to the 30kW limit (with GPI's support). It is concerning that GPI appears to now argue that the limit is not appropriate despite previous discussions.

SCE raises concern with Proposal 19-e if the proposal envisions a study regime that ignores project sizing and calls for the same system review process notwithstanding project size. As explained above, this approach is not appropriate as projects should be reviewed based on their specific technical characteristics to allow for a safe and reliable electrical grid and proper cost allocations as applicable.

SCE also believes a number of representations shown with the tables one and two would benefit from clarifications. First, SCE believes the comparison of ZNE to other programs is inappropriate because ZNE projects would be processed under requirements issued under Rule 21 **and** the NEM successor tariff. SCE also disagrees with representations regarding SCE's current level of automation. Although SCE has put in place several automation and process improvements for projects under 30kW, it would be a mischaracterization to represent SCE has "mostly automated Rule 21" for this project type as maybe assumed within GPI's proposal. In addition, it is unclear at this time if all projects built under Title 24 standards would only be processed through Rule 21 (for example, behind-the-meter "microgrid" type of projects can be processed through Rule 21 and likely under the NEM program, but in-front-of-the-meter projects could potentially be processed through wholesale distribution tariffs).

SCE also provides comments to Table 2: Automation elements introduced in Table 2 would require SCE to develop and implement interconnection tools at additional cost and systems that would only be utilized as proposed for projects built under Title 24 standards. As discussed within the prior comments, SCE is already implementing an automated processing tool (GIPT) and supporting processes that will be used to support and benefit all interconnection requests as compared to one specific project type (such as ZNE). SCE's GIPT development was performed with funds authorized within SCE's General Rate Case allowing the Commission to review this request compared to other funding requests and their respective customer benefit. Proposal 19-e does not offer any funding mechanism.

In addition, SCE currently does not have automated within its systems most of the specific system information needed to perform many of the Initial Review system screens in an automated manner. As one example, secondary line information is not automated in a manner to perform voltage rise/drop calculation or to perform short circuit calculations that would be necessary to perform the automated analysis of the Initial Review screens. SCE clarifies that ICA information is not used to evaluate any of the Rule 21 Initial Review screens. Finally, SCE also clarifies that for SCE, no existing automation exists in relation to Supplemental Review (SR) screens.

SDG&E:

SDG&E opposes this proposal. During 2019, SDG&E provided PTO to its NEM customers, on average, within less than three calendar days after it received a completed application, which includes the electrical release from the local Authority Having Jurisdiction. The average approval time for non-NEM projects during 2019 was less than four business days and the average approval time for NEM projects with a capacity greater than 30 kW was 2.1 calendar days. These key performance metrics clearly demonstrate that SDG&E is consistently ready to meet the needs and timing requirements of its customers.

SDG&E continuously seeks opportunities to refine and streamline its interconnection application process. Significant and costly efforts to "automate" the interconnection portals should not be viewed in a vacuum and should not be designed to accommodate only a very limited number of applicants at the expense of non-benefitting customers and/or ratepayers in general. In Table 1, the interconnection process is the same for NEM, ZNE, and microgrid. The process is driven by project size and not by either of those three categories. None of GPI's proposals would contribute to a faster interconnection application process than SDG&E currently provides to its customers. For various reasons, typically associated with larger and more complex projects, there are times when delays occur. This is precisely why SDG&E encourages customers installing these sorts of projects to follow the guidance offered under Section D.13.b. of Rule 21, which states, in part:

> Applicants that include non-inverter-based Generators. Generators with non-Certified Equipment and/or Interconnection Requests that are anticipated to require new services (i.e., NEM-A) and/or the design and construction of Interconnection Facilities or Distribution Upgrades should plan to submit a completed Net Energy Metering Interconnection Request including all supporting documents sufficient for Distribution Provider to start the review process in Section F.2.a without waiting for the final inspection clearance. Applicants with such Generating Facilities are advised to submit their Interconnection Request at least six (6) months in advance of their planned Commercial Operation Date. Depending on the size and location of these Generating Facilities, additional time for review may be required and could include Supplemental Review, an Interconnection Impact System Impact Study and an Interconnection Facilities as set out in Section F. The advance submission of the Interconnection Request will better accommodate Distribution Provider's review and studies in a manner consistent with the timelines established in this Rule that may be required to complete the processing for these types of Interconnection Requests.

In 2019, interconnection applications for new home construction projects made up approximately two percent of the total interconnection requests received by SDG&E during the year. SDG&E anticipates that ZNE building codes will not cause a significant increase in the overall average annual interconnection requests it has received during the last several years. Because the processing of an interconnection application for projects operating under ZNE building codes is no different than the process for an otherwise similarly situated non-ZNE project from an interconnection perspective, SDG&E expects these projects, regardless of size, will also not have a negative impact on its already highly expedited approval timing going forward.

Based on all of the above, SDG&E asserts that GPI's automation proposals will not achieve further benefits within SDG&E's service territory in support of overall streamlining of interconnection application process and may instead interfere with the effectiveness of the current process.

Tesla:

Tesla supports efforts to streamline interconnection for projects of all scales where such streamlining is technically feasible and reasonable. As with the discussion regarding the development of SLD templates in the ZNE context, here again Tesla is unclear on why the ZNE criterion would systematically distinguish a project from other projects deployed in the non-ZNE context such that additional streamlining can be pursued for the ZNE associated projects that wouldn't be equally applicable to non-ZNE projects. In other words the mere fact that a project is being deployed on a ZNE facility or premise does not in of itself create incremental opportunities for streamlining that wouldn't also be relevant more broadly. To the degree there are opportunities to streamline the process for larger sale projects, those opportunities should be actively considered regardless of whether the context is ZNE or not.

GPI:

GPI response to SDG&E: GPI acknowledges, based on data that SDG&E has shared to date, that it is not experiencing the same problematic delays with interconnection that SCE and PG&E have experienced over the years. As such, the recommendations GPI has offered apply more fully to SCE and PG&E than to SDG&E.

GPI response to SCE: Unfortunately, much of the discussion over the issues of interconnection streamlining and automation have devolved to parties speaking past or over each other. GPI has directly addressed the concerns SCE raises in its comments here, a number of times. We do so again as follows:

- The Commission scoped ZNE interconnection streamlining as Issue 19 in order to determine whether the state's new focus on ZNE, as a new major policy initiative, required further interconnection streamlining to avoid interconnection becoming a major hurdle for ZNE mandates. The Commission is aware that interconnection is often the single biggest hurdle for DER in general, and that it will likely be a hurdle for larger ZNE projects also. GPI agrees that 30 kW and under DER (including ZNE) do not currently face significant issues with respect to interconnection, since there is a partially automated interconnection process available for these types of projects.
- GPI also agrees that ZNE projects are not different from non-ZNE projects from an engineering or design perspective. The Commission's point, however, in scoping interconnection streamlining for ZNE was to identify and remove potential hurdles for ZNE mandates, but also to provide more incentive for buildings to become ZNE. Easier interconnection means more ZNE.
- GPI's primary recommendation was for utilities to consider to what degree automation procedures already being used for projects 30 kW and under could also be applied to ZNE projects larger than 30 kW, without creating engineering or safety issues. SCE has claimed that they can't go beyond 30 kW, for ZNE or any other types of projects, because the 30-kW limit was negotiated two years ago in Working Group 2. SCE and other utilities refused to answer the question from GPI, posed on a

number of occasions, specifically why at least some of the automation measures applicable to projects 30-kW and under cannot be applied to at least some ZNE projects over 30 kW.

- SCE is incorrect in stating that streamlining and automation were discussed extensively in previous working groups. They were raised, and some discussion was had, but discussion was then tabled (as described in the WG2 Final Report) for later more robust discussion – including for Issue 19! It is due to this earlier direction by the Energy Division staff and the Working Group that GPI has revived and expanded upon earlier proposals for streamlining and automation in the context of Issue 19.
- GPI and the Clean Coalition developed a semi-comprehensive review of potential streamlining and automation options for Rule 21 interconnection, which was attached to the Working Group Two final report as Appendix A. The WG2 Final Report states, specifically (p. 85): "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."
- It is now two years since that final report was issued and we still have not had a robust discussion of automation options for interconnection. The utilities keep claiming such discussions are out of scope and the Commission keeps deferring full discussion to a later date.
- It is now almost a decade since the Commission itself (Energy Division staff first raised the "Interconnection 3.0" automation discussion) first began discussing automation. It is time for the Commission to issue more definitive guidance on this key set of issues.
- SCE is mis-reading GPI's proposal. It asks IOUs to consider to what degree streamlining and automation of interconnections for projects under 30 kW may apply to ZNE projects over 30 kW. There is nothing in GPI's proposal about "casting aside" these limits. Rather, GPI is asking for a considered investigation by IOUs regarding what additional streamlining and automation may apply to larger-than-30-kW ZNE projects as well as those under 30 kW. And that is entirely in keeping with the Commission's scoping language of this issue.

GPI response to PG&E: GPI appreciates PG&E's substantive response to its Issue 19 proposals. However, we disagree with PG&E's conclusions for the following reasons:

- GPI's primary recommendation was for utilities to consider to what degree the 30 kW and under expedited interconnection process (which enjoys an 18-day average from Complete Package until Permission to Operate for SCE, as reported by SCE in its comments on the Issue 19-e proposals) could include ZNE projects over 30 kW. State policy has mandated ZNE for new residential multi-story and will soon do so for commercial buildings, many of which will require systems over 30 kW to meet this mandate. As such, state policy highly favors expedited interconnection for ZNE projects of all sizes where feasible.

- PG&E has not answered GPI's specific question, posed on a number of occasions, why at least some of the automation measures applicable to projects 30-kW and under cannot be applied to at least some ZNE projects over 30 kW.
- Projects over 30 kW can take far longer than projects less than 30 kW for interconnection. Large behind-the-meter and front-of-meter DER interconnections take 6-9 months and can take more than a year sometimes for the GIA to be signed. These longer timelines will apply to larger ZNE multi-unit residential buildings and commercial building projects. The need to speed up interconnection for these projects is why GPI has proposed its streamlining and automation recommendations.
- PG&E does not quantify the time savings it expects from Proposal 19-a other than stating it will be "months." It is not clear how Proposal 19-a will result in months of reductions in processing time so we request more data on this statement.
- In contrast, GPI did quantify the expected time savings from its proposals in the Final Report of Rule 21 Working Group Two, Appendix A, as follows:

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

- As is apparent from this figure, the Proposal 19-e recommendations, reducing the completeness review dramatically, and frontloading GIA offer and negotiation by months, could indeed reduce average interconnection timelines for larger ZNE projects by "months."
- Interconnection changes made in the current round of the Rule 21 proceeding must be made in keeping with ZNE goals and mandates over the next decade. Rule 21 proceeding cycles are at least seven years in duration, so the earliest the next Rule 21 reform cycle could be completed will be around 2027, based on the duration of the last two reform cycles. Accordingly, it is imperative that the utilities and the Commission "think big" in terms of interconnection streamlining for ZNE, since actions taken in this proceeding now will have a strong impact on state policy for the next decade.

Issue 29

Should the Commission establish a forum, either within this proceeding or externally, to develop interconnection safety standards to address safety and environmental risks as the interconnection of distributed energy resources devices grows?

Proposal Summary

Proposal 29-a: The Commission Should Solicit Input in the Future. Within six months after completion of the Rule 21 Working Group Four report, the Commission should issue a ruling soliciting input on safety, environmental, and other issues [safety and environmental risks] related to interconnection of DERs, to be discussed in a future Rule 21 Working Group, or in another forum. Energy Division should periodically solicit and maintain a public list of items proposed by parties to help judge whether a separate rulemaking forum is needed. Adoption of this proposal shall not foreclose the ability of stakeholders to submit motions to the Commission requesting more expeditious consideration of interconnection issues that may emerge and to have those motions considered outside of the schedule envisioned herein.

Supported by: CALSSA, CESA, Clean Coalition, IREC, Tesla, PG&E, SCE, SDG&E
Opposed by: <none>

Discussion

Most Working Group participants agree that a separate forum to address safety issues related to interconnection of DERs is not needed because the current Rule 21 Working Group process meets the needs suggested by this issue. Rule 21 is needed to help ensure interconnections do not impair the safety and reliability of a distribution provider's system and to guide the growth of distributed energy resources.

Other forums also exist to address safety of DERs, such as the upcoming Rule 21 Expedited Dispute Resolution process,[44] where issues regarding the application of existing interconnection rules and the actions required under those rules can be resolved to ensure safe and reliable interconnection. The Interconnection Discussion Forum is another venue where questions and practices can be addressed that do not require a formal decision on modifications to the tariff language.

Environmental issues are not covered by Rule 21. This proceeding and its potential successor are not the appropriate venue to consider environmental issues.

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44 On October 12, 2017, the Commission approved Resolution ALJ-347 establishing an Expedited Interconnection Dispute Resolution Process; see
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M197/K421/197421608.pdf

There are no further Rule 21 Working Groups or Rule 21 scoped issues scheduled for discussion in the current phase of the proceeding after Working Group Four completes in August 2020. Working Group members recommend allowing some time to pass before establishing a new list of interconnection topics, including topics related to application of existing interconnection rules and the actions required under these rules to ensure safe and reliable interconnections.

Party positions:

SDG&E:

Although SDG&E is listed in support of this proposal, SDG&E does not believe that a forum is necessary to develop standards pertaining to safety and environmental risks specific for the interconnection of DER. The Commission, standards development organizations, the DER industry, and the utilities have worked diligently over the years to adopt standards, protocols, testing, and certification to address safety and environmental risks. There are numerous safety standards in various sources that SDG&E applies to all aspects of its working practices and procedures. SDG&E believes that the existing tariff Rule 21, other industry standards, existing SDG&E internal standards and standard operating practices adequately address safety and environmental risks of all types of projects including generator interconnection projects. Because of these standards and practices, the utilities have safely interconnected countless DER and continue to do so. However, the Administrative Law Judge could issue a ruling soliciting input on safety and environmental issues related to interconnection of DERs nine months after the Working Group 4 report is filed. SDG&E is always open to reviewing safety and environmental concerns, should parties identify any at that time.

