**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF CALIFORNIA**

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| National Community Renaissance, A California nonprofit public benefit corporation,<br><br>Complainant,<br><br>v.<br><br>Southern California Edison Company (U338E), and San Diego Gas & Electric Company (U902E),<br><br>Defendant. | Case (C.) 25-09-011<br>(Filed September 11, 2025) |

# ANSWER OF DEFENDANT SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E)


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November 14, 2025

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Pursuant to Rules 1.11, 4.4 and 18.1 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure ("Rule"), defendant San Diego Gas & Electric Company ("SDG&E"), whose principal place of business is 8330 Century Park Court, San Diego, California 92123,[1] hereby files its answer in the above-captioned proceeding. Pursuant to Rules 1.8 (c) and (e), 1.11 and 4.4, the required verification follows this answer and has been signed electronically.

SDG&E received service of the complaint and Instructions to Answer on October 15, 2025, and returned the acknowledgement of receipt form to the Commission on October 16, 2025. Therefore, pursuant to Rules 1.15 (Computation of Time), 4.3 (Service of Complaints and Instructions to Answer), and 4.4 (Answers), this answer is timely.

[1] Rule 4.4 states that "Answers must include the … telephone number of defendant." Because defendant has numerous telephone numbers, defendant asks to use the work telephone number of its attorney (who is an employee of defendant) found on the cover and signature page of this answer.

## I. SUMMARY OF THE COMPLAINT

National Community Renaissance ("National CORE" or "Complainant")'s complaint alleges that SDG&E and Southern California Edison Company ("SCE") (collectively, "Defendants") violated Rule 21 and improperly delayed granting National CORE Permission to Operate ("PTO") solar photovoltaic ("PV") systems on its multi-unit residential developments. The complaint alleges that Defendants, generally, "won't [act] upon" National CORE's applications for PTO "for months, only [for the applications] to be rejected for issues as minor as typographical errors, only for the applications to again sit without action," and "even initially correct and complete applications face similar unexplained delays." It further alleges that "SDG&E in particular has refused to permit construction of a solar PV system at one project (The Iris at San Ysidro) until after COO [certificate of occupancy] issuance." (Complaint at F.)

The complaint attaches two charts—one relevant to SDG&E and one relevant to SCE—providing what National CORE purports to be "[d]etails of the National CORE projects and the associated delays." (Complaint at F.) The chart specific to SDG&E identifies four projects: two where the PTO was pending at the time of the complaint and two where the PTO has already been issued. Notably, the chart does not identify or include any details regarding The Iris at San Ysidro. There are also no factual allegations in the chart or body of the complaint specifying SDG&E's conduct that National CORE believes constituted violations of Rule 21 or improper delay in granting National CORE PTO.

National CORE further contends that its efforts "to informally address this problem with Defendants have failed" and that "[n]either of the Defendants will commit to dependable processing timeframes, nor to a consistent or transparent process to expedite PTO." (Complaint at F.) The complaint does not provide factual allegations detailing National CORE's efforts at informal resolution.

As relief, National CORE asks the Commission to (i) grant PTO for the identified projects where PTO has not been issued; (ii) order Defendants to disgorge the difference between what was paid to Defendants and what would have been paid had the PV systems been timely operating; (iii) order an accounting to and refunding to National CORE's present and former tenants all excess payments made; (iv) issue quasi-legislative relief to address Defendants' systemic failures to timely provide PTO to National CORE and all others similarly situated, including processing deadlines, requiring single points of contact and programmatic changes, and appointing a Commission staff person to oversee compliance; (v) order Defendants to cease and desist from refusing to permit solar PV systems to be constructed until after a COO is issued; and (v) order SDG&E to permit construction of the solar PV system at the Iris at San Ysidro project. (Complaint at H.)

SDG&E denies that Complainant is entitled to any relief. Pursuant to Rule 4.4, SDG&E addresses the complaint's specific allegations in Sections III and IV below.

## II. RULE 4.4 PROCEDURAL MATTERS

Pursuant to Rule 4.4, SDG&E <u>objects</u> to Complainant's request that the Commission schedule an in-person workshop and a public engagement workshop. (Complaint at (G)(5).) Such workshops are not necessary at this time because (1) SDG&E has held, as recently as September 30, 2025, workshops or interconnection discussion forums on Virtual Net Metering processes, timelines, and requirements—i.e., the specific issues raised by National CORE's complaint;[2] (2)

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[2] *See* Exhibit ("Ex.") A (2019 Workshop Invitation); the most recent interconnection discussion forum was held September 30, 2025, which was attended by at least one of National CORE's contractors for projects at-issue in the complaint, Sunrun. *Note, the Exhibits are bookmarked for convenience*.

the Commission recently concluded a rulemaking that addressed these issues and which resulted in IOU quarterly reporting requirements and a 95-100% goal for compliance with certain Rule 21 timelines and milestones;[3] and (3) SDG&E has consistently met the 95-100% compliance goal adopted in D.20-09-035. (*See*, e.g., Exs. C, D.) Further, on August 20, 2025, the Commission issued R.25-08-004, with the intent to consider refinements to the interconnection process under Rule 21. The purpose of the proceeding is in part, to update and improve Rule 21 and associated interconnection procedures. SDG&E suggests the Complainant become a party to this public proceeding. Involvement in Rule 21 issues should be undertaken through participation in a proceeding such as this.

For the same reasons, SDG&E also <u>objects</u> to and disagrees with Complainant's proposal that "[w]hether the Commission should issue quasi-legislative relief to address Defendants' systematic failures to timely provide PTO to National CORE and all others similarly situated" should be included in the issues to be considered in this proceeding. (Complaint at (G)(4).) Additionally, National CORE's complaint is not the proper vehicle for revisiting issues addressed in R.17-07-007 or seeking modifications to D.20-09-035.

The complaint does not allege that the matter has first been brought to Commission staff for informal resolution. *See* Rule 4.2(b). SDG&E has no objection to bringing the matter to staff under Rule 4.2(b).

SDG&E proposes the following procedure:

- **Category** – Adjudicatory, under Commission Rule 1.3(a).
- **Hearings –** SDG&E does not anticipate the need for hearings because SDG&E believes a decision may be rendered based on the documentary record and written testimony. However, in the event hearings are required, SDG&E provides the proposed schedule below.

