BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.	Rulemaking 17-07-007 (Filed July 13, 2017)

WORKING GROUP THREE FINAL REPORT

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June 14, 2019

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Pursuant to the *Scoping Memo of Assigned Commissioner and Administrative Law Judge*, dated October 2, 2017, as modified by the *Assigned Commissioner's Amended Scoping Memo and Joint Administrative Law Judge Ruling*, dated November 16, 2018, San Diego Gas & Electric Company (U 902-E), on behalf of itself and Pacific Gas and Electric Company (U 39-E) and Southern California Edison Company (U 338-E), hereby submits the Working Group Three Final Report.

Respectfully submitted,

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

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Working Group Three Background

Procedural Background

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

An amended scoping memo on November 16, 2018 tasked the third working group, "Working Group Three," to commence on December 1, 2018 and to develop and file a final report by June 14, 2019 for recommending proposals to address eleven issues. The amended scoping memo scheduled a workshop on Working Group Three proposals for June 21, 2019, scheduled an Administrative Law Judge ("ALJ") ruling on the Working Group Three Report by July 19, 2019, established a due-date for comments on Working Group Three proposals by August 2, 2019, and established a due-date for reply comments by August 12, 2019.[3]

Working Group Scope

Working Group Three developed proposals addressing eleven issues (12, 15, 16, 20, 22, 23, 24, 27, 28, A, and B) from the November 16, 2018 amended scoping memo:

> Issue 12. How can the Commission improve certainty around timelines for distribution upgrade planning, cost estimation, and construction? Should the Commission consider adopting enforcement measures with respect to these timelines? If so, what should those measures be?
>
> Issue 15. Should the Commission require itemized billing for distribution upgrades to enable customer comparison between estimated and billed costs and verification of the

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

[2] Interconnection Rulemaking 17-07-007, https://www.cpuc.ca.gov/General.aspx?id=6442455170, page updated January 2019

[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)

accuracy of billed costs?

Issue 16. Should the Commission encourage third party construction of upgrades to support more timely and cost-effective interconnection and, if so, how?

Issue 20. How should the Commission coordinate Commission-jurisdictional and Federal Energy Regulatory Commission- jurisdictional interconnection rules for behind-the-meter distributed energy resources, including modification of queuing rules for Rule 21 and Wholesale Distribution Access Tariff (WDAT) projects seeking to interconnect at the same location, clarification of the rules for projects wanting to transfer between the Rule 21 and WDAT queues, and streamlining of the transfer process?

Issue 22. Should the Commission require the Utilities to make improvements to their interconnection application portals? If yes, what should those improvements be?

Issue 23. Should the Commission consider issues related to the interconnection of electric vehicles and related charging infrastructure and devices and, if so, how?

Issue 24. Should the Commission modify the formula for calculating the Cost-of-Ownership charge and, if so, how?

Issue 27. What should be the operational requirements of smart inverters? What rules and procedures should the Commission adopt for adjusting smart inverter functions via communication controls?

Issue 28. How should the Commission coordinate with the Integrated Distributed Energy Resource proceeding to ensure operational requirements are aligned with any relevant valuation mechanisms?

Issue A. What changes are needed to clarify the parameters for approval of system design to achieve non-export and limited export.

Issue B. How should utilities treat generating capacity for behind the meter paired solar and storage systems that are not certified non-export?

The November 16, 2018 amended scoping memo also included Issue D as part of Issue 12. Working Group Three discussed Issue D, and these discussions resulted in a statement in the final report that no proposal was necessary for Issue D:

Issue D. When should the Commission consider results of an initial review or detailed study to be binding? Under what circumstances should the Commission allow the results to be changed?

Working Group Process

Working Group Three met 18 times between November 28, 2018 and May 29, 2019 to develop proposals to address Issues 12, 15, 16, 20, 22, 23, 24, 27, 28, A, B, and D. Nine meetings were via teleconference and lasted 2 hours, and nine meetings were in-person meetings that lasted 4 hours. Most of the in-person meetings took place at the Commission's San Francisco offices, and three meetings took place at other venues in San Francisco and Oakland. In addition, there were six joint meetings of Working Group Three and the Smart Inverter Working Group via teleconference that lasted 1.5 hours, to discuss Issues 27 and 28. Those joint WG3-SIWG meetings began on December 19, 2018 and concluded on April 4, 2019.

Working Group meetings included four meetings specifically designated to discuss the final report towards the conclusion of the Working Group, from May 1, 2019 through May 29, 2019. Two of these meetings were 2-hour teleconferences and two were 4-hour in-person meetings.

There were also a number of sub-group meetings that took place outside of the regular Working Group meetings, for supplemental discussion that parties deemed useful to make progress on proposals for a number of issues. In particular, sub-groups met on Issues 12, 22, 23, 27-28, and A-B. Typically, sub-groups were formed during a normal Working Group meeting, with either Gridworks as facilitator or a party suggesting that a sub-group meet, and a poll being taken during the meeting of parties desiring to participate in the sub-group. Proponents in the process of writing or revising proposals also consulted directly with one or more other parties as they deemed useful in the process of developing their proposals.

Gridworks was contracted to facilitate Working Group Three, which included maintaining the Working Group participant list, managing the Working Group schedule, arranging meeting logistics, setting meeting agendas, sending meeting announcements, preparing meeting slide decks, taking 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 proponents who were drafting proposals, coordinating comments and counter-proposals on proponent proposals, writing final report drafts for each issue in three stages of revision (versions "v1", "v2", and "v3"), setting the schedule of final report review and revision, providing guidance on the scope of party comments for each revision stage, soliciting and incorporating party comments on final report drafts, and preparing the final report.

The Working Group schedule was designed such that there would be an initial discussion and a final discussion on each issue (see Table 1). This meant that discussion of several issues was often proceeding in parallel. In any given meeting, discussion of a particular issue might be scheduled for a duration ranging from 20 to 90 minutes.

On some issues, Gridworks prepared an issue brief for the initial discussion, and on some issues a party proponent prepared the issue brief. Following the initial discussion, parties developed proposals, which were discussed, developed and commented upon in multiple rounds in the course of multiple Working Group meetings. At various stages of the process, utility parties were requested to comment on proponent proposals by given deadlines, and often submitted counter-proposals in the course of their comments. For Issues 22 and 23, surveys were also employed, with on-line survey links sent out to all Working Group Three participants.

The intention of this schedule was that by the final discussion for a given issue, proposals and party positions would be finalized. Following the final discussion, an issue proponent would finish writing their final proposal, and Gridworks would then write the first draft of the final report for that issue, based on the understandings reached in the final discussion and on the final proponent proposal. (Note: as this process was developed during the course of the Working Group, some of the first issues to be addressed did not follow this format as closely as the later issues, notably Issues 12, 15, and 16.)

Completion of the final report for each issue then proceeded in writing in three iterations (versions v1, v2, v3), followed by discussion and resolution at four meetings (May 1, May 8, May 22, and May 29) dedicated to the final report, including review of the text, and editing and agreement on any outstanding points requiring resolution that remained in the text.

Table 1: Schedule of Working Group Discussions by Issue

Issue(s)	Initial discussion	Final discussion	Number of meetings
12, 15	12/12/18	2/13	7
16	1/10	2/13	5
20, 24	3/6	4/17	5
22	3/6	3/27	3
23	1/10	3/27	9
27, 28	12/19/18	4/17	7*
A, B	1/23	3/6	5

(*) Six of the seven meetings for Issues 27 and 28 were joint meetings with the Smart Inverter Working Group

Consensus and Non-Consensus Proposals

Working group members made significant efforts to reach consensus on each issue. Of the 41 individual proposals across all eleven issues, 23 of these were consensus proposals and 18 were non-consensus proposals. 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.

The exception might have been Issues 22, 23, 24, and 27, where more time might have resulted in further progress, but in these cases a very substantial amount of additional time would have been required, much more than the Working Group could devote. Given the time constraints of the Working Group, Issue 22 contains a consensus proposal calling for further Commission action, Issue 23 contains a non-consensus proposal calling for a sub-group to be formed to continue working on technical recommendations, and Issue 27 contains a non-consensus proposal calling for a workshop at a later date.

A proposal marked "consensus" received general support from all Working Group members who participated in meetings when that proposal was discussed, and no party expressed opposition. A proposal marked "non- consensus" received both support and opposition from members who participated in meetings when that proposal was discussed.

For proposals where consensus was not reached, the Working Group attempted to document the various viewpoints in final report "Discussion" sections to provide the Commission with sufficient information to make an informed decision. Non-consensus proposals also include a list of supporters and opponents to provide information about the extent to which the proposal was supported and opposed.

All parties were given a final opportunity during drafting of this Final Report to indicate or change their support/oppose position on the list of supporters and opponents on any proposal, based on the final wording of each proposal. Parties were given until May 31 to so indicate; however, any changes in support/oppose position after the final May 29 Working Group meeting could not be accompanied by other changes to the text of party positions or proposal Discussion sections.

Substantive areas of non-consensus, with one or more non-consensus proposals developed to address these areas, included:

Issue 12: Timelines and goals for timeline tracking, review of progress towards goals, and substation upgrade notifications

Issue 16: Third-party work on existing de-energized distribution systems

Issue 23: Forming a sub-group to address technical requirements for V2G-AC (mobile inverter) interconnections, clarifying a pathway for pilot or experimental use of V2G-AC systems, and adding tracking of V2G interconnections to interconnection portals

Issue 24: Cost-of-ownership (COO) as applied to like-for-like replacements, replacement costs component of COO, and the concept of *net-additional* COO

Issue 27: Convening a workshop on DERMs and convening the Smart Inverter Working Group to refine specifications for the Set Active Power Mode function

Issue A-B: Allowing inverter settings to vary seasonally over the course of a year (to allow for scheduling under Working Group Two Issue 9)

A number of other areas of non-consensus arose in various issues during discussions, but these areas did not result in non-consensus proposals, mainly because either proponents withdrew the proposals, or because compromises and/or consensus was able to be reached on other related proposals.

Working Group Materials

Working Group materials were posted to and available publicly throughout the Working Group process on the Gridworks Working Group Three website: https://gridworks.org/initiatives/rule-21-working-group-3. In addition, the Working Group made active use of a OneDrive shared file space, which contained all the proposals, counter-proposals, and party comments on all issues discussed, including multiple rounds of party comments and edits on draft versions of this Final Report for each issue individually.

Working Group Participants

"Working Group Three" (or just "the Working Group") references all active parties participating in Working Group Three 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.

California Energy Commission ("CEC")
California Energy Storage Alliance ("CESA")
California Independent System Operator ("CAISO")
California Public Advocates Office
California Public Utilities Commission
California Solar & Storage Association ("CALSSA")
Clean Coalition
Electric Power Research Institute ("EPRI")
eMotorWerks
Enphase
Fiat Chrysler
Green Power Institute ("GPI")
Honda
Interstate Renewable Energy Council ("IREC")
JKB Energy
Kitu Systems

LPS
Nuvve
Opengrid
Pacific Gas & Electric ("PG&E")
Society of Automotive Engineers ("SAE")
Small Business Utility Advocates ("SBUA")
Southern California Edison ("SCE")
San Diego Gas and Electric ("SDG&E")
Solar Edge
Stem
Sunrun
Sunworks
TechFlow
Tesla
The Utility Reform Network ("TURN")
Willdan
X-Utility

Issue 12

How can the Commission improve certainty around timelines for distribution upgrade planning, cost estimation, and construction? Should the Commission consider adopting enforcement measures with respect to these timelines? If so, what should those measures be?

PROPOSAL SUMMARIES

Proposal 12-a. Consensus
Establish a framework for quarterly tracking and reporting on timelines for the interconnection application review process and for design and construction of interconnection-related distribution upgrades. The framework includes twelve specific timelines for tracking and reporting.

Proposal 12-b. Non-consensus
Include seven additional timelines in the framework for tracking and reporting.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy
Opposed by: PG&E, SCE, SDG&E

Proposal 12-c. Consensus
Establish standard timelines for design and construction of interconnection-related distribution upgrades, which can be either: (i) 60 business days for design and 60 business days for construction; or (ii) design and construction timelines as agreed with customer.

Proposal 12-d. Non-consensus
Establish standard timelines for installation of Net Generation Output Meters (NGOMs), which are either: (i) 20 business days for design and invoicing, and 20 business days for construction; or (ii) design and construction timelines as agreed with customer.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy, SDG&E, Tesla
Opposed by: PG&E, SCE

Proposal 12-e. Consensus
Customers will be notified whenever a timeline is not met, and notification will include: (a) new expected date; (b) category of delay; and (c) reason for the delay.

Proposal 12-f. Non-consensus
Set an overall goal that 95-100% of projects meet all timelines within the framework for tracking and reporting within two years after the start of tracking.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy, SCE, Tesla
Opposed by: PG&E, SDG&E

Proposal 12-g. Non-consensus
If initial tracking reveals that a utility is not meeting the goal established by Proposal 12-f, the utility shall: (1) set additional intermediate goals within the first two years after the start of tracking, and (2) establish a process to achieve compliance within two years of the start of tracking.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy, Tesla
Opposed by: PG&E, SCE, SDG&E

Proposal 12-h. Non-consensus
The overall goal for timelines from Proposal 12-f would apply to: (i) all non-NEM projects; and (ii) all NEM projects > 30 kW.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy, SCE, Tesla
Opposed by: PG&E, SDG&E

Proposal 12-i. Non-consensus
After two years of tracking and reporting have been completed, Energy Division will reconvene the parties for a discussion of whether the goals have been achieved and, if not, what further steps (if any, based on the situation presented), would be appropriate to take. The Commission should clearly indicate that financial penalties will be on the table for discussion if the goals are not met.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy
Opposed by: PG&E, SCE, SDG&E

Proposal 12-j. Non-consensus
Utilities should provide quarterly updates on substation upgrades to applicants whose projects are dependent on a given substation upgrade.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy
Opposed by: PG&E, SCE, SDG&E

BACKGROUND

Issue 12 was discussed over the course of four Working Group meetings and three conference calls. During initial discussions and in proposals, some parties claimed that distribution upgrade design and construction timelines are not being set, communicated, and/or adhered to in a sufficiently predictable and consistent manner. Some possible consequences are that: (a) project developers cannot give reliable estimates to their customers; (b) customers may have to carry their own facilities loan or leasing costs for what could be considered unreasonably or unpredictably long periods, forgoing revenue to cover loan or lease costs until facilities are operational; and (c) utilities are not being held sufficiently accountable for communicating and adhering to timelines. The significance, validity, and seriousness of the above claims varied depending on utility, project type, and project size.

Some parties claimed that delays, uncertainties, and lack of communication are serious issues, affecting the commercial viability of businesses, jobs, and the very willingness of companies to operate in the distributed energy sector. The Working Group reviewed some data and examples related to timeline issues, but recognized that comprehensive data regarding specific milestones discussed within the Issue 12 proposal does not currently exist. Parties also cited specific types of projects that could be associated with significant delays and uncertainties, again depending on the utility, such as NEM aggregation projects (which can require review of ownership and land), additional metering for solar and storage (with examples of this taking 6-12 months), and some residential 5-kW-range solar systems (with examples of taking 6-12 months for a transformer).

Fundamentally, parties wished to see measures that would create higher levels of accountability, transparency, communication, and consistency around all timelines, and to identify areas experiencing challenges that would benefit from further review. Timely and consistent notifications of project-specific delays to developers and customers was also identified as an area of concern.

While there is some limited reporting available to parties, public interconnection queues, and individual IOU NEM data, there are gaps in those sources that prevent the utilities, stakeholders and Commission from having an objective source of data to facilitate discussions about what is, and is not, working in the process. Parties in the past have proposed data gathering, and the discussion recognized that the CPUC is already conducting an independent study review of interconnection timelines during 2019. Nevertheless, Parties generally agreed that Issue 12 proposals can be put forth in parallel with that independent review.

Utilities provided information on their current practices related to upgrade timelines. All utilities said improvements had been made and were being made in timeline setting, communication, and adherence, and that anecdotes by parties might relate to past practices and not the current situation. With respect to the upgrade timelines, SDG&E noted that it agrees on specific timelines with the customer for each project, and these timelines are included in interconnection agreements and discussed and updated with the customer throughout the project life cycle. SCE noted that it already provides best-practice upgrade timelines, which include 60 business days for design and 60 business days for construction, and that timelines are included in interconnection agreements. PG&E said it had been working on service planning improvements for the past three years, and recently set up a dedicated centralized work group to handle all generation interconnection requests, an expected improvement because not all region-based cost estimators are very familiar with generation interconnections.

With respect to the broader process timelines, each of the utilities currently has a different method for tracking timelines. For some utilities, not all the timelines in Rule 21 are currently tracked directly and thus the parties worked together to come up with a list of timelines to track that could be reasonably achieved by all the utilities.

Utilities also explained some of the factors that cause variability and uncertainties in timelines. For example, some factors that extend construction timelines and only become apparent after design is completed are: (a) when replacing a pole need to coordinate with other agencies and the mechanism for approval by other agencies can be a 45-day process; (b) the FAA becomes involved if there is a need to increase height of pole by 1ft or more, and FAA has 45 days to respond; and (c) land rights or permitting issues. Also, construction timeline variability or uncertainties come from construction crews being used for emergency work, storm duty, or if a customer site is not ready or customer hasn't done necessary preparation work. In general, timelines depend on scope of work, jurisdiction, the timing of construction, the type of construction, permits, environmental reviews, environmental mitigations, trenching, time of year (i.e., cannot have substation outages during the summer), etc. Another factor cited was the introduction of new technologies, especially introduction of new types of batteries in home systems, which means that system planners not familiar with the technologies have to learn about them first.

In addition, interconnection customers also have to ensure their portion of the project is completed to allow for the utility connection which is not within the utility's control and can also lead to related utility delays if the interconnection customer's portion of the project is not ready.

Non-utility stakeholders responded to these utility explanations of factors by saying that exceptions will always be needed for emergencies, delays from other agencies, and other reasons, but that it is still useful to have standard expectations.

Although the scoping memo referred specifically to upgrade timelines, parties also discussed the need for improved tracking and accountability for all Rule 21 timelines, including specifically those associated with the major process steps.

The discussion also noted the linkage of Issue 12 with Issue 22 on interconnection portals, in providing online timeline information, updates, and notifications.

DISCUSSION

Proposal 12-a. Consensus

Establish a framework for quarterly tracking and reporting on timelines for the interconnection application review process and for design and construction of interconnection-related distribution upgrades. The framework includes twelve specific timelines for tracking and reporting:

1. Time from submission of Interconnection Request (IR) to utility's acknowledgment of receipt
2. Time from submission of IR to time deemed complete
3. Time from IR deemed complete to completion of initial review and provision of results
4. Time from Supplemental Review start date to completion of Supplemental Review
5. Time from Electrical Interdependence Test (EIT) start date to EIT completion.
6. Time from EIT completion until EIT results scoping meeting is held.
7. Time from study scoping meeting until study agreement provided.
8. Time from System Impact Study start date to System Impact Study completion date
9. Time to provide Draft Generator Interconnection Agreement after applicable milestone
10. Time from Draft Generator Interconnection Agreement Provided or Final Study Report date for Detailed Study to date Generator Interconnection Agreement executed
11. Time from when the customer provides the utility it has completed all of its obligations under the agreements (F.5.b), including commissioning tests, to when the utility provides the customer Permission to Operate

12. Total time from submission of IR to Permission to Operate (note: not in Rule 21, tracked for informational purposes)

Utilities did not want to establish retroactive baseline data, saying the burden was too great, but looked to establish future baselines, for example within six months after tracking begins.

SCE commented that its tracking and reporting of timelines #2 and #3 do not include reporting on generating initial (non-binding) estimates of upgrade costs, when required. SCE also commented that timelines #11 and #12 both include customer sponsored items, and that tracking of these timelines is being proposed for information reporting purposes only, and does not imply that a timeline metric is being suggested or is necessary.

SCE said that timeline tracking will necessitate some configuration in existing systems to enable comprehensive reporting capability. SCE proposed to modify its existing systems to enable timeline reporting of aforementioned process segments. Timeline reporting by SCE may commence as early as July 2019; if timeline reporting is expected to not commence by this date, SCE will inform Working Group Three. SCE further commented that it has a new IT platform currently under development which will be designed to enable enhanced visibility of timeline tracking for customers in the near future and which will make reporting of those metrics to regulators more efficient. Each utility operates with its own IT platform and resources and will have to make respective adjustments in order to report more effectively.

PG&E agrees in principle with establishing a framework for tracking and reporting on timelines as a means for identifying process gaps and moving beyond anecdotes for determining areas of the process with the most need for improvement.

Proposal 12-b. Non-Consensus

Include seven additional timelines in the framework for tracking and reporting, for purposes of either accountability or information.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy
Opposed by: PG&E, SCE, SDG&E

The proposed seven additional timelines are:

Timeline already defined in Rule 21 (as defined steps in the screening process), tracked for accountability purposes:

- Time from request to consider modification to determination whether modification is material (F.3.b.v).

Timelines not already defined in Rule 21, tracked for accountability purposes using timelines proposed below:

- Time for responding to line-side taps variance requests (for utilities that require a variance request)
- Design and invoice of net generation output meter
- Installation of net generation output meter

Timelines not already defined in Rule 21, tracked for informational purposes:

- Time from customer agreement to proceed to final design and issuance of invoice
- Time from customer payment of invoice and completion of customer work to completion of upgrade construction
- Time for scheduling of Commissioning Test.

<u>Proponent positions:</u>

IREC considers these timelines as an interim step that can commence quickly (by mid-2019) to begin tracking the process and construction timelines in Rule 21. This is not intended to replace or circumvent the efforts of the outside review being done by the Energy Division consultant. IREC, in particular, believes that there are likely more timelines that may need to be tracked, but agrees that the list identified here is a good start for now.

IREC says there is no clear timeline for scheduling of a commissioning test, despite the fact that this is a critically important juncture for projects to finally obtain permission to operate. It is thus important to track this step to ensure that it is happening within a reasonable timeframe. The lack of a timeline in the Tariff does not mean this is not important to track for informational purposes.

CALSSA called the timeline for responding to line-side taps variance requests a “pain point” for developers and said this should be included in the proposal to foster accountability. IREC believes there are good reasons to track the Rule 21 timeline for responding to modification requests (F.3.b.v), saying it is an important step in the process and has been the source of controversy and thus should be tracked and reported on.

Tesla says that design and invoice of net generation output meter and installation of net generation output meter are steps that have historically posed significant challenges in terms of the amount of time taken, and need to be tracked.

<u>Utility positions:</u>

SCE does not agree to include timelines for requests for modifications and scheduling of commissioning test as refined modification procedures were just approved in March 2019 and are pending update in the tariff with subsequent Advice Letters and related review/approval forthcoming. In addition, the Commissioning test is not a one side utility obligation and is contingent on the interconnection customer agreeing to test and providing access and therefore should be removed as it is customer contingent as well.

SCE and SDG&E said other timeline issues could be looked into in the future, given the overall framework being established in Proposal 12-a. SDG&E believes some of these additional timelines are more of a process issue and not a tracking issue, and that the Interconnection Discussion Forum is the proper venue to further discuss.

Proposal 12-c. Consensus
Establish standard timelines for design and construction of interconnection-related distribution upgrades, which can be either: (i) 60 business days for design and 60 business days for construction; or (ii) design and construction timelines as agreed with customer.

There was consensus that the "60-day clock" in the case of option (i) would commence upon payment and after the customer has done everything necessary on their end to prepare for construction.

Proposal 12-d. Non-consensus
Establish standard timelines for installation of Net Generation Output Meters (NGOMs), which are either: (i) 20 business days for design and invoicing, and 20 business days for construction; or (ii) design and construction timelines as agreed with customer.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy, SDG&E, Tesla
Opposed by: PG&E, SCE

CALSSA identified NGOMs timelines as an important issue in its original proposal. There was some discussion of the need for timelines specific to NGOMs. CALSSA initially proposed the 20 days/20 days for all projects.

Parties noted that it needs to be very clear what conditions start the 20-day clocks, including customer notification that customer is ready, customer has provided all information needed in order to invoice, payment has been made (invoice paid), and inspection is complete (always with local inspectors). Parties suggest that the timelines for design and estimate should begin upon submission of a signed interconnection agreement, and for construction the timeline should start on meter release or receipt of payment.

<u>Utility positions:</u>

SDG&E agrees to proposal, and said it supports the ability to have two-way flexibility with the customer in agreeing to the duration with the customer up front as it's SDG&E's goal to meet the customers in service date.

SCE does not agree to the proposal, and says it currently achieves 1-2-month installation for the vast majority of NGOM installations. However, process improvements that require IT system function improvement are in development to address the minority of complex NGOM installations requiring lengthier timeframes. These process improvements are already underway with a focus on administering NGOM requests in a similar fashion as with existing NEM Paired Storage, which currently averages 2 months for installation. SCE also offered to provide interim updates either through the interconnection forum or other means.

SCE noted during the discussion that 20 days for design and 20 days for construction was not based on average timeline tracking but was an arbitrary timeline proposed by CALSSA, although SCE supports establishing a reasonable timeline.

PG&E is open to developing IT infrastructure to track NGOM timelines, but does not agree with establishing a timeline of 20 business days for design and 20 business days for construction as these timelines can vary across the service territory based on local needs.

Proposal 12-e. Consensus

Customers will be notified whenever a timeline is not met, or at risk of not being met, and notification will include: (a) new expected date; (b) category of delay; and (c) reason for the delay. The reason for delay will be selected from set categories of reasons.

The category of delay is needed in order to track which types of delays are most common. However, on the question of further detailing of reason for delay beyond a set category, there was non-consensus among parties. CALSSA and IREC proposed that utilities provide project-specific reasons for delays to demonstrate why a project is delayed, and that the utility had given specific attention to the delay for that project. In other words, the obligation needs to be to provide a reason as to why the utility is not in compliance with its obligations for that project, not just a generic response that is auto-generated, that does not accomplish the goal of accountability or help the customer understand what is actually going on with their project.

PG&E agrees with notifying customers when a timeline is not met and currently utilizes an automated system to do so. Automatic delay notices provide a new expected date and point of contact. When the delay notice is issued by a PG&E representative, a reason is entered and tracked.

However, PG&E does not agree with site-specific reasoning for each delay notice because not all delay notifications are for construction tasks, therefore not all have a site-specific reasoning. For construction-related tasks, PG&E does its best to provide site-specific reasoning, but the workflow management databases are separate between Electric Grid Interconnection and Service Planning and EGI doesn't have a line of sight into the step by step construction process.

For SCE, with the implementation of the Grid Interconnection Process Tool (GIPT), it is expected that project timelines will be available on the portal to customers. Therefore, customer "notice" would be available to the interconnection customer through their project review on the GIPT interconnection portal. SCE makes this point so as to clarify SCE's understanding of what "notice" would involve. In addition, it is also expected that an automated notification will be issued through the GIPT system requesting the interconnection customer to check their project status. As GIPT is currently going through the implementation process, the additional notices discussed under this proposal are subject to the functionality become available.

It was also discussed, but no consensus was achieved, on whether CPUC Energy Division should be similarly notified. Parties said this notification could be addressed when details of the actual reporting are developed. SDG&E does not support notifying the CPUC Energy Division every time a timeline date is not met, as this process would be overly burdensome. PG&E is open to notifying Energy Division and suggests that if this is pursued, PG&E can provide a report to Energy Division of all notifications issued in the work management system. If Energy Division would rather be notified each time a timeline is not met, PG&E can add a CPUC email as a bcc. SCE proposes to place reporting on their interconnection site that parties can review at their own direction, as discussed above.

Substation upgrades need to be treated differently because they often have much longer timelines with more uncertainty. Rather than setting specific target completion dates and putting those in interconnection agreements, CALSSA proposes that utilities give quarterly updates to all customers that are waiting for the upgrade before they can be interconnected. This proposal was not discussed further, as substation upgrades were deemed out-of-scope during the first discussion for Issue 12.

Proposal 12-f. Non-consensus

Set an overall goal that 95-100% of projects meet all timelines within the framework for tracking and reporting within two years after the start of tracking.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy, SCE, Tesla
Opposed by: PG&E, SDG&E

Note by Working Group Facilitator Gridworks: PG&E changed its position on Proposal 12-f from support to oppose at the end of the Working Group process, when no discussion time remained for parties to respond, and the discussion below for Proposal 12-f was not changed.

During the Working Group meetings and calls, there was considerable discussion of goals. Both PG&E and SCE said they would work to commence tracking timelines in July 2019, and so the overall goal would be for July 2021. PG&E and SCE will report on their progress quarterly and agree to seek to come into full compliance on all timelines by July 2021.

Utility positions:

SCE agreed that goals were useful for process improvements and corrective actions. Goals stem from a benchmark of the mutually accepted effectiveness of a process or function. Once a goal is established, the goal serves to inform process owners as to process efficacy. The data collected for goal tracking is used for first, process or resource improvement, and second, for administration of corrective action or commendation depending on results of process improvement and optimization.

PG&E did not agree that goals should be linked to any future enforcement measures, but views tracking timelines toward goals as an opportunity that should be used to identify process gaps and parties should collaborate to address the process gaps. PG&E wants to leverage collective stakeholder expertise to analyze collected data, collaborate on identifying and closing any gaps and keep implementation of improvements prioritized to areas with the most need as determined by the data.

SDG&E was not in favor of beginning reporting in July 2019, but would begin reporting as ordered. SDG&E is not in consensus with setting an overall goal. With SDG&E Rule 21 applications accounting for less than approximately 0.1% of all applicants, setting requirements of establishing a goal or shortening duration of delays to reach compliance thresholds to incrementally improve progress is not beneficial to SDG&E ratepayers.

Proposal 12-g. Non-consensus

If initial tracking reveals that a utility is not meeting the goal established by Proposal 12-f, the utility shall: (1) set additional intermediate goals within the first two years after the start of tracking, and (2) establish a process to achieve compliance within two years of the start of tracking.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy, Tesla
Opposed by: PG&E, SCE, SDG&E

In addition to proposing an overall goal of 95-100% of projects meeting their timelines by the end of a two-year period, which was adopted as Proposal 12-f, IREC also proposes a step-wise process for utilities to set intermediate goals to incrementally improve progress until compliance is achieved. IREC also proposes a goal to shorten the duration of individual project delays.

IREC's proposal is that incremental progress goals be established as follows. If less than 95% of all projects meet the Rule 21 timeframes for all steps, the utility shall set incremental progress goals based on the baseline established in January 2020. The goals shall establish incremental improvement goals to be identified for each quarter. These goals shall be published on the utility's website.

The purpose of these incremental goals is to get the utilities on the path towards a period where all projects are being completed within the Rule 21 timeline, by ensuring that each step of the process is timely achieved.

In addition, while the goals identified above aim to achieve 95-100% compliance with each step of the timelines for every project, it is also important to ensure that in the interim no individual projects has to wait an unreasonably long period of time for results/utility response during any step. The purpose of this goal is thus to ensure that when there are delays, some projects are not held up for unreasonable periods of time. Thus, for each project that exceeds the allotted timeline by more than 5 days for increments 15 days or less, or by more than 10 days for increments greater than 15 days, the utility should document and report the unique reasons for the delay in the report and discuss specific steps taken to address or resolve the delay.

During each quarterly report, the utility shall identify progress toward these goals. If there are still outstanding timelines where the utility is not achieving 95-100% compliance, the utility should document what steps it is taking to make progress towards the goals above.

There was discussion of "improvement potential" being developed by the utilities once baselines are established, with more specific goals to be developed after baselines are established, for example starting in January 2020.

<u>Utility positions:</u>

> PG&E and SDG&E did not agree to set intermediate goals, and PG&E, SCE, and SDG&E did not agree to a workshop after two years to consider further financial accountability mechanisms if the overall goals have not been met.
>
> SCE will provide periodic updates on its progress at Interconnection Discussion Forums, as it commences timeline tracking and quarterly reporting. Updates may include steps SCE may be taking to achieve 95% timeline performance, should data show that it falls outside the performance band of 95 – 100%. Tracking efforts in 2019 and 2020 will serve to identify baseline data.
>
> PG&E wants to leverage collective stakeholder expertise to analyze collected data and collaborate on identifying and closing any gaps, as stated in Proposal 12-f. The data can be used to identify areas of opportunity, PG&E does not believe arbitrarily setting a deadline for fixes makes sense without knowing the scope of the solution.
>
> SDG&E Rule 21 interconnections account for less than approximately 0.1% of all applications, so setting requirements of establishing intermediate goals or shortening duration of delays to reach compliance thresholds to incrementally improve progress is not beneficial to SDG&E ratepayers.

Proposal 12-h. Non-consensus

The overall goal for timelines from Proposal 12-f would apply to: (i) all non-NEM projects; and (ii) all NEM projects > 30 kW.

> Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy, SCE, Tesla
> Opposed by: PG&E, SDG&E

Currently, the quarterly reports the utilities provide to the Commission do not include non-NEM projects. The reporting for NEM projects does not include any detail on the steps in the interconnection process. Thus, IREC proposed that the reporting herein cover all projects except NEM projects < 30 kW (Standard NEM). There is general agreement that standard NEM projects generally are interconnected quickly and the volume of projects would make reporting complicated.

The application of the overall goal for timelines to specific types of projects was discussed and agreed by all parties except PG&E. PG&E did not agree to applying this goal methodology to any subset of projects based on size. As stated in Proposal 12-f, PG&E wants to keep implementation of improvements prioritized to areas with the most need as determined by the data. Currently, standard NEM and NEM-paired storage have been highest volume programs, so PG&E's focus has been on improving those.

Initial reporting by SCE, to start in August 2019, will include Rule 21 non-exporting projects, with the remaining Rule 21 interconnection request types included for reporting and tracking as SCE's new database is built to support those new types of interconnection requests.

Proponent positions:

> Tesla believes that for the goals to be meaningful, it will be important to assess adherence to these timelines for projects of different sizes. Missed timelines is primarily an issue impacting larger projects so to assess success based on all projects will result in small projects, where this has not historically been as much of an issue, skewing the results and giving the false impression that there is not a concern. Given this, important to assess adherence for different project cohorts, based on NEM vs. non NEM and small (< 30 kW) and large (> 30 kW). Additional granularity may be appropriate.

Utility positions:

> SCE: There are current reporting obligations for Rule 21 submitted on a quarterly basis along with for NEM projects sent in accordance with the Distributed Generation Rulemaking. The reporting for NEM projects does not include any detail on the steps in the interconnection process as it focuses on the total project cycle. Thus, IREC proposed that the reporting herein cover all projects except NEM projects < 30 kW (aka Standard NEM). There is general agreement that standard NEM projects generally are interconnected quickly and the volume of projects would make reporting complicated.

Proposal 12-i. Non-consensus

After two years of tracking and reporting have been completed, Energy Division will reconvene the parties for a discussion of whether the goals have been achieved and, if not, what further steps (if any, based on the situation presented), would be appropriate to take. The Commission should clearly indicate that financial penalties will be on the table for discussion if the goals are not met.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy
Opposed by: PG&E, SCE, SDG&E

The utilities did not agree that discussion of financial penalties would be appropriate after two years of tracking, but did agree to reconvene for discussion of appropriate next steps. IREC and other stakeholders strongly believe that if there is a failure to largely come into compliance after the proposed goal setting process, that it is reasonable, and indeed necessary, to consider whether there needs to be more rigorous accountability measures adopted, including those that might impose financial penalties on the utility shareholders for failure to comply with the tariff.

Proponent positions:

IREC believes that a financial penalty mechanism may be appropriate, but is hopeful that with concrete goals, tracking and reporting that it will not be necessary. IREC believes the goals set are conservative, reasonable, and achievable. Thus, IREC believes it is reasonable to consider financial penalties if the voluntary goal setting process fails

TURN position:

TURN notes that if a financial penalty is being considered or later imposed, it needs to be made clear that the penalty will be paid by shareholder dollars, not ratepayer dollars.