IREC:

IREC supports this proposal because there was no specific need identified for a new forum. IREC believes that Rule 21 is inherently a set of safety standards for interconnection. No party identified a particular gap in environmental protection that needed to be addressed in a new forum. IREC supports the Commission actively engaging on interconnection improvements on an ongoing basis. The existing Interconnection Discussion Forum provides a venue to discuss needed changes but as technologies and the market for DERs evolves it is important to recognize that Rule 21 needs to evolve with them. We thus support having the Commission proactively address those issues in a timely manner. The proposal suggests “allowing some time to pass before establishing a new list of interconnection topics.” IREC does not believe this should be construed as a constraint on the Commission’s ability to move swiftly to address interconnection issues as they arise.

Issue F

What interconnection rules should the Commission adopt to account for the ability of Distributed Energy Resource Management Systems (DERMS) and aggregator commands to address operational flexibility need?

Proposal Summaries

Proposal F-1. Determine whether a DER operational alternative would be a sufficient mitigation for operational flexibility constraints. This proposal only applies after a Commission decision is taken on operationalizing ICA values within Rule 21 pursuant to the proposals by Rule 21 Working Group Two on Issues 8 and 9. If the output of a generating facility being interconnected is larger than the ICA values for that location with operational flexibility constraints taken into account (ICA-OF), but smaller than the ICA values without operational flexibility constraints taken into account (ICA-SG), then the distribution provider shall determine whether a DER operational alternative would be a sufficient mitigation for operational flexibility constraints, consistent with the Commission decision on operationalizing ICA values within Rule 21.

Initiating proponent: CALSSA
Supported by: Clean Coalition, Public Advocates Office, PG&E, SCE, SDG&E
Opposed by: <none>

Proposal F-2. Develop a Template Aggregator Agreement. The Commission should invite utilities and non-utility parties to submit a consensus template Aggregator Agreement or different proposals for a template Aggregator Agreement, no later than four months after a final Commission decision on Working Group Four issues.

Initiating proponent: CALSSA
Supported by: Clean Coalition, Public Advocates Office, PG&E, SCE, SDG&E
Opposed by: <none>

Proposal F-3. Establish a Smart Inverter Operationalization (SIO) Working Group. A CPUC-led SIO Working Group should be tasked with developing technical, regulatory, and operational implementation guidelines for high priority use cases, including operational flexibility need. The SIO Working Group could be an entirely new entity, or could be added to the scope of the existing SIWG, as discussed in Proposal F-4. For the purposes of this proposal, smart inverter operationalization means that smart inverters are actually in-use by grid operators to manage the distribution grid, with all required equipment deployments, rules, and tariffs completed and operational for a given use case. The scope of the SIO Working Group should include: (1) compile a comprehensive list of smart inverter use cases and establish priorities; (2) establish guidelines for all elements required to operationalize each specific high-priority use case; and

(3) integrate the guidelines for high-priority use cases into functional requirements for utility and third party SIO equipment.

Initiating proponent: Public Advocates Office
Supported by: CALSSA, Clean Coalition, PG&E, SCE, SDG&E
Opposed by: <none>

Proposal F-4. Establish Forum and Timing for SIO Working Group. The Commission should establish the SIO Working Group in 2020 within the Distribution Resources Planning (DRP) proceeding as a high priority to support work in multiple related proceedings.

Initiating proponent: Public Advocates Office
Supported by: CALSSA, Clean Coalition
Opposed by: PG&E, SCE

Proposal F-5. Include SIO as an Element of Grid Modernization. Smart Inverter Operationalization as Element of Grid Modernization. Smart Inverter Operationalization (SIO) is required to address the question posed by Issue F, and SIO requires coordination across multiple Commission proceedings. The Commission should include SIO as an element of Grid Modernization and establish the DRP proceeding as having overarching authority on SIO. SIO tasks within the DRP proceeding should include developing an SIO Plan, addressing the merits of operational flexibility compared to its potential adverse impacts of DER deployment, and inclusion of DERMS and SIO roadmaps within utility Grid Modernization Plans.

Initiating proponent: Public Advocates Office
Supported by: CALSSA, Clean Coalition
Opposed by: PG&E, SCE

Background

Issue F comes before Working Group Four at an important milestone relative to Commission and statewide efforts to integrate distributed energy resources (DERs) into the electric distribution system. Barring future Commission revisions, all smart inverter functionality capability has now been adopted by the Commission, with the exception of Phase 3 functions 4 and 7,[45] and capability is required of all new DERs installed per applications received on or after June 22, 2020.[46] This milestone means that all new inverter-based DERs will be deployed with

[45] Phase 3 Function 4 is Set Real Power Mode and Function 7 is Dynamic Reactive Current Support Mode.
[46] While Functions 4 and 7 are defined in D.16-06-052, implementation deadlines have not been set for these functions because they have not been incorporated into IEEE 1547. See Commission Resolution E-4898, p.40. Phase 3 functions 5 and 6 are already required per Rule 21 Section Hh. (See SCE Rule 21, sheets 150-151.)

well-defined new capabilities that have the potential to aid DER integration. However, only capabilities are required at this time; activation and performance requirements are still pending discussion and development. In other words, new DER integration tools will be deployed at the same time and location as new DERs with smart inverters that have Phase 3 functional capabilities.

The deployment of smart inverters in California represents the culmination of a process initiated in 2011. The Smart Inverter Working Group (SIWG) was formed in 2013 and provided recommendations on Phase 2 DER communications based on Institute of Electrical and Electronics Engineers (IEEE) 2030.5 protocol and the development of a shared usage guide which became known as the Common Smart Inverter Profile (CSIP) on February 28, 2015, and Phase 3 functions based on IEEE 1547 standard in March 2016.[47] SCE, PG&E, and SDG&E were, and continue to be, active SIWG members. The Commission adopted the SIWG recommendations in Commission Resolutions E-4832 and E-4898, but details regarding implementation have required, and continue to require, numerous SIWG stakeholder discussions and associated Commission action.

The Commission recognizes the potential benefits of specific smart inverter functions in promoting their development and deployment, as discussed within the Rule 21 and DRP proceedings.[48] Smart inverter functionality will both facilitate greater amounts of DERs on the distribution system and enable DERs to provide services that have traditionally been provided by power plants, grid stabilization equipment, and grid monitoring devices. SCE comment: Is there support that PAO can provide for this assertion? Is that stated within the 2017 Commission DER Action Plan? If there is reference, may be helpful to put in if reference is available. These capabilities are reflected in the following 2017 Commission DER Action Plan objective:

> By 2020, fully operationalize advanced (beyond Phase 1) smart inverter functionalities to enhance the integration of DERs into the grid.[49]

In their recent General Rate Case (GRC) applications, each IOU discussed DERMS and related communication system deployment and the associated costs. This provides status and planning information on the deployment of DERMS and associated communications and IT infrastructure, which is useful for developing a Commission resolution for Issue F. Annex 5

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[47] A history of SIWG, including Phase 2 and Phase 3 recommendation documents which define each Phase 3 function, are include as Attachment E to Decision (D.)16-06-052. Phase 1 autonomous smart inverter functions were approved by the Commission in D.14-12-035 and become mandatory for DER interconnections as of September 8, 2017.

[48] See ALJ Ruling dated June 11, 2013 in R.11-09-011, Attachment 1, pp. 2-4; D.14-12-035, pp. 14-15; and D.18-03-023, the DRP Grid Modernization Decision, which shows smart inverters as a "technology to mitigate [DER integration] challenge" for five of the ten potential system/integration challenges of DER listed. See Appendix C, pp. 7-11.

[49] California's Distributed Energy Resources Action Plan: Aligning Vision and Action, May 3, 2017, p. 5, Action Element 2.13. Also see OIR (R).17-07-007 dated July 21, 2017, p. 6.

contains a brief summary for each IOU's most recent GRC request related to Issue F, with citations for stakeholders who seek additional details.

DERMS and ICA Operational Flexibility Constraints

During the Integration Capacity Analysis (ICA) Working Group in 2016-2017, participants developed methodology for the Integration Capacity Analysis.[50] The Working Group agreed that ICA should be based on five constraints – thermal limits, steady state voltage, voltage fluctuation, protection, and operational flexibility.

The operational flexibility constraint was particularly difficult. The concept of operational flexibility within the ICA context is that utilities need the flexibility to reconfigure circuits during maintenance or unplanned outages. Because customers sometimes get switched to adjacent circuits, the impact of DERs on circuits that they might be connected to must be studied, even if they are not connected to those circuits in normal circumstances.

During the ICA Working Group, when ICA was still in the development phase, Working Group participants considered in general terms alternative mitigations of the ICA operational flexibility screen incorporating DERMS and related communication capabilities. But a workable methodology was not developed to fully analyze the differences between ICA system limitation values without operational flexibility compared against limitation values incorporating DERMS and related communication capabilities providing operational flexibility.

When an actual project is studied, utility engineers take into account the likelihood of being connected to an adjacent circuit, the availability of other switching options, and the extent of the risk if a DER is connected to the circuit in question. Utilities did not come up with a way that these factors could be applied accurately across the grid in the ICA calculations. The utilities proposed that the threshold of the operational flexibility constraint should be the DER size above which power could back-feed across a SCADA-controlled switching device. In finalizing the ICA Working Group Final Report[51], non-utility stakeholders agreed to support the proposal as an interim methodology, but recognized that further rules and refinement would be required. The report stated:[52]

> These WG members additionally recognize that one possible solution to this restriction could be that a utility may in the future utilize communication means to send commands directly to DER systems or may send communication through third-party aggregators to DER systems as to mitigate the issues related to operational flexibility. However, that capability will only be available after the CPUC develops rules for contractual relationships between utilities and DER system owners through a

[50] The ICA Working Group was scoped in the DRP Rulemaking 14-08-013.
[51] ICA Working Group Final Report; https://drpwg.org/wp-content/uploads/2016/07/ICA-WG-Final-Report.pdf
[52] Ibid, page 27

> stakeholder process, or such contracts are found mutually agreeable to counterparties and do not violate existing regulations.
>
> Finally, these WG members feel that further refinement of the operational flexibility criterion will include differentiating between different types of SCADA-operated devices, and recommend that IOUs include this data in their efforts to clean up data in preparation for the first system-wide rollout.
>
> The IOUs would also like to examine whether the operational problem may be solved in future years through the implementation of other potential solutions. Such solutions include the implementation of future DERMS, which would provide high levels of visibility and control and would mitigate the system flexibility limitation.

Both utility and non-utility Working Group participants acknowledged at the time that a solution to operational flexibility will come when communications is enabled between utilities and DERs such that DERs can be curtailed during abnormal grid configurations.

In addition to addressing operational flexibility in the ICA context, when DERs provide voltage control, energy on demand, or other grid support services, they increase the utilities' operational flexibility. Grid support from DERs has been advanced in pilot projects, in the local capacity requirements process, and in the DRP Distribution Investment Deferral Framework (DIDF). The Integrated Distributed Energy Resources (IDER) proceeding, R.14-10-003, is considering tariffs for grid support from DERs. The DER Action Plan and continued Commission emphasis on distribution deferral creates an expectation that utilities will increasingly rely on distributed solutions for grid management.

DERMS and Communications for Aggregator Commands

The smart inverter deadline for communications capabilities became effective on June 22, 2020. All DER interconnection applications submitted after that date must now include: (a) the capability to communicate with utilities using the Phase 2 communications protocol verified by the IEEE 2030.5 standard; (b) conformance with the Common Smart Inverter Profile (CSIP) developed by the IOUs in compliance with SIWG phase 2 recommendations; and (c) the capability for DER output to be reduced by communication of a remote command.

In addition to the smart inverter capabilities required of DERs, utilities must develop the capability to issue and deliver commands to the DERs, and also to monitor DER status and performance. Utilities have completed pilot studies[53] with DERMS that perform these functions, but PG&E and SDG&E have not selected a standard DERMS specification or implemented DERMS on a widespread basis. SCE has already developed initial DERMS specifications as part of SCE's proposed Advanced Distribution Management System. In this period when utilities are

[53] EPIC 1 SCE Advanced Technology Project (ID PS-13-014 Integrated Grid Project 2018)

developing their plans for rolling out DERMS, the Working Group is tasked with developing rules for how DERMS will be applied to the operational flexibility ICA constraint.

Beyond the technical capabilities, there must be a standard contractual relationship between utilities and customers wishing to use this functionality. Rule 21 Working Group Two considered aggregator agreements in Issue 6. A subgroup of the full working group discussed provisions that may be needed in a standard agreement. The subgroup made progress identifying the types of items that need to be included, but did not come to agreement on what the terms of those items should be. As discussed in Proposal F-2, stakeholders propose to conduct a series of meetings and put forth template aggregator agreement(s) following publication of this Working Group Four Final Report.