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[3] *See* Rulemaking ("R.") 17-07-007, Decision ("D.") 20-09-035 (requiring reporting) and D.24-12-034 (closing rulemaking). For convenience, D.20-09-035 is provided herewith as Ex. B.

- **Proposed Schedule**
  - Prehearing Conference – January 12, 2026 (to permit time for parties to engage in informal dispute resolution).
  - Prehearing Conference Statement – served and filed January 7, 2026, five (5) days before the Prehearing Conference.
  - Hearings (if necessary) – February 26, 2026, 45 days after Prehearing Conference.

- **Issues for Commission Adjudication**

The legal and factual issues to be decided should be limited to whether the complaint's allegations are true, whether the allegations entitle Complainant to relief in the form of refunded payments proven by the Complainant to be "excess," and/or an order to issue PTO for certain projects.

## III. BACKGROUND

### A. Interconnection of Virtual Net Metering Multi-Family Projects

SDG&E has implemented a transparent, prescriptive process for interconnecting VNM/VNBT (Virtual Net Metering/Virtual Net Billing Tarriff) multi-family projects like those at issue in National CORE's complaint. This process, which has been in place for over a decade, is published on SDG&E's website in a comprehensive step-by-step guide to assist applicants in navigating the VNM/VNBT project process,[4] contained in a checklist made available to applicants (Ex. E), and communicated directly to customers and their contractors at the outset of the application process—including to National CORE and its contractors when they have engaged with the process (*see*, e.g., Ex. F). Since 2022, SDG&E has had a dedicated email for Virtual interconnections to ensure applicants would be connected with a Subject Matter Expert. As indicated above, SDG&E has also held workshops to assist contractors and customers

[4] NEM/NBT Documents, Processes & Guides, *available at* https://www.sdge.com/residential/savings-center/solar-power-renewable-energy/net-energy-metering/nem-documents

engaging with the process, and has pursued proactive discussions with developers, emphasizing the importance of involving a qualified solar contractor and SDG&E early in the project lifecycle. Key steps in the process include:

1. **Virtual Request Submittal** – Contractor submits a complete request via the Virtual Net Metering Application email or Distribution Interconnection Information System ("DIIS") **before construction**, including a **site map** (showing electric panel locations) and a **Single Line Diagram ("SLD")** per SDG&E Service Guide requirements.[5]

2. **Submittal Review** – SDG&E Advisor reviews for completeness. If approved, contractor receives an **Initial Site Meeting Outlook invite**. If deficiencies exist, contractor is notified and the **review lead time restarts**.

3. **Initial Joint Site Meeting** – Held to confirm Net Generation Output Meter ("NGOM") meter location**,** field conditions**,** installation requirements, and Customer Generation ("CG") address.

4. **CG Account Setup** – SDG&E emails the **Customer Generation account number** within **5–10 business days** after the site meeting.

5. **Application Submission** – Contractor uploads required documents to DIIS, including a completed **Allocation Form**; SDG&E forwards the Allocation form to **Billing** for **eligibility review**; **customer emails the application ID** to proceed.

6. **Initial Review** – Upon eligibility confirmation, DIIS advances the application. **Distribution Planning** checks transformer capacity and **Secondary Service Assessment** verifies service adequacy. **Required upgrades**, if needed, are identified here.

7. **Customer Documentation** – Once Initial Review passes, **Customer Generation** emails required documents (including required **Rule 2 Contract for Special Facilities (i.e., NGOM)** and **NGOM invoice**) and moves the application to **Pending Authority Having Jurisdiction ("AHJ")** status in DIIS.

8. **Issue Resolution –** Contractor addresses all **open Issues** in the DIIS *Issue* tab.

9. **Pending SDG&E Inspection** – Application auto-updates once **AHJ approval** for the PV system and NGOM metering gear is posted.

10. **Final Inspection Request** – Contractor emails SDG&E requesting **Final Inspection**, including the **Final NGOM Photo Packet** reflecting conformity with Service Standards Guide Section 807.

[5] SDG&E 2025 Service Standards & Guide, *available at* https://www.sdge.com/sites/default/files/SG2025v0221e.pdf

11. **Final Joint Site Meeting** – Scheduled after SDG&E Advisor confirms a complete submittal. Deficiencies must be corrected; once resubmitted, **review time resets**.

12. **Meter Set & PTO** – After **Final Inspection passes**, a **meter set** is scheduled and installed within the prescribed timeline of no more than 20 business days from the date of passing the final inspection. **Permission to Operate (PTO)** follows once the meter is installed and **all DIIS issues are closed**.

In addition to receiving direct communications from SDG&E throughout the process (including automatic and direct emails specifying any issues, errors or omissions that prevent the application from advancing), applicants may access DIIS 24 hours a day, seven days a week to check in on the progress of their applications. Importantly, contrary to Complainant's allegation, *COO is not relevant to or considered by SDG&E in this process*.

### B. SDG&E's Rule 21 Timeline Compliance

As noted in Section II above, D.20-09-035 requires SDG&E to submit quarterly Rule 21 Timeline Compliance Reporting to the Commission, reflecting compliance with standards set forth in the Tariff for the various steps in the interconnection process, from the applicant's initial request to the PTO issuance.[6] SDG&E has consistently met the 95-100% compliance goal for reportable milestones established by D.20-09-035. Indeed, the two compliance reports provided herewith as Exhibit C (2025 Q2_SDGE) and Exhibit D (SDGE Rule 21 Q2 2024), report milestone compliance for National CORE's Valley Senior Village and Nestor Senior Village

[6] Some of the reportable milestones and the timelines relevant here include:

- Application Submitted to Deemed Complete (10 business days)
- Deemed Complete to Provide Fast Track Initial Review Results (15 business days)
- Deemed Complete to Send NGOM Invoice (20 business days)
- NGOM request to NGOM completed (20 business days)
- From last issue resolved date to PTO (30 business days)

Note, there is no Tariff standard applicable to Total Time from Submission of Interconnection Request to PTO.

developments, respectively, and reflect that SDG&E met the Tariff standards for both projects. (*See* Ex. C, Tab "Approved All Timelines" at Row 29; Ex. D, Tab "Nestor Virtual AGG2" at Row 23.) Significantly, the number of days from when the last issue was resolved to the date SDG&E issued PTO for Valley Senior Village was two business days (Ex. C, Tab "Approved All Timelines" at Row 29, Column BH); for Nestor Senior Village, SDG&E issued PTO in seven business days (Ex. D, Tab "Nestor Virtual AGG2 at Row 23, Column AM)—both well before the Rule 21 Section D.12.b 30-business day requirement.[7]