Utility positions:

PG&E, SCE, and SDG&E disagree that a penalty should be paid by either shareholder or ratepayers dollars. Consistent with the regulatory compact and cost of service regulatory ratemaking principals, the IOUs must be permitted to recover prudent, reasonable costs associated with generating facility interconnection.

SDG&E is not in consensus with this proposal as SDG&E does not want to prejudge the need for another workshop.

Proposal 12-j. Non-consensus
Utilities should provide quarterly updates on substation upgrades to applicants whose projects are dependent on a given substation upgrade.

Supported by: CALSSA, Clean Coalition, GPI, IREC, JKB Energy
Opposed by: PG&E, SCE, SDG&E

Parties agreed that substation upgrades, although sometimes the source of customer/applicant complaints about long delays and uncertainties, cannot be subject to benchmark timelines due to their complex nature.

Proponent positions:

CALSSA: Substation upgrades are the source of strong customer dissatisfaction about long delays and timelines that change over time. When a customer cannot interconnect until substation work is completed they have a difficult time balancing the timing of taking out a loan, doing construction, using the federal tax credit, and getting interconnection approval. It is greatly disruptive when a utility indicates that the work will take nine months and it ends up taking two years. However, substation upgrades cannot be subject to standard benchmark timelines because they tend to be complex and include multiple uncertainties. CALSSA recommends that utilities are not held to a standard for substation upgrade timelines but that they send quarterly communications to customers that are waiting for substation work to be completed before they can get permission to operate their systems.

Utility positions:

PG&E will entertain providing quarterly updates on substation upgrades as a business practice, but does not support adding this requirement to Rule 21. In addition, PG&E recently added a dedicated substation engineer to oversee substation upgrades related to generation interconnection projects and will continue to improve the Rule 21 process via collaboration with stakeholders and developers.

SCE: Project meetings are a regular part of the pre-construction and construction activity for projects with large upgrades, including substation upgrades. The first kickoff meeting of these regular project meetings occurs soon after execution of the interconnection agreement, if the work is to commence right away, or at a mutually agreed time prior to the commencement of "construction activities". The cadence of subsequent meetings is agreed to by all the parties, and if an IC wants more frequent meetings, or a meeting about a certain topic, those are reasonably accommodated. During these meetings; schedule, scope, and cost are always at the forefront of discussion. Thus, there already exists ample opportunity for SCE to have regular status updates with interconnection customers about substation upgrades and additional provisions in Rule 21 are not necessary.

SDG&E will continue to provide updates to its Rule 21 interconnection applicants via the project schedules it develops and updates throughout the design and construction of the project. SDG&E does not support adding this requirement as part of the Rule 21 tariff, but instead would continue to create two-way transparency based on design and construction milestones as agreed to and tracked by both the developer and SDG&E.

Issue 15

Should the Commission require itemized billing for distribution upgrades to enable customer comparison between estimated and billed costs and verification of the accuracy of billed costs?

PROPOSAL SUMMARIES

Proposal 15-a. Consensus
Utilities should do what is immediately possible to provide cost itemization based on existing capabilities. As utilities evolve their processes in the future, each utility should strive to improve their itemized billing processes for further applicant and customer clarity.

Proposal 15-b. Consensus
The Commission should consider "bill on estimate" cost estimates in the future. This would need to be scoped into a future Rule 21 Working Group or OIR.

BACKGROUND

Project developers typically provide cost estimates to customers based on the Unit Cost Guide. (Note that the Unit Cost Guide is based on general costs but not meant to replace a specific system study. In accordance with 16-06-052, the Unit Cost Guide is for informational purposes only and does not govern actual costs.)

If developers knew the actual costs incurred for some separate components of total cost, they could improve future estimations for their customers. Parties emphasized the need for cost estimates around major components like line runs and transformers. Utilities highlighted that there are already tools such as the Unit Cost Guide mentioned above, that also can guide developer cost estimates.

However, there is no consistency across the utilities regarding the level of detail provided in the final accounting invoice. Developers have expressed concern regarding the level of detail provided in utility estimates to better reconcile costs from the original study estimate.

Utilities in many cases provide initial cost estimates that are itemized by component but when they send the invoice there is only one cost number for the entire upgrade project. This lump sum billing does not allow for developers to improve future cost estimations, it agitates customers who get large bills without any substantial information, leaving them wondering what they've actually paid for. It also reduces the future potential for cost comparisons with third-party contractors doing distribution upgrades.

Parties discussed what could be an appropriate level of detail for cost itemization. Several agreed that the level of detail required is typically just a few simple line items, at roughly the same high-level of detail as given in the Unit Cost Guide, mostly line items for meters, line runs, transformer and SCADA. Therefore, issue proponents proposed that the cost categories could be modeled from the Unit Cost Guide.

One question facing the Working Group was how onerous is it for utilities to provide the appropriate level of detail of 3-5 line-items for a distribution upgrade project, given their existing information and management systems. If the amount the customer pays is based on a true-up of actual costs, it is difficult for utilities to estimate how much of the labor cost was for different components of the work. Utilities were open to discussing solutions within the capabilities of their existing IT and cost-accounting systems.

This discussion about possible solutions then led to a further discussion about different types of billing, specifically "bill-on-estimate" billing and reconciled billing. Under the bill-on-estimate construct, the interconnection customer's cost responsibility is equal to the estimated cost provided by the utility before construction begins. The utility does not reconcile and the cost estimate is itemized. Under reconciled billing, the customer pays a deposit at the time of the final estimate and may make further payments at other milestones. The utility reconciles based on actual costs and the final bill is not itemized. It is difficult for utilities to do itemized bills when they do reconciled billing, partly because they have to estimate how much of the total labor cost went to each item. PG&E currently does "bill-on-estimate" billing for projects below 1 MW and reconciled billing for projects above 1 MW. SCE does reconciled billing for all projects.

Given existing capabilities, of all three utilities, only SDG&E said they would be able to provide the type of cost itemization being discussed without the need to charge customers additional costs. Details are given below in the Discussion.

DISCUSSION

Proposal 15-a. Consensus

Utilities should do what is immediately possible to provide cost itemization based on existing capabilities. As utilities evolve their processes in the future, each utility should strive to improve their itemized billing processes for further applicant and customer clarity.

During the course of five Working Group in-person meetings, utilities investigated the options for providing itemized billing, based on their current IT and cost accounting systems. Only SDG&E is able to provide itemized cost estimates from their existing system, with no additional cost, based on their existing manual process. PG&E and SCE found that solutions were not simple, and required them to incur additional costs.

Utility positions:

> SCE currently prepares the estimate and final accounting invoice based upon interaction of systems that provide the underlying engineering study and then separately into an accounting system that provides a total amount for each Service Order. Given these existing systems, SCE would have to perform a manual process at an additional cost to provide itemization for the indefinite future. An automated version of this option is not feasible in

the foreseeable future due to system constraints and that billing system is tied to other supporting systems and the system topography would have to be revised which is not practical at this time.

PG&E's estimating tool, like SCE, would require IT work in order to automatically develop itemized estimates. To increase the level of detail provided in estimates within existing capabilities, PG&E's current estimating tool can provide an estimated cost for each order number associated with the project.

SDG&E is prepared to provide itemized billing that is consistent with the cost categories set forth in the Unit Cost Guide at no extra cost.

Proposal 15-b. Consensus

The Commission should consider "bill on estimate" cost estimates in the future. This would need to be scoped into a future Rule 21 Working Group or OIR.

As noted in the Background section, parties discussed "bill-on-estimate" billing as an approach that would eliminate the need for an itemized final bill. Under the bill-on-estimate construct, the interconnection customer's cost responsibility is equal to the estimated cost provided by the utility before construction begins, with no reconciliation. The cost estimate would be itemized.

Utility positions:

SCE currently is looking into a "bill-on-estimate' approach.

PG&E proposed a "bill-on-estimate" process to replace final reconciliation. In its research of projects that currently undergo reconciliation (Wholesale Distribution and Rule 21 Export), PG&E determined that on a portfolio level, employing bill-on-estimate would result in billed costs that are consistently lower than actual costs. Therefore, to account for the difference across the portfolio, there would need to be a fixed cost-multiplier applied to the estimate. This cost multiplier would apply to all customers for all projects that trigger capital work or mitigations, regardless of size.

After employing a data-driven approach to reach this number, PG&E can offer bill-on-estimate to all Rule 21 and NEM2 projects with a 20% estimate multiplier. This number may vary across the IOUs based on estimating methodology and tools. PG&E is conducting separate research to evaluate whether an additional percentage multiplier would be necessary for larger projects to provide cost certainty for complex upgrades with higher cost variability while ensuring that the portfolio is made whole.

During the Working Group discussion of PG&E's "bill-on-estimate" process, questions of project size limitations to which PG&E's "bill-on-estimate" would apply were raised by parties. PG&E's "bill-on-estimate" would apply newly only to systems larger than 1 MW, as currently systems smaller than 1 MW already undergo "bill-on-estimate."

Issue 16

Should the Commission encourage third party construction of upgrades to support more timely and cost-effective interconnection and, if so, how?

PROPOSAL SUMMARIES

Proposal 16-a. Consensus
Incorporate by reference tariff Rule 15 eligibility rules into Rule 21, specifically regarding Rule 15, Section G.2 (R15.G.2) minimum contractor qualifications," Rule 15, Section 15.G.3 (R15.G.3) "Other contractor qualifications," and Rule 15, Section I.1 (R15.I.1) "Facility relocation or rearrangement."

Proposal 16-b. Consensus
Have Rule 21 refer to applicable Rule 15 "competitive bidding" language.

Proposal 16-c. Consensus
Remove the "discretion" language in Rule 21 that states "Subject to the approval of Distribution Provider, a Producer may, at its option…" provided that the language is changed from "subject to approval" to "subject to/consistent with Rule 15" contractor selection rules cited in Proposal 16-a.

Proposal 16-d. Non-consensus
Allow third-parties to work on existing de-energized systems under specified scenarios, such as on dedicated lines and in other specified situations.

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

BACKGROUND

Issue proponents pointed to the potential benefits of allowing and encouraging third-party distribution upgrades, including ameliorating some of the ongoing problems with costs and timelines associated with various types of upgrades, creating a more competitive environment that could over time improve costs and timelines, and allowing the incremental costs of accelerated schedules to be borne by project developers benefiting from the accelerated schedules. Generally speaking, the presumption by issue proponents is that third-party upgrades will provide developers with more control over the timing, costs and choice of contractors performing the upgrades, as well as create a more competitive environment.

The primary concerns related to third-party upgrades are safety and reliability of the electrical grid and customers connected to the electric grid. In particular, Rule 21 currently already allows for third-party construction, subject to approval by the Distribution Provider, on interconnection facilities. In addition, as the ongoing operating maintenance and operating costs are based upon facility construction cost, it should not be assumed that use of third-party contractors always will translate to lower costs, considering both initial and ongoing costs.

It is critical that the type of facility for which third-party construction is allowed does not pose potential safety or liability concerns to other energized customers or facilities.

To enable third-party upgrades, parties discussed and considered eligibility rules and competitive bidding language. In preparing Proposals 16-a and 16-b, there was discussion about qualification of contractors, how contractors could be selected, whether there needed to be a list of approved contractors, who would maintain that list, and the role of the CPUC. Working Group participants emphasized it was acceptable to limit third-party involvement to those contractors already being used by the utilities, or by those third-party contractors that meet the requirements set forth in R15.G.2 and R15.G.3. Ultimately, reference to Rule 15 provisions in these proposals resolved those questions.

Parties emphasized that third-party upgrades will still be transferred to and maintained by the utility, as is currently the practice. And that such upgrades must ensure utility design specifications and safety standards are met, as determined by the utility. Utilities said there is a difference in particular when existing energized facilities are involved, for both liability and safety concerns.

Issue proponents GPI and Clean Coalition posed questions about how third-parties can be selected and qualified, what should be the role of the CPUC, and what language changes are proposed for Rule 21. These proponents also provided an issue brief and proposal that included examples where third-party distribution upgrades have been performed, including for SMUD, Imperial Irrigation District, and PG&E. However, subsequent to that issue brief, SCE responded that it contacted SMUD in March 2019 and SMUD represented that allowing third-party work on energized facilities is not consistent with its practices.

Note by Working Group Facilitator Gridworks: After the final discussion of Issue 16 in the Working Group, proponent GPI provided a revised proposal that included further ideas not discussed during the Working Group meetings and not vetted by any utility -- see Annex A.

DISCUSSION

Proposal 16-a. Consensus

Incorporate by reference tariff Rule 15 eligibility rules into Rule 21, specifically regarding R15G.2 minimum contractor qualifications," R15.G.3 "Other contractor qualifications," and R15.I.1 "Facility relocation or rearrangement."[4]

Eligibility rules are needed to ensure third-parties are sufficiently qualified for ensuring safety and reliability. Parties agreed that there was no need to adopt additional language in Rule 21 given that this language already exists in Rule 15.

Proposal 16-b. Consensus

Have Rule 21 refer to applicable Rule 15 "competitive bidding" language.

Only qualified contractors would be able to participate in the bidding, consistent with existing bidding and qualification practices. Parties agreed that here was no need to adopt additional language in Rule 21 given that this language already exists in Rule 15.

Rule 21 would refer to the following specific language in Rule 15:

> R15.G.1.a. – Upon completion of Applicant's installation and acceptance by [utility], ownership of all such facilities will transfer to [utility].
> R15.G.1.e. (part a) – Applicant shall pay to [utility] the estimated cost of [utility's] inspection, which shall be a fixed amount not subject to reconciliation.
> R15.G.1.f. – Only duly authorized employees of [utility] are allowed to connect to, disconnect from, or perform any work upon [utility's] facilities.

Proposal 16-c. Consensus

Remove the "discretion" language in Rule 21 that states "Subject to the approval of Distribution Provider, a Producer may, at its option…" provided that the language is changed from "subject to approval" to "subject to/consistent with Rule 15" contractor selection rules cited in Proposal 16-a.

[4] Along with incorporating R15.G.2, R15.G.3, and R15.I.1 tariff provisions, the existing warranty requirements that currently support these provisions should be included as found in Paragraph 12 of SCE's Form 14-188, *Terms and Conditions Agreement for Installation of Distribution Line Extension by Applicant*, that states: "Applicant warrants that all work and/or equipment furnished or installed by Applicant or its contractor shall be free of defects in workmanship and material. The warranty period shall begin from the date of final acceptance by SCE and extend for one year. Should the work develop defects during that period, SCE, at its election shall either (a) repair or replace the defective work and/or equipment or (b) demand that Applicant repair or replace the defective work and/or equipment, and, in either event, Applicant shall be liable for all costs associated with such repair and/or replacement. Applicant, upon demand by SCE, shall promptly correct to SCE's satisfaction and that of any governmental agency having jurisdiction, any breach of any warranty."

Proponents GPI and Clean Coalition believe that removing the “discretion” language from Rule 21 is a needed reform in achieving the benefits noted in the Background section. Some parties questioned the need for removing the “discretion” language, but in the end Working Group participants agreed this was acceptable as long as “subject to/consistent with Rule 15” is added.

Proposal 16-d. Non-consensus

Allow third-parties to work on existing de-energized systems under specified scenarios, such as on dedicated lines and in other specified situations.

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

There was much discussion about whether and under what circumstances third-parties could work on existing facilities. The utilities were asked to produce scenarios where third-parties could work on existing de-energized facilities. Concerns raised by the utilities included safety, liability, supervision, utility resources, managing customer impacts of planned outages, coordination with other utility construction work, and outage planning. Stakeholders well understood these concerns, but pressed for possible scenarios.

One scenario was initially put forward by PG&E that covered the case where a line was “dedicated” to only one customer, and could be de-energized for third-party work. This idea was incorporated by proponents GPI and Clean Coalition into a revised proposal for the Working Group. But later, the utilities said that in practice such distinctions between “dedicated” and “undedicated” lines are not relevant in determining scenarios open to third-party construction. Scenarios of upgrades to existing facilities by third-parties should remain consistent with Rule 15.I.1, “where new facilities can be constructed in a separate location, before abandonment or removal of any existing facilities…” Also, there remained great concern about safety risks and undermining of Public Utilities Code 399.2 on the utility obligation to design, engineer and maintain the utility's distribution system.[5]

In the end, the Working Group was left with no consensus on any scenarios in which third parties could work on existing de-energized facilities.

During the final discussion of this issue, stakeholders raised another alternative—that project developers could pay for the incremental costs of the utility itself hiring third-parties to have work done faster, consistent with current utility practices for hiring sub-contractors. Utilities replied that they wanted to retain their decision-making practices, that their construction practices often involved multiple projects and facilities coordinated together, and that the hiring of a third-party, should remain their sole decision. Utilities cited that they currently hire third-parties to augment

[5] Public Utilities Code 399.2 states that the utilities maintain control of their distribution facilities and are charged with doing so in a safe, reliable, efficient and cost-effective manner. It further states that each electrical corporation shall continue to be responsible for operating its own electric distribution grid, including, but not limited to, owning, controlling, operating, managing, maintaining, planning, engineering, designing, and constructing its own electric distribution grid.

resources and expedite construction schedules, therefore making the call for additional third-parties moot. SDG&E inquired as to whether there were particular steps in the construction process that posed the most concern for GPI and Clean Coalition. Utilities shared that the construction process involves the utilities as well as permitting processes with other outside agencies, etc. SDG&E expressed concern that having the customer hire a third party alone to assist with construction to expedite the schedule is not helpful because the availability of construction resources oftentimes is not the sole problem. Parties remain interested in continuing to explore incremental costs to applicants for putting additional construction resources (in the form of third parties) on a project if it can decrease construction time, similar to utilities bringing in additional contractors themselves.

Proponent position:

> GPI and Clean Coalition said it appears that all three utilities have “blanket" policies, that in exercising their discretion, they generally disallow third-party electrical upgrades. When GPI made this statement during Working Group discussions, it was not contradicted by utilities.

Utility positions:

> PG&E, SCE, and SDG&E represented support for using current facility practices as allowed under Rules 15 and 16 for construction of new (interconnection) non-energized facilities. There were no scenarios agreed in which a third-party could work on existing de-energized facilities.

Annex A: Issue 16, Proposal Refinement by Proponents

Note by Working Group Facilitator Gridworks: This Annex contains a revised proposal by proponents GPI and Clean Coalition, refined beyond their original proposal discussed by the Working Group. This revised proposal has not been discussed within the Working Group nor vetted by any utility. Gridworks as Working Group facilitator precluded any further discussion or comments on this revised proposal, in the interests of honoring the agreed Working Group schedule.

This revised proposal came on February 20, 2019, after the scheduled final discussion of Issue 16 in the Working Group on February 13, 2019. GPI and Clean Coalition said that in their discussions with utilities prior to February 13, 2019, as well as during the February 13, 2019 Working Group meeting, their proposal development had to undergo significant and last-minute changes and re-thinking, based on utility positions, and that they were not able to adequately respond within the timeframe scheduled for completion of Issue 16. Thus, they provided a revised proposal after discussion was closed.

GPI and Clean Coalition propose Rule 21 tariff changes as follows:

1) Extend Rule 15 to the following circumstances, with IOU oversight and all upgrades completed according to IOU specifications:
    a. De-energized existing facilities on single-customer dedicated distribution lines
    b. With written consent for temporary de-energizing by all other customers on the same distribution line as the applicant, with such written consent to be obtained by the applicant
2) IOUs must fully consider the use of third parties in negotiating GIA milestones (for IOU-required distribution line upgrades) to shorten timelines and reduce costs for these milestone requirements

Issue 20

How should the Commission coordinate Commission-jurisdictional and Federal Energy Regulatory Commission-jurisdictional interconnection rules for behind-the-meter distributed energy resources, including modification of queuing rules for Rule 21 and Wholesale Distribution Access Tariff (WDAT) projects seeking to interconnect at the same location, clarification of the rules for projects wanting to transfer between the Rule 21 and WDAT queues, and streamlining of the transfer process?

PROPOSAL SUMMARIES

Proposal 20-a. Consensus
Clarify through the use of FAQ webpages the transfer processes and permission-to-operate rules for: (i) how projects in the Rule 21 interconnection queue can transfer to the WDAT interconnection queue; and (ii) how eligible resources under existing Rule 21 interconnection agreements can begin the New Resource Implementation (NRI) process at the CAISO.

Proposal 20-b. Consensus
No modification is necessary to the queuing rules for Rule 21 and WDAT projects seeking to interconnect at the same location.

Proposal 20-c. Consensus
Provide some reference language or "soft link" within the Rule 21 tariff to the FAQ webpages and reference WDAT tariff documentation from Proposal 20-a.

BACKGROUND

Customer-sited and distribution-connected energy storage resources are generally interconnected under Rule 21, but proponents believe that other opportunities exist for behind-the-meter energy storage resources to export and sell energy to participate in the wholesale market. Such wholesale market participation must be interconnected under WDAT. Thus, for a DER resource already interconnected under Rule 21, it may become desirable to shift to being interconnected under WDAT.

Currently, the most readily available pathway for DERs to provide wholesale market services is to participate as a Proxy Demand Resource (PDR), which limits DERs to non-exporting configurations because of the demand response (DR) construct of load-based baselines to measure and compensate performance. For generating facilities such as behind-the-meter (BTM) non-exporting energy storage, the PDR market participation model has allowed it to participate readily and the Rule 21 interconnection processes have been streamlined to support timely deployment and aggregations into the wholesale market.

However, proponents believe that there are significant benefits in better utilizing the export capabilities of DERs and in accessing opportunities to provide additional wholesale market services as a CAISO Non-Generator Resource (NGR), opportunities which are not available to customers interconnecting under Rule 21. To better enable DER participation as NGRs, the Working Group considered approaches to clarifying and streamlining transfers from Rule 21 to WDAT, and to minimizing re-studies, where reasonable, if the operational mode (i.e., exporting or non-exporting) of a project remains unchanged.

Some key questions and clarifications that were raised in Working Group discussions included:

- Under what conditions is the WDAT interconnection process required to re-study resources already studied under the Rule 21 processes?
- Where re-study is required, what are the key differences (*e.g.*, reliability criteria) that must be re-studied?
- How have the investor-owned utilities (IOUs) managed Rule 21 and WDAT transitions in the past, if there are any such examples?
- Is it possible to modify the CAISO tariff or CPUC Resource Adequacy requirements such that a consequence of that revision is that deliverability can be achieved without a WDAT interconnection request?

For purposes of a final proposal for Issue 20, proponent CESA focused on the use case where Rule 21-interconnected BTM energy storage resources and other DERs (i.e., vehicle-to-grid systems) would not be expected to require a re-study when undergoing transfer from Rule 21 to WDAT. However, CESA noted that other use cases might also be considered, including aggregation of DERs.

DISCUSSION

Proposal 20-a. Consensus

Clarify through the use of FAQ webpages the transfer processes and permission-to-operate rules for: (i) how projects in the Rule 21 interconnection queue can transfer to the WDAT interconnection queue; and (ii) how eligible resources under existing Rule 21 interconnection agreements can begin the New Resource Implementation (NRI) process at the CAISO.

PG&E, SCE, and SDG&E informed the Working Group that they each have procedures already in place to enable transitions from Rule 21 to WDAT upon request from an interconnection customer. These procedures are summarized in Table 1.

Each of the utilities informally committed to making such resources available to their FAQ webpages, and there may not need to be any further Commission action. However, to ensure consistency across the IOUs, the Working Group recommends that utilities provide clarifications across each of the areas shown in Table 1, and their transfer processes should be made consistent as much as possible.

Table 1: Existing Utility Procedures to Enable Transitions from Rule 21 to WDAT

	PG&E	SCE	SDG&E
Initiation	The request by a Rule 21 Interconnection Request (IR) to transfer to a WDT Generator Interconnection Agreement (GIA) must be made in writing.	The request by a Rule 21 IR to transfer to a WDAT Generator Interconnection Agreement (GIA) must be made in writing.	Interconnection Customer (IC) must submit WDAT Interconnection Request (IR).
Study Process Transition	The IR must complete the study process (*e.g.*, Initial Review, Supplemental Review) before the transfer would be allowed.	The Rule 21 interconnection request has completed a "study process" and is ready to execute an Interconnection Agreement (IA). This requirement is non-negotiable, as the study (or successful screening) results form the basis for the plan-of-service system review outlined in the requested WDAT GIA. If a Distribution Service Agreement was required under the Rule 21 IR, the Customer must also apply for Distribution Service, from the SCE Distribution System to the CAISO-controlled grid, by submitting a Distribution Service Request in accordance with WDAT requirements.	Please refer to Sections 6.8.1.1 and 6.8.1.2 under SDG&E's WDAT.
Eligibility	The Rule 21 IR has been studied for export to the distribution system, which includes NEM resources.	The Rule 21 IR is exporting to the distribution system, which includes NEM resources.	Exporting resource connecting to the distribution system.
Material Modifications	Interconnection Customer (IC) cannot make any material modifications to the facility (*e.g.*, increasing facility size, changing POI) to qualify for transfer. Material modifications are governed by WDT provisions and can only be made after WDT GIA is signed and executed.	Interconnection Customer (IC) cannot make any material modifications to the facility (*e.g.*, increasing facility size, changing POI) to qualify for transfer. Material modifications are governed by WDAT provisions and can only be made after WDAT GIA is signed and executed.	IC cannot make any material modifications to the facility (*e.g.*, increasing facility size, changing POI) to qualify for transfer. Material modifications are governed by WDAT provisions and can only be made after WDAT GIA is signed and executed.
Timelines	PG&E and IC will agree in advance that the Rule 21 Interconnection Agreement (IA) will terminate on the date the WDT GIA is fully-executed.	Upon confirming eligibility, the IC will receive a draft WDAT IA within 30 Calendar Days and will launch a negotiation period within 120 calendar days from the	Please refer to Sections 6.8.1.1 and 6.8.1.2 under SDG&E's WDAT.

		date of eligibility notification, per the WDAT GIP.	
'U-Turn' Transfers	--	IC may request a single 'U-turn' transfer – a transfer from one tariff GIA to another tariff GIA and then back to the initial tariff GIA	Please refer to Sections 6.8.1.1 and 6.8.1.2 under SDG&E's WDAT.
Billing Credits	IC must forgo billing credits under RES-BCT and NEM upon conversion to WDT GIA.	IC must forgo billing credits under RES-BCT and NEM upon conversion to WDAT GIA.	CPUC jurisdictional tariffs do not apply to service provided under a WDAT Interconnection Agreement (IA).
Cost Envelope Option (CEO)	IRs waive any requested CEO treatment of its study results since there is no WDT-equivalent option.	IRs waive any requested CEO treatment of its study results since there is no WDAT-equivalent option.	IRs waive any requested CEO treatment of its study results since there is no WDAT-equivalent option.
Other WDAT-Relevant Processes	IC must apply separately to CAISO for Full Capacity Deliverability Status (FCDS) and must comply with study and fee requirements.	IC must separately apply for the CAISO New Resource Implementation (NRI) process, as well as QF status under PURPA. SCE is not responsible for assisting the IC in those processes.	IC must apply separately to CAISO for Full Capacity Deliverability Status (FCDS) and must comply with study and fee requirements.

CESA and Green Power Institute (GPI), among other stakeholders, believe that parties needing to transfer from Rule 21 to the WDAT interconnection queue could benefit from clarifications and guidance. Some projects that have started down the path of Rule 21 interconnection may sometimes need to shift to the WDAT process. Thus, parties seek clarifications and guidance on how utilities handle transfers to the WDAT process.

SCE noted that the transfer process would not create technical challenges as the study processes employed by SCE and CAISO are virtually identical and the studies are performed by the same engineering teams. SCE's WDAT has language under Section 4.9.1 to allow for WDAT project to transfer to Rule 21 GIA.

PG&E highlighted Section 6.8.1.1 of its Wholesale Distribution Tariff (WDT) Generator Interconnection Procedures (GIP) that describes the one-time opportunity to transition from Rule 21 to WDAT at the start of generator interconnection agreement negotiation and indicated that it will apply current CPUC-to-FERC contract conversion procedures.

Each of the utilities reiterated that for projects already granted PTO with proposed project changes (e.g., non-exporting to exporting), such projects would require a new interconnection request, where study procedures can be sufficiently different.

The WDAT study process can take up to 2 to 3 years depending on the route it takes (e.g., Fast Track, Independent Study Process, or Cluster study). Many projects choose the Fast Track process, which can take less than 6 months. As DERs seek WDAT interconnections to take advantage of different operational configurations (e.g., non-export to full export), DERs should be allowed to remain on the Rule 21 tariff and operate according to its Rule 21 interconnection agreement as the project(s) goes through the WDAT interconnection study process. In other words, a project should not be required to be taken offline during the WDAT interconnection study process so long as the resource does not violate the terms and conditions (*e.g.*, operational mode) of the resource.

SCE notes that this transfer process is already consistent with SCE's existing treatment for QF conversion, where the termination date of the Rule 21 Interconnection Agreement is the same as the effective date of the WDAT IA. SCE further notes that the NRI process is a CAISO controlled process that the utilities do not have control over. PG&E's process is largely similar to SCE's. SDG&E to-date has not seen a large number of transfers.

Proponent CESA is unaware of Rule 21 tariff or other online documentation detailing this transfer process, other than cursory mentions of requiring separate agreements required for other services under Section D.2. of the tariff and how Rule 21 interconnection agreements do not confer any rights to wheel electric power through the distribution system under Section D.3. of the tariff.

In proposing to document transfer processes and PTO rules, parties sought clarification of the New Resource Implementation (NRI) process and timeline. NRI sets a minimum 203-day mandatory timeline for the CAISO to establish whether a new resource can operate in the CAISO market, as this process is controlled and oversight provided by the CAISO with no utility involvement. However, this minimum timeline will become 84 days based on changes being made during late 2019.

Non-utility parties also sought clarification from CAISO on whether a generator interconnected under Rule 21 could continue to operate under its existing Rule 21 interconnection agreement until the NRI process is completed. The answer obtained from CAISO is that either a Rule 21 Exporting or WDAT interconnection agreement serves for submission during the first phase of deliverables for the CAISO NRI process ("Bucket 1"). CAISO provided two use cases below in answering this question:

- **Customer under Rule 21 Exporting interconnection agreement seeking NRI under new WDAT interconnection:** The customer can continue to operate under their Rule 21 Exporting interconnection agreement and submit a WDAT interconnection agreement when the interconnection agreement transfer is completed. The CAISO stipulated that continued operation of the system becomes null and void if the condition of the Rule 21 Exporting interconnection agreement changes (e.g., there is an increase in the export limitation or allowance) and that the resource would be required to start another NRI project (e.g., to be modeled with the higher maximum export capability to increase the resource's maximum output level (Pmax). The resource could continue to participate in the markets with the lower Pmax or export value during the NRI process. In sum, the CAISO indicated that resources under Rule 21 Exporting interconnection agreements would be able to continue to operate under exporting limitations or allowances of the original interconnection agreement during the NRI process, as the NRI process is controlled and run by the CAISO.

- **Customer under Rule 21 Non-Exporting interconnection agreement seeking NRI under new WDAT interconnection:** The CAISO stipulated to Tesla that for the NRI process controlled by the

CAISO, a resource under the use case with a Rule 21 Non-Exporting interconnection agreement would not be considered in the NRI process. They may, however, qualify for participation in the demand response participation model (*e.g.*, PDR), which does not require NRI but instead uses a registration process to obtain a resource ID and participate in the market as an economic resource. The PDR can continue to participate in the market and utilize the PDR's resource ID while it is pursuing a Rule 21 Exporting or WDAT interconnection agreement and is converting to another resource type (*i.e*., not PDR) in the NRI process. Once the NRI process is completed, this resource would have its PDR resource ID terminated and the newly modeled resource under the NRI process would allow for continuation of participation under a different participation model as a non-DR resource.

Utilities further clarified that two active interconnection agreements cannot be allowed at the same time, so a WDAT interconnection agreement cannot be valid until the existing Rule 21 interconnection agreement is terminated. At the same time, the utilities were sympathetic to not terminating a Rule 21 agreement early (e.g., creating a gap in the transition process), where a resource may not have any agreement at one time and thus not be allowed to operate.

One proposal raised during the Working Group discussions was to consider allowing interconnection customers to submit a future-dated WDAT interconnection agreement to meet the NRI submittal requirement. However, CAISO told the Working Group that it will not accept these as customers could only begin the NRI process once the interconnection agreement is completed. Existing Rule 21 agreements will be accepted to initiate the NRI process for applicable use cases. WDAT agreements can be submitted prior to a Commercial Operation Date (COD) being granted for the NRI process.

Proponent position:

> CESA: The clarifications proposed here would be very helpful, and would benefit interconnection customers by having the utilities document the Rule 21 to WDAT transfer process. This high-level overview should be provided within the applicable FAQ documentation and webpages.

Proposal 20-c. Consensus

Provide some reference language or "soft link" within the Rule 21 tariff to the FAQ webpages and reference WDAT tariff documentation from Proposal 20-a.

A soft link provides a shortcut to relevant information for contractors and interconnection applicants, in order to expedite finding answers and to minimize the need for phone and email inquiries with utilities. As the volume of requests increases, utilities may address specific use cases, examples of which are given in Annex B.

Annex B: Issue 20, Potential Use Cases of Transfer from Rule 21 to WDAT

Proponents provided a table of potential use cases, and agreed that posting of the cases in the applicable website FAQs may not be necessary at this time, but rather should be considered as inquires of this nature become more common in the future. Implementation of posting cases to website FAQs will be considered and managed by the utilities' internal teams at that time.

Original Rule 21 Program	New WDAT Program	System operation type changed?	Use case examples:
NEM	WDAT Export	No	**Example 1:** Customer has substantially decreased their onsite load and system is now sized far above the 100% annual production sizing limitation. Rather than curtailing the system the customer would like to monetize the production via the wholesale market. **Example 2:** Customer has a seasonal load (agricultural / water treatment plant, etc.) and would like to monetize on excess production rather than having the system shut off for long periods of time.
NEMA	WDAT Export	No	**Example 3:** Customer has 10 sites benefitting from the NEMA but is closing down 8 of the sites and looking at installing on site generation on the 1 remaining benefitting site. System is now sized far above the 100% annual usage sizing limitation. Rather than curtailing or downsizing the system the customer would like to monetize the production via the wholesale market.
Rule 21 Export	WDAT Export	No	**Example 4**: Customer has export only PURPA PPA with IOU for a system at a testing facility for electrical equipment. Customer needs to charge and discharge as part of their testing procedures. Currently customer does not have the ability to use a load bank or existing loads to offset the usage / discharge of energy. Customer would like to displace drawn energy to benefit a generating meter. (Unsure if this case is allowed under WDAT but proponent can't provide additional cases at this time.)
Demand Survey Response	WDAT Export	Yes	**Example 5:** Customer is currently participating in demand response but would like to switch to WDAT. *(If the mitigations will be completed prior to the COD being granted by CAISO, can the customer operate the system prior to COD being granted and can they receive PPA payments prior to COD being received by CAISO/ NRI?)*
Rule 21 Non-Export	WDAT Export	Yes	**Example 6:** Customer has a non-export system, however, they have decreased their load and now have a substantially oversized system. Additional battery capacity to store production is not a viable option. Customer would like to pursue changing to export in order to monetize their over production in the wholesale market. *Example for more context: Manufacturer has a plant with a 4 MW system. Manufacturer upgrades equipment that is more energy efficient in addition to manufacturing a product that takes less energy to make. They now only need to utilize 1 MW of the system to offset their loads and want to do something with the remaining 3 MW of capacity rather than downsize or shut off a large portion of the system.*
Rule 21 Non-Export	WDAT Non-Export	No	No examples; WDAT does not provide for non-export.