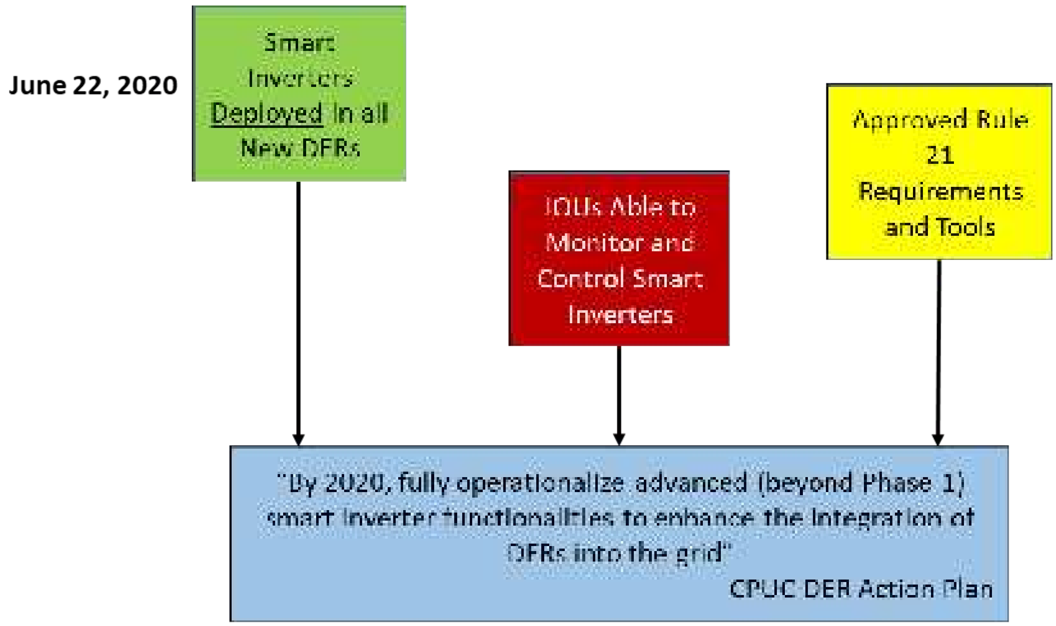
As stakeholders address the use of DERMS and DER communications for the purpose of addressing the operational flexibility ICA constraint, the same solutions are applicable to the other interconnection use cases of smart inverters that were identified by Rule 21 Working Group Three for Issue 27.

Smart Inverter Operationalization (SIO) and DERMs Technology Deployment

Issue F was first proposed by the California Solar and Storage Association (CALSSA) as new scope for Order Instituting Rulemaking (R.)17-07-007 and added to the scope of Working Group Four in the Amended Scoping Memo.[54] During Working Group Four, CALSSA provided initial versions of Proposals F-1 and F-2 on rules for addressing mitigation of ICA operational flexibility constraints with DERMs, as well as template aggregator agreements.

During Working Group discussions, the Public Advocates Office offered the viewpoint that it would be difficult to develop rules consistent with the defined scope of Issue F without a parallel discussion regarding the deployment timeline for DERMS technologies and other IOU assets potentially required for smart inverters to address operational flexibility needs. Public Advocates Office developed Figure F-1 to illustrate the three elements required to fully operationalize smart inverters: (1) deployment of DER/aggregator equipment, (2) deployment of IOU equipment, and (3) adoption of rules governing the interconnection and use of smart inverters. These three elements would enable delayed fulfilment of the Commission's DER Action Plan target to operationalize smart inverters by 2020, and would allow smart inverters to help address operational flexibility needs.

[54] Amended Scoping Memo filed November 16, 2018 in R.17-07-007, pp. 2 and 8.



"Operationalize" means used by Grid Operators to mange the grid

There was general agreement among Working Group participants on these three elements, and agreement that rules alone would be insufficient. Participants discussed whether interconnection rules proposed for Issue F could be implemented before DERMS and other technology capabilities were determined and/or deployed. There was general agreement that SIO requires coordination of technology, rules, and tariff development, but there was disagreement among parties as to whether consideration of SIO was within the scope of Issue F. And there was general recognition that there was insufficient time in Working Group Four to address these issues.

Given this discussion, CPUC Energy Division staff stated that proposals for smart inverter operationalization were within the scope of Issue F. The Public Advocates Office, as initiating proponent, then proceeded to further develop proposals F-3, F-4 and F-5 to address the larger SIO issues. Proposal F-3 establishes the basic concept and scope of a future SIO Working Group, but parties had diverging positions on the forum and timing for the proposed working group, so the forum and timing were separated into Proposal F-4 in the interest of consensus on the basic concept. Proposal F-3 also includes perspectives on whether the SIO Working Group scope should be expanded beyond SIO to cover operationalization of DERs and microgrids more broadly. And Proposal F-5 reflects the Public Advocates Office recommendation that the best way to achieve SIO in a timely manner is to synchronize the development of all four "precursors" to SIO as part of the DRP re-evaluation of Grid Modernization in 2021. These precursors include the three mentioned above—interconnection rules, DERMs deployment, and smart inverter capabilities—plus the long-standing issue of utility compensation for DERMs development.

As Working Group Four progressed, the Public Advocates Office further realized that Issue F represents just one use-case of the larger issue of SIO, and that Issues 4, 9, and 27 addressed by Rule 21 Working Groups Two and Three were also related to the larger issue of SIO.[55] SIO coordination also relates to Issue 28 on coordination with the Integrated Distributed Energy Resource (IDER) proceeding, to ensure operational requirements are aligned with any relevant valuation mechanisms.[56] Proposals F-1 and F-2 also build upon the results of both Working Groups, so that references to Working Groups Two and Three are part of the discussion of all five Issue F proposals.

Discussion

Proposal F-1. Determine Whether a DER Operational Alternative Would Be a Sufficient Mitigation for Operational Flexibility Constraints. This proposal only applies after a Commission decision is taken on operationalizing ICA values within Rule 21 pursuant to the proposals by Rule 21 Working Group Two on Issues 8 and 9. If the output of a generating facility being interconnected is larger than the ICA values for that location with operational flexibility constraints taken into account (ICA-OF), but smaller than the ICA values without operational flexibility constraints taken into account (ICA-SG), then the distribution provider shall determine whether a DER operational alternative would be a sufficient mitigation for operational flexibility constraints, consistent with the Commission decision on operationalizing ICA values within Rule 21.

Initiating proponent: CALSSA
Supported by: Clean Coalition, Public Advocates Office, PG&E, SCE, SDG&E
Opposed by: <none>

This proposal will potentially allow more DER capacity to be added to a circuit while still remaining within hosting capacity limits. The proposal addresses the problem that the ICA operational flexibility constraints may be severely limiting for many locations even if circuit reconfigurations at that location are rare. This leads to underutilization of existing hosting capacity. Also, DERs may be able to provide some grid support more effectively and/or at a cheaper cost than traditional approaches, but systems have not been established to make use of those opportunities.

Under the Rule 21 Working Group Two Issue 8 proposal, if the generating facility output is greater than ICA-OF, the distribution provider will consider site-specific conditions in Supplemental Review to determine whether mitigations are needed to address operational

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[55] Numbered issues were defined for R.17-07-007 in scoping memos dated October 2, 2017 and November 16, 2018.
[56] Amended Scoping Memo filed November 16, 2018 in R.17-07-007, p. 7.

flexibility. If mitigations are needed, the utility shall determine whether mitigation can be achieved via a DER operational alternative. If a DER operational alternative is a viable mitigation and is accepted by the customer, a provision shall be included in the interconnection agreement. Such an alternative may include the following types of actions during defined periods or abnormal grid configurations:

- Limiting or eliminating exported energy
- Modifying advanced inverter functions
- Monitoring and reporting
- Other functionality that supports grid operations

The provision shall contain terms for expressing the non-binding anticipated frequency and magnitude of curtailment or modification of settings and terms for notifications to the customer about expected and actual curtailments.

In addition to facilitating interconnection in challenging situations, smart inverters have capabilities to provide some grid support functions that can increase operational flexibility. Although grid support use cases may fit within the defined scope of this issue, the Working Group is not considering recommendations for those use cases because they are being considered in other Commission proceedings, including the DRP proceeding (R.14-08-013) and the IDER proceeding (R.14-10-003). As a principle, most Working Group participants agree that utilities should seek opportunities to utilize distributed energy resources, directly or through aggregators, to perform grid services that increase their grid management flexibility as may be approved or required by applicable Commission orders and dispositions.

Party Positions on Proposal F-1:

SCE:

SCE highlights that the underlying need supporting the ICA operational flexibility is to maintain grid safety in case of need for real time operation decisions. SCE is supportive of Proposal F-1 and believes it strikes an appropriate balance with evolving system capabilities.

PG&E:

PG&E is supportive of the proposal with the understanding that capabilities required to implement the operational alternatives suggested in the proposal are still under development and may not be available to all applicants initially. End-to-end pilots of operational systems would precede wider availability of operational alternatives.

Additional investments are required on the utility side in order to translate abnormal switching conditions into disconnect or curtailment commands and the Operational alternatives may evolve over time as new capabilities are deployed. Many of these foundational investments were identified in the PG&E Grid Modernization Roadmap in the last GRC[57], including the deployment of ADMS which will provide online power flows based on the real time system configuration and would allow for more precise dispatches based on real-time conditions.

Given the dynamic nature of system conditions it is not possible to predict all scenarios. As such, PG&E does not support any binding limit on the frequency or duration of curtailments.

SDG&E:

SDG&E supports this proposal with the contingency that there be no binding limitation on DER curtailment. The utilities cannot predict the system and operational needs regarding outages that are not planned. For this reason, SDG&E asserts that maximum flexibility is needed to realize the full benefits of DER is providing grid services to ratepayers without limiting or compromising system reliability. It will be difficult for operators to try to react to an operational condition, since it is hard to anticipate a disruption or the frequency of disruption on the distribution system.

SDG&E believes that setting up a "Demand Response style" program for controlling DER does not simplify the task of creating a DERMS management system. Demand Response programs simply enable on/off functionality, do not allow for varying levels of demand reduction nor do they enable the modification of smart inverter set points. It is possible that this solution is even more complicated than other alternatives as it attempts to determine a priori operational constraints for an indefinite planning horizon rather than computing dispatch constraints in real- or nearly real-time as part of operations.

From a distribution provider standpoint, we currently do not have a system in place that has the proposed features. A thorough analysis is performed on all new proposed generator projects. This analysis considers many factors, including the availability of circuit capacity and thermal ratings of each individual line segment. To allow for a more dynamic rating for bidirectional resources, a platform would need to consider all generators online, current switched state of the feeder, current thermal limits, and forecast load and generation for the future.

SDG&E does agree with parties that any proposal must include the provision for curtailing output without regard to other interconnection terms when any distribution circuit is in an abnormal operating state relating to either planned or unplanned outages. However, since outages can occur at any time a limitation on the number and extent of curtailments will impact SDG&E's operational flexibility and impact service restoration for our customers.

[57] PG&E GRC 2020 Ph I [A.18-12-009], Exhibit 4, Chapter 19, Grid Modernization Plan

Proposal F-2. Develop a Template Aggregator Agreement. The Commission should invite utilities and non-utility parties to submit a consensus template Aggregator Agreement or different proposals for a template Aggregator Agreement, no later than four months after a final Commission decision on Working Group Four issues.

Initiating proponent: CALSSA
Supported by: Clean Coalition, Public Advocates Office, PG&E, SCE, SDG&E
Opposed by: <none>

Smart inverter functionality can solve grid integration challenges, but some use cases may require contractual terms. If a customer uses a third-party aggregator to communicate with utilities, the aggregator must have a signed agreement with the utility to ensure the aggregator is capable of minimum requirements for managing customer communications with utilities. These minimal requirements shall include functional capabilities for providing aggregation service, cybersecurity protective measures, and management of customer privacy. This does not pertain to demonstration of smart inverter capabilities currently required of all customers. It pertains to actual communications established by mutual consent between utilities and customers. This agreement does not create any contractual obligation for the utility but rather only covers the responsibilities that aggregators have in terms of being a qualified communication aggregator in California.

In Rule 21 Working Group Two, participants of a subgroup discussed aggregator agreements and a draft template Aggregator Agreement produced by the utilities is included in the Working Group Two Final Report.[58] More work is needed to create a consensus document from this draft. The Working Group Two report states, "The Working Group proposes to develop forms and agreements to allow distributed energy resource ("DER") Aggregators to fulfill Rule 21 requirements. The draft template Aggregator Agreement appended to the Issue 6 proposal represents substantial progress toward that end, providing a basis for continued consideration."

Following the conclusion of Working Group Two, the Commission issued questions regarding the Working Group Two Final Report, including questions related to Aggregator Agreements. The Commission received party responses to those questions. These questions and answers are available as input on further work on a template aggregator agreement.

Minimal work on the topic of a template Aggregator Agreement was completed during discussion of Issue F in Working Group Four. Rather, parties propose to conduct a series of meetings and put forth a template aggregator agreement following publication of this Working Group Four Final Report.

[58] https://gridworks.org/wp-content/uploads/2018/12/Rule-21-Working-Group-Two-Final-Report-31oct2018.pdf; page 11.

The best process for submitting the results of those meetings to the Commission is not clear if there is disagreement on any of the provisions. A ruling from the Commission could invite different proposals but would require the Commission to prepare a ruling before receiving proposals.

Party Positions on Proposal F-2:

SCE agrees with CALSSA that an agreement needs to be in place. However, SCE believes that any continued discussions should be deferred until the Working Group Two decision is issued to account for any Commission action or directive on Issue 6 that may impact this effort.

PG&E supports the proposal to create the contractual basis for aggregator communication to utilities. PG&E believes that further development of the Aggregator Agreements should commence after the Working Group Two decision that will address Issue 6 where the Aggregator Agreement was previously discussed.

SDG&E agrees that an agreement needs to be in place. Currently no aggregator agreement model is in place and the responsibilities of all parties – utility, DER owner/operator, and aggregators – must be defined. Aggregator agreements must be established both for aggregators who solely wish to provide communication services for end DER as well as aggregators who wish to provide services to groups of DER resources for participation in markets. SDG&E is especially concerned that any aggregator agreements consider consumer protections to ensure that end DER users understand the nature of the agreements they are signing. SDG&E also notes that dispatching aggregation groups across multiple distribution feeders and interconnection points further complicates the process of DER constraint management and the *a priori* determination of any dispatch limits as envisioned in this proposal. As an example, SDG&E operations might need the ability to transfer specific DERs between aggregation groups for cutovers of portions of feeders.

Proposal F-3. Establish a Smart Inverter Operationalization (SIO) Working Group. A CPUC-led SIO Working Group should be tasked with developing technical, regulatory, and operational implementation guidelines for high priority use cases, including operational flexibility need. The SIO Working Group could be an entirely new entity, or could be added to the scope of the existing SIWG, as discussed in Proposal F-4. For the purposes of this proposal, smart inverter operationalization means that smart inverters are actually in-use by grid operators to manage the distribution grid, with all required equipment deployments, rules, and tariffs completed and operational for a given use case. The scope of the SIO Working Group should include: (1) compile a comprehensive list of smart inverter use cases and establish priorities; (2) establish guidelines for all elements required to operationalize each specific high-priority use case; and

(3) integrate the guidelines for high-priority use cases into functional requirements for utility and third party SIO equipment.