While SDG&E has a solid track record for meeting Rule 21 timelines, there are numerous ways in which the process can be delayed for reasons outside SDG&E's control. As is pertinent here, delays frequently are caused by applicants veering from the established process. Common challenges relevant to Complainant's projects include (i) submittal of incomplete or incorrect information with respect to the initial Virtual request or the Allocation Form; (ii) premature system construction prior to the necessary approvals, which does not conform to SDG&E standards; (iii) premature requests for SDG&E final inspections, without first checking project status via DIIS; (iv) incomplete photo documentation for final SDG&E inspections, often revealing non-compliant installations that require extensive follow-up; (v) unapproved changes to pre-approved equipment locations, which can invalidate prior reviews; (vi) incorrect placarding and system sizing calculations, resulting in compliance issues; and (vii) delays on the

[7] Rule 21 Section D.13.b states: For NEM-1, NEM-2 and NBT Generating Facilities with a capacity equal to or less than 1 MW , Distribution Provider approval for Interconnection (i.e., Permission to Operate) shall normally be processed not later than thirty (30) Business Days following Distribution Provider's receipt of 1) a completed NEM/NBT Interconnection Request including all supporting documents and required payments; 2) a completed signed NEM/NBT Generator Interconnection Agreement; and 3) evidence of Applicant's final electric inspection clearance from the Governmental Authority having jurisdiction over the Generating Facility. *See* Rule 21, a*vailable at* https://www.sdge.com/sites/default/files/elec_elec-rules_erule21.pdf

part of the contractor or customer to submit information or to remedy identified issues. SDG&E's records reflect that many of these common challenges were factors causing delays in the National CORE projects identified in the complaint.

### C. National CORE Projects Relevant to SDG&E

National CORE alleges no facts supporting its position that SDG&E somehow improperly delayed granting PTO for its projects—likely because it cannot. DIIS records and communications between SDG&E and Complainant indicate that National CORE's allegations are without merit. SDG&E also has no record of National CORE reaching out to communicate with SDG&E that it believed there were actionable delays associated with any of these projects or to initiate dispute resolution mechanisms in Rule 21 (e.g., Section K). What the application record shows for each National CORE project identified in the complaint and relevant to SDG&E is discussed in turn below.

1. Vista Santa Fe / Santa Fe Senior Village[8]

As Complainant's chart indicates, PTO has not been issued for this project; by its complaint, National CORE asks the Commission to order SDG&E to grant PTO. However, National CORE admits on the chart (and SDG&E's records confirm) that National CORE (or its contractor) has *not* submitted an initial application, and that the project is "still awaiting initial site walk w/SDGE." To state the obvious, absent an initial application, PTO cannot issue.

SDG&E's records show that on January 17, 2025, an SDG&E Customer Generation Advisor responded to the contractor's January 8, 2025 Initial Site Walk request, and advised the contractor to make corrections to the SLD to ensure it met SDG&E Service and Standards Guide

[8] We note that there is nothing in SDG&E's file for this project establishing that National CORE is associated with it. The only identified contact in the file is Richard Thompson at Sunrun.

section 806.7. (Ex. G.) The contractor submitted revisions almost four months later, on April 10, 2025. On May 29, 2025, following review from the Standards department, SDG&E notified the contractor there were additional issues with the proposed Point of Interconnection. (Ex. G.) Since that date, SDG&E has not received any further communication from the contractor or from Complainant. Given the status of this application, there is no basis for the Commission to grant National CORE's request to order SDG&E to issue PTO for this project.

2. Greenbrier

As Complainant's chart notes, PTO has not issued for this project; National CORE asks the Commission to order SDG&E to grant PTO. Complainant's chart indicates that the initial application was submitted September 23, 2024. It further contends that SDG&E's interconnection approval is required for this project *before* the City (i.e., AHJ) can conduct its inspection. This is incorrect. (*See* Rule 21 D.13.b). Instead, as described in Section III.A., above, the AHJ must *first* conduct its inspection upon request of the developer and then the AHJ must release the project for "New Service" to SDG&E via the DIIS portal or direct to an SDG&E dedicated department. SDG&E records the AHJ releases, which then automatically advances the application in the pipeline to a status of "Pending SDG&E inspection." (*See*, e.g., Ex. H.) SDG&E simply cannot issue PTO for this project without AHJ sign-off.

In addition to the absence of AHJ releases, records reflect that since the initial application submission, the process was delayed by multiple application deficiencies requiring several resubmissions, including (among others):

- The contractor uploaded the wrong SLD (Ex. I)
- Poor quality of SLD made details of the project illegible (Ex. J)
- Customer failed to sign Prevailing Wage Document (Ex. I)
- Generator meters and address were incorrect or omitted from the Allocation Form again and again (Ex. I, 10/4/2024 email; Ex. K, 5/5/2025 email; Ex. L, 2/26/2025 email)

Specifically, issues with the Allocation Form caused significant delays. For example, SDG&E notified the customer/contractor on February 26, 2025 that the Allocation Form was required (Ex. M). When it was finally submitted on April 3, 2025, the form was deficient due to omitted benefitting accounts. (Exs. K, L.) SDG&E did not receive a complete and correct Allocation Form until June 30, 2025—over three months after SDG&E initially requested it. (Ex. N.)

Likewise, on June 23, 2025, SDG&E notified the customer/contractor of several outstanding requirements, including NGOM Payment, NBT Virtual Interconnection Agreement, Bus Tap Drawings, and CG Meter Release. (Ex. N.) The customer/client did not submit the Bus Tap Drawings until October 15, 2025 (nearly 3 ½ months later) (Ex. X), and as of this Answer, SDG&E still has not received NGOM payment.

As of July 23, 2025, the status of the Greenbrier project is "Pending AHJ Inspection." (Ex. H.) Upon receipt of the AHJ release and final issue resolution, SDG&E will conduct a final field inspection. Until that time, PTO cannot issue and an order requiring PTO before AHJ release would be improper.

3. Valley Senior Village

PTO has issued for this project. Complainant's chart indicates that the initial application was submitted April 4, 2023, and PTO issued May 30, 2025, and notes that this reflects an 11-month, 12-day application-to-issuance time frame.