Issue 22

Should the Commission require the Utilities to make improvements to their interconnection application portals? If yes, what should those improvements be?

PROPOSAL SUMMARIES

Proposal 22-a. Consensus
The Commission should issue direction on 18 sub-proposals for specific types of portal improvements contained in this sub-proposal, taking into account existing utility plans, utility and other party comments, utility and other party support, and planned or currently ongoing improvements that may be related.

Proposal 22-b. Consensus
For functions that require improvements to the utility's existing electronic processing systems, the Commission should provide clear direction as to cost recovery mechanisms in support of functions to be implemented under Commission order that do not have existing approved recovery.

BACKGROUND

Distribution Resources Planning (DRP) Proceeding Decision D. 17-09-026 recognized that one of the key purposes of the that proceeding is to dramatically streamline the interconnection process, echoing the Commission's DRP Final Guidance document.

In the spirit of this precedent and the state's prioritization of DER as a major market sector for meeting state climate and energy goals, Working Group Three parties have generally acknowledged that there are opportunities for immediate and ongoing improvements to the utilities' interconnection application portals. Portals are an important aspect of the interconnection process and improvements to them can streamline the interconnection process.

Proponent GPI polled utilities and other stakeholders with respect to the capabilities of the current interconnection portals, problems with existing portals, ongoing efforts by utilities to make improvements, planned utility improvements in the future (perhaps pending funding), and other ways in which the portals could be improved that go beyond what utilities are currently planning. In addition to online polling, GPI coordinated a subgroup that met via conference call twice before the full Working Group discussed Issue 22.

A total of 18 proposed improvements to the interconnection portals were made by various parties. Descriptions of these sub-proposals are given in Annex C.

DISCUSSION

Proposal 22-a. Consensus

The Commission should issue direction on 18 sub-proposals for specific types of portal improvements contained in this sub-proposal, taking into account utility and other party comments, utility and other party support, and planned or currently ongoing improvements that may be related.

The sub-group and the full Working Group vetted the 18 sub-proposals and arrived at some prioritizations and categorizations, along with soliciting utility comments on which sub-proposals they supported and/or were already undertaking in some manner. The results are summarized in Tables 1 and 2. Table 2 contains a "priority score" developed by proponent GPI that is calculated from numerical scoring based on survey responses by parties on the priority ranking for each sub-proposal. Table 1 groups sub-proposals into tiers, taking into account both this priority score and the degree of utility support as expressed through comments and Working Group discussions.

Party comments on each of the 18 sub-proposals are given in Annex D. GPI commented that there was insufficient time during the Working Group for detailed in-person discussion on each of the 18 sub-proposals. Accordingly, GPI says it may be appropriate to create a standing sub-group to work through the details of those sub-proposals that the Commission approves. GPI also notes that comments on sub-proposals by utilities and other parties in some cases reflect misunderstandings about a particular sub-proposal, or that some sub-proposals evolved during discussions, such that some party comments aren't accurate with respect to the final sub-proposal text. For example, sub-proposal #19 is for harmonizing portals *or*, at the least, harmonizing terminology. Comments submitted by two utilities only address harmonizing portals and not harmonizing terminology. GPI comments that this again weighs in favor of additional substantive discussions on these technical topics, perhaps similar to the depth of discussion in the Smart Inverter Working Group, which did require a standing working group to resolve many of the technical issues.

Tesla commented that, as a general comment across all sub-proposals, the sub-proposals are not of equal priority to stakeholders. Tesla commented that should the Commission direct the utilities to implement the various sub-proposals, it will be critically important for that effort to begin with an implementation plan, to be developed by the utilities to ensure that prioritized items are treated as such. Additionally, according to Tesla, that implementation plan should include fairly specific detail regarding what changes or process improvements will be made as opposed to speaking in high level generalities. Tesla provided the Working Group with a mark-up along with its comments that it hoped could provide some color on this idea and the level of granularity ultimately required. Tesla said it supports sub-proposals 6, 9, 12, 13, 14, and 18 in particular.

GPI recommends that Commission direction entail a decision on whether each proposed improvement should be required, and if so, to what degree of specificity. In Table 2, the "Commission action" column shows GPI's recommendations for the kind of Commission action that would be appropriate/beneficial to implement each improvement. "Principle" means that the Commission could issue a statement of principle rather than specific actions. "Specific" action means the Commission could direct the utilities to complete specific actions to implement the sub-proposal at issue. The difference exists because some sub-proposals are not as amenable to specific actions by the Commission in a decision, but will still benefit from Commission direction at the level of principle to support the sub-proposal at issue.

An example of a "principle" action would be to order utilities to use the same or substantially similar naming and terminology conventions in their interconnection portals in order to reduce confusion across platforms. An example of a "specific" action would be to order all utilities to include V2G-DC as a customer interconnection option in their interconnection portals.

Commission direction should be more specific on those sub-proposals listed in Table 2 as "specific," and should be more general, about principles and policy preferences, for sub-proposals that are noted as "principle."

Table 1: Sub-Proposals Grouped by Utility Support and Proponent Ranking
(For details on each sub-proposal, see Annex C; for party comments on each, see Annex D)

	Sub-proposal	Utility support
Tier A: Strong Utility Support and Strong Proponent Ranking		
2	Include an option for transmission or distribution interconnection in the online application	PG&E, SCE, SDG&E (distribution only)
4	Add V2G-DC (vehicle-to-grid) interconnection options to portal	PG&E, SCE
7	Online signature option for all required interconnection application and related signatures such as Generator Interconnection Agreements	PG&E, SCE, SDG&E
9	Eliminate manual data entry as much as possible by integrating with applicant databases or allowing batch uploads	PG&E, SCE, SDG&E (partial, no batching)
10	Eliminate requirement to provide existing system info when applying for additional interconnection capacity (either solar or storage)	PG&E, SCE, SDG&E
11	Automated data validation check when submitting application	PG&E, SCE, SDG&E
15	Allow applicants to access updated project status at any time, make edits at any time, add search and filter functions based on contractor, customer, etc	PG&E, SCE, SDG&E
16	Online payments for all payments, including standard payments such as NGOMs for residential storage systems or meter socket adapters	PG&E, SCE
Tier B: Some Utility Support and Higher Proponent Ranking		
1	Question-response facility with 24-hour turnaround, ***or*** online chat box	For question-response option only: SDG&E 1 day; PG&E 3 days; SCE 1 day standard
6	Automate the "deemed complete" process for standardized or template-based single-line diagram projects	PG&E & SCE (to extent possible), SDG&E
8	Add link in ICA maps that allows applicant to jump from the ICA map to the online interconnection portal, location-specific info automatically populated	PG&E, SCE
14	Create one-click Authority Having Jurisdiction (AHJ) approval process, possibly app-based or web-based	SDG&E
17	Allow contractors to generate forms for standard agreements like IFFOA, NGOM, etc.	SCE
Tier C: No or Little Utility Support and Lower Proponent Ranking		
3	Provide an Application Programming Interface (API), harmonized across utilities	---
5	Add automated PAR option to portals. This would allow applicants to apply for, pay for, and receive PAR reports almost instantaneously	PG&E and SCE willing to review/explore
12	Notification-only process for standard residential interconnections (certain configurations of pre-defined "standard" residential systems under a certain size)	---
13	Remove customer interaction requirements in favor of customer notifications only. Customer is not required to sign any documents or be involved	---
18	Have one state-wide portal for consistency. ***Or,*** have consistency in project status names, visibility of utility vs. installer's hands, and due date tracking	---

Table 2: Priority-Ranked Portal Improvements

(Based on Working Group Surveys conducted by proponent GPI, which assigned priority scores and specified Commission action, plus Working Group discussions)

Sub-Proposal	Description	Priority Score	IOUs See Need	Commission Action?
"Must Have"				
11	Automated data validation check when submitting application	14	Yes	Principle
15	Allow applicants to access updated project status at any time, make edits at any time, add search and filter functions based on contractor, customer, etc.	14	Yes	Specific
9	Eliminate manual data entry as much as possible by integrating with applicant databases or allowing batch uploads	11	Yes	Principle
4	Add DC V2G (vehicle to grid) interconnection options to portal	10	Yes	Specific
"No Brainers"				
7	Online signature option for all required interconnection application and related signatures such as Generator Interconnection Agreements.	13	Yes	Specific
10	Eliminate requirement to provide existing system info when applying for additional interconnection capacity (either solar or storage).	12	Yes	Specific
16	Online payments for certain payments, including standard payments such as NGOMs for residential storage systems or meter socket adapters	12	Yes	Specific
"Highly Desired"				
18	Have one state-wide portal for consistency. **OR**, consistency in project status names, visibility utility vs. installer's hands, and due date tracking	11	No	Principle
6	Automate the "deemed complete" process for standardized or template-based single-line diagram projects	10	Yes	Principle
17	Allow contractors to generate forms for standard agreements like IFFOA, NGOM, etc.	9	Yes	Specific
2	Include an option for transmission or distribution interconnection in the online application	8	Yes	Specific
3	Provide an Application Programming Interface (API), harmonized across utilities	8	Yes	Principle
8	Add link in ICA maps that allows applicant to jump from the ICA map to the online interconnection portal, location-specific info automatically populated	8	Yes	Specific
"Good to Have"				
14	Create one-click Authority Having Jurisdiction (AHJ) approval process, possibly app-based or web-based	9	Yes	Principle
12	Notification-only process for standard residential interconnections (certain configurations of pre-defined "standard" residential systems under a certain size)	8	No	Principle
5	Add automated PAR option to portals. This would allow applicants to apply for, pay for, and receive PAR reports almost instantaneously	6	No	Principle
1	Question-response facility with 24-hour turnaround, **OR** chat-box	5	No	Principle
13	Remove customer interaction requirements in favor of customer notifications only. Customer is not required to sign any documents or be involved	5	No	Principle

Proposal 22-b. Consensus

For functions that require improvements to the utility's existing electronic processing systems, the Commission should provide clear direction as to cost recovery mechanisms in support of functions to be implemented under Commission order that do not have existing approved recovery.

Proponent GPI position:

> The Commission has prioritized dramatic streamlining of interconnection, along with an expanded focus on Distributed Energy Resources (DER) more generally. While costs should always be considered with respect to any new initiatives that the Commission directs, there is no legislative or policy requirement in the present case for cost-benefit analysis, as has been discussed extensively by parties in the Working Group. GPI supports Commission consideration of costs but not a cost-benefit analysis. The Commission has also made it clear that utilities are to be proactive in encouraging DER and improving, streamlining and automating the interconnection portals is part of this broader effort.

TURN position:

> If only a small group of developers benefit from the sub-proposal, and general ratepayers do not benefit, then TURN strongly opposes rate-basing the costs associated with the sub-proposal.

Utility positions:

> PG&E prefers that ordered changes to the utility's IT infrastructure that supports interconnection should be recovered from the Interconnection Request Fee (both the NEM Interconnection Request Fee and non-NEM Interconnection Request Fee) such that the costs for implementing the order are recovered from the particular set of customers who benefit.
>
> SDG&E: At the present time, the existing application processes are adequate to facilitate the interconnection requests and review processes. Given the volume of such applications, SDG&E has not observed a need for changes but is constantly monitoring the interconnection process to make system improvements based on identified needs and based upon careful cost-benefit analysis. SDG&E believes that the Utilities should retain the discretion to evaluate the volume of interconnection applications and areas for improvement to the web-portals, because mandating uniform changes may require applicants to bear costs that are not necessary. The Utility should retain the discretion to analyze its customer feedback and web portal to determine and prioritize ways to improve the system. Cost recovery is critical, and the Commission should also evaluate whether the benefits to the public outweigh the costs, and consider whether those who benefit from the sub-proposals are appropriately paying for the costs associated with the sub-proposals.

Annex C: Issue 22, Detailed Descriptions of Sub-Proposals

The following potential improvements were proposed by individual Working Group participants:

1. Question-response facility with 24-hour turnaround ***or*** chat box (proposed by CALSSA)
2. Include an option for transmission or distribution interconnection in the online application (proposed by JKB Energy)
3. Provide an Application Programming Interface (API), harmonized across utilities, to the online portals as this will be helpful when interconnecting large numbers of DERs like EVs (proposed by Nuvve)
4. Add DC V2G (vehicle to grid) interconnection options to portal (proposed by CESA)
5. Add automated PAR option to portals (proposed by GPI)
    a. This would allow applicants to apply for, pay for, and receive PAR reports almost instantaneously if they deem the ICA map information to be insufficient, outdated (because of the 30-day refresh rate), or unreliable for any reason
6. Automate the "deemed complete" process for standardized or template-based single-line diagram projects (proposed by GPI)
    a. An application must be processed by the utility within 10 Business Days (BDs), applicant notified of receipt, and if the Interconnection Request is deemed complete or not (Rule 21 E.5)
    b. If deemed complete, applicant is notified automatically by email that Initial Review will be completed within 15 BDs (E.5.a, F.2.a)
    c. If not deemed complete, applicant is notified automatically of the deficiencies and that it will have 10 BDs (per the tariff) to cure (E.5.b). Deficiencies will often result in multiple rounds of corrections, with each round requiring 10 BDs by the IOU. With an automated application portal, the need for corrections should be significantly diminished and the turnaround time for notifying applicants of deficiencies may also be significantly diminished.
    d. If the online portal application is populated correctly, the deemed completed process is automatable in two different ways:
        - Provide template single-line diagrams (SLDs), that can be modified as required, for simpler projects. SDG&E's DIIS system has largely automated this process for NEM projects, including an automated SLD process template that applies to many straightforward projects by allowing the customer to select a generic generator configuration from the DIIS tool instead of supplying a project-specific SLD, and that generic configuration then serves as the SLD
        - Larger behind-the-meter and front-of-meter projects require more complex SLDs and, for this type of project, dialogue windows should specify the needed information in order to safely interconnect such projects without requiring individualized SLD review
7. Online signature option for all required interconnection application and related signatures such as Generator Interconnection Agreements (proposed by GPI). However, it is also important to ensure that the developer always has visibility into whatever materials related to a project are being submitted to and signed by the customer (if there is a customer

involved who is not the developer). Accordingly, if the developer and the signatory are different parties (as in the case of most behind-the-meter projects), the developer should always be notified with the signatory of the online signature option.

8. Add link in ICA maps that allows applicant to jump from the ICA map to the online interconnection portal, with location-specific information automatically populated (proposed by GPI)
    a. This will begin a process of linking the ICA data to the interconnection portal
9. Eliminate manual data entry as much as possible by integrating with applicant databases or allowing batch uploads (proposed by Tesla)
    a. Installers currently manually type data points into the online portals. This data is often stored in internal databases, which could be accessed using software tools, or exported into a file. The installer could export a data file from their system in a specific format (where all meter numbers are in the first column, and all account numbers are in the second column, etc.) and upload it to the utility's portal. The portal could then automatically input the relevant data into the utility's portal.
    b. For NEM Aggregation accounts, there are 14 pieces of basic customer information, much of which is the same for all accounts included in an aggregation group. These fields are: Account Type, Parcel Number, First Name, Last Name, Company, Address, City, State, Zip, Account Number, RESBCT Account Number, Meter Number, Rate Schedule, Annual kWh. Entering 10-digit ID numbers many times is prone to manual errors. When the information is already in utility databases, it is not good practice. The portal user should be able to enter the account number and meter number and have other information auto-filled, then choose to use the same information for related accounts.
    c. Alternatively, the installer database and the utility's systems could be integrated to eliminate all manual touch points.
10. Eliminate requirement to provide existing system info when applying for additional interconnection capacity (either solar or storage) (proposed by Tesla)
    a. If this requirement is retained, then this information should automatically populate in the online portal after entering identifying customer information. For example, in SCE, if a customer is adding a battery to an existing solar system and does not have the existing system specifications, they must endure a month-long process to access this information. First, they must sign an authorization form to allow the installer to request the information on their behalf. Next, that form is submitted to the interconnection department at SCE. That team then sends a request to another SCE department to access the customer's existing system information. This information is then sent back to the interconnection team, who then sends it to the installer. Finally, the installer uses this information to fill out the interconnection application for the utility to review.
11. Automated data validation check when submitting application (proposed by Tesla)
    a. Automatically perform a data validation check (on a minimal number of data points) to prevent the application from being submitted if the customer's data is not accurate. Auto-populate data from utility systems after the installer enters data to validate that they are have a relationship with the customer. For example, after the installer inputs the meter number and account number, the customer's information would automatically populate in the system (i.e., name and service address). PG&E –

the applicant enters the customer's meter number and account number, after which the customer's name and service address auto-populate in the portal. If either piece of data is incorrect, the portal red flags this and does not allow the applicant to proceed. SDG&E – the applicant enters the customer's meter number, account number, name and service address. If one of the pieces of data does not match SDG&E's system, the portal red flags the incorrect field, and will not permit the applicant to proceed. None of the information auto-populates. SCE – the applicant enters the customer's service ID, and types in the customer's name and address. This data is not validated unless additional information is entered. The applicant may type in the customer's service ID and account number in order for the customer's name and address to auto-populate and to validate the service ID.

12. Notification-only process for standard residential interconnections (proposed by Tesla)
    a. Implement a "notification only" process for certain configurations of pre-defined "standard" residential systems under a certain size. If a project meets certain criteria, the installer would alert the utility of the installation, and would be able to proceed with turning the system on immediately upon passing the final building inspection without a formal PTO notification from the utility. Installers could be certified or have to maintain a specific success rate to participate in the notification-only process. For example, in NYSERDA's rebate program, installers are required to meet certain quality standards related to passed rebate inspections and complete application success rates. If the installer is not able to meet the standards, they are at risk of suspension from the rebate program. The Energy Trust or Oregon (ETO) rebate program issues an installer "report card" (example attached) which rates installers on a 3-star system in 3 categories. Higher ratings can quality installers for additional program offerings.
13. Remove customer interaction requirements in favor of customer notifications only (proposed by Tesla)
    a. Implement a process in which the customer is not required to sign any documents or be involved in the interconnection process. Precedent has been set by Sacramento Municipal Utility District (SMUD), which does not require customers to engage in the interconnection process.
14. Create one-click Authority Having Jurisdiction (AHJ) approval process, possibly app-based or web-based (proposed by Tesla)
    a. The utility should create a means by which the AHJ can automatically submit inspection approval to the utility using an automated "one click" process. Such a process could be implemented such that a developer is notified simultaneous with submission of inspection approval to the utility that the project can be turned on – providing the option for an automatic PTO if that is desired by developer. Is there potentially a role for the commission or the utilities as part of the Working Group process to do some outreach to priority AHJs? SDG&E only accepts inspection results from the AHJs directly. SDG&E has implemented an app to streamline receipt of notification that the AHJ inspection has passed. The AHJ inspector is able to look up a site address or meter number using an app on their phone, and search for the relevant utility application. The inspector clicks the relevant application, and is able to submit a notification of passed inspection directly to the utility. While there has been some adoption of this process, not all AHJs participate. When AHJs manually

send inspection notices to the utility, there are issues with permits not being received or having to be re-sent multiple times. PG&E accepted inspection results from either AHJs or applicants, but are planning to remove the feature whereby AHJs can submit inspection results from their online portal. The portal prompts the applicant to enter the initial permit date, inspection date, permit number and then searches to check if the AHJ has submitted inspection results. If the AHJ has not sent the results but the applicant has a copy, the applicant is able to upload a copy. SCE does not accept the inspection certificate from the AHJ directly. The applicant uploads a copy of the inspection certificate.

15. Allow applicants to access updated project status at any time, make edits at any time, and add search and filter functions based on contractor, customer, etc. (proposed by Tesla)
    a. Installers should have access to project statuses in the portals, including visibility on a projects age in status or "due date" to move into the next step. The portal should grant the ability to search and filter for projects based on contractor, customer and status (e.g., ability to search for all incomplete applications, or all projects currently undergoing engineering review, etc.). It should also include the ability to "self-serve" by allowing installers to edit applications after submission or cancel applications. It should also include a simple notes log to allow notes back and forth to replace manual emails.
16. Online payments for all payments (proposed by Tesla)
    a. Online payment is accepted for NEM systems but not for other standard payments such as NGOMs for residential storage systems or meter socket adapters. Online payment should be accepted for all payments.
17. Allow contractors to generate forms for standard agreements like IFFOA, NGOM, etc. (proposed by Tesla)
18. Have one state-wide portal for consistency (proposed by Tesla). Or, if the portals remain separate, there should be consistency in project status names, visibility on whether the application is in the utility's hands or the installer's hands, and due date tracking. For example, PG&E does not provide any status updates in their portal, while SDG&E provides 3 general statuses (in progress, incomplete, and PTO), and SCE provides about 10 distinct project statuses.

Annex D: Issue 22, Party Comments on Sub-Proposals

1. Question-response facility with 24-hour turnaround *or* chat box

Tesla wants to clarify that while we are not opposed to the chat box idea, we are more interested in simply ensuring timely responses, whether via email or other channels.

CALSSA comments:

> CALSSA maintains its sub-proposal for a chat box unless each of the utilities commits to a 24-hour turnaround time for queries, especially those queries related to initial application submittal and curing deficiencies in applications that have not been deemed complete.
>
> One of the largest frustrations that portal users have is not being able to get simple answers to simple questions. PG&E in particular is painfully slow in responding to inquiries. They have a "team inbox" as their sole opportunity for contact. They take at least 10 business days to respond to questions, and the responses normally come from a nameless account so there is no way to continue the conversation with a simple follow-up question with the same PG&E representative. A follow-up question must go to the general inbox with the application number noted, and then a different PG&E representative will research the issue and respond. This is an incredibly inefficient system for both sides. It is difficult to have a proper relationship with a customer when simple matters are often put on hold for a month and a half to account for back-and-forth communication with the utility.
>
> Customer service representatives who answer the customer inquiry phone line are not trained in interconnection and regularly give incorrect information or are unable to answer questions.
>
> Basic application processing includes the ability for users to ask simple questions about the application. There should be functionality within the application portal to get quick answers to simple questions. A chat box staffed by trained interconnection staff would be effective. It would ensure that interconnection-related questions are directed to people who are trained to answer them. This would save time for customer service representatives who are currently trying to answer questions they are not trained to answer.
>
> As an alternative, the portal could include a phone number or email address that pops up in various places and directs inquiries to appropriately trained staff. A 24-hour turnaround time would be slower than a chat box but would still allow for a reasonable relationship with a customer.

PG&E: One business day is likely unreasonable due to the varying levels of complexity that inquiries may have as well as during certain times of the year (such as the holidays) having subject matter experts available to answer questions that may or may not come in during the time period is unreasonable. As such, a three-business day turnaround as a compliance timeline, with a goal of answering simple requests within one-business day would be more reasonable.

SCE: Although a chat function is being considered for SCE's Grid Interconnection Process Tool (GIPT), there is no current decision to implement this function up to this point in development because the need has not been substantiated, nor has this function been accounted for in the current project scope and funding. GIPT is being designed and developed with (among other things) a goal to improve interconnection customer's visibility as to status of a given project at any given time. Despite this added functionality and utility, the IOUs collectively agree that improved response time to customer inquiries is an important aspect of customer service.

SDG&E Customer Generation's business policy is to return all emails and phone calls within the same business day. Customers needing assistance may call a direct phone number or send an email to a dedicated email address (netmetering@semprautilities.com). Calls and emails are monitored throughout the day within the Customer Generation group. In fact, most contractors and customers contact SDG&E employees directly with any questions, as employees share business cards at meetings in the field. There is not sufficient need or staff to monitor a chat-box, which would add system and labor costs to implement.

2. Include an option for transmission or distribution interconnection in the online application

PG&E is not currently doing this (assuming Distribution or Transmission is related to the electrical connection and not generating facility jurisdiction). With regards to FERC versus CPUC applications, our portals already do that delineation.

SCE: It is expected that the GIPT system will accommodate projects under Rule 21 Non-Export in 2019. Requests to interconnect under Rule 21 export, NEM, and SCE's Wholesale Distribution Access Tariff (WDAT) represent added functionality that is expected to be implemented in additional phases of GIPT development, currently slated for 2020 and beyond subject to Phase 1 functionality and function review for Phase 2 (and approved Commission funding as applicable). For projects that request to interconnect to the transmission system that is under the CAISO control, these projects will most often flow through CAISO

SDG&E maintains full automation for all NEM-ST, Non-NEM, and Rule 21 generators in its online portal. WDAT projects are not included, as there is not sufficient volume and therefore need yet. If the need changes, SDG&E will be willing to make improvements to its online portal. In consideration of ensuring just and reasonable rates and fees, SDG&E weighs the needs and demands against cost implications. Making the proposed system upgrade to include WDAT is out of scope of this proceeding and will add substantial cost that is not warranted by the volume of applications within SDG&E's service territory to date.

3. Provide an Application Programming Interface (API), harmonized across utilities

PG&E: Not doing and don't believe this would be an efficient use of resources.

SCE: Harmonizing systems across utilities is extremely costly and complex because current systems support the particular system infrastructure of the utility, which are unique to each of the three California IOUs. SCE does not support this consideration as each utility manages according to its own system parameters and existing IT operating systems. With that said, FAQs and other customer focused material is available to aid the customer experience for each particular system.

SDG&E: As reflected in the spreadsheet circulated after the March 27th meeting, this sub-proposal is highly desired by other parties. However, SDG&E does not see a need for an API. As stated in SCE's initial comments on the sub-proposal, "Harmonizing systems across utilities is extremely costly and complex because current systems support the particular system infrastructure of the utility, which are unique to each of the three California IOUs." SDG&E has made substantial capital investment into the development of its application portal, which is a sunk cost. This sub-proposal requires new capital investment that has substantial cost implications. Nuvve has not stated how it proposes to finance a uniform application portal – whether socialized through rates and imposed on captive ratepayers or through interconnection fees. This is a convenience item that benefits large companies that process applications throughout the state, but the cost of implementing it would be socialized. Such an API is not a need and should not be adopted. SDG&E has not had the volume to support such a capital-intensive undertaking. Equity is a key principle to just and reasonable rates; no ratepayer should ever finance any other ratepayer, or else the rates are not equitable. SDG&E does not support this sub-proposal.

4. Add V2G-DC (vehicle-to-grid) interconnection options to portal

Tesla is not opposed to incorporating this into portals but does question the degree of urgency given the nascent state of V2G currently.

GPI disagrees with Tesla and urges the Commission to address this now in order to provide a proactive environment for V2G, rather than being reactive.

PG&E: Our systems support the inclusion of EVSE inverters as "inverters" but there would be no data point to link them to being "EVSE inverters". As such, if the Commission would like to have the additional granularity or expects to issue data requests for this kind of information, PG&E would support making adjustments as necessary to enable such reporting.

SCE supports the inclusion of EVSE inverters in GIPT. SCE expects that this function can be incorporated into the Generation Interconnection Processing Tool (GIPT) drop down menu for new applications within the later phases of platform development subject to Phase 1 functionality confirmation and Phase 2 function review. Expects DC V2G interconnections will be added to SCE's GIPT system in later phases of system development.

SDG&E has only processed one interconnection application to-date for a DC-coupled V2G facility that was behind a billing meter at a charger. SDG&E does not support this sub-proposal. The scope and cost to revise SDG&E's web portal have not been determined because so few V2G applications have been submitted to date. As the number of V2G applications increase, SDG&E will work with its Information Technology group to determine the detailed scope of work and associated costs to revise the portal to allow streamlined application processes for V2G and weigh those costs with the potential benefits. At the present time, the existing application processes are adequate to facilitate the interconnection request and review process for V2G systems. Given the lack of such applications, SDG&E has not observed a need but is constantly monitoring the interconnection process to make system improvements based on identified needs and based upon careful cost-benefit analysis. Furthermore, SDG&E's online application portal requires the application to be associated with an account number and a meter number for the interconnection process. SDG&E is not sure how V2G applicants are going to interconnect if they are not associated with an account and meter number. The application portal will not allow applicants to proceed past the first step in the online process without an account number or meter number. Step 4 includes the equipment list of approved inverters.

5. Add automated pre-application report option to portals. This would allow applicants to apply for, pay for, and receive pre-application reports almost instantaneously.

PG&E: Willing to explore, but not currently working on. Pre-Application reports do not seem to have a high volume, nor do they directly impact the interconnection process per se.

SCE is willing to review the extent to which pre-application reports can be automated but makes no commitment to institute automated PARs until deemed possible within the GIPT platform subject to final review, the optional enhanced PAR cannot be automated as it requires physical verification of utility infrastructure

SDG&E does not currently have sufficient volume to add pre-application reports to the DIIS online portal. In 2018, SDG&E received a total of eleven PARs, eight of which were for fuel cells and were submitted by the same company. SDG&E only received six PARs in 2017 and 17 in 2016. The average processing time for these requests is less than five business days. Again, if the need arises in the future, SDG&E will consider modifying the online portal to include the option to request a pre-application report. However, due the lack of volume, SDG&E does not support adoption of this sub-proposal, as it would impose unnecessary cost and unwarranted requirements.

6. Automate the "deemed complete" process for standardized or template-based single-line diagram projects

PG&E utilizes the "Basic SLD" concept for Standard NEM (Solar <30 kW). We are currently engaged in applying a similar process for Standard NEM Paired with Energy Storage since that volume has increased. To the greatest extent possible, PG&E supports "smart application forms" to reduce possible application deficiencies. However, there are components to our application process that do require manual review (such as customer signatures).

SCE: To the extent possible, SCE will automate the Intake process when conditions are satisfied results in "Deemed Complete". However, SCE insists that engineering involvement must occur with verification of SLDs to determine safe and reliable interconnection. SCE believes that a SLD utility template creates duplicate effort for installers as the authority having jurisdiction requires comprehensive SLDs to be submitted and approved.

SDG&E is already doing this. SDG&E utilizes the "standard SLD" for NEM-ST customers with systems that are 30kW or less that do not require a disconnect or a CT-rated panel. SDG&E has a very high percentage of contractors that utilize this option. SDG&E has also implemented a Fast Track process for these same customers in which the contractor can upload a picture of the customer's service panel, meter, and warning placard in lieu of a field inspection. Approximately 80 percent of the NEM-ST applications submitted to SDG&E utilize this feature.

7. Online signature option for all required interconnection application and related signatures such as Generator Interconnection Agreements.

PG&E: not currently doing, but willing to explore. Ideally, this would be restricted to template-based forms that do not require a high level of sophistication to automatically produce the contract. This becomes more difficult for contracts that have high levels of variability such as Rule 21 Export Interconnection Agreements that specifically state the scope of work as well as Special Facilities Agreements. For contracts without those items, this could be explored.

SCE intends to enable online signatures via DocuSign which will work in conjunction with GIPT. This function is expected to be phased in as of Q4 2019.

SDG&E accepts electronic signatures for all applications through the DIIS portal. For NEM-ST customers with systems that are 1-MW or less, as soon as the application is submitted, the customer receives a link via email to electronically accept the Interconnection Application and its Terms and Conditions. Customers are also able to print a copy of the completed application and Interconnection Agreement. For consumer protection, the contractor cannot execute the document on behalf of a customer.

8. Add link in ICA maps that allows applicant to jump from the ICA map to the online interconnection portal, location-specific info automatically populated

PG&E: Currently exploring, as stated in the Interconnection Tools project under our GRC, but not currently in flight.

SCE: intends to link our ICA system with GIPT to enable review of site and circuit capacity based on a point in time. It is expected that this functionality will be available between Q4 2019 and Q2 2020.

SDG&E: Our ICA maps are not integrated with our Application Portal at this time, as they only went live in December. Furthermore, the volume of Rule 21 applications that would rely on ICA maps is insufficient to support this functionality. In 2018, based on system size, the number of Rule 21 applicants that might have filed an application from an ICA map would have been less than 0.1 percent, assuming all would have utilized the ICA maps. SDG&E believes that this sub-proposal is neither practical nor valuable. ICA values span line segments up to a thousand feet and across multiple addresses or land parcels. By contrast, the interconnection points are specific to a location. Therefore, SDG&E believes that this sub-proposal is neither feasible nor practical. Such few applicants would utilize the functions with little to no benefits in return. If adopted by the Commission, this sub-proposal would require time and money simply to address the feasibility and the costs associated with implementation. Furthermore, the value added to both the utility and the customer would still need to be evaluated. SDG&E does not believe there is a direct value to most customers, let alone to ratepayers as a whole.

9. Eliminate manual data entry as much as possible by integrating with applicant databases or allowing batch uploads

Tesla would like to underscore that we think this is an important item as it would dramatically streamline the application process and also serve as a way to support batch processing in the future by reducing the number of fields that would need to be entered or provided by the applicant. Tesla has provided a mark-up (the same mark-up referenced in our comments above) to flag those items in the application that we think lend themselves to auto-population once the utility customer and applicant databases are integrated.

CALSSA: Working Group participants agreed that reducing manual data entry is a good goal, but noted that the sub-proposal is not specific enough to be actionable. One specific improvement that was discussed was for the portal to automatically fill in customer information based on meter number or service ID number. This is especially true for NEMA applications, which contain many repetitive fields that are prone to errors. PG&E already auto-populates certain information for generating accounts, but they do not do the same for benefitting accounts.

CALSSA: Under PG&E's NEM Aggregation section of the online application, there are 14 inputs of basic customer information for every meter included on a NEMA arrangement. If the applicant is submitting a large project, there could easily be 10 + meters on an arrangement. That's 140 inputs for an applicant to fill out. Not only is the process time consuming, but it's also duplicative and prone to errors. A NEMA spreadsheet is submitted with each application which has all of the requested information included on it. All of this information could be auto-populated by PG&E from their database by integrating the database to the application. They already auto-populate this data for the generator account. PG&E also already has the application programmed to pull data and verify inputs as an application is being filled out (generator account only). On the first page of the application, you have to submit the service agreement (SA) ID and meter number. The SA ID is unique to the service point. Therefore, if those two numbers do not coincide to the correct service point, PG&E does not allow you to continue with the application. Applying automation to this portion of the application could reduce the 14 inputs to one or two inputs.

PG&E: Already doing/done. Any additional user input from stakeholders on items that still need automation within the application is always welcome.

SCE: Data entry will be automated to the extent that both customer and developer information are present and updated in SCE's database.[6] Drop down menus will enable autofill of numerous fields and related data. However, incorrect data entered by the developer and/or customer will still trigger a deficiency requiring correction.

SDG&E's latest portal upgrade partially addressed this sub-proposal. After the account and meter number is verified during Step 1 in the application process, the system automatically populates all existing generation onsite from SDG&E's database to eliminate manual entry. SDG&E does not allow edits to the interconnection application after it is submitted unless the customer asks to have the application reopened for corrections by simply calling or sending an email request. SDG&E is very responsive to these requests, as stated previously. SDG&E needs to know when to process an application. Locking the application to disallow edits ensures that the application is ready for review. SDG&E does not currently allow batch uploads, as there has not been a request in the service area. The average time it takes a self-installer (e.g. someone not familiar with the DIIS portal) to submit an application is less than ten minutes. Therefore, SDG&E does not see a need or justification for an investment in portal upgrades to allow batch uploads in order to benefit the few companies that would utilize the service.

10. Eliminate requirement to provide existing system info when applying for additional interconnection capacity (either solar or storage).

PG&E: Done for all but Rule 21 Export projects (since they use a different application portal at this time).

SCE: Existing system must always be verified in case the customer or predecessor has modified the existing system without notifying SCE prior to doing so. SCE engineering approval relies on accurate and verified system information. This is also not an IT/portal issue, but an issue related to Rule 21 interconnection process requirements.

SDG&E's latest portal upgrade addressed this sub-proposal. After the account and meter numbers are verified during Step 1 in the application process, the system will automatically populate all existing generation onsite from the SDG&E database to eliminate manual entry.