Initiating proponent: Public Advocates Office
Supported by: CALSSA, Clean Coalition, PG&E, SDG&E
Opposed by: <none>

To date, the Commission has promulgated smart inverter requirements that have only applied to inverter manufacturers, not IOUs. However, IOU control and monitoring of DERs via the IEEE 2030.5 client-server model requires new equipment owned by DER owners, aggregators (for aggregated DERs), and IOUs. Realization of smart inverter benefits will likely require the Commission to order the IOUs to take specific actions by specific dates, just as it has done for smart inverter manufacturers in the Rule 21 proceeding (in the context of inverter capabilities and not actual performance).[59] As a result, this proposal and also Proposal F-4 seek to establish a timely process for establishing new deadlines and/or target implementation dates through a new SIO Working Group.

A party's support of Proposal F-3 indicates that a party supports the need for an SIO Working Group, but does not imply support for the further issues in Proposal F-4 related to the SIO Working Group.

IOU comments on Issue F indicated that they believe it is difficult to formulate the required interconnection rules before required technologies such as DERMS are designed and/or deployed. IOU DERMS Roadmaps reviewed by the Working Group indicated a wide range of initial implementation dates:

- For SCE, a first use case will be deployed in 2021-2022.
- For PG&E, two key functions will be available in 2021: (1) telemetry to DERs (1MW and above) between a utility IEEE2030.5 Headend Server and a customer owned site gateway; and (2) dispatch of DERs (via the IEEE 2030.5 headend server) that are providing grid services as part of the Distribution Investment Deferral Framework.[60]
- SDG&E is focused on foundational capabilities necessary to implement a future DERMS and is continuing to develop and advance its grid management system from its existing Advanced Distribution Management System (ADMS) and microgrids in support of a future grid management system that includes DERMS. An updated and more complete roadmap is anticipated to be included as part of SDG&E's Grid Modernization Plan, which will be included in SDG&E's next General Rate Case (GRC) Application (scheduled to be filed in May 2022).

[59] The Commission established inverter requirements in R.11-09-011 and R.17-07-007 that must be met by interconnecting DERs which are codified in the Rule 21 tariff for each IOU, Section Hh. See D.14-12-035, D.16-06-052, and Commission Resolutions E-4898, E-4920, and E-5000.
[60] This provides the foundation for future communication to aggregators.

The primary objective of the SIO Working Group should be to develop the guidelines required for SIO and provide these guidelines as recommendations to impacted Commission proceedings. Meeting this objective entails four high-level scoping elements: (1) SIO use cases should be compiled and prioritized; (2) the top tier of high priority use cases should be evaluated to establish all requirements for SIO in each use case; (3) compile use cases into a "technical roadmap," and integrate the requirements developed for each use case tier into functional requirement descriptions; and (4) the SIO Working Group should develop recommendations to ensure that SIO is performed on a statewide basis that minimizes differences in the capabilities of each IOU.

Working Group Four members discussed the potential for a broader scope for the SIO Working Group, beyond SIO to operationalization of DERs and microgrids more broadly. This is expressed in PG&E's position on Proposal F-3 below.

For further details on the proposed SIO Working Group objectives and scope, see Annex 4.

Party Positions on Proposal F-3

PG&E:

PG&E supports Proposal F-3, and notes the following items which may enhance the proposed working group. This working group may benefit from broadening the focus to all Distributed Energy Resources providing distribution system service use cases and interconnection enablement use cases. The focus on Smart Inverters presupposes that utility control is required, but it is possible that the DERs can be controlled by third parties through their own proprietary communication protocols and backhaul networks and headend systems. Furthermore, microgrids and the ability to control microgrid generation assets through a microgrid controller, is not a smart inverter as defined here. While PG&E supports a working group that reviews use cases for DER assets overall and then reviewing the technical and process architectures required to enable those functions, limiting this to Smart Inverters only may not cover the breadth of capabilities that DERs can provide.

SDG&E:

SDG&E agrees with PG&E's comments on this proposal.

SCE:

SCE generally supports the need of the working group as proposed within Proposal F-3 subject to concerns raised regarding appropriate venue within SCE's response to Proposal F-4.

SCE notes, however, that SIO Working Group should focus on defining the interaction between utility and DER/aggregator to achieve high level industry outcomes. SCE is concerned that if a balance is not found within the SIO Working Group this would impede a potential SIO Working Group's ability to develop standardized use cases that are focused on the utility to DER/DER Aggregator interaction to enable smart inverter operationalization. Use case discussions and development, if not bounded by defined guide rails, tend to evolve in scope, especially when the use cases are technical in nature. SCE would like to minimize any discussion around IOUs' back-office architecture and technologies as this information can be confidential and sensitive in nature and the IOUs have different technology and infrastructure associated with IT back office systems.

SCE also notes that the SIO Working Group should perform an exercise of filtering the use cases to identify the use cases applicable to Rule 21 interconnection. The list developed by Public Advocates Office lists a number of use cases and SCE expects that some of these use cases will not be applicable to Rule 21 interconnection objectives consistent with focus of this Working Group.

CALSSA:

It is essential to create a forum outside of GRCs to discuss smart inverter operationalization and grid modernization. The utilities have successfully steered discussion of grid services from distributed energy resources to the Distribution Investment Deferral Framework, which will be chronically ineffective at maximizing the potential of DERs, while they undervalue those services in GRCs and get approval for massive amounts of spending. In other words, they get approval for non-DER approaches to grid management and then pull a small number of projects out of those spending plans rather than designing a DER-heavy approach to their grid management and modernization plans from the start.

The number of projects that get pulled out of their GRC plans by DIDF will always be small because timing constraints make it difficult to defer traditional projects after the traditional projects have already been selected and baked into the overall plan. Also, it is difficult for non-utility parties to convince the Commission to force the utilities to take a DER-heavy approach to grid management and modernization within the GRCs because there are many issues at play and it is not uncommon for GRC applications to be settled as a package.

A policy forum is needed to consider ways to maximize the potential of DERs for grid management and modernization. CALSSA supports creation of a working group. That working group could be relevant to multiple proceedings. It could be established in this proceeding in response to these Working Group recommendations. The Commission can also choose to issue a ruling in the DRP proceeding to make further use of the same working group. Either could happen first.

CALSSA is open to the suggestion to broaden the scope into a Grid Modernization Working Group, to include microgrid controls and other issues. This could be a series of informal conversations as a precursor to the Commission's 2021 revisit of the grid modernization decision. Parties need to talk about grid modernization under the leadership of Energy Division and outside of GRC settlement negotiations.

Proposal F-4. Establish Forum and Timing for SIO Working Group. The Commission should establish the SIO Working Group in 2020 within the Distribution Resources Planning (DRP) proceeding as a high priority to support work in multiple related proceedings.

Initiating proponent: Public Advocates Office
Supported by: CALSSA, Clean Coalition
Opposed by: PG&E, SCE

"Forum" refers to the CPUC proceeding that would provide oversight for the SIO Working Group, including setting the scope and schedule and acting on working group recommendations. "Timing" refers to the overall urgency or priority of SIO Working Group activity relative to multiple legislative, regulatory, and other objectives. There is disagreement in party positions about both forum and timing, including whether the working group should be established in 2020 and whether oversight should occur through the current or successor Rule 21 OIR, through the DRP proceeding, or through some other forum. In addition, there was disagreement regarding whether the scope of the working group should include more than SIO, for example whether the role of microgrids or DERs controlled only by aggregators should be within the SIO Working Group scope.

The SIO Working Group should be authorized and managed within the scope of a Commission proceeding, as opposed to the current SIWG which operates as an autonomous entity. The initiating proponent Public Advocates Office explains that the existing DRP Proceeding provides the fastest means of initiating this working group within the existing scopes of related proceedings.[61] Further details and justification for the proposed SIO Working Group formation, oversight, and timing are provided in Annex 4.

The schedules in several other proceedings drive SIO, and formation of the SIO Working Group as a high priority for two reasons. First, many proceedings could benefit from SIO Working Group recommendations as soon as they can be provided. Second, the lack of a new GRC application to review in 2020 and the first half of 2021 provides a one-time opportunity for parties that participate in GRCs to focus resources on SIO that would otherwise be occupied with supporting a major GRC case.

If the Commission does not act quickly to set targets or deadlines for IOUs to deploy their portion of IEEE 2030.5 control and monitoring systems, deployment will be significantly delayed. The results could include unnecessary ratepayer investments in SCADA based control and monitoring systems and feeder/substation-specific DER-driven upgrades that could

[61] Page 6 of the latest Scoping Memo in DRP issued January 9, 2020 includes revisions to the Grid Modernization process and interaction with GRCs as in scope topics.

potentially be avoided through strategic use of advanced smart inverter functions. If costly upgrades are approved while smart inverter capabilities are underutilized, it could reduce the perceived value of DERs in pending proceedings such as NEM 3.0.

Party Positions on Proposal F-4

SCE:

SCE disagrees with the Public Advocates Office's proposed procedural venue for the SIO Working Group. SCE believes it is inappropriate for the Public Advocates Office to recommend that the SIO Working Group be within the DRP proceeding on a number of grounds including: 1) the discussion of the creation of a working group overseen by the DRP should not be made within a separate rulemaking outside of the DRP; 2) DRP stakeholders are not present to comment on the validity of the proposal; 3) this topic is best suited for a new DER rulemaking and proceeding that focuses on the multitude of DER integration challenges holistically rather than another disparate DER proceeding; and 4) SCE disagrees with the Public Advocates Office's characterization of D.18-03-026 and the DRP Second Amended Scoping Ruling.

D.18-03-026 states "the Commission intends to formally revisit Grid Modernization in 2021" which eludes to the Commission possibly not seeing the need to revisit Grid Modernization within the DRP. It is more prudent to provide recommendations for Grid Modernization when the Commission decides to formally revisit that issue. The Second Amended Scoping Memo mentions nothing about Smart Inverters but instead continues the scope already established within the DRP and mainly focused on moving the LNBA avoided distribution cost use case to the IDER proceeding. Finally, D.18-03-026 established a framework for Grid Modernization by giving a definition, identifying technologies considered as Grid Modernization, and establishing a process for which Grid Modernization requests are reviewed. D.18-03-026 clearly states the GRC is the appropriate venue to discuss Grid Modernization investments where the IOUs provide a Grid Mod Plan (GMP) as an appendix with details that align with the technology categories within the Grid Modernization classification tables. D.18-03-026 makes no mention of debating the technical components of Grid Modernization technologies.

SCE also believes that the proposed working group would not be best served within a Rule 21 "Interconnection Rulemaking" due to the proposed expansive scope of the SIO Working Group addressing issues beyond safe and reliable interconnection and supporting processes, which have been the primary focus of interconnection rulemakings. Furthermore, SCE highlights that from its experience the SIWG within Rule 21 has looked to national membership and has not been California only membership. SCE believes that, should the Commission believe that the SIO Working Group is appropriate, the Commission should review the SIO Working Group within a separate DER successor rulemaking that focuses on DER integration holistically. On an interim basis prior to a final Working Group Four decision, the Commission could also direct the

IOUs and Energy Division to work together to establish the SIO Working Group on a voluntary basis and encourage parties along with other interested stakeholders to participate, especially given the material interconnection revisions contemplated by Working Groups Two and Three.

PG&E:

PG&E does not support Proposal F-4. The use of aggregated smart inverters to potentially defer distribution investments is already within the scope of the DIDF, and therefore there is no urgent need to identify additional "high priority use cases" within the context of the DRP. In addition, it would be inappropriate for a WG within the DRP to establish "...functional requirements for utility and third party SIO equipment", as such technical considerations are not consistent with the DRP scope.

Rule 21 currently contains all of the technical and policy-related record for smart inverters to date. By contrast, the DRP proceeding was developed to carry out the legislative mandate for the IOUs to file their respective Distribution Resources Plans and for the Commission to approve, or modify and approve, those plans. The IOUs filed their DRPs in July 2015, and they have neither been approved nor modified and approved.

PG&E could support a successor Rule 21 proceeding for the oversight of the proposed working group, based on the history of the SIWG, the established working group processes in Rule 21, and that utility subject matter experts already work on Rule 21. PG&E would recommend the working group not commence until working group 2, working group 3 and V2G issues currently outstanding in the Rule 21 proceeding be decided on and implemented, including the use of the ICA in interconnection.

Further, for timing, PG&E would respectfully request that this working group be deferred for at least a year. There is significant work being executed some critical priority related efforts: wildfire risk mitigation, 2020 and 2021 PSPS mitigation and operational improvements, and resilience related efforts as a part of the Microgrid OIR. PG&E would respectfully ask that it be allowed to focus on these priorities whereby it will be able to then give this working group the attention it deserves.

SDG&E:

Rule 21 contains all of the technical and policy-related record for smart inverters to date. By contrast, the DRP proceeding was developed to carry out the legislative mandate for the IOUs to file their respective Distribution Resources Plans and for the Commission to approve, or modify and approve, those plans. The IOUs filed their DRPs in July 2015, and they have neither been approved nor modified and approved.
SDG&E supports smart inverter operationalization and continued conversation in a working group setting. The SIWG has a long precedent for taking charge of highly technical review of smart inverter functionality and has guided smart inverter requirements within Rule 21. SDG&E believes that any general working group efforts

should be focused on creating a well understood and commonly shared definition of DERMS, its component capabilities, use cases, and the requirements to achieve the desired end state. SIWG stakeholders contain this expertise, and the work will inform the Commission, utilities, and stakeholders going forward.