First, as noted above in footnote 6, there is no Tariff standard or compliance milestone applicable to total time from submission of interconnection request to PTO; the 30-day clock to issue PTO starts after a complete and correct NGOM packet has been submitted and all issues have been resolved. In this case, the last customer issue was not resolved until May 28, 2025, and PTO issued *two days later*. (*See* Ex. C, Tab "Approved All Timelines" at Row 29, Column BH.)[9]

Second, it is disingenuous for Complainant to represent that any clock started on April 4, 2023. Complainant submitted an application on this date as a placeholder to meet the April 13, 2023 NEM-ST sunset date.[10] SDG&E confirmed on May 31, 2023 that the meter was set, but the contractor did not request an initial site visit until November 1, 2023--five months later. (Ex. Y.) Moreover, when the initial site inspection did occur on January 4, 2024, the NGOM and disconnects were already installed and did not meet SDG&E standards. (Ex. O.) The contractor was still correcting installation issues in February 2025, over a year after the site inspection. (Ex. P.[11]) SDG&E also notified the contractor early in the process that the required Allocation Form was missing. SDG&E sent a second request for the Allocation Form on June 20, 2024. (Ex. Q.) The contractor finally submitted the Allocation form on August 8, 2024, *eight months* after SDG&E first requested it. (Ex. R.) Likewise, when the contractor submitted the NGOM photo packet (Ex. S[12]), it required five rounds of corrections, which is atypical for any applicant.

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[9] SDG&E met every other reportable timeline for this project, as well: Application Review, same day turnaround; Fast Tack Initial Review, four business days; NGOM, 11 business days to invoice, eight days to install. (Ex. C, Tab "Approved All Timelines" at Row 29.)

[10] The sunsetting of the NEM-ST tariff and commencement of the new billing tariff (NBT) on April 15, 2023 drove contractors and self-installers to submit "placeholder" applications. SDG&E received over 70k applications within the first 100 days of 2023. In the decision enacting NBT, applications received before midnight on April 14, 2023 were granted a three-year period to complete their project (by April 14, 2026) to take service on NEM-ST. The volume of applications submitted in advance of the sunset date caused some delays in SDG&E's review process, which were communicated to applicants at the time.

[11] Exhibit P is a partial document due to file corruption issues.

[12] Exhibit S is a partial document to due file corruption issues.

This project suffered from multiple delays that were completely outside of SDG&E's control. The facts do not support any relief to Complainant related to this project, disgorgement of "excess payments" or otherwise.

4. Nestor Senior Village

PTO has issued for this project. As Complainant's chart reflects, the initial application was submitted November 15, 2023, the City inspected the project on December 21, 2023, and SDG&E issued PTO June 25, 2024. Here, again, delays leading to PTO were primarily due to actions outside of SDG&E's control.

For example, the contractor initially submitted a deficient Allocation Form and was notified on December 19, 2023 (Ex. T); a complete and correct form was not submitted until March 8, 2024—3½ months after SDG&E first requested it (Exs. U, V). Then NGOM was delayed twice due to incorrect wiring and safe access issues. (*See*, e.g., Ex. W, May 21, 2024 email.) The customer or contractor finally resolved the NGOM issues on June 18, 2024,[13] and PTO was granted *one week later*.

SDG&E met every milestone timeline standard for Nestor Senior Village during the PTO process (*see* Ex. D, Tab "Nestor Virtual AGG2" at Row 23), and because any significant delay was due to issues beyond SDG&E's control, the facts to not support any relief to Complainant related to this project.

[13] The June 18, 2024 resolution date is reflected within the DIIS application portal, a screenshot of which is copied below:

| | | | | |
|---|---|---|---|---|
| CG Meter Requested/Set | RMatana | Apr 17, 2024 | Jun 18, 2024 | orders 11901912 & 11570135 for 5/27/24 |

5. The Iris at San Ysidro

This project is not identified on the chart, and the complaint provides no factual details about it, other than to allege that SDG&E is refusing to permit construction until after the COO is issued. (Complaint at H.) As stated in Section III.A. above, COO is irrelevant and it is not SDG&E's practice to consider it in any way during the PTO process.

Based on a search of SDG&E's records, SDG&E believes The Iris at San Ysidro to be a project located at 1663 Dairy Mart Road, San Diego. The initial site inspection took place on October 28, 2025 (after National CORE filed its complaint), and SDG&E instructed the customer/contractor to complete an application. (Ex. Z.) SDG&E created a CG account number and transmitted it to the contractor on November 4, 2025, (*Id*.), and SDG&E received the project application on November 13, 2025. By SDG&E's records, the project appears to be progressing through the application process, and there is no basis for granting any form of relief to Complainant in connection with this project.

## IV. ANSWER

### A. Answer to Material Allegations

SDG&E answers each material allegation of the complaint as follows, and based upon information and belief, denies each and every factual allegation set forth in the complaint except as expressly admitted below. The italicized references below are quotes from the complaint, Section F.

*1. National Community Renaissance ("National CORE") is a leading nonprofit affordable housing developer, having developed over 10,000 units housing 30,000 residents of modest means throughout the states of California, Texas, and Florida. National CORE has been recognized for its work by the Southern California of Governments, the U.S. Green Building Council, and the National Association of Housing and Redevelopment Officials.*

Answer: SDG&E lacks sufficient information to admit or deny the allegation that "National Community Renaissance ("National CORE") is a leading nonprofit affordable housing developer, having developed over 10,000 units housing 30,000 residents of modest means throughout the states of California, Texas, and Florida." SDG&E also lacks sufficient information to admit or deny that "National CORE has been recognized for its work by the Southern California of Governments, the U.S. Green Building Council, and the National Association of Housing and Redevelopment Officials."

*2. Pursuant to 24 CCR 10-101 et seq., National CORE is required to install large solar photovoltaic ("PV") systems at all of its residential developments, with capacities in excess of 100kW.*

Answer: SDG&E denies this allegation on the basis it constitutes a legal conclusion of law to which no response is required.