11. Automated data validation check when submitting application.

Tesla believes that while SDG&E's portal has some data validation capabilities, there is a lot more that could be done. At this time, the SDG&E portal validates that the account and meter number match, but leaves open the possibility of an applicant submitting the application under the incorrect name on the UB. Higher levels of sophistication around data validation are present on other portals – for example auto-populating relevant customer information based on the account/meter number. In contrast SDG&E requires manual entry for this data. We don't mention this to pick on SDG&E –

[6] Functions as this one and others will include customer authentication processes as discussed within stakeholder calls.

we commend the utility for incorporating some data validation capabilities into their system, but rather to highlight the need to have a more rigorous understanding of the extent of the utilities efforts for each of the sub-proposals under discussion and to identify opportunities for additional improvements.

PG&E: Linked to Item 10. Pre-population is preferred to validation where possible. Where not possible, the specific fields in question would have to be defined before PG&E could comment on each of them.

SCE is incorporating this function into its platform to the degree that it is technically possible. This means automated analysis may be available for some fields, but may not be possible for all fields requiring validation. However, to the extent associated data resides in SCE's database, or if simple calculations can be generated, then validation will exceed what is available on SCE's present PCI-based portal.

SDG&E: In Step 1 of the application process, the portal verifies the active status of the account and that the account and meter numbers match. The system will flag an "error" in these fields to let the applicant know that the numbers do not match. The system will not move to Step 2 until this is correct.

12. Notification-only process for standard residential interconnections (certain configurations of pre-defined "standard" residential systems under a certain size).

PG&E: Generators should not operate until given express permission from the utility.

SCE: This is a process question and not specific to the IT/portal function. This matter was also addressed in Working Group Two Issue 11.

SDG&E: This is an issue that should be addressed in a more technical forum and not treated as simply a portal improvement.

SDG&E opposes this sub-proposal and does not allow notification only. SDG&E has an active process for detecting and monitoring contractors and customers who have reverse power flow from unauthorized, unpermitted systems. SDG&E views notification-only as the same level of general public and utility worker safety hazard as reverse power flow from such unauthorized systems. To protect works and the public, SDG&E digitizes its geographic information systems (GIS) maps daily to the transformer level of the projects that were approved that day. In 2018, SDG&E approved over 24,000 customers, with an average processing and approval time for the entire year of 2.5 calendar days. If customers are already circumventing a 2.5-day process, SDG&E has not confidence that a notification-only process will offer enough benefit to justify the risk of public and utility worker safety. SDG&E's interconnection portal generates automatic emails that are sent to both the customer and the contractor through all steps of the application process so that they know immediately when the status has changed. SDG&E receives multiple applications from different contractors for the same address. Customers routinely call and complain that they decided to hire a different contractor and did not authorize a particular contractor to submit an application on their behalf. SDG&E must have an interconnection process that ensures that it can validate the requests.

13. Remove customer interaction requirements in favor of customer notifications only. Customer is not required to sign any documents or be involved

PG&E: The customer is whom the interconnection process is for and the one who executes the interconnection agreement. Therefore, this cannot and should not be done.

SCE must verify that any modification to customer's facility with respect to electrical load or generation is sanctioned by the customer. Therefore, this is not a consideration for either Rule 21 process or IT/portal.

SDG&E must interact with customers and opposes customer notifications only. SDG&E routinely received emails and phone calls from customers once they receive an automatic notification from the DIIS portal that an application was submitted on their behalf that they never authorized, often because they switched contractors and the previous contractor had prematurely submitted an application. SDG&E finds this common among contractors and receives duplicate applications from multiple contractors for the same customer. The DIIS portal requires the contractor to list the customer email address and only the customer can accept the Interconnection Agreement and Terms and Conditions. The customer and contractor are both copied on all correspondence throughout the entire process, which protects the customer and ensures that SDG&E is processing the correct and authorized application.

14. Create one-click Authority Having Jurisdiction (AHJ) approval process, possibly app-based or web-based.

PG&E: not currently in scope.

SCE: This capability is not in scope at this time and not considered under current funding assumptions. Furthermore, there is no guarantee considering the numerous city/county jurisdictions SCE serves that all AHJ's would agree to utilize the capability, thus making the application inconsistent and not cost effective. In particular, unlike other IOU service territories (ex: San Diego is mainly composed of the City of San Diego), SCE's service territory is composed of numerous cities).

SDG&E developed and launched an application in July 2017 that ties directly into the DIIS interconnection portal so that the AHJs can release all generation types with one click by phone, tablet, or desktop. In 2017, SDG&E received over 4,800 electrical releases with the new process, validating the need and utility for customers and AHJs. In 2018, SDG&E received over 23,000 electrical releases, showing substantial utilization with the service territory. SDG&E has proactively met with over 30 AHJs in the territory to show the benefits of using the process by expediting the release process, enhancing the customer experience, and eliminating the potential errors in manual data entry.

15. Allow applicants to access updated project status at any time, make edits at any time, add search and filter functions based on contractor, customer, etc.

PG&E: Project Status is done for ACE-IT applications (defined as Non-Standard NEM and Non – Rule 21 Export) at this time. We do not have the capability to allow edits or resolve deficiencies for these projects through the ACE-IT portal at this time, but are exploring the option. Standard NEM does have the capability to upload corrections for deficiencies through the portal but cannot view project status. Rule 21 Export projects have neither functionality at this time.

SCE: It is expected that project status updates will be built into GIPT within Phase 1 of platform development (Q4 2019). Customers may make edits provided that the agreement has not been executed. The system will be enabled with search and sort functions limited to projects under the customer's control.

SDG&E's online DIIS portal allows both the applicant and contractor to access the project status at any time. In fact, they can access and view all applications that they have submitted and can include as many contacts for their company notifications as they would like. They can update this list at any time within their own portal page. They have the ability to view our portal via any portable device such as smart phone, tablets, laptops, or desktop. Once the application is submitted to the utility it is locked for edits to signal that the application is ready for review; however, the contractor can request at any time it be opened to make additional edits or corrections without having the application cancelled and having to resubmit.

16. Online payments for all payments, including standard payments such as NGOMs for residential storage systems or meter socket adapters

PG&E: Online payment for $145 where the system can confirm that it is required is done. For other payments, not currently in scope, but mentioned as a potential item in our 2020 GRC. It would have to explored with the online payment vendors how contracts would change and what dollar limits there are on processing payments submitted online.

SCE: Online payment will be included in GIPT Phase 1 with an expected phase in date of Q4 2019 (subject to final confirmation).

SDG&E does allow online payments in within the DIIS portal via PayPal or Braintree for NEM-ST applications and the Renewable Meter Adapter fee. SDG&E does not have standard payments for NGOMs as there is no standard cost; the cost varies based on the voltage, meter type, and if wiring is required. SDG&E does not currently have the volume to justify the costs for the non-NEM Rule 21 customers over 1 MW. If the need develops, SDG&E can assess such an improvement and evaluate whether the cost is justified.

17. Allow contractors to generate forms for standard agreements like IFFOA, NGOM, etc.

PG&E: Depends on the complexity of the form. Forms are available for download from www.pge.com/tariffs and can be filled out as needed by applicants.

SCE: It is not clear if this question pertains to blank forms or filled forms. However, all forms generated through GIPT will be available for print but will only be fillable and approvable through the GIPT portal.

SDG&E: NGOM forms are standardized for SDG&E Renewable Meter adapter, as it is a set fee. The other NGOM forms are not standardized for the same reason as the online payment. The costs vary depending on the meter type, voltage, and wiring requirements.

18. Have one state-wide portal for consistency. OR, consistency in project status names, visibility utility vs. installer's hands, and due date tracking

Tesla would like to be clear that while we would not be opposed to having one statewide portal, we are not advocating for that. Tesla is of the view that consistency in terms of functionality/capabilities is the objective, not that the exact same interface or system be used across all three IOUs.

Small Business Utility Advocates (SBUA) recommends that the Commission order a single interconnection application portal to be used for all applications under Rule 21. For this purpose, the Commission should maintain this portal. Having a single portal for all applications would give the Commission and the customers/developers better visibility as to the status of the applications.

PG&E is willing to explore naming conventions and terminology to align application material to minimize any confusion.

SCE: Please reference SCE response to sub-proposal #3.

SDG&E does not see a need for one statewide portal. The utilities have each incurred significant costs in implementing their respective portals, and both customers and developers have become familiar with those portals. SDG&E does not believe that this would be prudent investment or fair to ratepayers given the sunk cost of existing investments in the existing portals. This sub-proposal may add convenience to large companies that process applications throughout the state, but the implementation costs would be socialized and not fair to non-participating ratepayers within SDG&E's service territory. Such a uniform portal is not a need and should not be adopted. Equity is a key principle to just and reasonable rates. SDG&E does not support this sub-proposal and the additional investment it entails.

Issue 23

Should the Commission consider issues related to the interconnection of electric vehicles and related charging infrastructure and devices and, if so, how?

PROPOSAL SUMMARIES

Proposal 23-a. Consensus
Recognize that in the case of unidirectional charge-only V1G with no discharge capability, Rule 21 does not apply. V1G must comply with Rules 2, 15, and 16.

Proposal 23-b. Consensus
Modify Rule 21 Section B.4 to clarify that Rule 21 applies to the interconnection of both stationary and mobile energy storage systems, with language as follows:

> "For retail customers interconnecting stationary or mobile energy storage devices pursuant to this Rule, the load aspects of the storage devices will be treated pursuant to Rules 2, 3, 15, and 16 just like other load, using the incremental net load for non-residential customers, if any, of the storage devices."

Proposal 23-c. Consensus
Recognize that V2G-DC/EVSE systems (Electric Vehicle Supply Equipment with stationary inverter for DC charging of vehicles) may be interconnected under the current Rule 21 language, with no Rule 21 language changes or additional authorization needed, provided that the EVSE meets all Rule 21 requirements, including UL 1741 SA and other updated smart inverter standards.

Proposal 23-d. Consensus
Allow V2G-DC/EVSE systems (stationary inverter for DC charging of vehicles) to connect as V1G, load-only, and operate in unidirectional (charge-only) mode upon satisfying pre-defined criteria. These criteria include UL Power Control Systems CRD (UL CRD) and UL 1741 SA certification testing, which will demonstrate that: (1) the EV will not discharge if the EVSE is set to unidirectional mode; (2) the EVSE will not inadvertently change to bidirectional mode; and (3) that factory default settings are set to unidirectional mode. Further, require that the operational mode cannot be changed without utility authorization.

Proposal 23-e. Consensus
Allow bidirectional mode to be enabled for a V2G-DC/EVSE (stationary inverter) system only upon receiving Permission to Operate (PTO) from the utility. When V2G-DC/EVSE owners wish to switch to bidirectional mode, they must first complete the Rule 21 interconnect process and receive PTO from the utility. If PTO has been received, the manufacturer or approved third-party installer can then program/enable bidirectional operation.

Proposal 23-f. Non-consensus

Modify interconnection portals to enable simple tracking of V2G interconnections, such as by adding new EVSE inverter types in drop-down menus or flagging interconnections as V2G. (This item is also covered in Issue 22.)

Supported by: CESA, Clean Coalition, eMotorWerks, Fiat-Chrysler, GPI, Honda, Nuvve, PG&E, SCE (conditional; see Discussion section)

Opposed by: SDG&E

Proposal 23-g. Non-consensus

Establish a sub-group inviting stakeholders from the Smart Inverter Working Group and SAE, among others, to develop technical recommendations to enable V2G-AC (mobile inverter) interconnections. This sub-group would be led by a stakeholder in coordination with the CPUC Energy Division and in collaboration with one or more utilities, and would provide a CPUC recommendation on technical requirements for the implementation of V2G-AC interconnections. Recommendations to the CPUC from this sub-group would be provided six months after the issuance of the Working Group Three Final Report if consensus can be reached, or six months after a CPUC decision on the Working Group Three Final Report if parties are in a non-consensus position.

Supported by: CESA, Clean Coalition, eMotorWerks, Fiat-Chrysler, GPI, Honda, Nuvve, SCE

Opposed by: PG&E, SDG&E

Proposal 23-h. Non-consensus

Modify Section N to allow streamlined study process for V2G-DC (stationary inverter) EVSE interconnections.

Supported by: CESA, Clean Coalition, eMotorWerks, Fiat-Chrysler, GPI, Honda, Nuvve, SDG&E (partial; see Discussion section)

Opposed by: PG&E, SCE

Proposal 23-i. Non-consensus

Clarify a pathway for parties to interconnect V2G-AC (mobile inverter) systems on a timely basis for experimental, pilot, and/or temporary use until the appropriate rules are updated in the future.

Supported by: CEC, CESA, eMotorWerks, EPRI, Fiat-Chrysler, Ford, GPI, Honda, Kitu Systems, Nuvve

Opposed by: PG&E, SCE, SDG&E

BACKGROUND

California has a goal of 5 million zero-emission vehicles (ZEVs) by 2030, along with 250,000 electric-vehicle charging stations by 2025. Given these goals, ZEV deployment and buildout of electric vehicle (EV) charging infrastructure are important topics for Rule 21 interconnection to address, including the role of EVs and Electric Vehicle Supply Equipment (EVSEs, also known as EV charging stations, electric recharging points or just charging points) in supporting the grid as 'storage-like' resources.

The California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and California Energy Commission (CEC) jointly published the Vehicle-Grid Integration (VGI) Roadmap in 2014 and the CPUC opened an Alternative Fuel Vehicles (AFV) rulemaking (R.13-11-007) to define the VGI use cases and define the barriers and activities needed to achieve the vision of the roadmap.[7] Since then, significant efforts in California have been underway to increase investments to further deployment of EVs and EVSEs, and to develop time-of-use (TOU) rates to encourage off-peak charging.

The potential for EVs and EVSEs to be activated for grid services has been recognized most recently in California's system-wide modeling efforts in the Integrated Resource Plan (IRP) proceeding (R.16-02-007), which found that "flexible EV charging" could reduce the amount of renewable generation and energy storage selected to meet 2030 greenhouse-gas planning targets.[8] More of the focus to date has been on the potential to mobilize the one-way managed or "smart" charging (V1G) capabilities of EVSEs, both through direct (e.g. demand response) and indirect (e.g. rates) mechanisms. While V1G can help manage customer bills and provide load response, there may be instances where bidirectional EV capabilities may be able to provide additional customer and grid services, especially at higher levels of EV penetration.

V2G technologies represent an opportunity to take advantage of the 'storage-like' systems integrated in EVs, plug-in hybrid electric vehicles (PHEVs), and EVSEs to support a number of use-cases for effective vehicle-grid integration. For the purposes of this report, V2G is defined to encompass a range of use-cases, technologies, means, and solutions that involve two-way electricity flow between the EV/EVSE and the grid.

Studies have shown that V2G has the bidirectional capability to provide load shifting, regulation services, and operating reserves.[9] The capability of V2G to export energy from the EV battery, through the EVSE, to onsite load or to the grid presents new opportunities with potential value. Many possible future use cases are under discussion and/or piloting, and may include the capability to manage electricity demand and customer bills, participate in the energy and ancillary services markets at the CAISO through mechanisms such as demand response, or provide distribution grid

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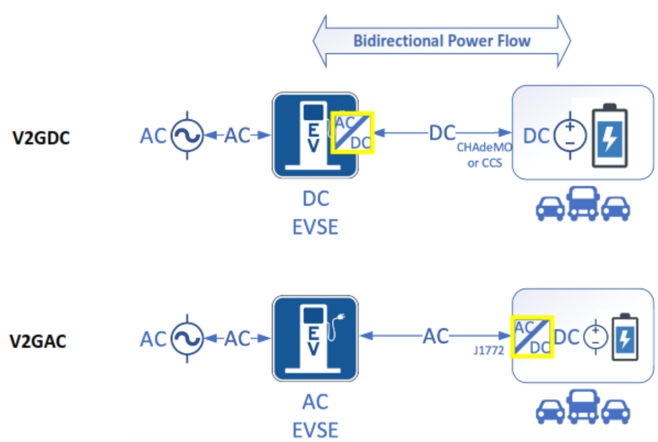
[7] *California Vehicle-Grid Integration (VGI) Roadmap: Enabling vehicle-based grid services*, published in February 2014. http://www.caiso.com/documents/vehicle-gridintegrationroadmap.pdf

[8] *Attachment A: Proposed Reference System Plan*, published on September 18, 2017, p. 139. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M195/K910/195910807.PDF

[9] Steward, Darlene. *Critical Elements of Vehicle-to-Grid Economics*, National Renewable Energy Laboratory, published in September 2017. https://www.nrel.gov/docs/fy17osti/69017.pdf

services to the utility (e.g., distribution deferral, voltage support). Proponents argue that such future V2G use cases, even if still unproven, may have the potential to enhance the net-benefit of EVs and thus accelerate their adoption, particularly among certain EV customer classes.

V2G systems fall into two categories: (1) those that utilize bidirectional inverters within the EVSE ("V2G-DC");[10] and (2) those that utilize bidirectional onboard inverters within the EV ("V2G-AC"). For each category, there may be tradeoffs in terms of overall cost, path to certification, and best-fit use cases. In either case, the V2G systems need to be safe and reliable as they interconnect to the grid. Below is an additional illustration of the difference of the two categories, as presented by Nuvve during Working Group discussions.



Currently, there are a number of pilots operating around the United States and in California that aim to demonstrate the viability of V2G use cases. The first V2G system demonstration was launched by the University of Delaware and NRG in collaboration with automotive OEMs, Honda and BMW. In California, automotive OEMs Honda and Nissan are working with Nuvve, a software aggregator, in the Electric Vehicle Storage Accelerator and the INVENT project to test different use cases of V2G technologies at the University of California San Diego campus. Specific use cases being tested include wholesale market participation, demand charge management, frequency regulation, solar PV

[10] The first bidirectional DC EVSE received Permission to Operate (PTO) from at LA Air Force Base. The next one was in SDG&E territory on April 24, 2018.

optimization, and backup power. At the Los Angeles Air Force Base, Kisensum, and Lawrence Berkeley National Laboratory, using Princeton Power EVSEs, worked with Southern California Edison to demonstrate V2G capabilities to bid energy and ancillary services directly into the CAISO's wholesale markets and to evaluate the revenue potential of having V2G resources participate as demand response.[11] [12]

Progress is being made in each of these pilots and the technology is maturing, but at the moment, there may be issues and barriers, including those related to the technical components of V2G-AC systems and interconnection technical requirements, that limit potential market opportunities for V2G systems. V2G systems have Rule 21 interconnection implications in specific use cases, both as individual units and as an aggregated resource. Furthermore, while utilities support the development of V2G through pilots such as these, utilities also emphasize that it is critical not to violate safety and reliability requirements that prevent hazardous events, such as the possibility of back-feeding power to the utility during a grid outage.

Some pilots have encountered interconnection challenges when attempting to test new configurations and use cases. The technical requirements for interconnection, as specified in Rule 21, remains a challenge for V2G-AC systems affecting market access for V2G deployments, and may influence investment in V2G-AC production models. Distribution System Operators are unable to approve interconnection requests for V2G-AC systems due to the difficulties of V2G systems in meeting the technical requirements for interconnection that ensure safety and reliability, and existing interconnection standards and procedures do not provide a clear pathway for approval of mobile inverters onboard the EV. Establishing standardized requirements and procedures that are mutually agreeable to all parties, including the automotive and utility players, is essential for this industry to move forward and to ensure that interconnection continues to accommodate progress on market access, business model testing and development, and the regulatory certainty auto manufacturers need to invest in V2G production models.

In comments to the initial Issue 23 proposal by proponents CESA, Nuvve, and Honda, PG&E emphasized the need to coordinate the work and outcomes on Issue 23 with other state-agency-led initiatives addressing VGI, including but not limited to the CEC-led VGI Roadmap Update and the CPUC's Transportation Electrification (DRIVE) Rulemaking (R.18-12-006). Likewise, PG&E also commented on the need to ensure alignment between EV VGI solutions with other inverter-based DERs – *i.e.*, findings and proposals on Issue 23 should be coordinated with the IOUs' strategic approach to smart inverters.[13] CESA agrees and notes that the CPUC and CEC staff for the respective and related proceedings have been involved in the Working Group discussions. Duplicative or conflicting strategies and policies should be avoided as much as possible.

[11] *Southern California Edison Company's Department of Defense Vehicle-to-Grid Final Report*, submitted on December 22, 2017. www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455793

[12] Black, Douglas, *et al*., Lawrence Berkeley National Laboratory. 2017. *Los Angeles Air Force Base Vehicle-to-Grid Demonstration*. California Energy Commission. Publication Number: CEC-500-2018-025. https://www.energy.ca.gov/2018publications/CEC-500-2018-025/CEC-500-2018-025.pdf

[13] *Enabling Smart Inverters for Distribution Grid Services*, Joint IOU White Paper published on October 2018. https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/Joint-IOU-SI-White-Paper.pdf

ISSUE SCOPE

To fulfill their primary mobility objective, EV batteries and EVSEs are normally treated as end-use loads that are connected to the grid through service connections, and thus are not subject to Rule 21 interconnection review. Such basic EV charging load should continue to be treated as end-use loads. In addition, modulated and V1G "smart charging" also should not be subject to Rule 21 interconnection review, and should maintain service connection as a means to connect this end-use load to the grid. Like other demand response and grid-responsive loads, Rule 21 interconnection review is not applicable to, and should not be required for V1G.

Electrified vehicles or EVSEs with V1G capabilities can adjust their charging profile by modulating the power draw from the grid in response, directly or indirectly, to a given schedule or a signal. The EVSE and EV batteries can act as demand-responsive loads similar to other grid-responsive loads, such as air-conditioning units and smart thermostats, which <u>do not require</u> Rule 21 interconnection review. This is made clear in Section B.1 of the Rule 21 tariff where interconnection only applies to generating facilities, which do not encompass load-side facilities:

> *"This Rule describes the Interconnection, operating and Metering requirements for those <u>Generating Facilities</u> to be connected to Distribution Provider's Distribution System and Transmission System over which the California Public Utilities Commission (Commission) has jurisdiction."* [emphasis added]

However, V2G systems differ from V1G systems in that the EV battery can discharge as a behind-the-meter (BTM) energy storage resource, serving AC loads, either (1) to reduce customer AC load as non-export energy storage system ("V2G Non-Export") or to (2) export across the point of common coupling [PCC] ("V2G Export"). Since bidirectional inverters can be integrated in either the EVSE (stationary inverter) or the EV itself (mobile inverter), Rule 21 jurisdiction applies to V2G systems in either stationary or mobile situation, because the system can now function as a generating facility (see Section B.1 below):

> *"This Rule describes the Interconnection, operating and Metering requirements for those <u>Generating Facilities</u> to be connected to Distribution Provider's Distribution System and Transmission System over which the California Public Utilities Commission (Commission) has jurisdiction. All Generating Facilities seeking Interconnection with Distribution Provider's Transmission System shall apply to the California Independent System Operator (CAISO) for Interconnection and be subject to CAISO Tariff except for 1) Net Energy Metering Generating Facilities and 2) <u>Generating Facilities that do not export to the grid or sell any exports sent to the grid (Non-Export Generating Facilities)</u>. NEM Generating Facilities and Non-Export Generating Facilities subject to Commission jurisdiction shall interconnect under this Rule regardless of whether they interconnect to Distribution Provider's Distribution or Transmission System. Subject to the requirements of this Rule, Distribution Provider will allow the Interconnection of Generating Facilities with its Distribution or Transmission System."* [emphasis added]

While basic EV charging load and V1G systems are not Rule 21 applicable, proponent CESA believes that V2G systems are all Rule 21 applicable. In Table 1, CESA provides a more detailed categorization of V2G configurations, which distinguishes between the bidirectional inverter installed within the EV (mobile inverter) or within the EVSE (stationary inverter), and also distinguishes between Non-Export and Export.

Table 1: Categorization of V2G Configurations by CESA

Configuration	Does Rule 21 apply?	Details
Basic EV Charging Load	No	Some EV owners do not engage in smart charging programs and may simply voluntarily respond to whatever rate they take service under.
V1G EVSE + EV	No	V1G systems are strictly load and are subject to Rules 15/16, which reviews load thresholds to trigger distribution upgrades but otherwise are service connections without study processes.[14] They should not be subject to generator studies under Rule 21, similar to traditional DR services, even as load-responsive services can be provided.
V2G Non-Export EVSE ("V2G-DC")	Yes	In this case, the EVSE is integrated with a bidirectional inverter and the DC EV battery serves as the load and Generator, similar to most BTM energy storage systems. The "Non-Export Generating Facilities" provisions within Rule 21 should apply. Similarly, the load-side study may involve Rules 2, 3, 15, and 16.
V2G Non-Export EV ("V2G-AC")	Yes	In this case, the EV is integrated with an onboard bidirectional inverter alongside the EV battery, serving as the load and Generator, similar to BTM energy storage with integrated inverters within the same module. The "Non-Export Generating Facilities" provisions within Rule 21 should apply, only if these functions are utilized or enabled. Similarly, the load-side study may involve Rules 2, 3, 15, and 16.
V2G Export EVSE ("V2G-DC")	Depends	WDAT may apply when exporting to the CAISO grid, while Rule 21 may apply when exporting and selling to the distribution utility, such as distribution capacity for deferral purposes.
V2G Export EV ("V2G-AC")	Depends	WDAT may apply when exporting to the CAISO grid, while Rule 21 may apply when exporting and selling to the distribution utility, such as distribution capacity for deferral purposes.

[14] CESA recognizes that the exemption to Rule 15 and Rule 16 may not be renewed past its current expiration date of June 30, 2019.

For all V2G configurations in Table 1, Rule 21 interconnection review is required to support the interconnection of any Generating Facility and utility-interactive inverter, but the current Rule 21 does not include language for interconnection considerations explicitly for inverters for mobile energy resources. Currently, interconnection requests for mobile energy resources would be handled in the same manner as any other interconnection request.

Interconnection of V2G systems have been done on a case-by-case basis to date.[15] The potential need for modifications to Rule 21 to set a standardized interconnection review process specifically for V2G systems is being discussed among industry stakeholders.

Customer experience in each of these scenarios may also bear consideration. Over the course of multiple meetings on Issue 23, Working Group participants focused on V2G Non-Export and Export EVSE (stationary inverter, V2G-DC) configurations, and deferred consideration of V2G Non-Export and Export EV (mobile inverter, V2G-AC) configurations to a later time.

For several potential V2G use cases, the Working Group considered applicable codes and standards as well. These include interconnection requirements IEEE 1547 (Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces), product certification standard UL 1741 (Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources), and Society of Automotive Engineers (SAE) J-3072 (Interconnection Requirements for Onboard, Utility-Interactive Inverter Systems). In addition, there are testing standards IEEE 1547.1 (Draft Standard for Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces) and UL 1741 Supplement A (UL 1741 SA).

These standards are linked or becoming linked in relation to Rule 21 and V2G. A new Section Hh on smart inverter certification and requirements has been added to Rule 21 to incorporate the UL 1741 SA standard for all inverter-based generation. And pursuant to the 2018 CPUC Resolution E-4898, Rule 21 Section Hh must be harmonized with IEEE 1547 in the future.

For bidirectional mobile (onboard) inverters used in V2G-AC applications, the SAE J-3072 standard was developed to take into account the 2003 version of IEEE 1547 (IEEE 1547-2003), but has not been updated to account for the requirements in the most current version of IEEE 1547 (IEEE 1547-2018). Further, SAE J-3072 has not yet fully taken into account the requirements of current Rule 21 and UL 1741, which is the standard for safe inverter interconnections to the distribution grid.

Some discussion took place in the Working Group on how much SAE standards align with (and/or have gaps compared to) IEEE 1547 and UL 1741, including some preliminary work initiated by SCE and SAE on how SAE may align with IEEE 1547 standards. These discussions and work resulted in Proposal 23-g to establish a technical sub-group comprised of utility and industry stakeholders to investigate the testing and certification requirements for V2G-AC systems that would satisfy safety and reliability requirements for on-board (mobile) inverters used in V2G-AC configurations.

[15] A municipal utility in Delaware is a precedent for consideration in this Working Group.

In the particular case of V2G approaches for commercial vehicle fleets, the Working Group flagged but did not discuss the issue of how sub-metered EVs and EVSEs can address Rule 21 technical requirements in aggregate at the customer meter without having to interconnect each EV or EVSE individually. Once an interconnection pathway for applicable individual EVs and EVSEs is clarified and defined, the next step may be for the CPUC, IOUs, and stakeholders to work together on enabling fleet-level interconnections. PG&E added that, though aggregation and sub-metering may be relevant to interconnection, they are wide-reaching issues that extend well beyond interconnection and likely require coordination with other proceedings and stakeholders. CESA agreed that it may be reasonable to not include aggregation issues in the scope of Issue 23 at this time, but noted that interconnection issues related to DER aggregations, including with V2G systems, will increasingly become a prevalent issue that must be addressed in the near future.

In summary, the scope of Issue 23 and the related proposals was identified as follows:

- Clarify applicability of Rule 21 to V2G-capable systems
- Focus on interconnection processes and pathways for V2G Non-Export and Export EVSE (stationary inverter, V2G-DC) configurations
- Focus on single-site V2G Non-Export interconnections under Rule 21
- Review for the applicability of UL 1741 SA, SAE J-3072, IEEE 1547, and other standards/certifications to enable V2G-DC and V2G-AC interconnections
- Ensure that all findings and proposals for Issue #23 are coordinated with all relevant agencies, stakeholders, and proceedings

DISCUSSION

Proposal 23-a. Consensus

Recognize that in the case of unidirectional charge-only V1G with no discharge capability, Rule 21 does not apply. V1G must comply with Rules 2, 15, and 16.

Parties wanted to explicitly recognize that Rule 21 does not apply to V1G, in order to remove any uncertainty. Parties broadly agreed that V1G devices and technologies do not need to comply with Rule 21 since V1G is considered to be "load" not "generation." At the same time, parties emphasized that V1G still needs to comply with Rules 2, 15, and 16 load interconnection requirements.

Proposal 23-b. Consensus

Modify Rule 21 Section B.4 to clarify that Rule 21 applies to the interconnection of both stationary and mobile energy storage systems, with language as follows:

> "For retail customers interconnecting stationary or mobile energy storage devices pursuant to this Rule, the load aspects of the storage devices will be treated pursuant to Rules 2, 3, 15, and 16 just like other load, using the incremental net load for non-residential customers, if any, of the storage devices."

Rule 21 section B.4 has been applied to both stationary and mobile energy storage devices because it did not explicitly address mobile versus stationary in its plain language. In discussing Issue 23, parties said that clarifying that Rule 21 applies to both mobile and stationary energy storage systems would remove uncertainty or ambiguity.

Proposal 23-c. Consensus
Recognize that V2G-DC/EVSE systems (Electric Vehicle Supply Equipment with stationary inverter for DC charging of vehicles) may be interconnected under the current Rule 21 language, with no Rule 21 language changes or additional authorization needed, provided that the EVSE meets all Rule 21 requirements, including UL 1741 SA and other updated smart inverter standards.

As noted in the Issue Scope section, interconnection of V2G systems has been done on a case-by-case basis to date. Parties said that recognizing that V2G-DC/EVSE systems may be interconnected under the current Rule 21 language would also remove uncertainty in relation to such systems.

Proposal 23-d. Consensus
Allow V2G-DC/EVSE systems (stationary inverter for DC charging of vehicles) to connect as V1G, load-only, and operate in unidirectional (charge-only) mode upon satisfying pre-defined criteria. These criteria include UL Power Control Systems CRD (UL CRD) and UL 1741 SA certification testing, which will demonstrate that: (1) the EV will not discharge if the EVSE is set to unidirectional mode; (2) the EVSE will not inadvertently change to bidirectional mode; and (3) that factory default settings are set to unidirectional mode. Further, require that the operational mode cannot be changed without utility authorization.

During Working Group discussions, utilities wanted assurances and confidence that a V2G-DC system in charge-only mode would not discharge, and focused on the technical requirements and testing needed. Issue proponents were concerned about the potential costs of having to prove no-discharge and the potentially onerous burden of having to "prove a negative" – i.e., prove that something won't happen

The Working Group discussed the risks and potential need for testing and certifications, especially if V2G-DC interconnections become more prevalent. This led to initiating a technical sub-group to discuss potential testing and certification processes that would ensure V2G-DC/EVSE would be operated as unidirectional without need for an interconnection request.

The sub-group discussed technical requirements, evaluations and processes that are needed to allow connecting a V2G-DC-capable EVSE to the electric grid while operating it only unidirectionally until a desire to change the mode to "bidirectional" at which time an interconnection application would be submitted to the utility. The Working Group came to a consensus that all V2G-capable EVSEs used for V2G-DC shall:

a. Be evaluated and listed under UL 1741 SA via an OSHA-approved NRTL and, in the near future, be evaluated using UL 1741 that replaces the Supplement A with IEEE P1547.1-2019, which is projected to be approved by Q4 2019
b. Be evaluated, using the recently approved UL CRD for Power Control System to:
    i. Demonstrate that when the EVSE is set or programmed to unidirectional (charging) mode, the EVSE will not discharge
    ii. Prevent inadvertent change in operational mode (change from unidirectional to b-directional mode)
c. Be configured such that EVSE factory default mode shall be unidirectional (charging only)

When an EVSE has met the aforementioned requirements under (a), (b), and (c), then the EVSE may be interconnected as V1G, load only, and must comply with Rules 2, 15, and 16 in accordance with Proposal 23-a. This EVSE has the option to be evaluated at a future date as part of Rule 21 if the EVSE owner desires to operate the V2G-DC/EVSE as a bidirectional system.

Utilities also identified "pending items" that they may need to address at some point, including the entity responsible for reviewing/approving testing information and maintaining the list of approved equipment. CESA recommends that the list of approved equipment be maintained by the utilities until an equivalent CEC list can be developed.

Proposal 23-e. Consensus

Allow bidirectional mode to be enabled for a V2G-DC/EVSE (stationary inverter) system only upon receiving Permission to Operate (PTO) from the utility. When V2G-DC/EVSE owners wish to switch to bidirectional mode, they must first complete the Rule 21 interconnect process and receive PTO from the utility. If PTO has been received, the manufacturer or approved third-party installer can then program/enable bidirectional operation.

When V2G-DC/EVSE owners wish to switch to bidirectional mode, they must first complete the interconnect process and receive Permission to Operate (PTO) from the utility. If PTO has been received, the manufacturer or approved third-party installer can then program/enable bidirectional operation in accordance with EVSE instructions & UL CRD requirements.

There are a few implementation details that likely need to be worked out, which can occur in future Working Group actions or through advice letter filings. For example, it is to be determined on the implications of customers installing bidirectional capable V2G-DC/EVSE systems but not initiating a Rule 21 application to enable bidirectional mode for a long time, potentially leading to the risk that major costly retrofits are needed to meet new standards or certifications that have been adopted at a much later time. One possibility would be to have V2G-DC/EVSE owners to interconnect as charging-only mode to facilitate fast load connections and to have the Rule 21 process be started in parallel. The need to define a time period to initiate the Rule 21 process was also discussed. These implementation details remain unresolved at this time.

Specifically as related to the time period to initiate Rule 21 process, PG&E proposes the following: As relevant to the Interconnection Application, if the Interconnection Application is submitted within 6 months of inspection approval by the local Authority Having Jurisdiction (AHJ), and the EVSE owner desires to operate the EVSE in a V2G mode, in accordance with Rule 21, the EVSE inverter can be evaluated based on the applicable regulatory requirements and standards at the time of inspection approval. Otherwise, the EVSE inverter shall be evaluated as V2G based on the regulatory requirements applicable at the date of Application Deemed Complete. Consistent with current process, the interconnection study for grid impact will always be conducted at the date of Application Deemed Complete.