However, SDG&E does not support dictating to the Commission any specific regulatory venue outside of the SIWG and Rule 21 until this work is developed and understood. Even if the decision on the WG4 report closes the Rule 21 proceeding, this is still procedurally appropriate. The decision can direct the IOUs and Energy Division to work together to establish a SIO Working Group, and encourage the parties and other interested stakeholders to participate in the Working Group. Consensus proposals pertaining to SIO Working Group recommendations or Rule 21 interconnection more broadly may be brought forward for Commission consideration by the IOUs in the form of Advice Letters or Applications as appropriate, and Energy Division can also assist in bringing forth consensus proposals on SIWG issues. There are disparate DER-related issues scattered across a number of proceedings at this time, rather than in a crosscutting fashion. For this reason, SDG&E recommends that Working Group Four not dictate a specific home for the SIO Working Group at this time. The Commission should consider the suite of open rulemaking proceedings at the time of making its decision and take a comprehensive approach to delegating this work. The following excerpt from D.16-06-052, which closed the predecessor Rule 21 OIR, is an example of the Commission suggesting that a working group forum continue, with the IOUs filing an advice letter with the results of those efforts:

> *Smart Inverted Working Group – Continued Collaboration: Early in the nearly five-year time this proceeding has been open, the parties created the SIWG as a forum for collaboratively developing advanced inverter functionality for inclusion in Rule 21. The productive history, current work, and a compliance filing requirement for the Working Group is detailed in Attachment E. We encourage the parties and other interested stakeholders to continue to participate in the Working Group. Our Staff in the Energy Division will also continue to monitor emerging issues as improved inverters are deployed and communication protocols developed. Consensus proposals pertaining to SIWG recommendations or Rule 21 interconnection more broadly may be brought forward for Commission consideration by the Utilities in the form of Advice Letters or Applications as appropriate. Other parties may file Petitions for Rulemaking pursuant to Rule 6.3 of the Commission's Rules of Practice and Procedure or Complaints as set forth in Rule 4. The Commission has opened two proceedings related to distributed resources where interconnection issues may also be addressed: Rulemakings (R.) 14-08-013 and R.14-10-003.*

Such a process culminated in IOU advice letters and Resolutions E-4832 and E-4898 – both of which implemented Rule 21 smart inverter requirements for communications and autonomous functions. The outcomes of the SIO Working Group process – meaning what issues are developed and resolved – can drive the best approach to introducing the appropriate IOU or stakeholder requests.

Timelines should be established based on need. This needs to consider both use case and the likely date where a critical mass of smart inverters exist to control.

Proposal F-5. Include Smart Inverter Operationalization as an Element of Grid Modernization. Smart Inverter Operationalization (SIO) is required to address the question posed by Issue F, and SIO requires coordination across multiple Commission proceedings. The Commission should include SIO as an element of Grid Modernization and establish the DRP proceeding as having overarching authority on SIO. SIO tasks within the DRP proceeding should include developing an SIO Plan, addressing the merits of operational flexibility compared to its potential adverse impacts of DER deployment, and inclusion of DERMS and SIO roadmaps within utility Grid Modernization Plans.

Initiating proponent: Public Advocates Office
Supported by: CALSSA, Clean Coalition
Opposed by: PG&E, SCE

When considering how SIO can be included as an element of grid modernization, the Commission should consider the following four scoping elements:

1. An SIO Plan should be developed by Commission staff and managed within the DRP proceeding to coordinate SIO activities across all Commission proceedings. Details of the SIO Plan will be determined by Commission staff, but the Public Advocates Office recommends that four high-level components be included:

- Replace the current 2020 operationalization target with a new target or targets based on the need date for SIO in each impacted Commission proceeding,
- Establish SIO as an element of Grid Modernization,[62]
- Establish that DRP is the lead proceeding on SIO,[63]
- Define the role of each impacted proceeding in achieving SIO, including those listed in Annex 4.

[62] DERMS as a component of a Grid Management System (GMS) and two types of communication networks (FAN WAN) are currently included in the Grid Modernization Classification Tables to be included in utility GMPs. These and/or third-party communication networks are necessary prerequisites to SIO, but they are not sufficient for SIO without all components discussed in this proposal.

[63] The rationale supporting DRP as the oversight proceeding for the SIO Working Group in Proposal 1 above are applicable here. The fact that DRP has addressed all types of DERs, has developed detailed rules regarding ICA and DIDF development and use, and valuation methods such as the LNBA are particularly applicable regarding the SIO Plan.

2. The reliability benefits of operational flexibility (OpFlex) should be evaluated relative to its potential adverse impacts on DER deployment.[64] A central assumption of Issue F is that OpFlex must be preserved even if it reduces the allowable penetration of DERs. This is reflected in the initial deployment of the ICA, in which ICA values with OpFlex are lower than ICA values without OpFlex. The reliability benefits of OpFlex are promoted in the recent GRC's of SCE and PG&E, and are used to justify significant investments in distribution automation and the addition of new feeders to increase OpFlex.[65] In recent testimony on SCE's TY 2021 GRC, the Public Advocates Office raised concerns regarding SCE's efforts to increase OpFlex through new equipment investments, and to maintain existing OpFlex through use of the current ICA methodology could adversely impact DER deployment.[66] Within WG-4, the Public Advocates Office asked if IOUs could "point to directives to increase reliability scores except through worst circuit rehabilitation," and the utilities confirmed that there are no such directives.[67] Limiting the duration and scope of distribution grid outages is a valid and important objective for every electric utility, however this objective must be considered and balanced against mandated Commission requirements regarding climate change, wildfire prevention, and grid resiliency, and attempting to make electric rates affordable. An evaluation of the merits of OpFlex compared to other state policy objectives has not been performed to date but should be performed as part of the 2021 reevaluation of Grid Modernization.

3. Utility GMPs, included with each GRC application, should include detailed DERMS and SIO roadmaps. Each IOU submitted and discussed "DERMS Roadmaps" as part of the WG-4 discussion of Issue F.[68] The level of detail ranged from SCE's chart of five DERMS capabilities and proposed availability dates, to PG&E's discussion of EPIC projects as precursors to DERMS deployment, to SDG&E's discussion of DERMS vision, drivers, and deployment challenges. None of the IOU presentations met the definition of a technology roadmap as being "a flexible planning technique to support strategic and long-range planning, by matching short-term and long-term goals with specific technology solutions."[69] Roadmaps for DERMS and SIO that show milestones, interdependences, and dates will aid the Commission in establishing and managing a SIO Plan, and help Commission staff and stakeholders in other Commission proceedings understand when DERMS for specific use cases could be available. It is important to recognize that dates within a roadmap are typically target dates rather than hard deadlines, and are

[64] OpFlex is the ability for grid operators to reconfigure distribution feeders and transfer loads to reduce the scope and/or duration of an outage.
[65] Refer to Section II of this document.
[66] Advocates Office opening testimony in A.19-08-013 dated April 10, 2020, Ex. PAO-05, Appendix C.
[67] Refer to June 2, 2020 WG-4 materials: May 29, 2020 responses for each IOU regarding Public Advocates Office's Issue F Questions, Question 7.
[68] Refer to April 14, 2020 WG-4 materials: April 10, 2020 DERMS presentations for each IOU.
[69] Wiki https://en.wikipedia.org/wiki/Technology_roadmap. Examples of technology roadmaps indicate they are typically a chart similar to a Gantt chart that show milestones, interdependences, and dates.

provided to show how modifications to one component of a project or program can impact other target dates.

4. In addition to including DERMS and SIO roadmaps in IOU GMPs, the Commission should also require that these roadmaps be included in IOU annual GNA/DDOR filings within the DRP DIDF process. This additional requirement is justified because DIDF is an SIO use case identified by PG&E as previously mentioned, and because the three year GRC cycle in place when D.18-03-023 was adopted was increased to a four-year GRC cycle per D.20-01-002.[70] Synchronizing GMP updates with GRCs makes sense for utility owned assets, because GMPs currently only include IOU equipment. However, a four-year roadmap update cycle is too infrequent, particularly for the annual DIDF process.

Party Positions on Proposal F-5

PG&E:

PG&E does not support this proposal. As noted in prior comments PG&E does not believe that the DRP is the appropriate venue for the proposed Smart Inverter Operationalization work scope, but rather suggest it be part of a successor Rule 21 Proceeding.

Generally, timelines for investments in technology that integrate into the broader utility grid management platforms should be addressed and vetted holistically as part of the GRC process and it is not appropriate to require annual review of grid modernization investment plans outside of the GRC. Furthermore investment timelines will vary across each of the IOUs based on the state of related grid technologies and the specific grid needs and configurations. PG&E believes that it is important to tie the timing of deployment of DERMS functions to specific grid needs and use cases at specific locations where there is a clear value across all customers.

It is unnecessary to establish Smart Inverter Operationalization (SIO) requirements in the Grid Modernization Plans, as the GMPs already consider the operationalization of DERs including those with smart inverters in the 10-year plans. Mandating specific focus on smart inverters within the consideration of broader grid modernization will impede a holistic prioritization and development of DERMS and broader grid modernization efforts. Furthermore a deep dive within the GMP on smart inverter technology integration and operationalization is not in line with prior scoping of the GMPs in D.18-03-026.

SCE:

[70] D.18-03-023 in R.14-08-013, pp. 34-36, and Refer to D.20-01-002 in R.13-11-006, pp. 49 and 55.

As noted in SCE's comments on Proposal F-4, SCE does not agree that the DRP is the appropriate home for the SIO Working Group, believes the SIO Working Group is better suited for a DER successor proceeding that encompasses integration challenges holistically, and believes that suggesting the SIO Working Group be included in the DRP without formal DRP stakeholder comment and process is inappropriate. The DRP track 3 is scoped as policy issues and does not establish new technical requirements for grid technology. SCE takes exception with the scoping of this issue as to propose requirements within a GMP or the IOUs' annual GNA/DDOR filed under a separate proceeding through a separate rulemaking focused on the use of DERMs and Operational Flexibility ICA screens. If PAO feels it is appropriate to add additional scoping items within the GMP or GNA/DDOR, it should be formally scoped and formally ruled upon through a decision within the DRP proceeding, not through a roundabout approach through this rulemaking. Additionally, PAO's suggestion to include DERMS and SIO roadmaps in the IOUs' annual GNA/DDOR filings is inappropriate and outside of the scope of those filings. The GNA and DDOR specifically focus on the output of the annual distribution planning process and have never mentioned any requirements of technology roadmaps or any iteration of a roadmap. The DRP has established a pathway via party comments for annual modifications to the Distribution Investment Deferral Framework (DIDF) for which the annual GNA/DDOR filings are a major component. Any modification to the GNA and DDOR filing must go through that formal process.
Further, it is clear that D.18-03-026 establishes a framework for Grid Modernization by giving a definition, identifying technologies considered as Grid Modernization within the classification tables, and establishing a process for which Grid Modernization requests are reviewed. D.18-03-026 makes no mention of debating the granular technical aspects of each Grid Modernization technology but rather identifies the use cases for technology. The implementation of that technology is then subject to review in each IOU's GRC. In addition, any formal revisit of Grid Modernization should be issued directly by the Commission itself.

SDG&E:

SDG&E does not support this proposal. The Grid Modernization Plan (GMP) is an attachment to each IOU's GRC application as required by the Commission.[71] Per D. 18-03-023, the Commission established a process for the development, review and approval of the IOUs GMPs. The framework determined that the DRP Grid-level Scenarios and Assumptions along with the DRP's Annual GNA would *inform* each of the IOUs GMP, which would subsequently include specific grid investment projects for review and authorized funding within their respective GRCs.[72] The GMP is a *plan* to modernize the grid by identifying technologies and/or functions that are needed to enable penetration, integration and value maximization of DERs that aligns with the IOU's 10-year grid modernization vision. Furthermore, the Commission concluded "that

[71] D.18-03.023 provided a framework for guidance on the IOUs GMPs to inform future GRCs and Resolution E-4982 updated the Grid Modernization Classification Tables.
[72] D.18-03-023 at p. 15.

an additional review process prior to the GRC will be impractical"[73] because each IOU's GMP will be specific to their needs and cannot be separated from the context of each IOU's overall distribution revenue requirement. GMPs are required as part of the IOU's GRC application – having to update annually does not align with the IOU GRC cycle established by the Commission. PAO says annual update is part of DIDF not GRC A roadmap with timelines cannot be developed if the technology is not currently available and implementable at the Utility scale. Proposal F-5 seems to request that the development, review and approval of an IOU's GMP become part of an annual mini-GRC, including cost recovery PAO says not correct, versus its current role as an attachment to the GRC Application to provide supporting documentation for requests for funds in the IOU's GRC Application. The Commission has already established the venue and process via the GRC for reconciling IOU investments within the GRC that relates to Grid Modernization Plans. This proposal is contrary to what the Commission has established in D.18-03-023.