*3. These systems impose serious upfront financial burdens on National CORE, in excess of $50,000 per system. The value proposition of such systems is they can offset most or all of a project's electricity needs, in theory eventually offsetting the significant up-front costs. That promised offset has significant ramifications for project economics; if it does not eventuate, the cost of long-term financing (which is based on first-year revenues and utility costs) significantly increases, often by millions of dollars. That in turn obstructs National CORE's ability to effectively deliver much-needed affordable housing in the face of California's affordable housing crisis. It also directly impacts National CORE's residents, who each receive that much larger utility bill; the resulting damages are regressive, given those residents' modest means.*

Answer: SDG&E lacks sufficient information to admit or deny these allegations, except SDG&E admits that, generally, larger utility bills may specifically "impact" residents with "modest means."

*4. As the Commission knows, solar PV systems cannot generate a single watt unless and until the relevant utility provider grants permission-to-operate ("PTO") pursuant to Electric Rule 21. Until PTO is granted, the system serves as nothing but a roof shade, neither benefiting the project, nor its residents, nor the grid.*

Answer: SDG&E admits that "solar PV systems" like those at-issue in National CORE's complaint cannot begin to generate "until the relevant utility provider grants permission-to-operate ('PTO') pursuant to Rule 21." SDG&E lacks sufficient information to admit or deny whether, for any one system, "[u]ntil PTO is granted, the system serves as nothing but a roof shade, neither benefitting the project, nor its residents, nor the grid."

*5. National CORE and the building industry as a whole face systemic delays in obtaining PTO from each of the Defendants. Projects consistently languish without PTO for months (and sometimes over a year) after the issuance of certificates of occupancy ("COO") from the local approving agency.*

Answer: SDG&E lacks sufficient information to admit or deny these allegations as they pertain to co-defendant, SCE. SDG&E denies that "National CORE and the building industry as a whole face systemic delays in obtaining PTO from" SDG&E. SDG&E lacks sufficient information to admit or deny that "[p]rojects consistently languish without PTO for months (and sometimes over a year) after issuance of certificates of occupancy ("COO") from the local approving agency"; to the extent Complainant establishes facts proving this allegation, SDG&E denies that it is the result of SDG&E's conduct.

SDG&E further contends that the complaint is deficient in that it alleges no facts specific to either Defendant, notifying Defendants of the particular conduct Complainant alleges is actionable or violates any rule, decision, order, statute, or regulation. The complaint should be amended to address this defect.

*6. PTO applications won't be acted upon for months, only to be rejected for issues as minor as typographical errors, only for the corrected applications to again sit without action. Even initially correct and complete applications face similar unexplained delays.*

<u>Answer</u>: SDG&E lacks sufficient information to admit or deny these allegations as they pertain to co-defendant, SCE. SDG&E denies that "PTO applications won't be acted upon for months, only to be rejected for issues as minor as typographical errors, only for the corrected applications to again sit without action" due to any conduct on the part of SDG&E. SDG&E denies that "initially correct and complete applications face similar unexplained delays," due to SDG&E's conduct.

SDG&E further contends that the complaint is deficient in that it alleges no facts specific to either Defendant, notifying Defendants of the particular conduct Complainant alleges is actionable or violates any rule, decision, order, statute, or regulation. The complaint should be amended to address this defect.

*7. Even more devastating, SDG&E in particular has refused to permit construction of a solar PV system at one project (The Iris at San Ysidro) until after the COO issuance, further compounding these delays and their associated damages.*

<u>Answer</u>: SDG&E denies that it "has refused to permit construction at [The Iris of San Ysidro] until after COO issuance"; COO issuance is irrelevant to SDG&E's process and

timelines for granting PTOs for Virtual Net Metering projects. SDG&E further denies that its conduct "compound[ed] these delays and their associated damages."

SDG&E further contends that the complaint is deficient in that it does not provide any details about this project to permit SDG&E to identify it in its records, or make any factual allegations to put SDG&E on notice of the particular conduct Complainant alleges is actionable or violates any rule, decision, order, statute, or regulation. The complaint should be amended to address these defects.

*8. Details of the National CORE projects and the associated delays are contained in the spreadsheet in Attachment 1.*

Answer: SDG&E lacks sufficient information to admit or deny this allegation as it pertains to co-defendant, SCE. To the extent that this allegation implies that SDG&E's conduct caused actionable delays for any National CORE project contained on the chart, SDG&E denies the allegation. SDG&E repeats and realleges the allegations made in Section III as if set forth fully herein.

SDG&E further contends that the complaint is defective in that the Attachment 1 charts purporting to allege "details of the National CORE projects and the associated delays" are uncertain, vague, and unintelligible in that they contain no facts notifying Defendants of the particular delays at issue, the conduct Complainant alleges caused delays, or of conduct Complainant believes is actionable or violates any rule, decision, order, statute, or regulation. The complaint is further defective in that the chart specific to SDG&E does not include the Iris at San Ysidro project. The complaint should be amended to address these defects.

*9. Efforts by members of the industry and National CORE specifically to informally address this problem with Defendants have failed.*

Answer: SDG&E lacks sufficient information to admit or deny these allegations as they pertain to co-defendant, SCE. SDG&E denies that "[e]fforts by members of the industry and National CORE specifically to informally address this problem with Defendants have failed" on the basis that SDG&E has no record of National CORE initiating or seeking to engage in informal dispute resolution pursuant to Rule 21 Section K or otherwise.

SDG&E further contends the Complaint is deficient in that it fails to allege any specific facts identifying any efforts made by "the industry" or "National CORE" "to informally address" issues or supporting that the purported efforts failed.

*10. Neither of the Defendants will commit to dependable processing timeframes, nor to a consistent or transparent process to expedite PTO. This is not surprising, given Defendants have no incentive to expedite PTO, as they can continue to charge their full rates in the meantime.*

Answer: SDG&E lacks sufficient information to admit or deny these allegations as they pertain to co-defendant, SCE. SDG&E denies that it "will [not] commit to dependable processing timelines nor to a consistent or transparent process to expedite PTO," for the reasons set forth in Section III, above. SDG&E repeats and realleges the allegations made in Section III as if set forth fully herein. SDG&E also denies that it "ha[s] no incentive to expedite PTO, as [it] can continue to charge [its] full rates in the meantime." SDG&E is bound and committed to dependable timeframes by Rule 21, D.20-09-035 and Commission oversight, and has consistently met the prescribed timelines. Likewise, SDG&E's process and requirements for obtaining PTO is transparent in that it is communicated directly to applicants when they initiate the interconnection application process, published on SDG&E's website, and reinforced and clarified in stakeholder workshops held by SDG&E.