Proposal 23-f. Non-consensus

Modify interconnection portals to enable simple tracking of V2G interconnections, such as by adding new EVSE inverter types in drop-down menus or flagging interconnections as V2G. (This item is also covered in Issue 22.)

Supported by: CESA, Clean Coalition, eMotorWerks, Fiat-Chrysler, GPI, Honda, Nuvve, PG&E, SCE (conditional; see utility position)
Opposed by: SDG&E

In Working Group discussions, proponents believed that simple tracking of V2G interconnections would provide further data and understanding of V2G development in California that could support future policy and decision-making.

Tesla position:

In comments for Issue 22, sub-proposal #4 on adding V2G to interconnection portals, Tesla commented that it is not opposed to incorporating V2G into portals, but it does question the degree of urgency given the nascent state of V2G currently.

GPI position:

In comments for Issue 22, sub-proposal #4, GPI disagreed with Tesla and urges the Commission to address this now in order to provide a proactive environment for V2G, rather than being reactive.

Utility positions:

SDG&E does not support this proposal. To date, SDG&E has only processed one interconnection application for a DC-coupled V2G facility that was behind an existing billing meter at a charger. The scope and cost to revise SDG&E's web portal have not been determined because so few V2G applications have been submitted to date. As the number of V2G applications increase, SDG&E will work with its Information Technology group to determine the detailed scope of work and associated costs to revise the portal to allow streamlined application processes for V2G and weigh those costs with the potential benefits.

SDG&E asserts that at the present time, the existing application processes are adequate to facilitate the interconnection request and review process for V2G systems. Given the lack of such applications, SDG&E does not see a need at this time to begin the engineering work to determine the scope and cost of implementing changes to its portal.

While SDG&E does not have a current need to improve the interconnection process for V2G DC systems, its practice is to make system improvements including streamlining changes that will improve efficiencies and expedite the interconnection processes as the need arises.

Although SCE has not seen any current V2G projects, SCE supports the inclusion of EVSE inverters in future updates of SCE's Generation Interconnection Processing Tool (GIPT) system (as discussed within Issue 22 and discussion of interconnection portals). SCE expects that this function should be able to be incorporated into the GIPT drop down menu for new applications within the later phases of platform development subject to Phase 1 GIPT functionality confirmation and Phase 2 function capability review.

Proposal 23-g. Non-consensus

Establish a sub-group inviting stakeholders from the Smart Inverter Working Group and SAE, among others, to develop technical recommendations to enable V2G-AC (mobile inverter) interconnections. This sub-group would be led by a stakeholder in coordination with the CPUC Energy Division and in collaboration with one or more utilities, and would provide a CPUC recommendation on technical requirements for the implementation of V2G-AC interconnections. Recommendations to the CPUC from this sub-group would be provided six months after the issuance of the Working Group Three Final Report if consensus can be reached, or six months after a CPUC decision on the Working Group Three Final Report if parties are in a non-consensus position.

Supported by: CESA, Clean Coalition, eMotorWerks, Fiat-Chrysler, GPI, Honda, Nuvve, SCE
Opposed by: PG&E, SDG&E

At the March 27, 2019, a tentative (verbal) consensus was reached to have a technical sub-group be established to address V2G interconnection issues. This sub-group would be "informal" but would be open to participants from the relevant stakeholder groups (*e.g.*, SIWG, SAE, DRIVE OIR, VGI Working Group) to participate in these technical discussions. There was tentative agreement that the group could develop recommendations that could be later introduced into the formal procedural record in time for the adoption of the Working Group #3 Proposed Decision, which may occur sometime in Q3 2019.

There are still uncertainties as to how any consensus proposals from this sub-group would be re-introduced back into the record, who would supervise the sub-group, and by what timeframe recommendations would be delivered. Some ideas included: (a) having the recommendations be introduced through the SIWG, which is meeting on an ongoing basis; (b) having a dedicated Rule 21 workshop; and/or (c) the VGI Working Group in the DRIVE OIR, which is slated to begin meeting in

July 2019. The sub-group itself may ultimately determine where any proposals would enter into the record. Not all stakeholders were in favor of this procedural pathway, as PG&E reserved judgment.

<u>Proponent positions:</u>

> CESA does not believe that the limited time available in Working Group Three dedicated to Issue #23 was sufficient time to comprehensively and effectively address Rule 21 interconnection issues for certain V2G-AC systems with mobile onboard inverters seeking interconnection through SAE J3072, or other longer-term interconnection issues such as hybridization of V2G systems with solar and/or energy storage systems. There are a number of technical details that need to be discussed between IOUs and other stakeholders to understand the concerns, address gaps, and propose the appropriate changes.
>
> CESA understands that a new proceeding (R.18-12-006) has been opened to address a range of issues related to vehicle electrification rates, infrastructure, and VGI issues. While this issue could be scoped there, CESA believes that R.18-12-006 is already overloaded with a wide range of issues and instead recommends that the Rule 21 proceeding is the appropriate forum to discuss these matters, which require the involvement of IOU interconnection engineers and specific tariff rule changes. The Smart Inverter Working Group (SIWG) was also raised as a possible venue to address these outstanding or longer-term issues, but CESA is again concerned that the SIWG is already tasked with a large agenda, including the timely implementation of Resolution E-4898 functions, which have already been delayed multiple times. Instead, CESA believes that a dedicated V2G-focused sub-group in this proceeding is the appropriate time and place to address these technical matters more deeply.
>
> In sum, CESA believes that more time is needed on various V2G interconnection issues.

<u>Utility positions:</u>

> While PG&E supports the advancement of industry efforts on the technical aspects of V2G AC, PG&E makes the following two comments: First, addressing the regulatory needs and/or requirements around technical aspects of V2G AC should not be done in isolation but rather as part of a broader VGI effort that clearly identifies and prioritizes VGI's technical challenges and barriers. Second, the need and/or value of V2G AC should be clearly articulated, especially relative to the more technologically and commercially mature V2G DC, before and in order to justify launching dedicated efforts to address the technical aspects of V2G AC through ratepayer-funded policy and regulatory proceedings. PG&E supports the continuation of private industry efforts to address these issues. Part of those private industry efforts may be through the participation in SAE activities. EV manufacturers should play a leading role in the development of automotive standards, while utilities can advise and engage voluntarily as needed. For example, some automakers have expressed concern with UL requirements because they take up too much space in the vehicle. This automotive design issue affecting V2G AC is best addressed by SAE and EV manufacturers rather than Rule 21 Working Group. After SAE develop the automotive equivalent of UL 1741 SA, utilities can review it for adequacy and, if adequate, adopt it in Rule 21.

PG&E believes that SIWG in its current form may not have sufficient EV expertise, and SAE technical personnel may need to lead and proactively support potential future V2G AC standards development effort, to ensure that EV technical issues are properly addressed.

PG&E also notes that the proposed timeline in this proposal may be dependent on the timeline associated with SAE standards and level of involvement.

SCE agreed with CESA on the need for additional time to address all the V2G-AC implementation procedures. SCE recommends that this sub-group be a collaboration of the SIWG including technical standards personnel, including from SAE, UL and IEEE to address expected technical topics, such as:

- Compliance requirement under the various standards (*e.g.*, SAE J3072, UL 2594, UL 1741 SA, SAE J2836, IEEE 1547-2018, IEEE 1547.1-2019, IEEE 2030.5)
- Compliance with NEC codes
- Necessary Rule 21 modifications

SCE: While SIWG has been tasked with addressing a number of technical issues, especially for Resolution E-4898, SCE believes that the SIWG has largely completed with those tasks and thus would be available for working on these complex technical issues. However, SAE technical personnel must participate in the SIWG to ensure that all technical issues are properly addressed.

SCE: Given the complexity of the technical and standard requirements related to V2G-AC, SCE does not support adding this scope to future working groups (i.e., Working Group Four). Instead, SCE proposed that a working group overseen by IOUs and supervised by CPUC Energy Division be established to provide a CPUC recommendation on technical requirements for the implementation of V2G AC interconnections as outlined in Proposal 23-g and consistent with prior SIWG practice. SCE proposed that recommendations based on discussions occurring in this forum could be provided 6 months to the CPUC after the issuance of the Working Group Three report if consensus can be reached or 6 months after the CPUC decision on Working Group Three report if parties are in a non-consensus position as outlined in Proposal 23-g.

SDG&E understands that a draft motion to create this sub-group is in circulation and may soon be filed proposing to begin this subgroup in Q2-Q3 2019 – prior to the Commission's review and decisions on proposals contained in this Working Group Three Final Report. SDG&E believes that it is premature and potentially extremely inefficient to begin a technical sub-group prior to the Commission issuing a decision that holistically considers all the recommendations within this Working Group Three Final Report. EV industry stakeholders have stated that V2G AC systems cannot pass the UL 1741 SA compliance tests because UL 1741 SA contains test criteria that mobile inverters cannot meet. The EV industry stakeholders have proposed SAE J3072 as an alternative testing standard to UL 1741 SA. In order for the IOUs to accept SAE J3072 as an acceptable replacement to UL 1741 SA, it will be necessary for the EV industry stakeholders to do a comparative analysis between SAE J3072 and UL 1741 SA (and IEEE 1547). EV industry stakeholders would also need to identify changes to SAE J3072 that will incorporate the essential tests to ensure on-board inverters in V2G AC systems will operate safely and reliably. When the changes to SAE J3072 have been identified, then IOU stakeholders will need to verify the proposed changes will provide the same safety and reliability tests now provided by UL 1741 SA. After verification that SAE J3072 contains the same tests to ensure safety and reliability now provided by UL 1741 SA, it may be appropriate for all stakeholders to collaboratively determine implementation steps.

SDG&E: The initial phases of work to perform the comparative analysis between the SAE and UL/IEEE standards and to identify changes needed to SAE J3072 can be performed by the EV industry stakeholders, and should not require significant input from the IOUs. The IOUs will not need to participate in the work effort until the changes to SAE J3072 have been proposed. Therefore, it is not appropriate to assemble a mandatory working group led by IOUs and EV industry stakeholders, nor to conduct meetings with all parties until the proposed changes to SAE J3072 have been developed. Once the proposed changes to SAE J3072 have been developed, communication between EV industry representatives and the IOUs and other industry stakeholders should take place to verify SAE J3072 adequately supplants UL 1741 SA, and to determine implementation steps.

Proposal 23-h. Non-consensus
Modify Section N to allow streamlined study process for V2G-DC (stationary inverter) EVSE interconnections.

Supported by: CESA, Clean Coalition, eMotorWerks, Fiat-Chrysler, GPI, Honda, Nuvve, SDG&E (partial; see utility position)
Opposed by: PG&E, SCE

Proponent position by CESA:

For V2G Non-Export EVSE use cases, CESA raised the possibility of considering how Rule 21 interconnection review processes could be adapted from the recently approved one-year pilot for expedited interconnection review of non-export, standalone energy storage systems that meet specific eligibility criteria.[16] Existing Section N Criteria and CESA's proposed changes are given in Table 2.

Utilities filed advice letters on September 1, 2018 reporting on outcomes of this pilot process. CESA believes that it may be worthwhile to consider how this process, perhaps adapted in some way to V2G use cases, could establish a performance-based interconnection review process.

[16] Rule 21 Section N.

Table 2: Existing Section N Criteria and CESA's Proposed Changes

Existing Section N Criteria	CESA's Proposed Changes
Cannot exceed 0.5 MW in aggregate inverter and/or rectifier nameplate rating (but any energy storage kWh rating may apply)	**A similar threshold could be set.** CESA does not see any reason why this threshold should be differentiated for stationary BTM energy storage versus stationary V2G EVSEs that have similar capabilities but with the 'storage reservoir' located in the EV batteries rather than integrated in the same 'box' where storage controls are located. Similarly, the load studies should focus on the inverter rating of the EVSE as opposed to the EV battery capacity and should allow for any kWh rating to apply. Perhaps a policy question for the CPUC in the future could be on reassessing this 500-kW threshold, which for EV fleets, could be easily reached – e.g., from four 150-kW DC fast chargers.
Must be behind a single, clearly marked, and accessible disconnect	**No changes are needed.** The disconnect can be located and managed at the EVSE. This appears to already be mandatory for Level 2 EVSEs.[17]
Only Screen I Protection Options 3 and 4 are eligible, as well as potentially AC/DC converters pending their lab results	**No changes are needed.**
Must be at a single retail meter point of interconnection	**No changes are needed.**
Must have a single or coordinated control system for charging functions	**No changes are needed.**
Must operate under "Charging Mode 2" wherein charging functions do not increase the host facility's existing peak load demand	**No changes are needed, but further discussion would be helpful to view this criterion.** Within the context of EV charging load, customer peak demand may increase in certain applications. Some EVSEs are also taking service under separate rates from the host customer load.[18] CESA is open to discussion on whether this criterion would need to be adjusted for V2G EVSEs.
Must have a UL 1741 certified inverter	**No changes are needed.** V2G-DC systems should be certifiable under UL 1741.
Must include a single-line diagram and description of operations	**No changes are needed.**
Must meet all Electric Service Requirements	**No changes are needed.**

[17] See PG&E's code at https://www.pge.com/includes/docs/pdfs/about/environment/pge/electricvehicles/ev5pt3.pdf

[18] CESA notes that other jurisdictions, such as District of Columbia, are dealing with the challenge of distinguishing between electricity as a fuel versus electricity as a service.

To implement the above proposed changes, CESA proposes the following redline modifications to the Rule 21 tariff Section D (General Rules, Rights, and Obligations) to extend the applicability of the expedited interconnection review process for non-exporting energy storage systems to non-exporting V2G-DC interconnection use cases:

> 14. Special Provisions Applicable to Non-Export Energy Storage Generating Facilities
>
> Applicants with Non-Export Energy Storage Generating Facilities, including direct current vehicle-to-grid energy storage systems, that meet the criteria listed in Section N shall be eligible to elect to have their Interconnection Requests processed in an expedited timeframe, subject to the terms and conditions of Section N.

Similarly, the opening applicability paragraph of Section N would need to be modified:

> Upon implementation by Distribution Provider, Applicants with Interconnection Requests for Non-Export Energy Storage Generating Facilities, including direct current vehicle-to-grid energy storage systems, who meet the requirements outlined below are eligible for expedited interconnection, as provided herein, in accordance with the Fast Track Process technical review requirements of Section F.2. Applicants with Non-Export AC/DC Converters that meet the requirements outlined in Section O below are also eligible.

Alternatively, a new sub-section of Section N could be created for V2G-DC systems and broadly for V2G systems in general, thus teeing up future consideration of V2G-AC interconnections.

For fleet applications, language preventing multiple generators behind the same PCC would have to be removed or modified. Otherwise, V2G-DC interconnections would be required to follow the normal Fast Track procedures and applicable timelines. CESA therefore recommends the following redline modifications to Section N.2.c:

> The Generating Facility must be located behind an existing single retail meter and Point of Common Coupling with a single, clearly marked and accessible disconnect. ~~No other Generators, other than isolated back-up Generators, may be at the same Point of Interconnection or Point of Common Coupling.~~

Additionally, under Rule 21 Section N.2.e., CESA raised the possibility of striking the provisions around control systems ensuring that there is no increase in a customer's existing peak load demand, which CESA believes should be accommodated by Rule 16. In many applications, there may be high-capacity EV charging use cases that will likely exceed a customer's peak load. CESA understands that Section N was established to streamline interconnection by limiting overload concerns from coincident charging, so CESA wishes to explore the flexibility of reassessing this criterion and whether it is appropriate. This may be a broader policy matter that needs to be addressed within the context of not only V2G-DC systems but with the broader subset of energy storage systems. CESA flags this as a consideration in such future discussions.

Finally, CESA requests clarity on the status of the pilots conducted leveraging the process and conditions set in Section N. CESA understands the expedited interconnection process for non-exporting energy storage was a pilot that expired on June 30, 2018. While CESA strongly recommends the continuance of this process and maintaining Section N in the tariff, a CPUC determination to discontinue this separate process for energy storage would have an impact on our recommendations.

For V2G Export EV or V2G Export EVSE configurations, CESA recommends the creation of expedited interconnection processes similar to what has been established for Net Energy Metering (NEM) generating facilities. Currently, NEM generating facilities under 1 MW are processed in 30 days or less after submitting a completed interconnection application,[19] and are eligible for fast-track evaluation when sized no larger than 3 MW on a 12 kV, 16 kV, or 33 kV lines.[20] As a policy decision, CESA believes it may be reasonable to assess whether size thresholds could be established such that expedited fast-track processes or certain screen bypassing can be extended to V2G DC systems to facilitate the interconnection of V2G EVSEs that support the state's VGI objectives and provide additional grid services. For example, specific provisions for NEM generating facilities is granted under Screen K for NEM facilities below a certain size threshold (500 kW). This is a policy decision that should be considered by the CPUC.

At the January 10, 2019 workshop, SCE raised potential jurisdictional issues for V2G exporting use cases. CESA is unaware of any energy storage projects being FERC jurisdictional under the Public Utility Regulatory Policies Act (PURPA) provisions, though there is some recent active consideration of this jurisdictional issue.[21] Jurisdictional issues were also raised in the Community Energy Storage Working Group in R.15-03-011 on September 13, 2017. While it is likely that energy storage may be considered a qualifying facility (QF) by which utilities would be required to purchase electricity at avoided costs, CESA does not view that as applicable, at this time, for the V2G use cases discussed here, where there is no eligible generation resource that is being paired with V2G systems. Similar conclusions, though not definitive, were made in the community storage discussions. In the future, such PURPA-related questions may need to be addressed as V2G systems are paired with eligible generation resources, but at this time, CESA recommends that such FERC/PURPA jurisdictional issues do not need to be addressed in this proceeding at this time. Additionally, the FERC jurisdictional issue likely applies to a broader set of BTM distributed energy resources as well, such as BTM energy storage that wishes to export power. These macro questions should be addressed in the appropriate policy proceeding as opposed to this technical interconnection proceeding.

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[19] Rule 21 Section D.13.b.

[20] Rule 21 Section E.2.b.i.

[21] Bade, Gavin. "Montana case could set FERC precedent for paired storage treatment under PURPA." *Utility Dive*, published October 9, 2018. https://www.utilitydive.com/news/montana-case-could-set-ferc-precedent-for-paired-storage-treatment-under-pu/539213/

Instead, the focus may more appropriately be on how exporting V2G systems (as well as exporting energy storage systems) are treated for interconnection when providing CPUC-jurisdictional distribution services, such as in the IDER RFOs being conducted annually going forward. CESA believes that such projects are Rule 21 applicable as they would be "selling" capacity, not energy, to the utility. This is the appropriate focus for this Working Group at this time in identifying interconnection pathways for exporting V2G-DC systems.

Finally, CESA understands that there are metering provisions for interconnecting energy storage systems and other Generating Facilities. CESA recommends that this Working Group not address that matter at this time, as metering and sub-metering approaches is more appropriately addressed in the new Vehicle Electrification proceeding (18-12-006).

<u>Utility positions / general:</u>

Utilities agreed that stationary inverters for V2G-DC interconnections should be required to comply with Rule 21 requirements and the UL 1741 SA certification process or current approved certification process, as these V2G systems will use non-mobile (stationary) inverters where EVs will have the storage onboard but the inverter will be off-board and stationary. The EVSE must be certified and listed by an OSHA-approved NRTL and certification of compliance documents should be provided to utility equivalent to stationary energy storage inverter. In other words, V2G DC interconnections should follow the same Rule 21 Section Hh requirements as any other inverter-based DER subject to the Rule 21 tariff, including forthcoming transition to updated IEEE 1547-2018 and IEEE 1547.1-2019/20 standards once approved and adopted in Rule 21.

<u>Utility positions / SCE:</u>

SCE does not agree to this proposal and related revisions to Section N for interconnection of V2G-DC/EVSE systems. By way of background, Section N was adopted for the very specific use case of expanding the interconnection of non-export energy storage projects (the use case for the pilot was very well established as well). To meet this very specific use case, stakeholders in previous Rule 21 proceedings agreed on specific project and technical requirements outlined in Section N which as highlighted below:

1. Generating Facility must only be comprised of Non-Exporting inverter-based energy storage. This is required as having other technologies would require additional engineering technical review which would prevent the ability to expedite the interconnection process for this class of non-export energy storage projects.
2. Generating Facility must have an aggregate inverter nameplate capacity rating of no more than 500KW. This is necessary as having this limit will minimize any impacts based on screens F and G and thus allow expediting the Interconnection Process.
3. Control system must ensure that there is no increase in customer's increase peak demand. This is required to prevent the need to perform a load study and thus allow the expediting of the interconnection process.

Modifying Section N as proposed by CESA could undermine the current Section N approach as it was developed for a specific group of established use cases in accordance with prior stakeholder discussions and approved by the Commission.

Instead, SCE proposes that once certification requirements are met for the EVSE's as outlined in Proposal 23-d, then SCE believes the Fast Track process is sufficient to meet the needs of V2G-DC/EVSEs*. Further, to the extent that generating facilities with V2G-DC/EVSEs desire to interconnect using the existing Section N, they are able to do so as long as they meet the current Section N requirements. Therefore,* SCE does not support the red-line proposed by CESA on Rule 21 Section D.14 along with the proposed Section N redline.

1. As discussed within Working Group Three discussions, SCE did not agree to modify Section N as proposed by CESA [22] on the following grounds as summarized below:

    a. Section N was designed and approved to allow the expedited interconnection of energy storage projects with a specific set of technical and procedural requirements in support of an established system use case;
    b. Modifying section N as proposed by CESA could potentially delay the interconnection process for projects which are currently evaluated under Section N in accordance with existing tariff provisions. Section N, as currently approved within Rule 21, has been successful for the projects currently processed in accordance with Section N requirements and expansion to greater use cases not envisioned could create negative consequences for the projects that are currently processed in accordance with Section N.
    c. For V2G-DC systems which have met the requirements as outlined in proposal 23-d and which meet the requirements of Section N, are able to use Section N today without additional issues.

2. SCE does not agree to modify section D.14 as proposed by CESA. For purposes of interconnection, the energy storage within the V2G-DC electric vehicle is not relevant. In fact, Rule 21 section N.2.b indicates that "*There is no limit on an Energy storage device KHW capacity rating*". For purpose of interconnection, the relevant device is the stationary EVSE just like for stationary storage systems where the relevant device is the inverter. Thus, for section D.14, the red line language proposed by CESA is not necessary and should not be added.

3. SCE disagrees with CESA's proposal of establishing NEM equivalent process for EVSEs (V2G-DC PVEs). SCE notes that NEM expedited process is based on meeting rule 21 system review screens A-H and being below 11KVA is what currently allows NEM eligible projects to be reviewed under the specific expedited process. Thus, to the extent that EVSE's satisfy the existing certification requirements as stated in proposal 23-d, size limit requirements as outlined in Rule 21 Screen J, along with the simplified interconnections as generally NEM type of projects pose, then SCE believes that these EVSE can be

[22] CESA's January 24, 2019 proposal on Page 16.

interconnected in an expedited manner equivalent to small storage projects and should be able to satisfy Section N as discussed above.

Therefore, SCE does not support creating a specific process for EVSE which do not have the same regulatory structure requirements equivalent to an NEM program tariff requirements and process. For example, under the PUC NEM program structure, NEM projects which are less than 1MW in capacity are not required for system upgrades or studies. Until an equivalent regulatory structure is created for V2G/EVSE systems, the same process as NEM should not be used for V2G/EVSE systems.

SCE has the following specific comments on the Section N Criteria changes proposed by CESA:

<u>Cannot exceed 0.5 MW in aggregate inverter and/or rectifier nameplate rating</u>
SCE agrees that there should be no difference between stationary storage interconnections (Inverter and storage at a site) and mobile storage interconnections (stationary EVSE and storage on the vehicle). Thus, both stationary and mobile storage systems should be treated equally for purposes of this screen.

<u>Must be behind a single, clearly marked, and accessible disconnect</u>
For purposes of disconnecting means as required in Rule 21 section H.1.d, the generating facility must include the necessary accessible disconnecting means with the requirements specified in Rule 21 Section H.1.d. To the extent that disconnecting means for the EVSE meet the requirements of Rule 21 Section H.1.d, SCE would accept such disconnecting means otherwise a separate set of disconnecting means will be required.

<u>Must operate under “Charging Mode 2” wherein charging functions do not increase the host facility’s existing peak load demand</u>
SCE proposes to modify to: “The control system must ensure that there is no increase in the Interconnecting Customer’s existing peak load demand.” The main intent of Rule 21 Section N was to expedite the Interconnection of Non-Export Energy Storage. To be able to expedite the review and approval of the interconnection, it is necessary to eliminate as many of the technical reviews. One major technical review is the ability for the existing electrical service components to be able to support the increased load. However, if it can be assured that the storage control systems will not allow an increase in load, then there is no need to perform an engineering review for the load portion and thus expediting the technical review process.

If generating facility cannot meet this criterion, then two technical sets of technical evaluations would be required:

1. Evaluate that the existing electrical facilities are adequate for the increased load. This process would follow existing rules 2, 15, and 16
2. Evaluate that the existing generating facilities meet all Rule 21 requirements.

Thus, because the intent for Section N was to expedite the interconnection process for non-exporting generators, a requirement to have a control to not increased customer’s peak demand is required otherwise there is no way to expedite the interconnection process for non-exporting storage.

To the extent that V2G-DC/EVSE systems can meet the requirement of this criteria, then these systems could be treated equally as Rule 21 Section N non-exporting storage otherwise, these projects would need to be evaluated for load increases and generating interconnection requirements to insure DER-Grid interconnection is safe under charging and discharging operating conditions.

Utility positions / PG&E:

PG&E supports enabling streamlined V2G-DC interconnections via Section N, which is why it disagrees with modifying Section N. An EV with energy storage meets the Rule 21 definition of a Generator, therefore no changes to Section N are required. PG&E believes that existing Section N is flexible enough to accommodate vehicle batteries already and does not need to be modified. The proposed redlines are not needed because Rule 21 is technology agnostic.

Utility positions / SDG&E:

SDG&E supports the proposal to include non-exporting V2G-DC systems in Section N. However, SDG&E disagrees with CESA's proposal to modify Section N and delete the stipulation that "no other generators other than isolated back-up generators, may be at the same point of interconnection or point of common coupling." If a V2G-DC system seeks to interconnect behind a meter where there are other generators, then the utilities will need the full review time provided under the normal Fast Track timelines, and not the expedited timelines prescribed in Section N. This is because the presence of other generators will require engineering review to determine the type generation and connectivity of the generator, and a determination of whether additional metering is necessary if that generation receives NEM treatment.

Proposal 23-i. Non-consensus

Clarify a pathway for parties to interconnect V2G-AC (mobile inverter) systems on a timely basis for experimental and/or temporary use until the appropriate rules are updated in the future.

Supported by: CEC, CESA, eMotorWerks, EPRI, Fiat-Chrysler, Ford, GPI, Honda, Kitu Systems, Nuvve
Opposed by: PG&E, SCE, SDG&E

Proponent position by CESA:

As the CPUC, utilities, and stakeholders work through V2G-AC interconnection issues, CESA recommends that a path for some timely interconnection and deployment of V2G-AC systems for pilots and/or temporary use be allowed. R.18-02-006, the newly opened proceeding, may direct pilots for V2G systems that would face barriers to operate and learn if interconnection stands as a barrier. In these limited instances, the utilities should clarify a path for some temporary allowance for pilots and experimentation and not hinder pilot deployments due to interconnection issues, which may have *de minimis* impacts and are necessary to generate lessons learned for full deployment and achievement of VGI policy objectives. The details of the interconnection study process can continue to be developed in the meantime.

There are currently a few known existing pilots that are seeking this type of interconnection, shown in Table 3.

Table 3: Existing Pilots Seeking V2G-AC Interconnection

Project Name	**Funding Source**	**Funding Total**	**CA IOU Territory**	**Timeline**
Electric Vehicle Storage Accelerator (EVSA)	NRG-EVgo Settlement	$1 million	SDG&E	2015 - June 2019
Intelligent Electric Vehicle Integration (INVENT)	California Energy Commission	$4 million	SDG&E / Others	Oct 2017 - Dec 2020
Rialto V2G Electric School Bus	US DOE, SCAQMD	$6.8 million	SCE	Jun 2017 - 2021
Marine Corps Air Station (MCAS) Miramar V2G Microgrid	California Energy Commission	$2.9 million	SDG&E	Jul 2017- Jun 2020

Currently, there are no non-pilot deployments of V2G systems on California's distribution grid, and nearly all have been pursued under either direct sponsorship or oversight by regulatory agencies including the CPUC and CEC.

Thus, a temporary exemption from Rule 21 smart inverter requirements appears to be worthy of consideration at this time while being supplemented by SAE J3072 certification. At the same time, CESA recognizes the importance of smart inverter requirements and prefers to work toward long-term sustainable solutions where smart inverter requirements can be appropriately applied to V2G AC interconnections.

Issue proponents hold the view that a small number of already approved and funded pilot projects should be allowed to interconnect, which can provide data and real-world use cases to inform future policymaking.

Utility positions:

SDG&E does not support any exemptions or deviations from Rule 21 that could compromise safety or deprive the IOU's of adequate time needed to completely review projects to ensure safety requirements are met and that projects cause no adverse impacts to the grid. The safety requirements currently prescribed in Rule 21 protect utility workers and the public. The prescribed study processes and associated timelines ensure that interconnecting project applicants are adequately studied and that applicable safety requirements are complied with to prevent safety or reliability issues.

SCE does not support any type of temporary or experimental interconnection for interconnection systems, which has not been deemed to be safe by certification under UL 1741. Doing so would be against SCE's principle of "safety first" given the safety risks associated with the proposal. Thus, to the extent that certification compliance to UL 1741 standard is part of the experimental "pilot" interconnection request, SCE can work with interested stakeholders on how to potentially structure a "temporary interconnection." In this vein, SCE voiced support to temporarily exempt V2G systems from smart inverter requirements, Rule 21 Section Hh, as to facilitate pilots, but the NRTL certification would be required under Section L for inverters using Section H (pre "Smart Inverters"). This exemption would be supported until the revision of IEEE 1547.1 is updated and adopted under Rule 21.

PG&E believes that this proposal is premature, since the SAE standard is not ready for this application at this time. And PG&E does not support this proposal. Among other reasons, similar to those highlighted by SCE and SDG&E, the UL 1741 SA is the primary safety mechanism that utilities rely on.

Survey of parties on V2G-AC (mobile inverter) pilots and responses:

On March 29, 2019, the Working Group issued a five-question survey to stakeholders in the Rule 21 and DRIVE proceedings to solicit responses on whether and what the criteria should be to streamline interconnections for V2G-AC (mobile inverter) pilots. Eleven parties responded to the survey. A complete record of survey answers is provided in Annex E and a summary of responses is given below.

Question 1. Should the process for granting interconnection approvals to pilot projects involving AC-coupled EVs be streamlined?

"Yes": CEC, EPRI, Honda, Ford, Fiat, GPI, Kitu Systems
"No": SDG&E, PG&E
"Conditional": SCE

Question 2. What existing pilots are seeking this type of interconnection and what is their current status?

A number of pilot projects were cited in responses, including an EPIC pilot by SCE, pilots under development by Honda and Ford, Miramar fleet management, UC San Diego, National Strategies electric school buses, LA Air Force Base, and Department of Energy EASE project.

<u>Question 3</u>. Should specific eligibility criteria for such a streamlined process be developed?

Criteria and considerations cited in responses include standards such as IEEE 1547, UL 1741, and SAE J-3072, maximum discharge capacity specification, electrical compatibility, charging conformance and interoperability requirements (J2953), a clearly defined V2G-AC use-case that is distinct from and cannot be fulfilled by a V2G-DC use case, and EPIC standards for making data and findings publicly available. Also, allow the on-board inverter to be treated as a [single][isolated] component for safety standards and allow participants to submit a report showing compliance for the component and not the vehicle.

Utility responses to Question 3 were:

> SCE does not see the need to develop eligibility criteria for a few pilot projects which are temporary in nature. It is best to look at each project individually and determine what type of expedited processes under Rule 21 could be utilized to streamline the interconnection for each of the pilots.
>
> PG&E does not believe that the process for granting interconnection approvals should be streamlined at this time for V2G- AC pilots. Streamlining the process may be addressed after the certification standards are approved. At this time, it is not clear whether there are additional vehicle limitations or whether the SAE standard will incorporate the full UL 1741 SA requirements. It is also not clear whether additional mitigations may be required to ensure the safety of the interconnection.
>
> SDG&E: It is premature to consider eligibility criteria for a streamlined interconnection process until such a streamlined interconnection process itself has been developed. To date, there has been consideration within Rule 21 Working Group Three that an additional technical working group would be appropriate to consider what, if any, automobile-specific standards for V2G could be established for Rule 21 interconnections. Such a working group would be a good place to consider such eligibility criteria for a streamlined process.

<u>Question 4</u>. Should the Commission establish a target number of pilots or a limit on how many pilots may qualify for the streamlined process? Should only pilots be eligible for this streamlined process?

CEC responded: “The Commission should establish a minimum target of at least two OBACC bidirectional inverter pilots (defined by the number of unique customers or addresses) per utility territory. Two will allow for data to be gathered from multiple vendors’ approaches. The Commission’s audit of existing pilots (described above) could account toward this minimum pilot requirement. In addition, the Commission should impose a maximum limit on the number of pilots that may qualify for the streamlined process."

EPRI responded about the types of pilots: "The pilots that will help inform the process include assessment of technology readiness on vehicle, utility and EV interconnection side, value of applying such technology at scale and the barriers to scale deployment as well as specific scenarios where the value is maximized, and mechanisms that maximize customer participation that lead to technology adoption in large numbers."

Honda, Ford, Fiat, and Kitu Systems responded that pilots should not be limited.

Utility responses to Question 4 were:

> PG&E does not believe that the process for granting interconnection approvals should be streamlined at this point for V2G- AC pilots. However, should such streamlining be requested, PG&E believes that: (1) only pilots should be eligible for this streamlined process, and (2) the number of pilots should be limited to one active pilot per year per IOU service territory. One pilot may be active and extend for more than one year.
>
> SCE does not see the need for having a particular count and as long as requirements under question #1 are met, then SCE could support a variety of pilot projects as they are developed.
>
> SDG&E: It is imprudent to make exceptions for pilots that could compromise safety. However, if streamlined procedures can be developed that would not compromise safety, then it may be desirable from a resource requirement and tracking perspective to limit the pilots to one pilot per service area. There is concern that without such a limit there could be a risk of companies rushing pilots through a window of opportunity.

<u>Question 5</u>. Any other comments?

A number of responses are given in Annex E.

Annex E: Issue 23, Survey on V2G-AC (Mobile) Pilots

Response of the California Energy Commission

Question 1. Should the process for granting interconnection approvals to pilot projects involving AC-coupled EVs be streamlined?

Yes, approval for on-board AC-coupled electric vehicle (EV) interconnection pilot projects need a streamlined path to support efforts undertaken by private stakeholders and other state agencies demonstrating pre-commercial vehicle- grid integration (VGI) technologies. These pilots allow all stakeholders to gain a greater understanding of the potential modifications to electrical and safety requirements for accommodating EVs with discharge capabilities. For example, at the CEC's VGI Symposium in October 2018, Honda stated their objective to produce and deploy mass market EVs capable of AC vehicle-to-grid (V2G) in the early 2020s. Given the proposed 3 to 5-year timeline needed to produce new vehicle products, Honda is making electrical design and manufacturing decisions imminently. In addition, proposed legislation in Senate Bill (SB) 676 states an intent to require load serving entities to achieve a VGI target, which includes charging and discharging, of at least 10 percent of annual total EV load by 2025 and increases to 25 percent by 2030. By streamlining the interconnection approval process for on-board AC-coupled (OBACC) bidirectional inverter pilot projects, it will reduce the barrier to leverage a larger number of mass-produced V2G vehicles in the State to achieve such targets in a timely manner, and enable higher levels of transportation de-carbonization.