[73] *Id.*

Annex 1. IOU System Configuration Comparisons

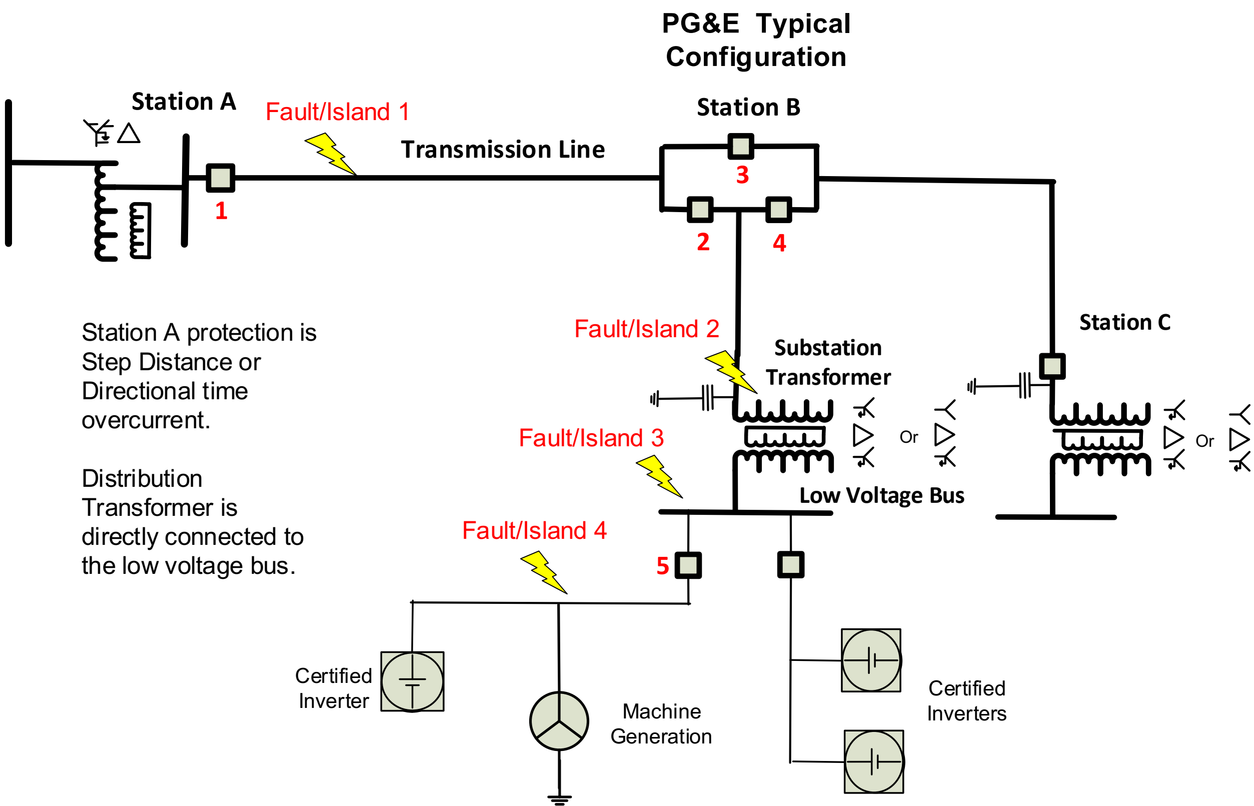

Figure-1

PG&E Configuration fault and islanding sequence.

<u>Fault/Island 1</u>

Relays at station A open circuit breaker 1. Fault or unintended island is fed by generation at Station B. Generation may not detect the fault, therefore rely on anti-islanding for generation tripping. In the case of an ungrounded substation transformer winding configuration, excessive voltage on transmission equipment can occur under certain transmission fault conditions, removal of generation within 2 seconds prevents possible equipment damage.

<u>Fault/Island 2 (transformer fault)</u>

Relays at station B open circuit breakers 2 and 4. Fault or unintended island is fed by generation at Station B. Generation may not the detect fault, rely on anti-islanding for tripping. In the case of an ungrounded substation transformer winding configuration on the transmission side, excessive voltage on transmission equipment can occur under certain transmission fault conditions, removal of generation within 2 seconds prevents possible equipment damage.

<u>Fault/Island 3 (Transformer low voltage bus.)</u>

Relays at station B open circuit breakers 2 and 4. Fault or unintended island is fed by generation at Station B. Generation may not detect fault, rely on anti-islanding for tripping.

<u>Fault/Island 4</u>

Relays at station B open circuit breakers 5. Fault or unintended island is fed by generation located on the feeder supplied by circuit breaker 5. Generation may detect the fault.

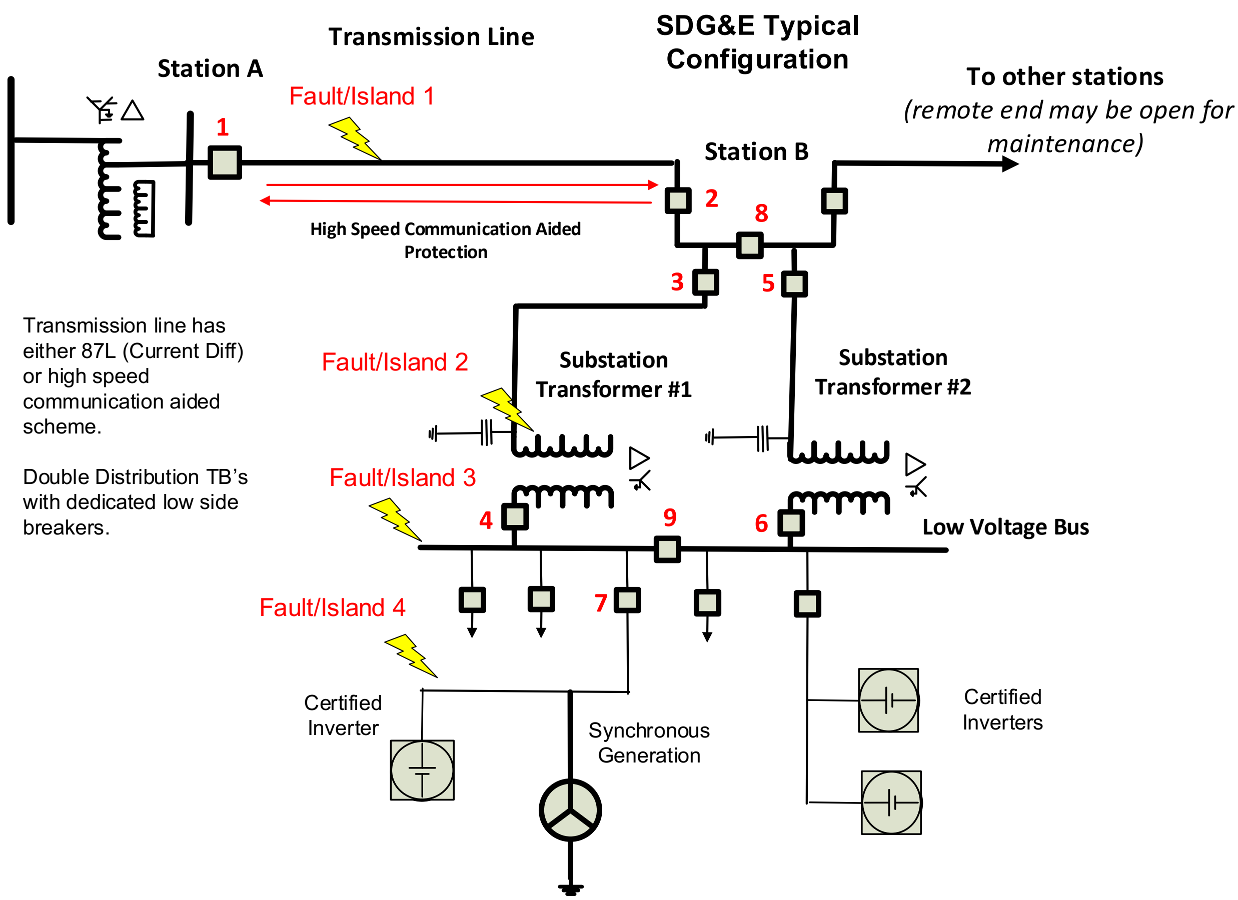

Figure 2

SDG&E Configuration fault and islanding sequence

<u>Fault/Island 1</u>
Transmission line relays at station A and station B open circuit breakers 1 and 2. Fault is isolated and, only if remaining transmission line is out of service as well, an unintended sustained island may be possible by generation at Station B.

<u>Fault 2 (transformer fault)</u>
Relays at station B open circuit breakers 3 and 4. Fault is isolated, there are no islanding concerns since generation is connected to the system through the in-service transformer #2.

<u>Fault/Island 3 (Transformer low voltage bus.)</u>
Relays at station B open circuit breakers 4 and 9. Fault is isolated from the substation source with only distribution loads and DG connected to the faulted bus. It is expected the DG would trip offline, completely de-energizing the faulted bus within cycles of the event. An unintended sustained fault or island may be possible by generation at Station B connected to the circuit fed by circuit breaker 7.

<u>Fault/Island 4</u>
Relays at station B open circuit breaker 7. An unintended sustained fault or island may be possible by generation at Station B connected to the circuit fed by circuit breaker 7.

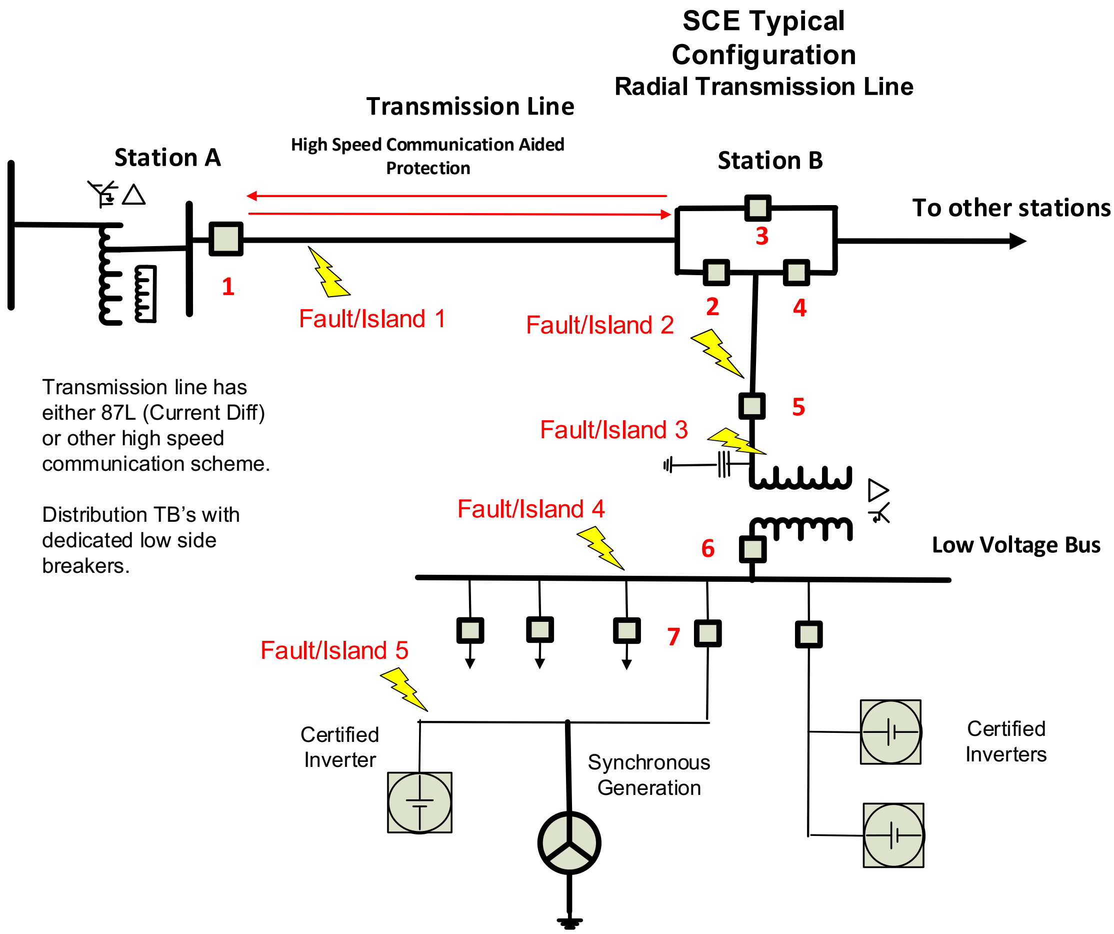

Figure 3

SCE Configuration fault and islanding sequence

(This is a typical configuration; it does not cover all possible configurations or protection elements. For specific configurations SCE should be contacted).

<u>Fault/Island 1</u>
Transmission line relays at station A and station B open circuit breakers 1, 2 and 3. Fault is isolated, generation is isolated at Station B

<u>Fault/Island 2 (Tie line fault)</u>
Relays at station A open circuit breakers 2, 4 and 5. Fault is isolated, generation is isolated at Station B.

<u>Fault/Island 3 (transformer fault)</u>
Relays at station B open circuit breakers 5 and 6. Fault is isolated, generation is isolated at Station B.

<u>Fault/Island 4 (Transformer low voltage bus.)</u>
Relays at station B open circuit breakers 6, and 7. Fault is isolated, generation is isolated on the feeder supplied by circuit breaker 7.

<u>Fault/Island 5</u>
Relays at station B open circuit breakers 7. Fault and generation is isolated to the feeder supplied by circuit breaker 7.

Discussion

A major concern is the presence of a high impedance fault or a fault that cannot be detected by the interconnected distributed generation, such as a fault on the transmission system or an internal transformer fault. The result could be extended fault durations degrading safety, increased wildfire ignition potential or in the case of an ungrounded substation transformer possible transmission equipment damage under certain fault conditions. In these cases, anti-islanding protection is relied upon to ensure distributed generation is removed from service. Additionally, unintended islanding on the transmission system can result in a large number of customers affected. PG&E transmission operations requires automatic separation of the island from the transmission verses manual intervention. As shown in Figure-2 and Figure-3 the SCE and SDG&E system separates each affected component from the distribution interconnected generation, while the PG&E configuration requires the distribution connected generation to trip.

Annex 2. Risk of Islanding Study Assessment Procedure

1. Feeder/Station Modeling
    a. Develop feeder model in MATLAB/Simulink using data provided by utility. (Cyme or similar)

2. Modeling Details In order to reduce model complexity and speed simulation time, several aggregation steps can be performed on the models.
    a. Any nodes with identical conductors, no branches, and no equipment connected (i.e., circuit segments that are in series and have the same impedance per unit length) were combined into a single circuit segment with conductor length equal to the sum of the individual segment lengths. This step simplifies the model yet has no impact on model accuracy.
    b. The important equipment of all single-phase nodes, such as loads, capacitors, and transformers, were aggregated to the three-phase trunk. To account for real and reactive losses in the series circuit elements in these aggregated single- and two-phase sections, the aggregated loads were adjusted to draw an additional 2% real power and 5% reactive power. This aggregation step causes a minor loss of fidelity, but the 2% and 5% adjustments just mentioned compensate for this loss of fidelity so that it should be negligible for purposes of this study.
    c. After the model is built, any connected impedance nodes representing overhead lines with no branches and no equipment were aggregated into a single node with the same impedance. This step is similar to step #1 except that it also aggregates circuit segments with dissimilar conductors, as long as they are purely in series.
    d. Load shall be constant Z load as a default, constant power loads (ie Motor loads), may be required depending on the location.