### B. Response to Prayer for Relief

Defendant specifically denies that complainant is entitled to the relief sought, or any relief at all. It is well-established in Commission complaint proceedings that the complainant has the burden of proof.[14] California Public Utilities Code, Section 1702, requires that the complaint specifically "set forth any action or thing done or omitted to be done by any public utility, including any rule or charge heretofore established or fixed by or for any public utility, in violation or claimed to be in violation, of any provision of law or of any order or rule of the commission." As set forth above, National CORE has not met its burden here.

SDG&E denies the allegations in the prayer for relief, and affirmatively alleges (1) that the complaint fails to state a claim upon which relief can be granted,[15] (2) SDG&E has complied with its obligations and met the timelines applicable to granting PTO for the projects identified in the complaint, and (3) the quasi-legislative relief sought by the complaint is unnecessary and improper. Therefore, SDG&E submits that the complaint is without merit and requests that it be dismissed, and that all relief sought therein be denied.

## V. AFFIRMATIVE DEFENSES

**First Affirmative Defense**

The complaint does not state facts sufficient to constitute a cause of action.

**Second Affirmative Defense**

The complaint is uncertain and ambiguous. [16]

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[14] D.92-03-041, 1992 Cal. PUC LEXIS 288 at *6. SDG&E has provided a copy of this decision herewith as Exhibit AA for convenient reference.

[15] *See* Federal Rule of Civil Procedure Section 12(b)(6) and Code of Civil Procedure ("CCP") Section 430.10(e).

[16] *See* CCP Section 430.10(f), ("The pleading is uncertain. As used in this subdivision, 'uncertain' includes ambiguous and unintelligible.").

**Third Affirmative Defense**

The actions of SDG&E were, are, and continue to be consistent with the law.

**Fourth Affirmative Defense**

The complaint is not ripe for Commission adjudication, because Complainant failed to invoke informal resolution pursuant to Rule 21 Section K or otherwise.

**Fifth Affirmative Defense**

Complainant has committed laches.

**Sixth Affirmative Defense**

Complainant comes before the Commission with unclean hands.

**Seventh Affirmative Defense**

SDG&E has not knowingly or intentionally waived any applicable affirmative defenses, and reserves the right to assert and rely on such other applicable affirmative defenses as may become available or apparent during the course of this proceeding.

**WHEREFORE,** Defendant respectfully requests that the complaint in the above-captioned proceeding be dismissed.

Dated in San Diego, California, this 14 day of November 2025.

Respectfully submitted,

/s/ Krista S. deBoer

Krista S. deBoer
8330 Century Park Court, CP32D
San Diego, CA 92123-1530
Telephone: (858) 253-2104
E-Mail: kdeboer@sdge.com

Attorney for:
SAN DIEGO GAS & ELECTRIC COMPANY

**VERIFICATION**

I, Will Speer, declare the following:

I am an officer of San Diego Gas & Electric Company and am authorized to make this Verification on its behalf. I am informed and believe that the matters stated in the foregoing ANSWER OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) - Case (C.) 25-09-011 are true to my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 14th day of November 2025, at San Diego, California.

Will Speer

Will Speer
V.P. Electric Engineering & Construction

SAN DIEGO GAS & ELECTRIC COMPANY

# Exhibit A

**Ken Parks**
Customer Generation, Manager

San Diego Gas & Electric
8316 Century Park Court
CP52F
San Diego, CA 92123

Tel: (858) 636.5581
Fax: (619) 819.4448
Mobile: (858) 583.9429
kparks@semprautilities.com

April 19, 2019

San Diego Gas & Electric (SDG&E) invites you and your team to participate in an interactive and informative discussion on the requirements for Virtual Net Energy Metering (VNM), Net Energy Metering Aggregation (NEM-AGG) and Solar on Multifamily Affordable Housing (SOMAH) interconnection application process. The primary purpose for the discussion will be to provide an opportunity for solar installers to become familiar with the process of interconnecting their renewable generation system(s) under these 3 program types.

**WHEN:** **May 6, 2019, 8:30 a.m. – 10:30 a.m.**

**WHERE:** **SDG&E's Energy Innovation Center**
**4760 Clairemont Mesa Blvd.**
**San Diego, CA 92117**

**AGENDA:**

| | |
|---|---|
| **8:30 a.m. – 9:00 a.m.** | **Continental Breakfast and Meet & Greet** |
| **9:00 a.m. – 9:15 a.m.** | **Safety Message and Introduction of SDG&E Team** |
| **9:15 a.m. – 10:00 a.m.** | **VNM, NEM-AGG and SOMAH presentation** |
| **10:00 a.m. – 10:20 a.m.** | **Review of the FastTrack process** |
| **10:20 a.m. – 10:30 a.m.** | **Closing Remarks** |

We are asking that you send at least one representative from your organization to this very important event. Please RSVP by May 1st, with a list of attendees to Kelvin Ellis at kellis@semprautilities.com.

**Ken Parks**
San Diego Gas & Electric
Customer Generation Manager
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Cell: (858) 583-9429
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https://www.sdge.com/customer-privacy

# Exhibit B

COM/MGA/avs **Date of Issuance 9/30/2020**

Decision 20-09-035 September 24, 2020

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

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

# DECISION ADOPTING RECOMMENDATIONS FROM WORKING GROUPS TWO, THREE, AND SUBGROUP

## TABLE OF CONTENTS

# DECISION ADOPTING RECOMMENDATIONS FROM WORKING GROUPS TWO, THREE, AND SUBGROUP

## Summary

This decision modifies Electric Tariff Rule 21 of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities), which governs the interconnection of distributed energy resources. Our primary objective in adopting the modifications is to streamline the interconnection process by incorporating the Integration Capacity Analysis results from Rulemaking 14-08-013, the Distribution Resources Plans proceeding. Other objectives include improving efficiency, transparency, certainty, and clarity. The adopted changes emanate from recommendations contained in three reports: Working Group Two Report, Working Group Three Report, and Vehicle-to-Grid Alternating Current Subgroup. Utilities are directed to implement these changes as described in the Ordering Paragraphs of this decision.