Question 2. What existing pilots are seeking this type of interconnection and what is their current status?

San Diego Gas & Electric – Lawrence Berkeley National Laboratory (CEC 600-13-009) - Miramar The CEC agreement, 600-13-009, with Lawrence Berkeley National Laboratory (LBNL) is a pilot project actively deploying EVs and service equipment capable of bidirectional power transfer. The project, Optimized Electric Vehicle Fleet Management and Grid Transaction, without the guidance of the California Public Utilities Commission (Commission) will be stalled without a defined path forward between the project partners and SDG&E. The project is a $4.7M total investment with $3M from the CEC's Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) funding for EV infrastructure deployment. This pilot includes six EV's utilizing OBACC bidirectional inverters. In conjunction with the agreement, an on-site battery storage system is being deployed for integration with the grid. The V2G system will have an energy capacity of 140kW. A drawn-out interconnection process will jeopardize the availability of the already-encumbered public funds and use of procured equipment.

San Diego Gas & Electric – Electric Power Research Institute (CEC EPC-14-086) – University of California, San Diego The CEC agreement, EPC-14-086, with Electric Power Research Institute, Inc. (EPRI) has completed a pilot project at the University of California, San Diego campus, Distribution System Aware Vehicle to Grid Services for Improved Grid Stability and Reliability. The project was a $2.3M total investment with $1.5M coming from the CEC's Electric Program Investment Charge (EPIC) Program funding. The V2G system has a capacity of ~20kW. Project hurdles included SDG&E rejecting permission for interconnection. The project partner's perspective is that there is no interconnection "screening" guideline for V2G capable EVs for the utilities. This issue is compounded by the difference in the standards accepted between the automobile manufactures and IOUs. The manufactures will not certify their hardware to UL 1741, whereas the utilities may require UL 1741 for grid integration of OBACC bidirectional inverters.

Southern California Edison – National Strategies, LLC (CEC ARV-13-011) – Electric School Bus The CEC agreement, ARV-13-011, with National Strategies, LLC is deploying 2 electric school buses in the Torrance Unified School Districts capable of V2G with OBACC bidirectional inverters. The project is a $3.8M total investment with $1.5M coming from the CEC's ARFVTP funding for EV infrastructure deployment. The project has interconnected with the grid, and economic modeling on vehicle-to-building data is currently underway, with data gleaned in March 2019. A project report is anticipated April 2019. The buses will be able to demonstrate full standard operation defined as charging at base, transporting students, and the addition of V2G capability discharging to the building.

Southern California Edison – LBNL (CEC 500-11-025) – Los Angeles Air Force Base The CEC agreement which began in 2012, 500-11-025, with LBNL at the Los Angeles Air Force Base (LA AFB), has completed a pilot project where both AC and DC coupled bidirectional inverters are deployed. The project was a $1.5M total investment from the ARFVTP. This project was completed in 2017 and actively demonstrated the ability to achieve V2G capability and transactions with the California Independent System Operator early on in EV technology. The AC-coupled inverters were deployed across 11 EV light duty vans having a combined energy capacity of 230kW.

Pacific Gas & Electric – National Strategies, LLC. – Electric School Bus (CEC ARV-13-011) The CEC agreement, ARV-13-011, with National Strategies, LLC is deploying 2 electric school buses in the Napa Valley Districts capable of V2G with OBACC bidirectional inverters. After a 2-year recall period due to reliability issues with the installed electric drivetrain; the project has not yet demonstrated exports from the vehicle. Kings Canyon Unified school is no longer participating, and the 2 buses will be returning to the vendor. Project managers continue to gauge interest from other school districts for redeployment of these buses. There is no timetable on anticipated future participation for the remaining buses or within which utility territory. The project is a $3.8M total investment with $1.5M from the CEC's ARFVTP funding for EV infrastructure deployment.

Question 3. Should specific eligibility criteria for such a streamlined process be developed?

Yes, eligibility criteria should be considered on two distinct levels for an approval of pilot projects and re-assessed when the interconnection process is ready for commercial deployment.
The first level of eligibility should require hardware standards that foster product application development. Such requirements should include hardware to be deployed in a pilot project if they meet industry standard(s) for inverters acceptable to stakeholders in both the automotive and electric utility industries such as IEEE 1547 (Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces), Underwriters Laboratories (UL) 1741 (Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources), or SAE J-3072 (Interconnection Requirements for Onboard, Utility-Interactive Inverter Systems). Note: The UL-1741-SA is an additional capability to UL-1741, but may not necessarily be required for safe operation on the electrical grid.

The second level of eligibility could be based on defining the maximum amount of V2G discharge capability when compared to a customer's other (non-V2G) demand measured at their primary electric meter. Such a proposal may allow the installation of sufficient V2G capacity for rate arbitrage or demand mitigation while also preventing V2G energy discharge from back-feeding into the utility distribution grid. For example, to balance these objectives the Commission could consider pilot projects for streamlined approval if the total vehicle V2G discharge capacity is less than or equal to 50 percent of the customer's minimum daily loads (kW), averaged over one year.

Question 4. Should the Commission establish a target number of pilots or a limit on how many pilots may qualify for the streamlined process? Should only pilots be eligible for this streamlined process?

The Commission should establish a minimum target of at least two OBACC bidirectional inverter pilots (defined by the number of unique customers or addresses) per utility territory. Two will allow for data to be gathered from multiple vendors' approaches. The Commission's audit of existing pilots (described above) could account toward this minimum pilot requirement.

In addition, the Commission should impose a maximum limit on the number of pilots that may qualify for the streamlined process. The intent of this maximum would serve not only to minimize any potential negative utility grid impacts, but should also demonstrate an intention to encourage the utilities' timely deployment of V2G technologies, which as described above, are anticipated for mass market deployment in the near future. Once an individual utility has established five pilots within the completed project scope, lessons should be incorporated into a more consistent interconnection process for commercial deployment in a way that is coordinated statewide, amongst utilities technology providers, researchers, and policymakers like the CEC.

For the second part of this question, the Commission might consider any project that meets the criteria outlined in #3 as eligible to use OBACC bidirectional inverters in a non-pilot setting. Based on the brief discussions at the Rule 21 working group thus far about those standards, J-3072 and the IEEE standards appear to be the most commonly tested by stakeholders for OBACC V2G implementation.

Question 5. Any other comments?

The Miramar and UCSD pilots, outlined in the response to question #2 above, are each located within the SDG&E territory. The UCSD pilot completed its interconnection in early 2018, prior to the Miramar pilot being denied permission for interconnection in late 2018. SDG&E's reason for denying interconnection at Miramar is that the OBACC bidirectional inverter is not compliant with the additional requirements from the UL 1741-SA standard. The Miramar vehicles' OBACC are UL 1741 compliant, since they were procured prior to the introduction of UL 1741-SA. The UCSD pilot operated using the SAE J-3072 standard to demonstrate V2G capabilities with the OBACC bidirectional inverters. The intent of the SAE J-3072 standard is similar to SDG&E's imposition of the UL 1741-SA requirement insofar as both standards define inverter interactions with the utility grid.

Additionally, the Miramar pilot is operating on a separate Federally-owned and operated distribution grid, which is under the purview of the Department of Defense for national security. The Miramar and UCSD projects are similar in that they are installing V2G equipment on large electrical systems that are interconnected to SDG&E's distribution grid, but operated by other entities. The Commission should consider advising the utilities to grant permission for pilots being deployed on alike micro-grids that are sufficiently large such that the impact on the SDG&E grid may be considered de minimis.

Overall, the LA AFB and School Bus pilots, outlined in the response to question #2 above, in the PG&E and SCE territories have been granted approval for OBACC bidirectional inverter interconnections prior to and in lieu of the Rule 21 Working Group discussion of Issue 23. In contrast, to staff's knowledge, SDG&E has not interconnected a vehicle with OBACC bidirectional inverter for V2G in its territory. While the working group has not achieved a consensus on interconnection requirements, the interconnection processes for the V2G processes to date have been lengthy and inconsistent. The Commission should consider reviewing and confirming the utilities' methodologies for project approvals or denials that occurred prior to the Rule 21 discussions. This audit should have a specific goal to reduce the number of unique processes across the utilities.

Response of Honda

Question 1. Should the process for granting interconnection approvals to pilot projects involving AC-coupled EVs be streamlined?

Yes

Question 2. What existing pilots are seeking this type of interconnection and what is their current status?

Honda pilots are under development

Question 3. Should specific eligibility criteria for such a streamlined process be developed?

Yes. The criteria should apply to all vehicle segments - light, medium, and heavy duty. Additionally, vehicles should be required to meet Federal Motor Vehicle Safety Standards and IEEE 1547.

Question 4. Should the Commission establish a target number of pilots or a limit on how many pilots may qualify for the streamlined process? Should only pilots be eligible for this streamlined process?

No; pilots should not be limited. As long as the eligibility criteria are met, the project should be approved, whether called/titled a "pilot" or not.

Question 5. Any other comments?

Honda applauds this effort to allow V2G AC pilots participate in a streamlined interconnection process. However, requiring UL 1741 will limit the scope and participation of any resulting pilot because it precludes automaker participation with V2G AC enabled light-duty vehicles.

Honda has rolled out a customer program for V1G called Honda Smart Charge (https://cleantechnica.com/2018/08/02/emotorwerks-honda-southern-california- edison-offer-nations-first-smart-charging-program/). By this time next year (April 2020), Honda plans to enable V2G via small-scale pilot project under this program, seeking to expand pilot project enrollment to current Honda Smart Charge customers throughout 2020-2022. Honda would like to plan these V2G pilots and seeks appropriate utility partners to prove out the program.

Response of the Electric Power Research Institute (EPRI)

Question 1. Should the process for granting interconnection approvals to pilot projects involving AC-coupled EVs be streamlined?

Yes. EPRI, Kitu Systems and AeroVironment as well as Fiat Chrysler Automobiles collaborated on CEC EPC 14-086 On-Vehicle V2G project with Nuvve/Honda's EVSA project, and the team was compelled to seek assistance and waiver from interconnection requirements from UCSD Microgrid as the local IOU was unable to approve interconnection. V2G technology was demonstrated to be ready both on-vehicle and off-vehicle (i.e., EVSE). The standard set verified is consistent with SAE J2847/3 and SAE J3072 as well as IEEE2030.5, meaning that once interconnection requirements are clarified, on-vehicle, grid- tied V2G converters should be able to be treated in the same manner as smart inverters given their functional and operational similarity. The interconnection requirements developed by Smart Inverter Working Group are directly applicable to on-vehicle V2G systems.

Question 2. What existing pilots are seeking this type of interconnection and what is their current status?

As mentioned in #1 above, the recently concluded pilot at UCSD microgrid jointly among Nuvve/Honda and EPRI/FCA Group/Kitu/AeroVironment would have greatly benefited. Additional pilots can be established to jointly assess interconnection readiness, requirement effectiveness, grid impacts, customer benefits, cybersecurity, and value assessment at scale.

Question 3. Should specific eligibility criteria for such a streamlined process be developed?

Specific eligibility criteria that will be extremely helpful to EV manufacturers, equipment manufacturers, utilities and third-party integrators would be electrical compatibility (EMI, EMC, harmonic distortion, power factor, isolation, voltage surge/sag, etc), communications/dispatch simplicity (authorization, authentication, service discovery, end to end cybersecurity, circuit capacity and grid condition identification, weather data and DSO / ISO control and data messaging, customer interfaces). Emphasis on open standards that are a part of the NIST catalog of standards would be the correct approach to scaling the technology deployment.

Question 4. Should the Commission establish a target number of pilots or a limit on how many pilots may qualify for the streamlined process? Should only pilots be eligible for this streamlined process?

The pilots that will help inform the process include assessment of technology readiness on vehicle, utility and EV interconnection side, value of applying such technology at scale and the barriers to scale deployment as well as specific scenarios where the value is maximized, and mechanisms that maximize customer participation that lead to technology adoption in large numbers. These pilots can deploy the streamlined interconnection process which can be assessed in terms of effectiveness and integration of such data into distribution resource planning and long-term procurement planning processes.

Question 5. Any other comments?

V2G technology today, especially on-vehicle, has the potential to provide significant grid benefits documented in the recently published CEC report (https://www.energy.ca.gov/2019publications/CEC-500-2019-027/index.html [energy.ca.gov]). In order for these benefits to be realized, streamlined interconnection screening requirements have been identified as a key technical barrier. Smart Inverter Working Group is already taking a proactive stance to allow the off-vehicle V2G inverters to be treated as smart inverters for interconnection screening requirements. Same is possible to do with on-vehicle V2G systems which carry additional advantages of being a mobile resource. Once the requirements have been defined, scaled pilots can be a useful pathway to validating and confirming the requirements among multiple stakeholders (OEMs, equipment manufacturers, third-party integrators, utilities, and customers)

Response of SDG&E

Question 1. Should the process for granting interconnection approvals to pilot projects involving AC-coupled EVs be streamlined?

It is not appropriate to make exceptions for pilots that could compromise safety. SDG&E is an active participant in working groups and discussions to consider alternative or streamlined interconnection requirements that will ensure the safety and reliability of AC-based V2G units. Until conclusions are reached with consensus on the content and applicability of alternative or streamlined processes, all AC-coupled V2G's should adhere to the interconnection requirements in Rule 21 without exception. This requirement is necessary to ensure that all inverters, mobile or stationary, have been tested and certified to conform to the requirements of UL1741SA, especially safety related measures such as preventing a generator from back-feeding into the electric grid during an outage, which would create significant hazards for utility personnel working on the lines and the public.

Question 2. What existing pilots are seeking this type of interconnection and what is their current status?

SDG&E has received several applications for V2G projects, and only one has been approved: a DC-based V2G project submitted by Nuvve at UCSD. SDG&E has filed a V2G school bus pilot with the CPUC and anticipates a decision during the second quarter of 2019. The preliminarily selected project partners have indicated a desire to deploy a solution in which the inverter is on the school bus (AC-based inverter).

Question 3. Should specific eligibility criteria for such a streamlined process be developed?

It is premature to consider eligibility criteria for a streamlined interconnection process until such a streamlined interconnection process itself has been developed. To date, there has been consideration within Rule 21 Working Group 3 that an additional technical working group would be appropriate to consider what, if any, automobile-specific standards for V2G could be established for Rule 21 interconnections. Such a working group would be a good place to consider such eligibility criteria for a streamlined process.

Question 4. Should the Commission establish a target number of pilots or a limit on how many pilots may qualify for the streamlined process? Should only pilots be eligible for this streamlined process?

As stated above, it is imprudent to make exceptions for pilots that could compromise safety. However, if streamlined procedures can be developed that would not compromise safety, then it may be desirable from a resource requirement and tracking perspective to limit the pilots to one pilot per service area. There is concern that without such a limit there could be a risk of companies rushing pilots through a window of opportunity.

Question 5. Any other comments?

SDG&E is a strong supporter of the electric vehicle industry and is proud to have the opportunity to enable electric vehicle adoption through its many CPUC- approved programs. SDG&E also supports V2G technology and is hopeful for approval on its V2G pilot referenced above. As such, SDG&E supports this working group and the collaborative push to find a solution for AC-coupled V2G. However, we must find a technical solution that ensures safety and reliability first and foremost.

Response of Ford Motor Company

Question 1. Should the process for granting interconnection approvals to pilot projects involving AC-coupled EVs be streamlined?

Yes, the interconnection approval process should be streamlined allowing OEMs and Utilities to launch their pilots without delay to normal timing.

Question 2. What existing pilots are seeking this type of interconnection and what is their current status?

Pilots from Ford are under development hence no specifics are available at this time.

Question 3. Should specific eligibility criteria for such a streamlined process be developed?

The streamlined process should apply to LD/MD/HD vehicle segments. To ensure safe operation, vehicles should comply with: a. FMVSS and SAE for on-vehicle requirements/ standards in-lieu of UL-1741/ NFPA 70E/NEC b. IEEE-1547 Standard for Interconnection and Interoperability of DERs. On & Off board inverters should comply with SAE J-3072.

Question 4. Should the Commission establish a target number of pilots or a limit on how many pilots may qualify for the streamlined process? Should only pilots be eligible for this streamlined process?

The CPUC should not limit the number of pilots nor restrict the participation of any pilot not originally noted as a pilot from benefiting from the streamlined process.

Question 5. Any other comments?

CPUC should temporarily exempt V2G systems from meeting the UL-1741 SA or any other smart inverter requirements while being supplemented by SAE J3072 certification. End user customer experience should be an important factor for consideration of a streamlined process. V2G DC and some V2G AC systems should be authorized via fast-track approval process to enable key learnings. CPUC should assist with developing and defining the value proposition for V2G DC/AC that would enable rapid adoption.

Response of PG&E

Question 1. Should the process for granting interconnection approvals to pilot projects involving AC-coupled EVs be streamlined?

No, pending the feedback and lessons learned from the pilot projects. One of the main objectives of potential future V2G-AC pilots would be to identify potential challenges, bottlenecks, and learnings in relation to interconnection. Any proposed streamlining for granting interconnection approvals should be done after the pilots are executed, not before, in order to ensure an informed approach to improving the interconnection process. Given the very nascent nature of the market, any proposed streamlining of the interconnection process for V2G-AC projects should be informed by and based on: (1) clear outcomes and findings from implemented V2G-AC pilots, and (2) the state's overall VGI goals and objectives that are still a subject of discussion through the PUC's VGI Working Group as part of the TE OIR. Additionally, any improvements implemented should be generalized to other interconnection application types to the greatest extent possible.

Question 3. Should specific eligibility criteria for such a streamlined process be developed?

Per our answer to question 1, PG&E does not believe that the process for granting interconnection approvals should be streamlined at this time for V2G- AC pilots. However, should such streamlining be requested, PG&E believes that the following minimum eligibility criteria should be developed: (a) the proposed pilot should aim to test a clearly defined VGI use-case, with clearly identifiable value; the pilot should also demonstrate how the said VGI use-case is distinct from, and cannot be otherwise fulfilled through, an EVSE-coupled DC inverter; (b) the pilot should comply with all relevant and applicable interconnection requirements relevant to grid safety and cybersecurity; (c) the proposed pilot should adhere to EPIC standards in terms of making its data, findings, and learnings available for public use.

Question 4. Should the Commission establish a target number of pilots or a limit on how many pilots may qualify for the streamlined process? Should only pilots be eligible for this streamlined process?

Per our answer to question 2, PG&E does not believe that the process for granting interconnection approvals should be streamlined at this point for V2G- AC pilots. However, should such streamlining be requested, PG&E believes that: (1) only pilots should be eligible for this streamlined process, and (2) the number of pilots should be limited to one active pilot per year per IOU service territory. One pilot may be active and extend for more than one year.

Question 5. Any other comments?

While PG&E supports the advancement of industry efforts on the technical aspects of V2G AC, PG&E makes the following two comments. First, addressing the regulatory needs and/or requirements around technical aspects of V2G AC should not be done in isolation but rather as part of a broader VGI effort that clearly identifies and prioritizes VGI's technical challenges and barriers. Second, the need and/or value of V2G AC should be clearly articulated, especially relative to the more technologically and commercially mature V2G DC, before and in order to justify dedicated efforts to address the technical aspects of V2G AC through ratepayer-funded policy and regulatory proceedings. PG&E supports the continuation of private industry efforts to address these issues. Part of those private industry efforts may be through the participation in SAE activities. For example, some automakers have expressed concern with UL requirements because they take up too much space in the vehicle. This automotive design issue affecting V2G AC is best addressed by SAE rather than Rule 21 Working Group. After SAE develop the automotive equivalent of UL-1741 SA, IOUs can review it for adequacy and, if adequate, adopt it in Rule 21.

Response of the Green Power Institute

Question 1. Should the process for granting interconnection approvals to pilot projects involving AC-coupled EVs be streamlined?

Yes, the Commission has made it clear that it wants "dramatic streamlining" of all interconnection (as it has described in the DRP Final Guidance and various other Commission decisions and documents).

Question 3. Should specific eligibility criteria for such a streamlined process be developed?

The large majority of EV interconnections should be streamlined, but an "off ramp" should also be provided for more unusual or complicated cases.

Question 4. Should the Commission establish a target number of pilots or a limit on how many pilots may qualify for the streamlined process? Should only pilots be eligible for this streamlined process?

GPI feels that we are at a point in the development of interconnection processes and related technologies that we don't need pilots for EV interconnection. Rather, EV interconnection should be incorporated into portals at this time on a test basis and IOUs should report back every 3 months on how the new procedures, once developed and deployed, are working.

Question 5. Any other comments?

We may need to discuss funding of these improvements b/c IOUs are trying in general to rate-base such upgrades rather than expense them. GPI supports reasonable rate-basing of these costs.

Response of Fiat Chrysler

Question 1. Should the process for granting interconnection approvals to pilot projects involving AC-coupled EVs be streamlined?

Yes

Question 2. What existing pilots are seeking this type of interconnection and what is their current status?

DoE EASE project with SCE

Question 3. Should specific eligibility criteria for such a streamlined process be developed?

Yes. The vehicle OEM can submit a report of the onboard charging system being compliant to the requirements and include the safety aspects. UL and IEEE standards do not apply to vehicles but SAE standards used these to identify the inverter requirements in J3072 and conformance requirements can be added to J2953 that includes charging conformance and interoperability requirements.

Question 4. Should the Commission establish a target number of pilots or a limit on how many pilots may qualify for the streamlined process? Should only pilots be eligible for this streamlined process?

There should not be limits since the industry is continuing to implement more Rule 21 features and then update the SAE automotive standards accordingly. As we continue to match vehicle V2G with solar and stationary storage, it is clear that we can continue to improve the system to make the grid more robust and allow CA to meet its PEV targets.

Question 5. Any other comments?

Vehicles are using Telematics to connect with utility servers prior to reaching a charging site and can provide advanced planning information for the utility and vehicle. Once the vehicle connects either WiFi or PLC can be used for more refined communication at the site. The customers are connected via their phones and can get alerts or text communication for any adjustments that may arise while connected and able to continually adjust the charging/discharging session to match the grid requirements. Pilots need to embrace this ever adjusting and dynamic approach for advanced planning thru micromanagement stages to utilize the PEV resources while still meeting the customer's desire to have their vehicle charged to an adequate level when used again for the next route.

Response of George Bellino, Consultant

Question 1. Should the process for granting interconnection approvals to pilot projects involving AC-coupled EVs be streamlined?

Yes

Question 2. What existing pilots are seeking this type of interconnection and what is their current status?

Nuvve/EDF Program in UK, recently completed CEC 14-086 Project (final report published), SCE DOE EASE Project

Question 3. Should specific eligibility criteria for such a streamlined process be developed?

Yes, there are significant potential applications for a mobile storage resource including the DOD military bases and emergency resiliency needs.

Question 4. Should the Commission establish a target number of pilots or a limit on how many pilots may qualify for the streamlined process? Should only pilots be eligible for this streamlined process?

No limit should be established. Need to have open eligibility for pilots to maximize stakeholder investment in technology development and safety validation. Pilot learnings need to inform regulatory/policy development and standards development based on learnings. Collaboration will be critical between OEMs, EVSE manufacturers, utilities, and the standards bodies. There may be need to address V2H and V2B applications to inform utility connection safety requirements and integration requirements of V2G with local DER assets

Response of Kitu Systems

Question 1. Should the process for granting interconnection approvals to pilot projects involving AC-coupled EVs be streamlined?

Yes

Question 2. What existing pilots are seeking this type of interconnection and what is their current status?

SCE DoE EASE project

Question 3. Should specific eligibility criteria for such a streamlined process be developed?

Yes. Specifically, allow the on-board inverter to be treated as a component for safety standards and allow participants to submit report showing compliance for the component and not the vehicle.

Question 4. Should the Commission establish a target number of pilots or a limit on how many pilots may qualify for the streamlined process? Should only pilots be eligible for this streamlined process?

No limits as there is a lot of development required by Manufactures prior to interconnection. The more the pilots will encourage more investment and allow CA to meet its EV targets

Response of SCE

Question 1. Should the process for granting interconnection approvals to pilot projects involving AC-coupled EVs be streamlined?

To the extent the pilots DER projects meet the Rule 21 interconnection requirements which pertain to safety and reliability, SCE would explore processes to evaluate pilots during technical evaluation and overall interconnection process. As discussed in recent working group discussions, SCE emphasizes again that DER pilots that do not meet safety requirements as provided under Rule 21 will not be supported. SCE's experience with past projects showed that the delay in the interconnection process was mostly on DER inability to meet safety requirements (in particular, certification).

Question 2. What existing pilots are seeking this type of interconnection and what is their current status?

Discussions at the team level confirmed that we have currently in the initiation phase an EPIC Pilot Vehicle to Grid Utilizing an Onboard Inverter intending to demonstrate J3072 interconnections among other items. In addition, SCE has processed an AC-coupled V2G project utilizing non-exporting provision of Rule 21 so as to support on-site load.

Question 3. Should specific eligibility criteria for such a streamlined process be developed?

SCE does not see the need to develop eligibility criteria for a few pilot projects which are temporary in nature. For SCE, it is best to look at each project individually and determine what type of expedited processes under Rule 21 could be utilized to streamline the interconnection for each of the pilots.

Question 4. Should the Commission establish a target number of pilots or a limit on how many pilots may qualify for the streamlined process? Should only pilots be eligible for this streamlined process?

SCE does not see the need for having a particular count and as long as requirements under question #1 are met, then SCE could support a variety of pilot projects as they are developed.

Question 5. Any other comments?

None at this time and SCE appreciates being allowed to submit feedback to the questions above.

Issue 24

Should the Commission modify the formula for calculating the Cost-of-Ownership charge and, if so, how?

PROPOSAL SUMMARIES

Proposal 24-a. Non-consensus
In applying Cost-of-Ownership (COO) to new facilities, the utility and ratepayers will neither be subject to additional costs resulting from the new generator interconnection nor inappropriately transfer costs to the generation applicant that the utility would have otherwise normally incurred. Utilities may, at their discretion, determine that the facility replacement is "like-for-like" in terms of COO implications and no COO would be allocated to the applicant.

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

Proposal 24-b. Non-consensus
The following three COO replacement costs options should be made available to the interconnection applicant while maintaining ratepayer indifference: (1) Charge for Replacement in perpetuity, (2) Charge for Replacement for fixed term in 10-year increments, and (3) Customer responsibility for actual cost of replacement if and when needed (with customer pre-authorization of emergency replacement of upgraded facilities for a term agreed in the GIA).

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

Proposal 24-c. Non-consensus
When replacing existing facilities with new facilities that are not designated as "like-for-like" replacements by the utility, the interconnection applicant will be credited for the utility cost of ownership of the equipment that was replaced and only be charged any *net-additional* COO. *Net-additional* COO is defined as the COO that would not have otherwise occurred, if no interconnection request had been made. That is, net-additional COO excludes the portion of COO of the replacement equipment that represents the continued share or obligation of ratepayers for that equipment, under the principle of rate-payer indifference.

Supported by: CALSSA, Clean Coalition, JKB Energy, Tesla
Opposed by: PG&E, SCE, SDG&E, TURN

BACKGROUND

Based on the scope of Issue 24 as scoped in this proceeding and the issue brief provided by Clean Coalition, parties sought during the Working Group to determine whether Cost-of-Ownership (COO) charges are being appropriately applied to generator interconnection applicants, identify best practices and inconsistencies between utilities, and recommend or propose changes to consistently reflect best or preferred practices regarding COO application in Rule 21.

Parties agreed that the purpose and intent of COO charges on interconnection applicants is to prevent shifting costs from one customer class to the broader class of captive ratepayers, such that the utility and ratepayers will neither be subject to additional costs resulting from the new generator interconnection nor inappropriately transfer costs to the generation applicant that the utility would have otherwise normally incurred.

Parties acknowledged that accounting practices may not allow precise determination of actual individual costs, and such determinations would be impractical to attempt. As such, the use of standardized rates for COO applied based on the capital cost of facilities is a reasonable and acceptable practice supporting consistency and ease of application, and avoids any aggregate cost shifts between ratepayers and generation applicants.

Parties further acknowledged and agreed that the standardized COO rates themselves, as percentages of capital costs, are not within the scope of this proceeding, and are determined individually for each utility.

Instead, parties sought to determine what types of costs and cost components are, or should be, subject to the standardized COO rates. This includes the allocation of COO to customer-financed capital costs versus utility-financed capital costs, and how and whether the correct and appropriate portions of those costs are subject to the standardized COO rates under various scenarios.

Two other issues that were discussed by the Working Group were determined to be current utility practices, so they are not included as proposals but this report includes them to memorialize relevant discussion points.

First, depreciation and rate of return are two elements within the COO. There was uncertainty during Working Group discussions whether utilities charge for depreciation and rate of return for facilities that are paid for by customers. In the end, the utilities confirmed that they do not charge these items for facilities they did not finance.

Second, COO should not be charged for non-capital expenses. The Working Group discussed examples of such charges being erroneously charged in the past, but it was agreed that it should not happen. Changes to settings of existing utility equipment, engineering reviews, inspections, and project management are not subject to COO.

DISCUSSION

Proposal 24-a. Non-consensus
In applying Cost-of-Ownership (COO) to new facilities, the utility and ratepayers will neither be subject to additional costs resulting from the new generator interconnection nor inappropriately transfer costs to the generation applicant that the utility would have otherwise normally incurred. Utilities may, at their discretion, determine that the facility replacement is "like-for-like" in terms of COO implications and no COO would be allocated to the applicant.

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

Proponents provided indicative scenario examples of common distribution facilities upgrades where like-for-like comparability usually exists:

- Existing pole or equipment not upgraded but relocated and continued in use for same customers (and new customer)
- Minor pole upgrade - existing single wood pole replaced with next size larger wood pole

Proponents also provided indicative scenario examples of common distribution facilities upgrades where like-for-like comparability could exist, depending on circumstances:

- Major pole upgrade - existing four wood poles replaced with two steel poles
- Transformer upgrade - existing transformer, upgraded to higher capacity to serve same customers plus a new generation/storage application
- Single customer upgrade--existing distribution system line extension and transformer providing load service to a single customer, upgraded to accommodate a new generation interconnection request
- Single customer upgrade -- existing customer service line drop providing load service (load side of point of common coupling with utility grid, utility side of meter), upgraded to accommodate a new generation interconnection request

PG&E position:

"Like-for-like" should be defined as equivalent facilities – in cost and function – such that the utility and ratepayers will neither be subject to additional costs resulting from the new generator interconnection nor inappropriately transfer costs to the generation applicant that the utility would have otherwise normally incurred. Based on this definition, there are no cases in interconnection where a generator would be assigned a like-for-like upgrade.

Additionally, the removal of equipment does not reduce the net plant component of rate base since the original cost of the asset is deducted from both the gross plant-in-service and the accumulated depreciation, so net plant is not reduced, and our revenue requirement is not reduced when plant and equipment is removed. (Indeed, the cost of removing equipment is charged to the depreciation reserve and increases rate base.) The installation of new equipment increases plant and rate base and thus increase our revenue requirement. Assuming the interconnection customer paid for the new equipment, there would be no increase in net plant.

The scenarios listed in this proposal are not truly like-for-like because there is a cost increase associated with relocation or upgrade. Each of these scenarios is an example of an upgraded facility that is required to accommodate an interconnection request and should be subject to COO. In the case of the transformer upgrade example, if COO wasn't applied, ratepayers would then be paying for the COO of two transformers (the existing transformer and the new transformer required to serve the interconnection request)

<u>SCE position:</u>

As discussed throughout workshop discussions on this topic and also represented in SCE's response dated April 9, 2019 to a Commission Data Request along with written response to stakeholder questions dated April 24, 2019, since practices and governing rules related to the Cost of Ownership impact customer classes beyond "interconnecting customers," review of COO related issues are better suited for review within a General Rate Case. By way of background, COO rules are established under Rule 2 and apply to all facilities requested by an applicant which are in addition to or substitution for standard facilities. They include, but are not limited to, *all types of equipment normally installed by SCE in the development of its service to a customer or a customer's receipt or utilization of electrical service*. Fundamentally, the COO offsets SCE's revenue requirement for operating and maintaining (along with the capital related revenue requirement when applicable) for the underlying asset.

In particular for Issue 24-a, SCE disagrees there is consensus on this issue. SCE does not charge ongoing O&M for like-for-like replacements, for example, when replacing a 35-foot wood pole with a 45-foot wood pole. It is because equipment is more similar than different than, for example, replacing the wood pole with a steel tower. (In the latter case, for example, SCE does charge ongoing O&M.)

SCE pointed out during Working Group discussions that non-utility stakeholders wanted to keep the like-for-like policy, but receive partial credit for the previous O&M costs in the case of a non-like-for-like replacement. The two cases cannot be looked at in isolation. If additional granularity is desired to calculate the incremental/decremental cost of O&M when an asset is replaced, this should be looked at in the context of a General Rate Case as further discussed above. By definition, if ongoing O&M costs are reduced for interconnection customers from the current practice, *those costs would flow through to ratepayers, who are not all represented in the Working Group, which implicates rate-making issues that are out of scope for this portion of the proceeding.*

<u>SDG&E position:</u>

Special Facilities covered under the Rule 2 tariff are new facilities or dedications of existing facilities, requested by an applicant, which are added to or substituted for the standard facilities that the utility would normally install, maintain, and use. Special Facilities are the property of the utility, which is responsible for their operation, maintenance, and replacement. However, they are not funded through the GRC process, nor are they paid for by rates.

As a result, COO assessments should not shift costs between parties and should thus be based on the concept of ratepayer indifference. SDG&E believes in the principle of equity that has long been embedded in utility regulation; ratepayer indifference thus means that no customer class should subsidize another customer class. Such equity is well established and founded upon the seminal works of Alfred Kahn and James Bonbright. Distributed energy resources interconnecting under Rule 21 should be treated the same way that any other type of business or customer class requiring Special Facilities under Rule 2 above and beyond standard load service under Rules 15 and 16. All SDG&E costs not required to serve utility ratepayer load requirements and included in a GRC authorization process should be appropriately charged to the requesting applicant.

Customer requests that require facilities beyond normal service facilities already provided by SDG&E under Rule 15 "Distribution Line Extensions" and Rule 16 "Service Line Extensions" are considered Special Facilities, which are defined and governed under the Rule 2 tariff. Rule 2 Special Facilities is not exclusive to Generation Facilities but rather encompasses the entire range of customer classes in a non-discriminatory manner.

When a customer requests a Special Facility under the Rule 2 tariff requirements, the costs provided to the customer are a financial estimate which is designed to cover the full cost of ownership, which includes the construction, design and installation of the designated equipment and the related expenses incurred through its use. If the special facility replaces equipment that had been previously installed to serve the utility ratepayers and was approved through its GRC process, SDG&E would continue to recover the cost of the asset from ratepayers. SDG&E does not recover its fixed assets cost upfront from ratepayers, the recovery mechanism occurs overtime through depreciation expense over the average service life of the asset. When a fixed asset is removed from service, SDG&E follows the FERC regulatory guidelines to retire the asset, consistent with its general practices.

As stated in this discussion, "like-for-like" replacements only achieve ratepayer indifference if the existing assets are at the very end of life and fully depreciated. If the asset being replaced has remaining undepreciated costs, then the ratepayer continues paying for the removed asset and also paying for the new replacement asset if the DER customers are allowed to avoid the COO and shift their impact on costs to other existing ratepayers. COO relative to the operating and maintenance components is not specifically known asset by asset but rather as an average for all assets in the class. This proposal if adopted as proposed by the DER customers would not have a negative impact on SDG&E's shareholders it would only shift costs from them to all the other existing ratepayers. This proposal as presented unfairly benefits one group, the DER customer as all other customer and ratepayers bear additional costs.