   Model Validation
   Circuit impedances should be validated against expectations by comparing the calculated fault currents expected against those predicted by the MATLAB/Simulink feeder model. This is performed by applying LLL, LLG, LL and LG faults and comparing against the Utility model, they shall match within 10%.

3. PV Machine Plant Modeling:
    a) PV Modeling shall use manufacturer-specific proprietary anti-islanding controls.
    b) Machine modeling shall use Matlab's built in sixth order machine model.
    c) PV and Machine generation shall have the applicable voltage and frequency trip settings installed. If they are not known PV inverter settings will utilize Rule Table HH ride though settings. Machine settings will be obtained by the utility.

4. Risk of Islanding Study Procedure:

a) Select a breaker, switch or other device that can form an island that includes the DG under study, loads, and a VAR source. If inactive VAR source(s) are present on the line segment and not being utilized, they should be removed or otherwise deactivated and excluded from the scope of the Risk of Islanding study.
b) Define the balance point is found at which the output of all real and reactive power sources in the island matches the demand of the loads in the island.
c) Once that point is located, a batch-mode coarse-resolution sweep is run over the expected range of loading fractions* (LF) and power factors (PF). For all LF and PF pairs in the batch, a simulation is run in which an island is formed without a fault by opening a breaker of interest, and the resulting run-on timeb (ROT) of the DG plant, defined as the time from switch opening to plant shutdown, is recorded. The coarse resolution allows the batch to be run in a reasonable length of time, and facilitates the location of the edges of any nondetection zone (NDZ) that may exist. Finer-resolution batches can be run to obtain better resolution if needed. The NDZ is defined as the range of loads over which the ROTs of the PV plant are longer than the IEEE 1547 limit of 2 sec. for the entire islanded section.
d) Once the NDZ location or lack of an NDZ has been determined with suitable confidence and the maximum ROTs are known, NPPT and utility engineers confer to decide whether the NDZ is such that the risk of islanding is negligible, or whether it represents a realistic loading scenario and additional mitigation is needed.
e) This process is repeated for each breaker, switch or interrupter that can form an island including the DG under study.

**For these simulations, LF is given as a percentage of the total connected load. The PF values given are the uncompensated PF values. What this means is that the PF values are the values of the R-L loads, but without the utility capacitors included. Thus, the PF that is being swept in these simulations is that of the load and feeder only, excluding the capacitors.*

5. Study Results: The end result of the Risk of Islanding study should contain a detailed assessment as to the reasonable feasibility of an extended ROT exceeding 2 seconds. The conclusion should contain language that addresses this question specifically as well as any potential solutions that could be implemented in lieu of conventional means of managing Risk of Islanding on both the distribution and transmission levels. The intent is to allow islanding mitigation methods to evolve with state of the art technology and stakeholder understanding of conditions that may result in islanding.

These solutions include but are not limited to:

a) Setting changes using smart inverter technology that destabilize the island
b) Utilizing inverters with different method(s) of anti-islanding that perform better in the given grid conditions

c) Setting changes to synchronous generator protection schemes or operating parameters
d) Installing IOU approved relays or site controllers that provide the required response time at the Point of Interconnection
e) Utilization of localized Distributed Energy Resource Management Systems (DERMS)

Approval and implementation of any mitigation method shall be at the sole discretion of the IOU Engineer.

Annex 3: Comparison of Proposed Configurations for Pre-approved Designs and Single Line Diagrams

--- = included in Microgrid Decision 20-06-017
--- = partially included in Microgrid Decision 20-06-017
--- = not included in Microgrid Decision 20-06-017

Microgrid Decision 20-06-017 requires template SLDs for configurations that account for at least 80% of applications in each of the following categories.

(1) Rule 21 non-export storage, (<10 kw) ---
(2), NEM + Paired storage (both AC Coupled and DC coupled; solar <30 kW and storage <10 kW), --- and
(3) Net Energy Metering (NEM) Solar (<30 kW). ---

- *Template SLDs are not required for configurations that account for less than 20% of applications in any category, regardless of the total number of similar applications received, and no provision is made to require future updates as needs change.*
- *Template SLDs do not apply to retrofit applications or modifications of existing systems, such as when a customer adds storage additional PV capacity.*
- *D. 20-06-017 states "While we adopt the single line diagrams for these particular behind-the-meter projects, we recognize that fuel-cell installation requirements may need to be considered at a later time, along with other technologies that meet California Air Resources Board distributed generation standards. We also recognize that greater than 10 kW storage must be considered. These considerations may be addressed in subsequent tracks of this proceeding." (at 24)*

Clean Coalition ZNE Standard SLD templates: generation and storage configurations[74]

Proposal: That the working group recommend publication by utilities of standard proposed facility configuration single line diagrams for use in ZNE[75] interconnection applications, subject to adopted threshold demand criteria.

1) PV* only *(Decision 20-06-017 only addresses NEM)* ---
2) AC-coupled solar*+storage *(Decision 20-06-017 only addresses NEM)* ---
3) DC-coupled solar*+storage *(Decision 20-06-017 only addresses NEM)* ---

**PV or other inverter-based generation such as fuel cell*

[74] Some single line diagrams (SLD) templates are currently published (see for example: https://www.sce.com/sites/default/files/inline-files/Grid%2BInterconnection%2BSample%2BDrawings%2BSept%2B2015_AA_4.pdf
The working group should review and recommend updates, including editable online or pdf forms
[75] ZNE sites may also consider islandable microgrid options, and publication of such should be coordinated, ideally such that an applicant may select SLD from check list of applicable tariffs and features, and provide additional information as necessary.

These scenarios should assume ZNE resources may be configured under any of the following Rule 21 Tariff options:[76][77]

1. NEM
    a. single customer *(Included in Decision 20-06-017)* ---
    b. NEMA (aggregated) *(Not specified in Decision 20-06-017)* ---
    c. NEM-MT (multiple-tariff) *(Not specified in Decision 20-06-017)* ---
    d. VNEM (virtual) including SOMAH (multifamily) *(Not specified in Decision 20-06-017)* ---

   NEM-PS (paired storage) alternatives as applicable: *(AC & DC coupled storage included in Decision 20-06-017)* ---
        i. battery only non-export *(Not specified in Decision 20-06-017)* ---
        ii. battery no grid charging *(Not specified in Decision 20-06-017)* ---
2. Basic single customer (not NEM) ---
    a. non-export *(Decision 20-06-017 only addresses storage)*[78] ---
    b. non-export & battery no grid charging *(Decision 20-06-017 only addresses storage)* ---
    c. export *(Not included in Decision 20-06-017)* ---
        i. battery non-export *(Not included in Decision 20-06-017)* ---
        ii. battery no grid charging *(Not included in Decision 20-06-017)* ---

3. Future variations
    a. provision of grid services or energy sales outside of NEM ---
        i. to host utility (Rule 21) *(Not included in Decision 20-06-017)* ---
        ii. to wholesale aggregator, transactive or FERC regulated market *(Not included in Decision 20-06-017- applies to CCA procurement)* ---

[76] Note any change in requirements based on size categories up to 1 MW
[77] Note if variation required for non-inverter based generation
[78] In response to Decision 20-06-017 SLD's for non-export storage are only provided for Protection Options 3 and 6, and only for sizes up to 10 kW.

Annex 4: SIO Working Group Objectives, Scope, Formation, Oversight, and Timing

Objectives and Scope

The primary objective of the SIO Working Group should be to develop the guidelines required for SIO and provide these guidelines as recommendations to impacted Commission proceedings. The Commission has previously acknowledged the impact of Rule 21 on multiple proceedings including the Distributed Resources Planning (DRP) proceeding (See Rule 21 OIR, dated July 21, 2017, pp. 13 and 17 and Rule 21 Scoping Ruling, dated October 2, 2017, pp. 17 and 20-21). Therefore, these guidelines will be incorporated into impacted proceedings, such as the DRP proceeding, as warranted. Meeting this objective entails four high-level scoping elements.

This will entail compiling previously defined use cases, consideration of any other use cases proposed by SIO Working Group members, development of prioritization criteria,[79] development of tiers that define the action for specific use cases,[80] and using the tools developed to prioritize each use case.

The following use cases and sources of use cases were identified as part of the Issue F discussion:

- Rule 21 working group Issue F
- DRP Distribution Investment Deferral Framework (DIDF)
- DER monitoring for non-actionable data collection and subsequent analysis
- Rule 21 working group final reports, including Issues 4, 9, and 2
- SCE's TY 2018 and TY 2021 GRC DERMS requests
- PG&E EPIC 2.02 project
- PG&E EPIC 3.03 project
- SDG&E's Spir
- SDG&E's TY 2019 GRC DERMS request
- Ongoing work by EPRI
- Ongoing work by Smart Electric Power Alliance (SEPA)
- IEEE 2030.11 Working Group[81]

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[79] D.18-02-004 discusses screening criteria and prioritization metrics at pages 42-52. They are cited as examples of a prioritization process, not for the criteria to be used by the SIO Working Group.

[80] IOU DDORs group candidate deferral projects into tiers that define recommended action. For an example, see SCE's Narrative on the 2019 DDOR, included in the amended GNA/DDOR report filed August 23, 2019 in R.14-08-013, pp. 14-16.

[81] IEEE P2030.11 DER Management Systems (DERMS) Functional Specifications. See https://site.ieee.org/sagroups-2030-11/ for meeting information, including meetings on May 7, 2020 and June 3, 2020.

All viable use cases should be compiled, even if they are only applicable to one IOU, but the breadth of applicability (i.e. for one IOU versus statewide) should be considered as a prioritization criterion. It should be noted that the IOUs are not in identical positions in DERMS and supporting system development. Previous and pending IOU investments that impact SIO should be considered when prioritizing use cases. For example, SCE has already contracted initial DERMS scope with third party vendors that include a DERM use case and functionality. Any changes to scope and requirements associated with DERMS use cases above and beyond what SCE has already contracted for DERMS deployment as a result of this proposed SIO Working Group could have the potential to impact scope, schedule, and budget associated with SCE's DERMS development.

Second, the top tier of high priority use cases should be evaluated to establish all guidelines required for SIO for each use case. The evaluation should establish guidelines for IOU, DER provider, and any other third-party-owned equipment; interconnection rules; operational rules; elements of tariffs that impact the use of operationalized smart inverters; and inputs to subsequent cost/benefit evaluations. SIO Working Group guidance on each use case should include a list of actionable tasks that are required to implement use cases. IOUs can then provide timelines and potential paths to complete those tasks.

Third, SIO will require specific investments in new IOU equipment and software,[82] tariff development, and potential modifications to requirement and testing standards such as IEEE 2030.5-2018, CSIP, and IEEE 1547.1-2020. This work cannot be piecemealed or tailored to each individual use case since funding for SIO components such as DERMS will be requested in a GRC, and these requests will be for assets such as DERMS, not for functions such as "DERMS for the DIDF use case." The SIO Working Group should compile use cases into a "technical roadmap," and integrate the guidelines developed for each use case tier into functional requirement descriptions.[83]

Fourth, the SIO Working Group should develop recommendations to ensure that SIO is performed on a statewide basis that minimizes differences in the capabilities of each IOU. SIO is being promoted based on the potential to leverage existing capabilities and integrate DERs into the distribution grid. Smart inverter and communication requirements are established on a statewide basis. However, there have not been statewide requirements on the IOUs to implement communications and DERMS. The reasons are driven by capital costs and nascency in DERMS and communications technology.

Working Group Four discussions and written comments clarified that DERMS is a function rather than a piece of equipment that sends standardized commands to DERs and receives DER monitoring data. In comments, PG&E referenced a white paper that clarifies that DERMS can

[82] For example, communication and cybersecurity equipment and software tools such as GIS, ADMS, and DERMS.
[83] One description of a technical roadmap is "a flexible planning technique to support strategic and long-range planning, by matching short-term and long-term goals with specific technology solutions." See https://en.wikipedia.org/wiki/Technology_roadmap. Examples of technology roadmaps indicate they are typically a chart like a Gantt chart that show milestones, interdependences, and dates.

take many forms ranging from a simple manually-operated DERMS[84] to more complicated schemes where a central DERMS controls distributed DERMS, including microgrid controllers.[85] Going forward, the term "DERMS" can be used at a high level to refer to the basic function of monitoring and controlling DERs, but that for technical evaluations, DERMS should be defined based on the use cases it is designed to support.

Working Group Formation and Oversight

The SIO Working Group should be authorized and managed within the scope of a Commission proceeding, as opposed to the current SIWG which operates as an autonomous entity. Different Commission proceedings were discussed within Working Group 4 with IOUs recommending Rule 21 or a successor rulemaking proceeding for this role and some non-IOU parties recommending DRP (as proposed in Proposal F-4).

Rule 21 or successor: Recommendations from SDG&E and PG&E supporting Rule 21 for the oversight proceeding was based in the history of the SIWG, the established working group processes in Rule 21, and the fact that utility subject matter experts already work on Rule 21. SCE, however, highlighted that as the traditional focus of the SIWG has been the technical requirements supporting safe and reliable interconnection, not the broad discussions as proposed for the SIO Working Group.