The October 2, 2017 *Scoping Memo of Assigned Commissioner and Administrative Law Judge* contemplated a second phase of this proceeding to address cost allocation issues. This decision directs Utilities to develop testimony, related to costs and cost allocation of certain proposals from the working group reports, and serve the testimony in phase two of this proceeding. Final consideration of these proposals will be addressed in a future decision.

Rulemaking 17-07-007 remains open to address other streamlining issues in Working Group 4, as well as the cost-related and small multi-jurisdictional utilities phases of this proceeding.

## 1. Procedural Background

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

The October 2, 2017 *Scoping Memo of Assigned Commissioner and Administrative Law Judge* (Scoping Memo) set forth the scope and schedule of the proceeding. The proceeding will be conducted in three phases that will address technical issues, cost-related issues, and issues related to small multi-jurisdictional utilities. The Scoping Memo established the working group process, whereby resolution of the technical issues of the proceeding (*see* Section 2 below) would be proposed by six working groups, Working Groups One through Six. In addition, four issues were assigned to the Smart Inverter Working Group, including issues 5 and 6.[2] Decision (D.) 19-03-013 adopted certain recommendations made by Working Group One. This decision solely addresses the recommendations of Working Groups Two and Three and the Vehicle-to-Grid Alternating Current Interconnection Subgroup (V2G AC Subgroup), as described further below.

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

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

A February 14, 2018 Ruling directed that Working Group Two would commence on March 15, 2018 and subsequently file its recommendations report on September 15, 2018. The Ruling also reassigned Issue 6 to Working Group Two. On August 15, 2018, the Administrative Law Judge issued a Ruling allowing additional time for Working Group Two to resolve issues, including subissues encountered, and delaying the filing of the recommendations report to October 31, 2018. The Administrative Law Judge facilitated a workshop on November 7, 2018 to discuss the recommendations provided in the October 31, 2018 report.

On November 16, 2018, the assigned Commissioner issued an Assigned Commissioner's Amended Scoping Memo and Joint Administrative Law Judge Ruling (Amended Scoping Memo) delaying the commencement of Working Group Three to December 1, 2018 and requiring Working Group Three to file its recommendations report on June 14, 2019. The Amended Scoping Memo also decreased the number of working groups and redistributed issues across two working groups and the Interconnection Discussion Forum[3] such that Working Group Three was assigned issues 12, 15, 16, 20, 22, 23, 24, 27 28, and New Issues A and B (*see* Section 2 below for a description of the issues.)

In response to the November 7, 2018 workshop on the Working Group Two Report, a December 7, 2018 Ruling directed parties to respond to questions on the report. Responses to the questions, along with comments on the Working Group Report, were filed by the following parties on February 1, 2019: California Energy Storage Alliance (CESA); California Solar & Storage Association (CALSSA); Clean Coalition; Green Power Institute; Interstate Renewable Energy Council, Inc. (IREC); PG&E; Public Advocates Office of the Public Utilities Commission (Public Advocates Office);

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

SDG&E; Small Business Utility Advocates (SBUA); SCE; Tesla, Inc. (Tesla); and The Utility Reform Network (TURN). Replies were filed by the following parties on February 22, 2019: CESA; CALSSA; Clean Coalition; Green Power Institute; Interstate Renewable Energy Council, Inc.; PG&E; SDG&E; SCE; and Tesla.

Working Group Three filed its report on June 14, 2019, which was followed by a staff-facilitated workshop on June 19, 2019.

An August 23, 2019 Ruling issued in this proceeding and in R.18-12-006 (the Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification) established the V2G AC Subgroup with meetings to begin on September 11, 2019. The purpose of this subgroup is to discuss and identify existing standards to fulfill safety requirements for the interconnection of mobile inverters. (The specific issues of the subgroup are described in Section 3 below.) The ruling directed a final recommendations report from the subgroup to be filed on December 6, 2019 with a workshop on the subgroup report to be held on December 17, 2019.

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

On January 6, 2020, the following parties filed comments to the December 6, 2019 V2G AC subgroup report: CESA; Green Power Institute; SDG&E with PG&E; SCE; and Vehicle-Grid Integration Council.

On January 13, 2020, the following parties filed replies to the comments on the V2G AC subgroup report: SDG&E with PG&E; SCE; and Vehicle-Grid Integration Council.

On January 13, 2020, the following parties filed responses to the questions contained in the November 27, 2019 ruling, along with comments to the Working Group Three Report: CESA; CALSSA; Clean Coalition; IREC; PG&E; Public Advocates Office; SBUA; SCE; and Tesla.

On January 27, 2020, the following parties filed replies to the January 13, 2020 responses and Working Group Three Report comments: CALSSA; Clean Coalition; IREC; PG&E; Public Advocates Office; SCE; Tesla; and TURN.

This decision resolves the set of issues assigned to Working Groups Two and Three, as described in Section 3 below, as well as the issues assigned to the V2G AC Subgroup, also described in Section 3 below.

R.17-07-007 remains open to address the issues assigned to Working Group Four, as well as the issues in two future phases of the proceeding.

## 2. Brief Overview of Rule 21

Electric Rule 21 is a tariff that describes the interconnection, operating and metering requirements for generation facilities to be connected to a utility's distribution system. Rule 21 provides customers wanting to install generating or storage facilities on their premises with access to the electric grid while protecting the safety and reliability of the distribution and transmission systems at the local and system levels.[4]

Rule 21 governs Commission-jurisdictional interconnections, which include the interconnection of all net energy metering facilities, "Non-Export" facilities, and qualifying facilities intending to sell power at avoided cost to the host utility. Rule 21 does not apply to the interconnection of generating or storage facilities intending to participate in wholesale markets overseen by the Federal Energy Regulatory Commission (FERC). These facilities must typically apply for interconnection under the FERC-jurisdictional Wholesale Distribution Access Tariff (when connecting to the distribution system) or the California Independent System Operator (CAISO) Tariff (when connecting to the transmission system).

Rule 21 contains provisions governing the multiple aspects of interconnection, including:

- Procedures and timeframes for reviewing applications;

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[4] Commission website: https://www.cpuc.ca.gov/Rule21/

- Fee schedules to process applications and perform impact studies;
- Pro forma application and agreement forms;
- Allocation of interconnection costs;
- Provisions specific to net energy metered facilities;
- Technical operating parameters;
- Certification and testing criteria;
- Technical requirements for inverters;
- Metering and monitoring requirements; and
- Procedures for dispute resolution.