Proposal 24-b. Non-consensus

The following three COO replacement costs options should be made available to the interconnection applicant while maintaining ratepayer indifference: (1) Charge for Replacement in perpetuity, (2) Charge for Replacement for fixed term in 10-year increments, and (3) Customer responsibility for actual cost of replacement if and when needed (with customer pre-authorization of emergency replacement of upgraded facilities for a term agreed in the GIA).

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

The following COO replacement costs options should be made available to the interconnection applicant while maintaining ratepayer indifference:

- Charge for replacement in perpetuity - with customer option of a monthly or lump sum assessment (no additional cost to customer if replacement occurs)
- Charge for replacement for fixed term in 10-year increments (i.e., 10, 20, 30 years) - with customer option of a monthly or lump-sum assessment (no additional cost to customer if replacement occurs during the fixed term, and customer responsible for actual costs thereafter)
- Customer responsibility for actual cost of replacement if and when needed (with customer pre-authorization of emergency replacement of upgraded facilities for a term agreed in the GIA)

Proponent Clean Coalition posed the question: t*o what extent does replacement cost factor into COO charges?* To gain insight into this question, the Working Group reviewed an example provided by SCE of added facilities rate components. In this example, for annually-paid COO on a customer-financed facility, annual replacement cost accounts for 22% of total COO when replacement is covered in perpetuity, 5% of total COO when replacement is covered for 20 years, and 0% when the customer assumes full responsibility for replacement cost when and if replacement is required. Clean Coalition concluded that replacement coverage options can greatly affect interconnection customer costs, without affecting ratepayers.

SCE pointed out that ongoing O&M is relatively steady from year to year, but replacement cost is charged on a constant recurring annual basis (straight-line basis), even though one would expect the replacements to come later in the asset's life.

Proponent Clean Coalition also posed the question: *If the service life of the equipment exceeds the term of the GIA, is it appropriate to assess replacement costs?* The Working Group learned that a Generation Interconnection Agreements (GIA) remains in effect in perpetuity, until canceled by customer (although SCE GIA's provide for 30-year terms). However, Clean Coalition concluded that where charges to cover the risk of replacement are defined for a limited period aligned with the operational life of the customer's generation facility, the replacement cost component of COO is greatly reduced, and the remaining components of COO may be significantly reduced. This can significantly reduce the customer cost of adding distributed generation or storage when upgrades are needed, without transferring risk or burden to other ratepayers. For example, a customer electing 20-year replacement coverage paid as a one-time payment would see more than a 40% reduction in total COO costs (reduced from $82,000 to $48,000 on a $100,000 distribution upgrade).

Clean Coalition asserted that if replacement cost charges are not aligned with actual replacement costs, this will result in a positive or negative cost shift between the interconnection customer and other ratepayers.

SCE pointed out that this would be average replacement costs over a number of years, and there is a standard rate that is adjudicated in the GRC.

As noted previously, Parties acknowledged that the use of standardized rates for COO applied based on the capital cost of facilities is reasonable and acceptable practice supporting consistency, ease of application, and avoids overall shifts in costs.

Utilities differ in how they address COO replacement charges. SCE put forward the opportunity for replacement coverage to be a customer elective associated with monthly COO payments, but did not offer this with the one-time payment, and limited term coverage has not been implemented. PG&E does require coverage calculated without term limit (in perpetuity), but states that that they refund unused one-time payment replacement costs based on annualized insurance/risk assessment whenever the customer terminates the GIA. SDG&E includes replacement cost as a factor in the cost of ownership that is paid by the applicant, based upon the specific equipment requested by the applicant. These practices avoid under-collection from interconnection customers, but do not all avoid over-collection, potentially burdening interconnection customers with excess charges, especially if paid as a lump sum.

<u>Utility positions:</u>

> PG&E does not support a provision to separately identify replacement facilities in the special facility cost of ownership. The replacement component in PG&E's special facility cost of ownership is determined in rate case proceedings, including our GRC, and having separate components for replacement creates excessive administration burden.
>
> SDG&E's position is consistent with the views expressed by SCE, the governing rules related to the Cost of Ownership, which includes replacement cost, impact customer classes beyond "interconnecting customers," review of COO related issues are better suited for review within a General Rate Case. Overall COO assessments should not shift costs between parties and should thus be based on the concept of ratepayer indifference. SDG&E believes in the principle of equity that has long been embedded in utility regulation; ratepayer indifference thus means that no customer class should subsidize another customer class. To the extent, that Generation Interconnection Agreements remain in effect in perpetuity all costs not required to serve utility ratepayer load requirements (including replacement of the special facilities) should be appropriately charged to the requesting applicant and not be borne by ratepayers.

SDG&E includes replacement cost as a factor in the cost of ownership that is paid by the applicant, based upon the specific equipment requested by the applicant. SDG&E does not support a special or preferential accounting mechanism for DER customers. SDG&E's position is that the service-life of replacement equipment has no bearing on the requirement of the ratepayer to bear the burden of the cost of upgraded equipment as requested by an applicant. This replacement equipment is installed for the applicant's benefit and at the applicant's request, and the older, replaced equipment supported the ratepayers' needs with no additional costs required. To the extent that a GIA continues in perpetuity, SDG&E expects that it will be required to replace the upgraded equipment at some point without any additional cost to the applicant (e.g. with ratepayer funds).

SCE: As discussed with Proposal 24-a**,** throughout workshop discussions on this topic and also represented in SCE's response dated April 9, 2019 to a Commission Data Request along with written response to stakeholder questions dated April 24, 2019, since practices and governing rules related to the Cost of Ownership impact customer classes beyond "interconnecting customers," review of COO related issues are better suited for review within a General Rate Case. By way of background, COO rules are established under Rule 2 and apply to all facilities requested by an applicant which are in addition to or substitution for standard facilities. They include, but are not limited to, *all types of equipment normally installed by SCE in the development of its service to a customer or a customer's receipt or utilization of electrical service*. Fundamentally, the COO offsets SCE's revenue requirement for operating and maintaining (along with the capital related revenue requirement when applicable) the underlying asset supporting ratepayer indifference. Therefore, COO refinements are better suited for review within a General Rate Case due to the comprehensive nature and potential rate impacts of the issue along with the governing rules that are housed outside of Rule 21 itself.

In addition, SCE's current practices allow for the *option* of replacement coverage under SCE's existing Rule 2 tariff, and while customers may appreciate lower costs associated with replacements in the early years of a contract (assuming that a replacement option would be allowed post contract), when those years expire, the cost of purchasing replacement coverage for additional years will likely be prohibitive. Also, again, establishing new rate options is better suited for review within a General Rate Case where both affected customers and potential ratepayer impacts could be reviewed.

Proposal 24-c. Non-consensus

When replacing existing facilities with new facilities that are not designated as "like-for-like" replacements by the utility, the interconnection applicant will be credited for the utility cost of ownership of the equipment that was replaced and only be charged any *net-additional* COO. *Net-additional* COO is defined as the COO that would not have otherwise occurred, if no interconnection request had been made. That is, net-additional COO excludes the portion of COO of the replacement equipment that represents the continued share or obligation of ratepayers for that equipment, under the principle of rate-payer indifference.

Supported by: CALSSA, Clean Coalition, JKB Energy, Tesla
Opposed by: PG&E, SCE, SDG&E, TURN

During Working Group discussions, there was continued uncertainty about whether some form of net-additional accounting of COO is currently employed in practice, under what circumstances, and the accounting methodologies involved. In general, parties recognized that utility accounting of COO actual costs is not project specific but aggregated and addressed in General Rate Cases, and that COO accounting is not specific to Rule 21 only, as COO treatment applies to all Special Facilities governed under Rule 2 and has impacts beyond only interconnecting customers.

There are a number of potential methodologies by which to calculate COO when existing facilities are being replaced. For example, reference was made to a methodology used by PG&E for Rules 15 and 16, in which a dummy scenario is created to reflect the whole system without the upgrade, and then costs (including O&M) are compared to the system with the upgrade, and the difference (capital and O&M separately) is calculated. This methodology, if applied to Rule 21 interconnections, would produce something similar to net-additional COO.

Proponents provided indicative scenario examples of common distribution facilities upgrades where some type of net-additional methodology could be used for Rule 21:

- Major pole upgrade - existing four wood poles replaced with two steel poles
- Transformer upgrade - existing transformer, upgraded to higher capacity to serve same customers plus a new generation/storage application
- Single-customer upgrade -- existing distribution system line extension and transformer providing load service to a single customer, upgraded to accommodate a new generation interconnection request
- Single-customer upgrade -- existing customer service line drop providing load service (load side of point of common coupling with utility grid, utility side of meter), upgraded to accommodate a new generation interconnection request

Proponent positions:

CALSSA: Rule 21 practices should allocate the COO costs to the interconnection customer in keeping with the principle that the utility and ratepayers will neither be subject to additional costs resulting from the new generator interconnection nor inappropriately transfer costs to the generation applicant that the utility would have otherwise normally incurred. For example, if a 500-kVA transformer that serves multiple customers is replaced with a 750-kVA transformer because one of the customers installs solar, the new transformer still provides services for the non-solar customers. The Commission had previously committed all of the customers to paying COO for the life of the 500-kVA transformer. That transformer is now being retired early, but the services are still being performed and customers should continue paying for them. The new solar customer should pay for the incremental increase in costs for operations and maintenance of the larger transformer.

Clean Coalition: Utilities have indicated that current accounting practices may remove the replaced facilities from their COO and this would result in an under collection if the generation customer is only charged for the net additional COO resulting from their interconnection relative to the COO that would have occurred but for that customer. If this is the case then this accounting practice and shortfall should be addressed in the appropriate proceeding, but it is not appropriate to allocate costs to the interconnection customer under Rule 21 tariff practices if these costs would have been incurred by the utility anyway and would therefore create a cost shift that improperly hinders customer DER deployment.

TURN position:

TURN strongly opposes any potential subsidy of the interconnecting project by ratepayers. Any methodology that could potentially result in a cost shift or subsidy, whether due to differences in accounting practice, indirect costs that are occurred, or other potential reasons should be clearly rejected by the Commission. TURN agrees with the standard proposed by SDG&E that all costs not required to serve utility load requirements and included in a GRC authorization process should be charged to the requesting applicant.

Collective utility position:

Utilities indicated that in cases where their current accounting practices remove replaced facilities from their COO, an under-collection of COO would result if the interconnection customer is only charged for the net-additional COO resulting from the interconnection request, rather than being charged the full COO of the replacement facilities.

SDG&E position:

The utilities do not have the detailed visibility to the granularity of individual asset costs to achieve this proposal as presented. This proposal would shift more costs to existing ratepayers and unfairly benefit only the DER customer – thus, not achieving ratepayer indifference. The existing asset, if not fully depreciated, continues to be paid for by existing ratepayers and this new asset if not fully paid for by the DER customer unfairly shifts additional costs to the existing ratepayers.

For this reason, when a customer requests a Special Facility under the Rule 2 tariff requirements to replace equipment that had been previously installed to serve the utility ratepayers and was approved through its GRC process, SDG&E would continue to recover the cost of the asset from ratepayers. SDG&E does not recover its fixed assets cost upfront from ratepayers, the recovery mechanism occurs overtime through depreciation expense over the average service life of the asset. When a fixed asset is removed from service, SDG&E follows the FERC regulatory guidelines[1] to retire the asset, consistent with its general practices.

SCE position:

As discussed with Proposals 24-a and 24-b, and throughout workshop discussions on this topic along with being represented in SCE's response dated April 9, 2019 to a Commission Data Request along with written response to stakeholder questions dated April 24, 2019, since practices and governing rules related to the Cost of Ownership impact customer classes beyond "interconnecting customers," review of COO related issues are better suited for review within a General Rate Case. By way of background, COO rules are established under Rule 2 and apply to all facilities requested by an applicant which are in addition to or substitution for standard facilities. They include, but are not limited to, *all types of equipment normally installed by SCE in the development of its service to a customer or a customer's receipt or utilization of electrical service*. Fundamentally, the COO offsets SCE's revenue requirement for operating and maintaining (along with the capital related revenue requirement when applicable) the underlying asset supporting ratepayer indifference

PG&E position:

Interconnection Customers must be responsible for the costs they cause and changes in COO assessment should not shift costs from generators to ratepayers: All PG&E costs not required to serve utility ratepayer load requirements and included in a GRC authorization process should be appropriately charged to the requesting applicant.

Due to cost causation principles, the entity that initiates the required upgrade will be responsible for COO on that piece of equipment. Applicants will pay for the added facilities necessary to accommodate the DER.

Typically, the revenue support for an upgrade or "allowance" is determined by calculating the cost to serve a load and comparing it to the new cost of serving additional load. As an example scenario, a customer plans to offset all load with generation. By offsetting the load (and the revenue support/allowance), the new special facility (transformer upgrade, line reconductor, etc.) that is needed to accommodate the generation is now the full responsibility of the interconnection customer. If the customer only offsets a portion of the load, there would be an allowance available to offset the cost of the special facility.

Issues 27 and 28

Issue 27: What should be the operational requirements of smart inverters? What rules and procedures should the Commission adopt for adjusting smart inverter functions via communication controls?

Issue 28: How should the Commission coordinate with the Integrated Distributed Energy Resource proceeding to ensure operational requirements are aligned with any relevant valuation mechanisms?

PROPOSAL SUMMARIES

Proposal 27-a. Consensus
Add within Rule 21 Section Hh language that states "with mutual agreement, changes to default settings are allowed." And within six months after release of an updated UL 1741 standard that includes IEEE 1547.1-2019, take the following two actions: (1) update Rule 21 to account for IEEE 1547 and IEEE 1547.1 requirements; and (2) determine the process for requesting and approving inverter settings that are different from the default settings, including modifications to generating facility inverter settings requested by either the distribution provider or by the Generating Facility owner or operator.[23]

Proposal 27-b. Non-consensus
The Commission should convene a workshop within 90 days of the Working Group Three Final Decision, in which utilities will present their DERMS roadmaps, followed by comments from parties. Roadmaps by utilities should include visions, tentative milestones, and major challenges.

Supported by: CALSSA, Clean Coalition, GPI, JKB Energy, PG&E, SCE (conditional; see Discussion section), Sunrun, Tesla
Opposed by: SDG&E, TURN

Proposal 27-c. Non-consensus
Convene the Smart Inverter Working Group to refine technical specifications for the Set Active Power Mode function.

Supported by: CALSSA, Clean Coalition, GPI, Nuvve, SCE
Opposed by: PG&E, SDG&E

Proposal 28-a. Consensus
After the decision on the IDER proceeding, the Energy Division should decide on the need to convene The Smart Inverter Working Group to determine if any technical work is needed.

[23] Reference is made to IEEE 1547.1-2019 in Proposal 27-a due to the expectation that the forthcoming update to IEEE 1547.1 will be released in 2019. Should the release be delayed into 2020, this proposal should be adjusted to state, "And within six months after release of an updated UL 1741 standard that includes IEEE 1547.1-2020…"

BACKGROUND

The Working Group considered the functional capabilities of smart inverters as approved during Phases I-III of the Smart Inverter Working Group (SIWG). These functional capabilities include Phase I Autonomous Functions (approved April 2015), Phase II Communication Capabilities (approved April 2017), and Phase III Advanced Functions. The Phase I Functions became mandatory for all new interconnection requests as of 2017. The Phase II Communications Capabilities are currently scheduled to become mandatory in August 2019, but the Commission is considering proposals to delay that compliance deadline. The Phase III Functions have a range of deadlines. Two Phase III functions became effective on February 22, 2019: Frequency Watt Mode and Volt-Watt Mode. Two Phase III functions, Monitor Key DER Data and Scheduling Power Values and Modes, are currently scheduled to become mandatory beginning on August 22, 2019, although the Commission is considering proposals to delay that compliance deadline. Two Phase III functions will become effective 12 months after approval of a nationally recognized standard that includes the function: Set Active Power Mode and Dynamic Reactive Support. Two more Phase III functions will become effective in December 2019: DER Disconnect and Reconnect Command (Cease to Energize and Return to Service) and Limit Maximum Active Power Mode.

The Working Group, over a series of six joint calls with interested parties from the SIWG, considered a variety of smart inverter use cases with potential economic and/or safety and reliability benefits that could make use of these functional capabilities, and whether technical standards or functions are existing or forthcoming that are needed to enable those use cases. Based on discussion of the capabilities and use cases, as well as safety and reliability requirements, the Working Group and SIWG then set out to assess, prioritize, categorize and recognize the operational requirements of smart inverters and procedures for changing settings, in terms of what should be considered first by the Commission, in terms of what additional technical work or standards are needed before operationalization is possible, in terms of future development of DERMS systems by the utilities, and in terms of what is expected to have the most benefit to both generation customers and utilities.

Parties noted that it is already established in Rule 21 that customers must maintain the default settings for smart inverter functions unless different settings are approved. During Working Group discussions, parties considered proposals related to non-default settings.

The Working Group developed, together with the SIWG, a framework of three Operational Categories #1-#3, within which changes to smart inverter default settings can be considered. See Annex F for details of this framework. Operational Category #1 pertains to default operations and maintenance of Rule 21 requirements. Operational Category #2 pertains to interconnection use cases. And Operational Category #3 pertains to grid services. Parties recognized that changes to default settings for Operational Categories #2 and #3 can be made with mutual agreement, provided the modification is evaluated to ensure that safety and reliability requirements are not compromised and if the modification does not negatively affect the interconnection requirements provided under Operational Category #1 or any previously implemented Operational Category #2 and #3 requirements.

Within this framework, the Working Group and SIWG also defined and considered a series of use cases that are detailed in Annex G. In particular, eight use cases were seen as important to harnessing the grid benefits of distributed resources in the future: (a) scheduled power reduction; (b) dynamic power reduction; (c) scheduled voltage correction; (d) dynamic voltage correction; (e) operational flexibility; (f) capacity; (g) constant voltage boost; (h) voltage reduction. These use cases are included in this report to signal the types of use cases that stakeholders think should be operationalized in the future, while recognizing that existing utility technology cannot support many of them at present. With regard to the use cases, the Working Group is not recommending any specific Commission action at this time.

Some parties also noted that the existing language of Rule 21 can be interpreted to allow a mitigation path using alternative smart inverter settings in response to the results of interconnection review. If the utility offers the option to use alternative settings as a condition of interconnection approval, the customer can accept that option and the utility will include the alternate settings in the interconnection agreement. The customer will be obligated to maintain those settings unless they receive later approval from the utility to change them. After the customer has received approval for settings changes, the customer must document the settings for the utility.

In relation to the second question of Issue 27 on rules and procedures for adjusting smart inverter functions via communication controls, the Working Group recognized that many of the Operational Category #2 and Operational Category #3 use cases would require utilities to send signals to DERs based on grid conditions and react to data received from DERs through the development of "DERMS" communication and control systems. DERMS are software platforms that can control or send signals to DERs over a variety of different time intervals, to perform actions for grid reliability management and/or grid services. DERMS can work in concert with Advanced Distribution Management Systems (ADMS), which monitor DERs and grid conditions for automated grid management decision making. Some of the use-case descriptions in Annex G elaborate on how DERMS could be used.

Each of the utilities has performed multiple tests and pilots of DERMS, but ongoing use of DERMS is still limited. DER providers have partnered with utilities for those pilots, some of which have used communications technology that had not yet been widely introduced into the marketplace. It has been a learning process for utilities and DER providers alike. Most stakeholders share a vision of DERMS becoming widespread, but there are conflicting interpretations of how quickly that can be achieved.

In relation to Issue 28, parties also considered which use cases would be relevant to IDER sourcing and valuation mechanisms being developed, and how and when the Working Group and SIWG could provide technical assistance to IDER in setting operational requirements for those sourcing and valuation mechanisms. This included providing information to IDER on what use cases and functions would be associated with different mechanisms, and the practical constraints or needs in operationalizing those use cases and functions.

DISCUSSION

Proposal 27-a. Consensus
Add within Rule 21 Section Hh language that states "with mutual agreement, changes to default settings are allowed." And within six months after release of an updated UL 1741 standard that includes IEEE 1547.1-2019, take the following two actions: (1) update Rule 21 to account for IEEE 1547 and IEEE 1547.1 requirements; and (2) determine the process for requesting and approving inverter settings that are different from the default settings, including modifications to generating facility inverter settings requested by either the distribution provider or by the Generating Facility owner or operator.

Rule 21 contains specific details on the default settings of smart inverter settings. For some of the functions Rule 21 states that certain types of alternative settings may be allowed. However, there is no general statement that alternative settings may be approved by mutual consent if they are useful for facilitating interconnection or providing grid services. This creates a lack of clarity whether the current Rule 21 language allows utilities to approve the full range of alternative smart inverter settings that could be useful for these purposes.

There is also no process specified for customers to request permission for different settings for purposes of providing grid services. Utilities can, at least in some cases, review and approve proposals for alternative settings, but a defined process could improve fairness and transparency.

A third potential need is a specified requirement for customers to change settings within a certain timeframe if a utility determines it is necessary for immediate safety and reliability concerns caused by the customer.

Proposal 27-b. Non-consensus
The Commission should convene a workshop within 90 days of the Working Group Three Final Decision, in which utilities will present their DERMS roadmaps, followed by comments from parties. Roadmaps by utilities should include visions, tentative milestones, and major challenges.

Supported by: CALSSA, Clean Coalition, GPI, JKB Energy, PG&E, SCE (conditional; see Discussion section), Sunrun, Tesla
Opposed by: SDG&E, TURN

Proponent position by CALSSA:

Several of the smart inverter use cases require utility DERMS. Customers have been required to install inverters with advanced functionality, but in order to make full use of those functions utilities need to work on their portion of the capabilities. Issue 27 considers what is necessary to make use of smart inverter capabilities, and the utility side of the equation is an important element.

The utilities have conducted pilots to test DERMS capabilities and plan to conduct further pilots. These pilots are important for utilities to gain experience and confidence. However, they should be part of a larger plan, and development of that plan should involve a public process.

TURN position:

A showing needs to be made, whether cost benefit or otherwise, to show that if the utilities need to build communications systems to utilize Phase 3 functions, the benefits to ratepayers will more than offset the costs to ratepayers. The analysis also needs to show that the benefits won't disproportionally be received by a small percentage of customers while other ratepayers are paying for the communications systems.

Utility positions:

PG&E is optimistic that certain direct control use cases related to Smart Inverter voltage functions and advanced functions could provide distribution grid services beyond autonomous use cases. However, PG&E's current utility operational systems are not yet capable of using these advanced SI functions to their fullest extent. Utility investment in an Advanced Distribution Management System (ADMS) and DERMS software would provide visibility and control of SI-enabled DERs to the utility and could allow DERs to fully realize their value through dynamic management for distribution grid services.

PG&E has filed its plans for ADMS/DERMS technology development in its Grid Modernization Chapter in its 2020 General Rate Case. However, due to the upcoming 1/29/19 bankruptcy filing and the company's focus on projects related to safety, compliance, and risk mitigation following the 2017 and 2018 wildfires, it is possible that certain aspects of ADMS/DERMS implementation may be delayed and/or pushed into the future.

PG&E: Additional DERMS demonstration work is needed by the IOUs (PG&E DERMS 2.0 project, which is currently on hold due to work reprioritization activities following the 2017 and 2018 wildfire seasons). Example use cases that could be pursued through additional DERMS demonstration work include:

- Constrained generation profile use case (i.e. alternative interconnection mitigation)
- Cybersecurity standard development/demonstration of end-to-end cybersecurity testing and implementation
- Measurement and verification of DERs' ability to provide a distribution grid service beyond simply mitigating the adverse impacts of high DER penetration

SCE is supportive of an informative workshop that outlines SCE's vision, tentative milestones, and major challenges. However, because DERMs has been reviewed within SCE's last GRC, it would be out of scope for this discussion to address further stakeholder modifications, proprietary tools, vendor contracts, Cybersecurity specifications and other sensitive information. SCE is supportive of an open dialog with stakeholders to share DERMS operational plans and maximize its capability with DER operations bounded by GRC approval limitation. SCE does not support TURN's position as justification for DERMS and other related tools to be reviewed outside the GRC due to their project nature as compared to only reviewed under an interconnection rulemaking.

SDG&E is opposed to this proposal, but rather suggests that a workshop be convened to actually assess the maturity of the DERMS commercial software vendors to support necessary use cases at scale, while providing robustness and security. Per the "Smart Inverters & DERMS: An Overview of Ongoing Research Efforts at EPRI" presentation convened by the Energy Division on April 11, 2019, it is obvious that the state of DERMS is nascent and undergoing significant research and development, making any substantive development timelines for the IOUs problematic. Additionally, DERMS deployment is predicated upon these same vendors' roadmaps, which the California IOUs have minimal influence. SDG&E's point solution vendor for DERMS/microgrid product have actually changed their business model to reflect the lack of a robust market for DERMS software.

SDG&E believes that the Commission should provide clarity on the role of DERS in helping to achieve State policy goals. This clarity will provide the necessary guidance for SDG&E to effectively implement its Distributed Energy Resource Management System (DERMS) toward those goals. This clarity will also provide guidance on the roles and responsibilities of DER market participants. In all cases, SDG&E believes that the Commission should mandate end-to-end testing procedures for smart inverter communications and functionality, such that any interconnected system delivers as expected for the benefit of consumers and for overall grid reliability.

Proposal 27-c. Non-consensus

Convene the Smart Inverter Working Group to refine technical specifications for the Set Active Power Mode function.

Supported by: CALSSA, Clean Coalition, GPI, Nuvve, SCE
Opposed by: PG&E, SDG&E

Proponent position by CALSSA:

The Smart Inverter Working Group recommended that Function 4 (Set Active Power Mode) and Function 7 (Dynamic Reactive Support) be included in the Phase III functions, but during discussions on implementing Phase III it was agreed that there was not sufficient technical specification. Further development of these functions has been delayed at least until after implementation of IEEE 1547-2018. It is now clear that Function 4 will likely be valuable for enabling customers to provide capacity as a grid service and should be reprioritized.

Utility positions:

PG&E sees limited usefulness for this function until the grid sees higher storage penetration levels. Also, this function cannot be used effectively until PG&E's existing grid control systems are upgraded with DER communication and control capabilities. For PG&E, the communication and control upgrades may not happen for a few more years until ADMS/DERMS is available.

SDG&E: These functions are neither currently needed nor is the SIWG currently an official entity empowered by the CPUC to take on these tasks. While a reconciliation of IEEE 1547 and Rule 21 needs to occur, the reconciliation should occur once the IEEE standard is approved. Previously, the SIWG had agreed to postpone additional advanced functions to await a revision of IEEE 1547, as reflected in Resolution E-4898. Any additional work on these functions should wait until compensation issues have been addressed in the IDER proceeding. Furthermore, there is no justification or value to incrementally modify the tariff to incorporate IEEE 1547-2018 if there is no use for this function at this time. The technology and industry are too undeveloped for any proposed tariff changes.

SDG&E can support this proposal with redline language added. SDG&E supports one process for updating Rule 21 to align with IEEE 1547.1, just like the timing of the tariff changes in Proposal 27-b. SDG&E can only support proposal 27-c if the timing of such that we end up with a single process to update Rule 21 with UL 1741 and which functions get incorporated into Rule 21. It would be more efficient and provide certainty to the inverter manufacturers to only have one update that would occur. There needs to be the IEEE 1547 and IEEE 1547.1 alignment of Rule 21 and UL 1741 test standard needs to be updated. Adding the set active power mode function in conjunction with this comprehensive reform will facilitate a single update of Rule 21.

Proposal 28-a. Consensus

After the decision on the IDER proceeding, the Energy Division should decide on the need to convene The Smart Inverter Working Group to determine if any technical work is needed.

<u>Proponent position by CALSSA:</u>

The Issue 27 proposal contains rules and procedures for tariffs that are anticipated from the IDER proceeding at this time. If new technical needs arise for smart inverter functions as a result of IDER tariff development, the Smart Inverter Working Group remains committed to being available.

<u>Utility positions:</u>

PG&E supports the above proposal for SIWG to evaluate the need for additional technical work that may be needed as required by any upcoming IDER tariffs, but only after those tariffs are approved.

SDG&E believes that future Smart Inverter Working Group meetings should be predicated on the approval of tariffs in the IDER proceeding if it is determined that any technical work is needed. Additionally, a regulatory pathway for implementation of any SIWG work must be available.

Annex F: Issue 27, Framework of Operational Categories for Smart Inverter Functions

The Working Group and SIWG developed a framework of three Operational Categories #1-#3. The purpose of this framework was to think about how use cases can fall into different operational categories, and to note that there are some functions still to be developed.

Changes to smart inverter default settings can be considered within this framework. Parties recognized that changes to default settings for Operational Categories #2 and #3 can be made with mutual agreement, provided the modification is evaluated to ensure that safety and reliability requirements are not compromised and if the modification does not negatively affect the interconnection requirements provided under Operational Category #1 or any previously implemented Operational Category #2 and #3 requirements.

Operational Category #1 (Default Operations; Maintenance of Rule 21 Requirements). Smart inverter operational requirements should be to maintain required Rule 21 default operational parameters unless alternate parameters are approved. The most important principle is that smart inverter operations must comply with the safety and reliability requirements set forth in Rule 21. As long as safety and reliability requirements are met, then the expanded use of smart inverter capabilities to provide a variety of interconnection and grid services may be allowed. These are the Operational Category #1 requirements:

a. Anti-Islanding **activated**
b. Low/High Voltage Ride Through **activated** with default settings
c. Low/High Frequency Ride Through **activated** with default settings
d. Dynamic Volt/Var Operations **activated** with default volt/var settings
e. Ramp Rates **activated** with default normal settings
f. Fixed Power Factor **deactivated**
g. Reconnect by "soft-start" **activated** with default settings
h. Frequency/Watt **activated** with default frequency/watt settings
i. Volt/Watt **activated** with default volt/watt settings

Operational Category #2 (Interconnection Use Cases). Modification of default Operational Category #1 settings to support an Interconnection Use Case at the interconnection customer's request for purposes of avoiding the need for grid upgrades. The default Operational Category #1 setting can be modified to meet the needs of the Operational Category #2 use case. The modification of the default Operational Category #1 settings must be evaluated to ensure that safety and reliability requirements are not compromised.

For new distributed energy resources (DERs) with smart inverters that have not received permission to operate, alternative default settings: (1) may be evaluated as requested within the DER Interconnection Request; and/or (2) alternative smart inverter functions or settings can be specified by the utility to mitigate DER impacts to the grid; and/or (3) alternative settings could be agreed to by mutual consent for any reason.

For existing inverter-based DERs with permission to operate, to allow the smart inverter the capability to provide services by modifying the smart inverter default settings, changes to the smart inverter should be considered as proposed below based on the Operational Category (i.e., interconnection or grid services).

a. Utilize alternative set points for the Volt/Var curve
b. Activate the Fixed Power Factor function at a specific power factor in lieu of the Volt/Var function
c. Utilize alternative parameters for the Volt/Watt function
d. Limit smart inverter output at given static value using smart inverter Phase III Function 3 (fixed output, short term application vision)
e. Limit smart inverter output dynamically using Phase III Function 3 when DER and utility communication systems have been developed and activated through utility DERMS systems (long term application vision)

Operational Category #3 (Grid Services). When a customer requests alternate settings for a grid service use case, the Distribution Provider will review proposed settings to ensure that the modifications to the Smart Inverter default settings do not negatively affect the interconnection requirements provided under Operational Category #1 or any previously implemented Operational Category #2 requirements.

Additional functionality may be developed and activated to more fully achieve the vision of utilizing smart inverters for Operational Categories #2 and #3 functionality. The Smart Inverter Working Group can be the venue for these discussions with discussion commencing after the Working Group Three final decision has been issued. These additional functions include the following:

a. IEEE 1547 Constant Reactive Power should be adopted and available for activation in Rule 21 when the Commission incorporates the updated IEEE 1547 standard into Rule 21. This function will allow Smart Inverters to provide reactive power capacity. While the current capabilities of Smart Inverters have functions to provide reactive power, namely the volt/var and fixed power factor, the volt/var and fixed power factor functions, these functions are most appropriate for Operational Category #1 applications. Constant Reactive Power more closely matches the reactive power support provided by capacitor banks and would be a better fit for the Constant Voltage Boost use case in Annex G.

b. The SIWG may choose to consider the Watt/Var function, developed under IEEE 1547-2018, for activation in Rule 21 when it considers incorporation of the broader IEEE 1547 standard. This function may be able to provide additional voltage control capabilities. This will give California stakeholders an opportunity to debate the functions in a California context.

c. Phase III Function #4 (Set Real Power Mode) or equivalent should be developed and be available for activation for the Capacity use case in Annex G, which may be the most near-term and important grid-services use case. While a recent Commission resolution, Resolution E-4898, has directed Function #4 to be developed as part of future national standards, it may be possible to develop this function earlier than the current schedule.

Annex G: Issue 27, Use Cases and Party Comments on Use Cases

The Working Group is not recommending any Commission action to approve specific use cases for smart inverter functions in this proceeding. The following use cases are included in this report to indicate potential use cases identified by stakeholders that the Commission may wish to consider for further development.

Interconnection Use Cases:

a) Scheduled Power Reduction – To address thermal hosting capacity constraints during certain hours of the year, a customer can schedule reduced power output during those hours. The maximum output values will be in the interconnection agreement.
   - Function 3 (Limit Maximum Active Power) and potentially Function 2 (Curtailment)
   - Function 8 (Scheduling)

b) Dynamic Power Reduction – To address thermal hosting capacity constraints as they approach levels of concern, the utility can send a command to reduce power output during those times. Curtailment permission and annual limitations on amount of curtailment will be in the interconnection agreement.
   - Function 3 (Limit Maximum Active Power) and potentially Function 2 (Curtailment)
   - Function 8 (Scheduling)
   - Real-time communications must be enabled
   - Requires utility DERMS

c) Scheduled Voltage Correction – To address voltage hosting capacity constraints during certain hours of the year, a customer can schedule increased reactive power production or absorption during those times.
   - Alternative settings for Volt-Var and Volt-Watt
   - Potentially enabling the Fixed Power Factor function
   - Potentially with Watt-Var

d) Dynamic Voltage Correction – To address voltage hosting capacity constraints as they approach levels of concern, the utility can send a command to increase production or absorption of reactive power during those times. Authorization to change the Volt-Var and Volt-Watt settings and annual limitations on the number of events will be in the interconnection agreement.
   - Alternative settings for Volt-Var and Volt-Watt
   - Potentially enabling the Fixed Power Factor function
   - Potentially with Watt-Var
   - Real-time communications must be enabled
   - Requires utility DERMS

e) Operational Flexibility – In a location that is constrained by operational flexibility, a customer can agree to reduce or curtail power during system maintenance or grid outages that involve the system reconfiguration that caused the operational flexibility constraint. The range of adjustability and limits on the number of events will be determined by mutual consent and included in the interconnection agreement.

- Function 3 and potentially Function 2
- Real-time communications must be enabled
- Requires utility DERMS

Grid Services Use Cases

f) Capacity – Coordinated dispatchable or scheduled electricity production in accordance with solicitation requirements or grid service tariff rules. This will mostly be the discharge of stored energy. Customer agrees to deliverability obligation. Communications must be enabled, which may be less than real-time if the discharge is scheduled ahead of time.
   - Reliability will be greatly increased with Function 4.

g) Constant Voltage Boost – Increase voltage that has become lower along a feeder due to distance from a substation and the existence of machine loads. This is achieved with constant or periodic production of reactive power.
   - Requires the Constant Reactive Power function developed under IEEE 1547-2018.
   - Can be scheduled with Function 8.

h) Voltage Reduction – Reduce voltage in locations that have regular occurrences of high voltage due to reasons beyond the specific customer site.
   - Alternative settings for Volt-Var and Volt-Watt.