DRP: The current Rule 21 scope for Phases 2 and 3 does not support a new SIO Working Group even conceptually.[86] In D.18-03-023, the Commission indicated that it intends to formally revisit established Grid Modernization in 2021, and SIO elements including DERMS and communication networks are also defined components of Grid Modernization.[87] Grid Modernization within the DRP considers all types and scales of DERs, in addition to reliability and safety. The formation and oversight of the SIO Working Group can also reasonably be interpreted as within the revised Grid Modernization Scope established in January 2020.[88]

Working Group Timing

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[84] SDG&E commented that manual DERMS operations are ok for pilots but do not scale for production.
[85] Electric Power Research Institute (EPRI) publication "Understanding DERMS" dated June 2018. Publicly available at https://www.epri.com/#/pages/product/3002013049/.
[86] The initial scoping memo in R.17-07-007 defined the scope of Phase Two as ratesetting and cost allocation and Phase Three as Small and Multi-Jurisdictional Utility Rules. See Scoping Memo of Assigned Commissioner and Administrative Law Judge dated October 2, 2018, p. 7.
[87] D.18-03-023 in R.14-08-013, pp. 29-30 and Appendix B. Also note that while Grid Modernization Plans (GMPs) only explicitly set requirements for IOU equipment, GMPs are required to "explain how the grid modernization proposal leverages existing AMI infrastructure, third party communication networks, and smart inverters to support grid modernization objectives." See D.18-03-024, Appendix A, p. 1, item 1.e.i.
[88] Joint Second Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge dated January 9, 2020 in R.14-08-013, pp. 5-6.

SIO was targeted in the 2017 DER Action Plan to be completed in 2020. This target will not be met for any use case at any IOU per the IOU DERMS roadmaps provided to WG-4. SIO could potentially impact the work in multiple high-profile proceedings, including the following:[89]

- R.17-07-007, Rule 21: as discussed by working groups of issues 4, 9, 27, and F.
- R.14-08-013, DRP: DERMS and communication systems are identified components of Grid Modernization Plans.
- R.14-10-003, IDER: Active use of smart inverter functionalities will likely be influenced by programs or tariffs that compensate DER owners for any reduction in real-power output.
- R.19-10-009, Microgrids: Microgrid controllers are a form of DERMS that provides local control of DERs and loads within a microgrid. Utility control of a microgrid requires a second layer of DERMS.
- A.19-08-013, SCE TY 2021 GRC – SCE has requested funding for a DERMS to be implemented as part of its Grid Modernization Plan, and is requesting funding for DER-driven grid upgrades that do not appear to account for the full impact of SIO. Overall, however, SCE's DER-driven Grid Modernization Plan has been scaled back through 2023 to provide resources for wildfire mitigation.
- A.21-06-TBD, PG&E TY 2023 GRC – PG&E's TY 2023 GRC will be filed in June 2021 and should include DERMS requirements in its Grid Modernization Plans. The new GRC filing schedule established in D.20-01-002 results in no GRC filing in 2020.[90]
- R.19-01-011- Building Decarbonization Proceeding – DERMS could control smart customer appliances such as programable controllable thermostats (PCTs) and controllable electric water heaters individually or via customer energy management systems.

The schedules in these proceedings drive SIO, and formation of the SIO WG, as a high priority for two reasons. First, many proceedings could benefit from SIO Working Group recommendations as soon as they can be provided, including the Microgrid proceeding Track 2 process; Rule 21 utilization of Smart Inverters for the Issue F and other use cases; activation of DER projects approved through the DRP DIDF process; to inform the review of the IOUs' GRC requests associated with their respective Grid Modernization Plans; and to provide input to the re-evaluation of Grid Modernization scheduled for 2021 in the DRP proceeding.[91]

Second, the lack of a new GRC application to review in 2020 and the first half of 2021 provides a one-time opportunity for parties that participate in GRCs to focus resources on SIO that would otherwise be occupied with supporting a major GRC case.

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[89] This list provides examples but is not a comprehensive list of proceedings that could be impacted by SIO.
[90] Refer to D.20-01-002 in R.13-11-006. The schedule on page 55 show that PG&E's Test Year (TY) 2023 GRC will be the next GRC application, to be filed on June 15, 2021. Subsequent GRC applications will be filed on May 15, 2020, two years prior to the test year, as indicated on p. 49 of the decision.
[91] See D.18-03-023 in R.14-08-013, pp. 29-30.

In addition, Phase 3 functionality approved by the Commission became effective for DERs interconnecting on or after June 22, 2020 but these capabilities will not be utilized until the other required elements of SIO have been developed, deployed, and activated. Inverter manufacturers and the DER industry have been required to incur the costs to comply with their part of SIO starting well before 2020. However, the Commission has not established deployment targets (i.e., dates and number of operationalized smart inverters) for the IOUs or the Commission to complete their roles in SIO.

IOU GRC requests summarized in Annex 5 have discussed smart inverters and DERMS. However, the utilization of existing and customer owned technologies such as smart inverters in IOU Grid Modernization Plans has been minimized and their deployment delayed compared to IOU plans to deploy SCADA-based monitoring and control schemes using new utility assets. Recent testimony from the Public Advocates Office stated: [92]

> "SCE's GMP discusses DER integration challenges from the perspective of an IOU which has a financial motivation to invest in new capital projects, and an operational motivation to maximize visibility and control of its distribution system while minimizing the scope and duration of customer outages. This is a valid perspective that the Commission must consider. However, the Commission must also consider the perspectives of ratepayer advocates, who seek to meet state policy goals at the minimum cost, and the perspectives of DER developers, who seek equitable sharing of interconnection costs and fair compensation for any grid service they provide."

[92] Public Advocates Office Opening Testimony in A.19-08-013 dated April 10, 2020, Ex. Public Advocates Office-05, pp. 82-83. SCE's GRC application, A.19-08-013, is an active proceeding and the outcome is in pending a CPUC decision.

Annex 5: Summaries of IOU GRC Requests Related to Issue F

SCE

To date, SCE has proposed, subject to Commission approval, a plan to upgrade its distribution grid in anticipation of potential DER integration issues. SCE proposed two key elements relative to Issue F in its Test Year (TY) 2018 application filed in 2016, which are also included in SCE's current TY 2021 GRC.[93] The first element is a fleet of new SCE assets to provide increased monitoring and control of the distribution grid. These include control/monitoring software, communication networks, and switches and sensors on distribution feeders that provide visibility into the electrical state of the grid at discrete points. SCE's TY 2018 requests for control software, including a DERMS, and a Field Area Network (FAN) were approved in D.19-05-020. SCE's TY 2021 GRC, including its first formal GMP, is currently being evaluated by GRC stakeholders and GRC requests are subject to final Commission approval and may be modified as the Commission deems appropriate.[94]

Another element of SCE's GRC request is upgrades to specific circuits and one substation based on DER and load forecasts that SCE disaggregated down to the service transformer level. This portion of SCE's request includes adding ten new feeders to provide operational flexibility.[95] The Public Advocates Office's Opening Testimony discussed how SCE's GMP improperly minimized the role of ECTs, including remote controlled smart inverters, and recommended that 1) SCE clarify the date by which it will be able to monitor and control DERs; and 2) for the Commission to order SCE to accelerate DERMS deployment.[96]

PG&E

PG&E's DER-driven GRC requests began in its TY 2017 GRC and these requests were expanded in 2018 in its TY 2020 GRC application.[97] Like SCE, these requests include both systemwide upgrades and location specific upgrades based on forecasted DER growth. D.17-05-013

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[93] SCE's TY <u>2018</u> GRC was A.16-09-001, and DER integration was addressed in opening testimony dated September 1, 2016: Exhibit (Ex.) SCE-02, Vol. 10, Grid Modernization; Ex. SCE-02, Vol. 3, System Planning; and Ex. SCE-04, Vol. 2, Capitalized Software. SCE's TY <u>2021</u> GRC is A.19-08-013 and DER integration was addressed in opening testimony dated August 30, 2019: Ex. SCE-02, Vol. 4, Part 1, Grid Modernization; Ex. SCE-02, Vol. 4, Part 2, System Planning; and Ex. SCE-06, Vol. 1, Part 2, Capitalized Software.

[94] The Public Advocates Office served its testimony on April 10, 2020, including Ex. Public Advocates Office-05 which reviewed and provided recommendations regarding Grid Modernization. Other parties served opening testimony on May 5, 2020 consistent with the Scoping Memo and Ruling in A.19-08-013 filed November 25, 2019 in A.19-08-013.

[95] A.19-08-013, Workpapers supporting Ex. SCE-02, Volume 4, Part 2, Chapter II: Book A, pp. 28-29, and Book B, pp. 13-15.

[96] Public Advocates Office opening testimony in A.19-08-013 dated April 10, 2020, Ex. Public Advocates Office-05, pp. 3 and 11-12.

[97] PG&E's TY <u>2017</u> GRC was A.15-09-001, and DER integration was addressed in opening testimony dated September 1, 2015: Ex. PG&E-4, Electric Distribution; and Ex. PG&E-7, Information Technology. PG&E's TY <u>2020</u> GRC was A.18-12-009, and DER integration was addressed in opening testimony dated December 13, 2018: Ex. PG&E-4, Part 1 and Part 2, Electric Distribution; and Ex. PG&E-7, Information Technology and Cybersecurity.

addressed PG&E's TY 2017 GRC and included approval of PG&E's requests for a FAN and Wide Area Network (WAN), and partial funding for PG&E's request for DER-driven circuit upgrades.[98]

PG&E's TY 2020 GRC included the state's first GMP and included requests for a wide range of new PG&E assets including extensions of its TY 2017 requests, and new requests including an advanced distribution grid control system.[99] PG&E requested only an Advanced Distribution Management System (ADMS) which includes the foundational capabilities needed to operationalize DERs across the service territory. PG&E did not request funding for a system wide DERMS but did propose geographically targeted DERMS capabilities to address near term telemetry and control of 3rd party DERs. While the Public Advocates Office recommended that PG&E propose a system to monitor and control third-party DERs in its <u>next</u> GRC (TY 2023), PG&E opposed this recommendation while clarifying that "PG&E's ADMS requirements include the ability to communicate with DER via the IEEE 1547 and IEEE 2030.5 communication protocols, both critical features for future monitoring and control of third party-owned, non-SCADA DER."[100] A partial settlement agreement adopted all of PG&E's forecast electric distribution capital expenditures, including its GMP requests, but a Commission decision addressing the settlement is still required.[101]

SDG&E

Aligning with SDG&E's phased approach, which includes implementing DERMS on a locational basis prior to a systemwide implementation, in 2013 SDG&E developed and deployed a microgrid and distributed energy resource management system as a planned foundation for DERMS, starting first with the microgrid controller functionality, then moving towards energy storage management, and finally integrating the DERMS solution with key enterprise systems. Between 2014 and 2019, SDG&E deployed this microgrid controller and distributed energy resource management system at the Borrego Springs Microgrid, including integration with a third-party transmission-interconnected solar array, and at five distinct energy storage systems located across SDG&E's territory, increasing functionality with each release. This product is currently in use and operational. However, because additional functionality and upgrades are required, SDG&E anticipates replacing this product as part of a future, systemwide DERMS implementation.

SDG&E's latest GRC application (Application (A.)17-10-007/008) was filed in October of 2017 for a 2019 test year. This request pre-dated the Commission requirement for a GMP and did not

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[98] D.17-05-013, pp. 58 and 98. Additional detail is provided in the Joint Motion for Settlement filed August 3, 2016 in A.15-09-001, Appendix A, 2017 Capital Expenditures table, lines 36, 37, and 101. FAN and WAN costs are provided in PG&E Testimony in A.15-09-001, Exhibit PG&E-7, pp. 9-39 and 9-42.
[99] GMPs were mandated in D.18-03-023 in the DRP Proceeding, R.14-08-013. One element of the GMP is a table to summarize all Grid Modernization Requests in one place.
[100] The Public Advocates Office recommendation is provided in its testimony, A.18-12-009, Ex. CalAdvocates-09, p.4. PG&E opposition was stated in its rebuttal testimony, Ex. PG&E-18, pp. 19-24 to 19-25.
[101]Joint Motion for Approval of Settlement in A.18-12-009 filed January 14, 2020, Appendix B, p. 9. A proposed decision has not yet been issued.

include a comprehensive request for DER-driven grid upgrades. However, SDG&E's testimony did specifically request funds for a DERMS and for the following: eight small DER-driven programs and communication and IT system upgrades including cybersecurity.[102] The Public Advocates Office offered conceptual support for a DERMS program, but opposed SDG&E's specific request because it did not support third-party DERs.[103] The Commission denied SDG&E's DERMS request, but approved most of SDG&E's other DER related requests.[104]

To further SDG&E's efforts towards increasing its management of DER and microgrids, SDG&E is currently in the process of deploying a Local Area Distribution Controller (LADC). The Commission approved the LADC in its Track 1 decision (D.20-06-017) in the Microgrids & Resiliency rulemaking proceeding. The LADC solution that SDG&E selected through a rigorous RFP process is a proprietary software and hardware solution with the capability to leverage IEEE 2030.5 protocol that can enhance microgrid operation by coordinating control of DERs and grid management devices to ensure reliable operation during both grid-connected and island scenarios. SDG&E believes that this is a cost-effective approach to employ further testing and research before scaling the use of this technology and implementing a full DERMS solution. SDG&E will consider opportunities to integrate additional control systems responsible for managing third-party DER with the LADC to expand the capabilities of planned and future SDG&E microgrids once the LADC has been successfully deployed.

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[102] SDG&E direct (opening) testimony in A.17-10-007/008 dated October 6, 2017: Ex. SDG&E-13, DER Policy; Ex. SDG&E-14, Section IV.L., DER Integration; Ex. SDG&E-14, Section V.A., IT Projects driven by Electric Distribution; Ex. SDG&E-24 workpapers, pp. 473-475, DERMS; Ex. SDG&-24, IT Projects; and Ex. SDG&E-25, Cybersecurity. Exhibit SDG&E-14 includes requests for many types of grid upgrades, including substation and feeder automation based on SCADA, but these requests were not justified by DER integration.

[103] Public Advocates Office opening testimony in A.17-10-007/008 dated April 13, 2018, Ex. ORA-06, pp. 112-114.

[104] D.19-09-051, p. 299: "[we] find it reasonable to deny approval of the DER Management System project because the workpapers do not explain why existing systems are inadequate." Other than DERMS, the decision approved all SDG&E IT requests related to electric distribution, and the vast majority of electric distribution and cybersecurity requests that could impact DER integration. See pp. 289, 291, 292-296, 299, 471, and 494.