Proponent comments on use cases:

CALSSA: Because solar systems can cause an increase in voltage on the grid near the point of interconnection, utilities have often required grid upgrades to address potential voltage problems caused by a new generating facility. One basic use case for smart inverter functions would be adjustment of the settings of Volt-Var and Volt-Watt if the default settings are not sufficient to counteract the impacts that a new generating facility is expected to cause. However, since the activation of Volt-Var with reactive power priority and Volt-Watt, it appears that the default settings for those functions are sufficient to address voltage concerns. If this is not the case for some customers, utilities should consider alternate settings to avoid the need for mitigations. If it continues to be the case for all customers, the Commission can focus its attention on the more advanced use cases below.

Utility comments on use cases:

SCE response to the voltage-related use cases (c), (d), (g) and (h):

> In regards to voltage control use cases c), SCE points out undervoltage or overvoltage conditions that are driven by abnormal conditions are generally severe, such that only equipment designed to regulate voltage (Voltage Regulators, Load tap changers) are the appropriate means to regulate voltage. While absorbing reactive power can

have a side effect of slight reduction of voltage (due to voltage drop caused by increase reactive loading on the line) or injecting reactive power can have a slight side effect of voltage rise, these slight increases or decreases are generally a few % (0.5%-3%) depending on the location of the DERS, the level of reactive power the DERS can inject/absorbed and strength of the local grid and DER settings.

Further, it should be accounted that DERs are required in the interconnection agreement to have a range of operation +/-.9PF to mitigate the issues that are created by the DERs and thus any additional reactive power support would have to be behind what is required the interconnection requirements. In most cases, it is the presence of DERs which may the high voltage issues. For example, if the system is configured in a way that the DERs are far away from the substation, then because of their location, DERs would now be more prone to create high voltage issues.

Additionally, a reactive power (VARs) source (such additional capacitor banks) must be available to provide reactive power to the inverters (Inverter do not lower voltage, they rely on voltage drop caused the reactive power flow on the grid low lower/increase voltage). In cases of reactive power injection, sufficient reactive power load must also be available to maintain the local grid at a near unity power factor otherwise reactive power would have to flow from the distribution system towards the transmission system which a non-desirable condition.

Lastly, the volt/var and PF function does not guarantee that the inverter will provide the reactive support. In the case of volt/var, if the local voltage is within the dead-band, then the inverter will operate at unity power factor and will not provide reactive power support. In the case of PF control, if the inverter is not producing real power, then it will not produce reactive power as PF is a function of real power production in this mode. Future functions under IEEE may provide additional capability (such as the Constant Reactive Power Mode) but until those are adopted and implemented in R21, they may not be available for use.

For all the reasons above, Volt/var and PF functions are not an appropriate function to support voltage support as indicated by the proponent.

SCE provided six use cases, along with technical requirements and discussions, in its proposals during the Working Group that are similar to the eight proposed above. The six use cases proposed by SCE are reactive power capacity, real power capacity, high voltage control, low voltage control, interconnection/overload, and interconnection/overvoltage.

PG&E would like to clarify that while these interconnection use cases may be possible in the future, PG&E's existing technology cannot support these use cases at the present time.

For example, the range of actual day-to-day variability of system conditions has not been tested for such an operational application of the Integration Capacity Analysis (ICA) tool. The geographical and temporal alignment of ICA to specific generators has not been fully characterized or quantified. It is thus too early in the technology development cycle of active DER management to rely on ICA. Actual field testing is needed to demonstrate methods for developing safe, reliable, and usable generator constraints that stand up to the dynamic reality of the power system.

For the dynamic control use cases, PG&E would also need a DERMS and/or ADMS to coordinate DER constraints with feeder conditions and to account for abnormally-switched feeder states. Example systems/requirements that do not exist today include:

- Utility database to store, retrieve, and communicate the new complexity of generator information defining a constrained generation profile
- DER Smart Inverter head end to exchange information with smart inverters at a complete operational scale, i.e. all generators qualifying for such a solution
- Reliable and cyber-secure end-to-end communication systems, be they provided by interconnection customers, aggregators, or utilities
- Utility systems to compare and validate profiles for specific generation facilities by two-way communication with the actual smart inverters or site controller to validate settings and constraint profile configuration, both up front and an on-going basis
- Adequate monitoring (i.e. telemetry on an adequately responsive time scale) for utility systems to detect excursions from operating profiles and alert grid operators as needed

For more detail related to technology requirements to enable dynamic operational constraints for interconnection, see the following comments filed Feb 1st, 2019: "Survey Responses of Pacific Gas and Electric Company (U 39-E) to Questions on Working Group Two Report."

PG&E recommends the following points be considered as general pre-requisites for enablement of the Smart Inverter use cases suggested by SCE:

- The Phase 2 communication capability deadline needs to be shifted out per IOU recommendations in response to the CALSSA PFM
    - Testing standards for Smart Inverter communications should be updated and aligned with IEEE 1547.1, after the 1547.1 revision is issued by IEEE.
- The utilities should update their Smart Inverter implementation plans to reflect incorporation of the IEEE 1547.1 standard updates, once the IEEE 1547.1 standard revision is issued.

PG&E: To enable grid services use cases, a change to Smart Inverter settings would be required. Such a change to settings would be a material modification since it would be relied upon for proper grid operation. If approved by the Distribution Planning engineer, it would need to be memorialized in the Interconnection Agreement as an operating parameter. The material modification process will be implemented as part of the Working Group 1 Proposed Decision.

PG&E says that prior to incorporating additional IEEE 1547 functions Constant Real Power and Watt/VAR into Rule 21, these functions should be evaluated through modeling, lab and field-testing by the utilities to determine if they are truly necessary and add value relative to the already-defined Rule 21 SI functions. If implementation/modification of Rule 21 is warranted per this evaluation, the applicable inverter certification and testing standards such as UL 1741 SA should be updated to certify these new functions via a NRTL.

PG&E also elaborates on further needs:

- Additional DERMS demonstration work is needed by the IOUs (PG&E DERMS 2.0 project, which is currently on hold due to work reprioritization activities following the 2017 and 2018 wildfire seasons). Example use cases that could be pursued through additional DERMS demonstration work include:
    - Constrained generation profile use case (i.e. alternative interconnection mitigation)
    - Cybersecurity standard development/demonstration of end-to-end cybersecurity testing and implementation
    - Measurement and verification of DERs' ability to provide a distribution grid service beyond simply mitigating the adverse impacts of high DER penetration
- Grid Modernization efforts should be allowed to proceed (PG&E Integrated Grid Platform effort).
- Additional economic modeling is needed to determine the grid value of DERs to provide grid services.[24]

SDG&E concurs with PG&E's comments above. Furthermore, SDG&E is in general concurrence with the characterization of the six use cases and notes the premature nature of these use cases today. In order for the SCE-identified use cases to be implemented, the Phase II communications need to exist and be activated, Phase III Functions 1 and 8 need to be activated, a DERMS needs to be available and be used to manage DER, and the IOUs must have identified applicable needs for DER and smart inverter services. At the time of interconnection, default setting can be provided to the inverters as part of the interconnection review process. Changes in the settings will require processes and procedures, and communications in place.

Any new functions to be developed and implemented should wait for the next revision of IEEE 1547. This will avoid the incremental updates to Rule 21 and the recertification of inverter models. This is consistent with CALSSA's arguments when the Commission sought to implement the Phase 2 and Phase 3 smart inverter functionality. Modifying inverter set-points will require communications that today are not available. Furthermore, by the end of 2019, all SDG&E residential customers will be defaulted onto a residential time-of-use (TOU) rate, and the impact of implementing this TOU rate on circuit loading is unclear.

[24] See PG&E Smart Inverter Modeling Report for an example of economic analysis needed: https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.03A_Modeling-Report.pdf

Still, SDG&E believes that, before any communications-related use cases can be achieved, the following roadmap will need to take place on a system-wide basis:

- IOU develops communications infrastructure to communicate with both inverters, energy management systems, and aggregators.
- IOU develops required DERMS capabilities for Phase II communications and Phase III Functions 1 and 8 additional smart inverter requirements.
- All parties establish and implement communications applications that comply with Rule 21 for integrating inverters, EMS, and aggregators with DERMS.
- IOU updates interconnection portals to collect necessary communications information for newly connected smart inverters.
- Standards bodies approve any applicable national standards for smart inverters (functionality and communications).
- Nationally Recognized Testing Laboratories (NRTL) establish end-to-end test environment for smart inverter communications based on national standards.
- IOUs obtain approval from CPUC through the general rate case (GRC) process to implement DERMS and communications networks for smart inverters.
- Develop compensation mechanisms based on outcome of other proceedings (e.g. IDER, DRP, NEM).
- Develop applicable contracts.

Issues A and B

Issue A: What changes are needed to clarify the parameters for approval of system design to achieve non-export and limited export?

Issue B: How should utilities treat generating capacity for behind the meter paired solar and storage systems that are not certified non-export?

PROPOSAL SUMMARIES

The two issues A and B are interrelated and the proposals address them jointly.

Proposal A-B #1. Consensus
Generating facilities that meet the following five specifications will be treated as non-export or limited export in interconnection review: (1) the Generating Facility uses a power control system (PCS) that passed testing in conformance with the Underwriters Laboratory Power Control Systems Certification Requirements Decision (UL CRD); (2) the control system has an open-loop response time of no more than 2 seconds as provided in the control systems specification data-sheets, and the PCS is required to reduce export power to the approved export limit within 2 seconds of exceeding the approved export limit; (3) the Generating Facility must utilize only UL 1741 certified and/or UL 1741 SA listed grid-support non-islanding inverters; (4) the Generating Facility control is set to zero-export or some non-zero controlled maximum export value; and (5) the Generating Facility is required to maintain voltage fluctuations to the limits specified in Rule 2. In addition, update Rule 21 language to include the use of a PCS for non-export and limited export interconnection applications.

Proposal A-B #2. Consensus
Generating facilities that meet the following six specifications will be treated as inadvertent export in interconnection review: (1) the Generating Facility uses a power control system (PCS) that passed testing in conformance with UL CRD; (2) the control system has an open-loop response time of no more than 10 seconds as provided in the control systems specification data-sheets, and the PCS is required to reduce export power to the approved export limit within 10 seconds of exceeding the approved export limit; (3) the Generating Facility must utilize only UL 1741 certified and/or UL 1741 SA listed grid-support non-islanding inverters; (4) the Generating Facility control is set to zero-export or some non-zero controlled maximum export value; (5) the Generating Facility is required to maintain voltage fluctuations to the limits specified in Rule 2; and (6) the Generating Facility installed nameplate capacity is equal to or less than 1000 kVA. In addition, update Rule 21 language to include the use of a PCS for non-export and limited-export interconnection applications.

Proposal A-B #3. Non-consensus
An inverter approved for non-export and limited-export can be set using different maximum export value settings at different times of the year, if it qualifies under Proposal A-B #1 (response time less than 2 seconds) or Proposal A-B #2 (response time between 2-10 seconds), and at the discretion of the utility until a future scheduling standard is released.

Supported by: CALSSA, Clean Coalition, GPI, IREC, Nuvve, Tesla
Opposed by: PG&E, SCE, SDG&E

Proposal A-B #4. Consensus
For SCE customers only, beginning 6 months after the approval of the Advice Letter implementing the final decision on Working Group Three, customers applying for interconnection with a PCS must use a PCS already on the approved list. Interconnection application forms are to be updated with new required fields including control information and limited export setting.

BACKGROUND

Background on Issue A for Non-Export

Interconnection customers can have good reasons for choosing non-export systems. For example, they may achieve greater bill savings by using on-site energy directly to power on-site load. Or, if the system includes storage, customers can benefit from time-of-use periods and rates, and store on-site generation and/or power purchased during periods of low rates, for use during periods with higher rates. Non-export strategies can also avoid reliance on net energy metering credits that are lower than retail rates due to non-bypassable charges.

In some circumstances, non-export systems could enable a customer to choose to interconnect within existing grid capacity and not incur the cost or delay of distribution system upgrades, at a location where interconnection of an exporting system might otherwise require distribution system upgrades.

However, even though a customer may choose to operate as non-export, utilities must determine whether a system has the *potential* to export and, if so, utilities must determine the magnitude of potential safety and reliability impacts to the grid. Rule 21 contains provisions to handle such determinations, such as Section N and Section G.i, in recognition that systems that do not export power have different grid impacts than full export projects. Other sections of Rule 21, such as Sections M and Mm, cover situations in which generating facilities may inadvertently export, which even if infrequent and for short durations, may have high potential safety and reliability impacts on the grid.

Currently, Rule 21 identifies four Options by which a project may qualify as a non-exporting system and two Options by which a project may qualify as inadvertent export (see Section G.1.i). Rule 21 does not, at this time, explicitly recognize the concept of limited export.

Non-Exporting:

- Option 1. Reverse Power Relay
- Option 2. Minimum Power Relay (Continuous Import)
- Option 3. Certified Non-Islanding Protection (Small System Compared to Service)
- Option 4. Relative Generating Facility Rating (Small System Compared to Load)

Inadvertent Export:

- Option 5. Inadvertent Export (Section M)
- Option 6. Inadvertent Export (Section Mm) – Designed for small UL 1741 SA inverter-based generating facilities

Customers who choose Option 1 are required to install a relay which causes the Generating Facility to disconnect if the relay senses reverse power (0.1% of transformer rating) for a time greater than 2 seconds. It should be noted that customers who operate their generation system under Option 1 would not be expected to operate in such a manner that their relay is tripped on a frequent basis, a situation which might cause the utility to disconnect the generating facility, and pose other operations issues. Thus, the relay used for this application is considered to be a safety backup and not part of normal operation.

If a customer installs a physical non-export relay it is relatively simple for the utility to validate that the system will not export. However, non-export relays can be prohibitively expensive. In addition, proponents IREC and CALSSA argue that if a PCS is capable of providing the same functionality, then any additional cost for a relay is unnecessary regardless of whether it is "affordable." IREC and CALSSA cite an example relay cost of $60,000 for a site with 1 MW PV and 500 kW energy storage, and assert that if the combined inverter nameplate of the system is less than 750 kW, a physical relay is likely to be unaffordable. The other available non-exporting options are challenging or impractical for a variety of different types of projects and applications.

The UL Power Control Systems CRD (UL CRD) test protocol was recently approved and provides a way for inverters and power control systems to be tested and qualified for non-export and limited export. The protocol is a UL Certification Requirements Decision developed to support 2020 National Electrical Code Section 705.13 and to create a framework for limited export systems.[25] It is an addendum to UL 1741. A power control system certified to the UL CRD allows a device to demonstrate that it is capable of preventing or limiting export, within a time-delay of up to 30 seconds. The documented test results of the power control system will identify the

[25] The language of the CRD is downloadable free of charge at https://www.shopulstandards.com/ProductDetail.aspx?UniqueKey=35560. This version is the final proposal that was later approved.

response time-delay of the system.

Parties agreed that the UL CRD may be used to test power control systems in the interim, until such time as UL incorporates the test protocols into the underlying UL 1741 standard.

To be compliant with the UL CRD, an inverter or generating facility power control system must, among other requirements, respond to changes in current at a reference point (such as the PCC) and include that functionality in its configuration file or otherwise have it embedded in a non-volatile file. The UL CRD standard requires that parameters, once set by the installer at the time of installation, can only be changed by contacting the inverter or power control system manufacturer, and cannot be changed by the customer or the installer.

Technical Insert 1: Physical Non-Export Relays and UL CRD Devices

Proposals A-B #1 and A-B #2 accept the use of the UL CRD standard for non-export and limited-export power control systems ("UL CRD devices") in place of a physical non-export relay, under the conditions specified in the proposals to ensure safety and reliability. However, there are still differences between non-export relays and UL CRD devices. A UL CRD device measures a single parameter (current flow) at a given point of reference (such as at the PCC) and responds based on that single measurement. A relay also measures this parameter, but can also measure, among other things, system frequency, voltage and phase rotation—measurements which can be used to satisfy other interconnection protection requirements. If some of these other measurements are required for safe interconnection to the grid, a UL CRD device would not be sufficient by itself.

A relay is a backstop to power control systems. It only acts in unexpected circumstances, when generating facility controls deviate from normal. A UL CRD device, in contrast, may operate much more frequently, or even continuously, to regulate system output under normal conditions. A further difference is the level of historical utility experience. Relays have been used for many decades, while very little experience yet exists with control systems approved under the UL CRD. While power control systems have been used historically, they have not been relied upon historically in the same way that UL CRD devices without a physical non-export relay are now being relied upon. Manufacturers and National Recognized Testing Laboratories (NRTLs) are currently in the process of developing capabilities to test power control systems under the UL CRD, so utilities have still not seen the results of that testing.

Technical Insert 2: Inadvertent Export and Open-Loop Survey Response Time

The example of a load-following generating facility with both solar and storage can illustrate the concepts of open-loop response time and inadvertent export. When load increases, the storage system discharges to meet that load. When the load decreases, the system reduces output or stops discharging but will inadvertently export to the grid for a period of time to the extent that instantaneous generation exceeds instantaneous load. This time period is referred to as the open loop response time of the control system. When load reduces quickly, power may be inadvertently exported to the grid during the time it takes for the system to sense the load reduction and tell the battery to stop discharging. If a system has been tested and certified under the UL CRD for limited export, the generating facility can export power up to nameplate capacity until the control system makes a correction within its certified open-loop response time.

Utilities must account for this inadvertent export while also recognizing that it is short-lived and non-coincidental among customers on a circuit segment because the load of neighboring customers does not go up and down in unison. Further, it should be noted that these control systems do not limit the number of export occurrences, and the instances of export are based on the customer's operating characteristics. Customers who have very cyclic loads will undergo inadvertent export many times, while customers who have relative steady load pattern will have very few instances of inadvertent export.

Background on Issue A for Limited Export

A limited export system is one that is designed and set to limit the level of export to some specified amount less than the nameplate capacity. A UL CRD power control system (PCS) can also provide limited export in addition to non-export, depending on its settings. A PCS will also limit export to a value below nameplate capacity and within some time interval characteristic of that specific device, such as less than 2 seconds, less than 10 seconds, or less than 30 seconds.

The UL CRD standard does not provide the recommended settings for a given application, however. The utility and customer need to agree on the settings for each application to ensure the PCS will perform properly for the given application.

There is not currently any provision in Rule 21 that recognizes the concept of limited export explicitly, though nothing prevents a project from limiting export. Projects may choose to limit their exports for various economic and technical reasons. If the proposal for Issue 9 as part of Working Group Two is adopted, a formal recognition of limited export capability will be needed.

Exporting systems are commonly designed and operated in ways that do not allow the full capacity to be exported to the grid. In order to study limited export projects differently (i.e. to not assume full export), for grid reliability and for the safety of utility customers and employees, utilities need assurances that intended limits will not be exceeded. Technical evaluation must account for the PCS response time (see Box 2). And the operating profile must be limited by system constraints that can only be changed as provided in the UL CRD standard.

Background on Issue B

Currently, a system that does not qualify for non-export gets studied in interconnection review using the maximum nameplate rating. Until the recent approval of the UL CRD, no standards existed governing the control of power output for non-export or limited-export cases for inverters and power control systems.

"Maximum nameplate rating" is interpreted differently in different situations and by different utilities. For AC-coupled solar-plus-storage systems, PG&E and SCE equate the maximum nameplate rating of the combined system with the sum of the individual nameplate ratings of the solar-connected-inverter and the storage-connected-inverter. SDG&E's practices differ, as SDG&E only considers the solar (inverter) nameplate, and not the storage device nameplate. For DC-coupled systems, the nameplate rating is just that of the inverter.

Proponents CALSSA and IREC call the "nameplate plus nameplate" methodology unrealistic, because it assumes that the solar system is generating at full capacity and the battery is discharging at full capacity every daytime hour of the year. CALSSA and IREC recognize, however, that in the absence of an UL CRD certified and approved power control system, utilities often choose to study it in this manner as a worst-case scenario.

More realistically, customers typically operate solar plus storage systems to satisfy their own load and minimize the amount of power they import from the utility, not to intentionally export at maximum levels. Assuming in technical review that a project will always be exporting the full nameplate plus nameplate amount (for AC-coupled systems) could have significant financial consequences. For example, assuming nameplate-plus-nameplate might trigger a distribution upgrade requirement, while in actual operation according to approved settings no such upgrade would actually be needed (i.e., solar and storage never concurrently export at maximum levels).

To give assurance to the utility that a system will always operate within set parameters a customer can use power controls that are certified to a national standard, with an appropriate response time and while insuring power quality for other customers is not negatively affected.

DISCUSSION

Proposal A-B #1. Consensus

Generating facilities that meet the following five specifications will be treated as non-export or limited export in interconnection review: (1) the Generating Facility uses a power control system (PCS) that passed testing in conformance with the Underwriters Laboratory Power Control Systems Certification Requirements Decision (UL CRD); (2) the control system has an open-loop response time of no more than 2 seconds as provided in the control systems specification data-sheets, and the PCS is required to reduce export power to the approved export limit within 2 seconds of exceeding the approved export limit; (3) the Generating Facility must utilize only UL 1741 certified and/or UL 1741 SA listed grid-support non-islanding inverters; (4) the Generating Facility control is set to zero-export or some non-zero controlled maximum export value; and (5) the Generating Facility is required to maintain voltage fluctuations to the limits specified in Rule 2. In addition, update Rule 21 language to include the use of a PCS for non-export and limited export interconnection applications.

Update Rule 21 language to include the use of a PCS for non-export and limited-export applications: Rule 21 must include options for all the following configurations: non-export with relay (already existing within Rule 21), non-export with PCS, limited export with PCS, and limited export with relay. Rule 21 already has provisions for the use of relays for non-export Interconnection Applications, so no updates to existing Rule 21 provisions are necessary for use of relays for non-export.

When a Generating Facility meets the six specifications in this proposal, technical evaluations should follow the following process:

I. Non-Export Interconnection Applications

1. A power control system (PCS) can be used to demonstrate non-export operation under Screen I.
2. Interconnection projects are not evaluated for Screen D.
3. Short circuit related analyses (Screens F and G) are based on the Generating Facility's Gross Nameplate Rating.

II. Limited-Export Interconnection Applications

1. The limited export value is used to determine the impacts to the grid in accordance with Rule 21 tariff procedures. The limited export value will be used in screens D, I, J, K, M, N, O, and P. Other screens, including A, E, and H, will still be applied as relevant.
2. Short circuit related analysis (Screens F and G) are based on Generating Facility's Nameplate rating.

Proponent position by CALSSA:

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

Utility positions:

SDG&E agrees with this proposal, based on the assumption that it only applies to certified inverter-based generation devices.

PG&E gives qualified support to this proposal. The CRD should be able to replace the need for discrete directional power relays and streamline the process. The two second trip time is fast enough to avoid the need for other relays.

PG&E: The UL CRD does provide potential benefits if used properly. It provides a lot of flexibility. So, the UL CRD certified PCS may be treated like a programmable device that needed to be set appropriately for the desired application. The guidance and specific certification for each application were not provided in the UL CRD itself despite PG&E suggestions to the task group. The UL CRD task group wanted to make the UL CRD more general for use in other jurisdictions as well. So, the specific guidance was left to the utilities. Currently, the UL CRD does not have the specific settings for each application. So, PG&E still need to provide guidance documents in the DIH on how to set the certified PCS to comply with the different applications before we can implement this UL CRD method.

PG&E provided an alternative wording of Issue B in the interests of clarification. This alternative wording is: “How should utilities treat generating capacity for behind the meter paired solar and storage systems that are certified not to export more than a preset value?” If this alternative wording by PG&E correctly interprets the intent of Issue B, then with this understanding, PG&E proposes to use the certified preset export value in its load flow interconnection studies instead of the nameplate rating of the PCS. Since fault current contribution is a function of the PCS nameplate, and not the controlled export value, the PCS nameplate will continue to be used for fault studies.

Proposal A-B #2. Consensus

Generating facilities that meet the following six specifications will be treated as inadvertent export in interconnection review: (1) the Generating Facility uses a power control system (PCS) that passed testing in conformance with UL CRD; (2) the control system has an open-loop response time of no more than 10 seconds as provided in the control systems specification data-sheets, and the PCS is required to reduce export power to the approved export limit within 10 seconds of exceeding the approved export limit; (3) the Generating Facility must utilize only UL 1741 certified and/or UL 1741 SA listed grid-support non-islanding inverters; (4) the Generating Facility control is set to zero-export or some non-zero controlled maximum export value; (5) the Generating Facility is required to maintain voltage fluctuations to the limits specified in Rule 2; and (6) the Generating Facility installed nameplate capacity is equal to or less than 1000 kVA. In addition, update Rule 21 language to include the use of a PCS for non-export and limited-export interconnection applications.

Update Rule 21 language to include the use of a PCS for limited-export interconnection applications. Screen P will include an additional note that the utility will consider, to the extent feasible, the customer's operating profile and the magnitude, duration, and frequency of anticipated export.

When a Generating Facility meets the six specifications in this proposal, technical evaluations should follow the following process:

1. Screens A-M are applied using the aggregate nameplate inverter rating, or nameplate rating utilized under existing utility practice if different.

2. When required to proceed to supplemental review and Distribution System upgrades are identified for mitigation of thermal and/or voltage deviations, the Distribution Provider will request from the customer the generating facility projected loading to identify the following: (a) the frequency of inadvertent export; (b) the real power (watts) level of inadvertent export; and (c) the length of inadvertent export. The customer will have 15 business days from the time of the request to provide the information, but will also be given the option of providing the information with their application and/or at the time that Supplemental Review commences (to facilitate faster review).

3. When Distribution upgrades are identified for mitigation of thermal and/or voltage deviations and customer has provided the information as outlined in (2), then Technical Review under Screen P recognizes power control parameters to the extent feasible taking into account local feeder conditions.

4. For Existing Generating Facilities that meet the requirements under this proposal, only the largest generating facility in the line section would be used for aggregate evaluation for subsequent interconnection requests.

Proponent position by CALSSA:

Now that the UL CRD is available to test power control system performance, it provides an opportunity to alter the review process to utilize a more pragmatic assessment of the potential impacts that non-export and limited export projects may have on the system.

Proposal A-B #1 addresses how this could be done for projects with a response time less than 2 seconds. For projects with a response time less than 10 seconds, the proponents recognize that these systems have reduced grid impact as compared to those that constantly export their maximum capacity. It is also true, however, that having projects inadvertently export with an uncontrolled frequency could impact the grid in an equivalent manner to those that constantly export.

Continuing to assume in the review process that projects with response times greater than 2 seconds but less than 10 seconds will be exporting at the full aggregate nameplate amount for all types of system impact assessments, can result in unnecessary upgrades and thereby increase the costs of DER development for both DER customers and other ratepayers. Thus, because there are not yet accepted practices or standards to guide how to screen or otherwise evaluate how uncontrolled exports up to 10 seconds will impact the system, this proposal is designed to allow the utilities to exercise their engineering judgment in evaluating whether they believe the uncontrolled inadvertent up to 10 seconds is likely to cause equipment overload or other significant negative system impacts. Projects meeting the criteria identified in the proposal would be evaluated at their nameplate capacity under the initial Fast Track screens. If in Supplemental Review the utilities identify that an upgrade may be necessary when assuming the full nameplate value is exported, they can then utilize information provided by the customer about expected system performance to evaluate whether upgrades are necessary if a project is limiting its export.

For example, if a customer has steady load, a power control system may be able to manage discharging with minimal instances of inadvertent export. Whereas if the customer has large machines that frequently turn on and off, the frequency of inadvertent export will be higher. The utility will be provided information that enables it to weigh these factors in assessing potential impacts.

In the long term, grid engineers may be able to develop analysis tools to incorporate new customer capabilities. In addition, the DER industry may also be able to improve their ability to limit the response time and frequency. In the meantime, this proposal seeks to implement an interim solution that recognizes that studying projects at full nameplate capacity may not be appropriate in all cases and allows the utilities to utilize information about the systems expected performance, and knowledge about the local grid conditions, to make that assessment.

Proponent position by Tesla:

Tesla believes this proposal is unduly conservative given the scenario of projects that export between 2 and 10 seconds. Essentially this approach treats a project that exports between 2 and 10 seconds the same as if the project exhibited unconstrained and continuous export. The inadvertent exports in this scenario do not raise the same safety/reliability concerns as unconstrained simultaneous export and should not be treated as such. Also to the degree the concern is that inadvertent export events across multiple installations would happen simultaneously, we believe the odds of that are extremely low and would be on par with the presumed level of coincidence that utilities assume when doing load studies where they do not build out their system assuming all customers use all of their loads at the same time.

Utility positions:

PG&E supports SCE's general comments on Issues A & B, dated 3/21/19. PG&E believes that the 2 second limit can help streamline the current no-export and in-advertent export requirements substantially. Unlike the governor control of the synchronous machines that the existing inadvertent export provision (30 second delay) was designed for, the PCS is an electronically control device and may operate in milliseconds, rather than seconds, and we should try to capture its full capability and minimize potential system impacts whenever possible.

PG&E acknowledges that changing the time delay from 30 seconds to 10 second delay should lower potential system impact and may help to reduce the amount of review time needed. But PG&E believes that the existing Sec Mm provisions provide adequate flexibility to enable UL CRD certified PCS power system to interconnect already. The wording in the existing Rule 21 accounts for the possibility of PCS usage already. PG&E is open to considering minor adjustments to Rule 21 if there are specific gaps that need to be addressed.

Proposal A-B #3. Non-consensus
An inverter approved for non-export and limited-export can be set using different maximum export value settings at different times of the year, if it qualifies under Proposal A-B #1 (response time less than 2 seconds) or Proposal A-B #2-a (response time between 2-10 seconds), and at the discretion of the utility until a future scheduling standard is released.

Supported by: CALSSA, Clean Coalition, GPI, IREC, Nuvve, Tesla
Opposed by: PG&E, SCE, SDG&E

Conditions:

- Certified to the UL CRD
- Set to different export values at different times of the year
- Inverter-based and certified to UL 1741 SA
- At the discretion of the utility until a future Scheduling standard is released

Review Process:

- Same as Proposal A-B #1, using temporal profile, if the response time is less than two seconds
- Same as Proposal A-B #2-a, using temporal profile, if the response time is between two seconds and ten seconds

Proponent position by CALSSA:

Smart inverter Phase III Function 8 (Scheduling) will enable systems to have different maximum export values at different parts of the year. The export values could vary seasonally, monthly, or hourly. Although the Working Group Two report has not been ruled upon, this option would be used to implement the Issue 9 proposal, and potentially for other purposes associated with time of use rates or other economic conditions.

Distributed energy resources will be required to have this functionality as of August 2019. Until a standard is developed to test performance of the function, utilities will have the discretion to accept equipment functionality and will establish a mechanism for validating proposed profiles.

The scheduling proposed here does not require real-time communication, contrary to utility claims.

Utility positions:

SCE: This proposal is premature given that no standards have been developed to test control systems, as indicated in CALSSA and IREC's proposal. Thus, in concept, SCE is not against this proposal, but in order to implement this proposal, testing standards and requirements need to be implemented. Further SCE notes that several advanced functions, including Smart Inverter Function #8 (Scheduling) and Function #3 (Limit Real Maximum Real Power Mode) may be delayed beyond 2020. Further, the UL CRD must be updated to include the temporal testing procedures for which work has not commenced. For these reasons, SCE believes that it is premature to require these capabilities. Instead of addressing this proposal at this time, the CPUC should require that 9 months after these technical specifications and standards have been approved by the standards approving bodies, utilities shall make this capability available for use. This time will be needed by SCE to adopt tools, forms, and technical evaluation methods in the interconnection process and will allow the industry time to manufacture control equipment with this capability. This process has worked well as part of Smart Inverter implementation phases, and thus, should be followed here as well.

SDG&E does not support this proposal, since it is premature. Testing standards and requirements first need to be created before implementing smart inverter Phase II function 8. SDG&E does not support having the discretion to accept equipment functionality and establishing a mechanism for validating profiles. SDG&E's mechanism is to utilize a testing standard to validate the performance and establish universal standards.

SDG&E: Distributed energy resources are scheduled to be required to have this functionality as of August 2019, but discussions are ongoing with the Commission to evaluate if this date is premature and if a standard first needs to be developed.

PG&E agrees with SCE and SDG&E that this proposal is premature. Temporal control is not currently covered in the UL CRD. But this may be considered after the standards are in place and after the communication systems are in place and communicating with the appropriate PG&E grid control systems.

Proposal A-B #4. Consensus
For SCE customers only, beginning 6 months after the approval of the Advice Letter implementing the final decision on Working Group Three, customers applying for interconnection with a PCS must use a PCS already on the approved list. Interconnection application forms are to be updated with new required fields including control information and limited export setting.

SCE made this proposal, and parties agreed to it with the understanding that it would only apply to SCE customers, not to customers of other utilities.

Proponent position by CALSSA:

This proposal will allow utilities to have the certified control information available ahead of interconnection requests, which will significantly expedite the interconnection process.

Equivalent processes for the implementation of Smart Inverters though the usage of pre-approved lists (CEC-Inverter approved list) have allowed the utilities and DER applicants to have an efficient and cost-effective interconnection review process. Under those processes, the utilities include in their interconnection portals, the list of pre-approved systems which the customer can then select. When a pre-approved control system is selected, then the certification review as part of the application process is not necessary resulting an efficient overall interconnection process. SCE notes that the UL Power Control Systems CRD (UL CRD) testing procedures were approved March 2019 and thus by the time the final approval for Working Group Three is issued with the 6 months proposed, control manufactures would have had more than 12 months to certified their controls systems.

Utility position by SCE:

SCE believes that requiring customer to submit interconnection applications with pre-approved control systems will allow the utilities to maximize the efficiency in the interconnection portals in the interconnection application process. SCE also understands PCS control manufacturers may need time to certified equipment and thus the proposal allows up to six months after the final decision on Working Group Three for control manufactures to complete testing, certification and listing in the utility or relevant PCS control listing.

Issue D

When should the Commission consider results of an initial review or detailed study to be binding? Under what circumstances should the Commission allow the results to be changed?

PROPOSAL

The Working Group does not make any proposal for this issue.

BACKGROUND

CALSSA proposed this issue for consideration knowing that multiple customers had had the experience that a utility had told them after initial review that voltage rise studies indicated upgrades were not required, then after the customers installed systems the utility said voltage rise studies indicated upgrades were required. The same calculation was done twice with the same inputs and produced different results, causing customers to incur expenses that were contrary to the expectations they had been given. However, after the Working Group began discussing this issue, CALSSA learned that the utility in question had fixed the problem, harmonizing the calculation methodology between two different departments.

Utilities agree that as a general principle they should not change a determination of no mitigations being required unless new factors are considered or there is a material change to the application. Determinations can change between Supplemental Review and Detailed Study, but that is due to performing a more detailed analysis using additional inputs. In absence of any evidence of an ongoing problem CALSSA does not believe the Commission needs to take action at this time. There is no need to fix a problem that doesn't exist. CALSSA appreciates that the issue was resolved by the utility when it occurred and regrets causing an unnecessary discussion on the topic in the Working Group.

The Working Group also discussed the similar but different issue of binding cost estimates. However, this issue was considered extensively in R.11-09-011, with the result that the Commission created the Cost Envelope Option pilot program and the Enhanced Pre-Application Report in D.16-06-052. The Commission may need to consider another approach at some point, but with the pilot program still underway the Working Group recommends no action at this time.