## 3. Issues Before the Commission

Listed below are the issues assigned to Working Groups Two and Three, and the V2G AC Subgroup. The numbering below corresponds to the issues as listed in the Scoping Memo for Working Group Two, as provided in the Amended Scoping Memo for Working Group Three, and as described in the August 23, 2019 Ruling for the V2G AC Subgroup.

### 3.1. Working Group Two Issues: Integration Capacity Analysis and Streamlining Interconnection

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

Issue 8. How should the Commission incorporate the results of the Integration Capacity Analysis into Rule 21 to inform interconnection siting decisions, streamline the Fast Track process[5] for projects that are proposed below the integration capacity at a particular point on the system, and facilitate interconnection process automation?

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

Issue 10. How can the Commission coordinate the Integration Capacity Analysis and each Utility's Rule 21 processes with the Rule 2, Rule 15, and Rule 16 processes in order to improve efficiency of the overall interconnection process? This is a coordination issue at this time. However, modifications to Rules 2, 15, or 16 will be addressed if necessary.

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

[5] Allowing for a quick review of certain project without the Detailed Study, the Fast Track process has an Initial Review and, if necessary, a Supplemental Review. *See* Working Group Two Report at 44.

### 3.2. Working Group Three Issues: Timelines, Billing, Construction Upgrades, Cross-jurisdictional Coordination, Application Portals, Electric Vehicle Interconnection, Smart Inverters, and Other Technology Issues

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 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 (FERC)–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 wanting to transfer between the Rule 21 and WDAT queues, and streamlining of the transfer process?

Issue 22. Should the Commission require 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?

### 3.3. V2G AC Subgroup Issues: Process for Monitoring Development of Standards for Interconnection of Mobile Inverters

Issue 1. The V2G AC Subgroup shall: a) complete the mapping of existing standards from nationally-recognized testing laboratories against each other and b) determine how well the existing standards can be combined to fulfill safety requirements for interconnection of a mobile inverter at one fixed point.

Issue 2. If existing standards are sufficient for safe interconnection, the subgroup may recommend that the Commission include language citing existing standards to enable Rule 21 interconnection.

Issue 3. If existing standards are not sufficient, the subgroup should notify the testing laboratories to inform them of the gap in standards.

## 4. Working Group Two Adopted Recommendations

In this section, we describe each of the Working Group Two Issues, the proposals to resolve the issues and positions of parties, and the resolution of the issues. In most instances, the Commission can choose to adopt none or all of the proposals for each issue. However, in limited cases, adoption of one proposal is dependent upon adoption of other proposals.

### 4.1. Issue 6: Forms and Agreements to Allow Distributed Energy Resources Aggregators to Fulfill Rule 21 Requirements Related to Smart Inverters

As described below, the issue of whether to develop forms and agreements to enable distributed energy resources aggregators to fulfill Rule 21 smart inverter requirements has been addressed by the adoption of Resolution E-5000. In E-5000, the Commission found that language in SDG&E's Rule 21 is inconsistent with the Commission's intended implementation of the Phase 2 communications requirements. Resolution E-5000 directed Utilities to eliminate this language from Rule 21. Accordingly, Resolution E-5000 renders this issue moot, at this time.

#### 4.1.1. Issue 6: Background

In Issue 6, the working group reviewed Rule 21 requirements regarding smart inverter generating facility design and operating requirements, as well as the definition and role of an aggregator. Rule 21 describes an aggregator as one intended to perform a role that would otherwise be performed by individual generating facilities and one who acts as a conduit sending commands from the distribution provider to a generating facility and sending information from a generating facility to the distribution provider.[6] Other related requirements of Rule 21 include: 1) inverter function requirements that must be performed in response to communications made by the distribution provider[7] and 2) information communication requirements between an inverter-based generating facility and a distribution provider.[8] As described in the Working Group Two Report, the group focused on: a) improving the group's understanding of the communication functions an Aggregator provides; b) defining the technical and legal qualifications needed to provide those functions; and c) developing an agreement to represent the defined qualifications.

#### 4.1.2. Issue 6: Proposal

The Working Group Two Report provided a draft *Distributed Energy Resources Aggregation Agreement* but underscored that the draft agreement "is recognized as incomplete and in development by the Working Group, but nevertheless can serve as a basis for continued consideration of Issue 6."[9] Participants agree that an application form and supporting documentation standards will also need to be developed.

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[6] Rule 21 Section Hh.5.

[7] Rule 21 Section Hh.6 and Hh.8.

[8] Rule 21 Section Hh.7

[9] Working Group Two Report at 9.

#### 4.1.3. Resolving Issue 6

The Working Group Two Report provided three perspectives for moving forward: those posed by Utilities, Tesla, and Stem. However, as described below, the Commission's determination of a petition for modification of Resolutions E-4832 and E-4898, and the subsequent adoption of Resolution E-5000, render this issue moot.

CALSSA filed a petition for modification of Resolution E-4832 and E-4898 requesting the Commission clarify and modify the smart inverter Phase 2 and 3 requirements. Relevant to the instant decision, the CALSSA petition argued that compatibility testing should satisfy smart inverter Phase 2 requirements without the need for active aggregator agreements discussed in Issue 6 of this proceeding.[10] Resolution E-5000 found that the communications capabilities mandated by the Phase 2 communications requirements must be limited to technical capabilities and the establishment of contracts clearly constitutes a legal issue. The resolution concluded that the establishment of contracts may not be considered a prerequisite for the adoption of Phase 2 recommendations. The resolution also concluded that the language in SDG&E's Rule 21 Section Hh.5 stating that "allowance of aggregator use…is subject to Commission approval of applicable forms and agreement not currently developed" is inconsistent with "the Commission's intended implementation of the Phase 2 communications requirements.[11] The Commission directed SDG&E to amend its Rule 21 to

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[10] Resolution E-5000 at 8 citing the CALSSA petition at 12.

[11] *Id*. at 33-34.

remove the language. Directly related to the resolution of Issue 6 in this proceeding, E-5000 rejected the argument that the lack of a standard aggregator agreement should preclude aggregators from providing communications capabilities.[12] As a result of the adoption of Resolution E-5000, Issue 6 is considered moot at this time and, therefore, resolved.

### 4.2. Issue 8: Incorporating the Integration Capacity Analysis Results into Rule 21

This decision adopts the following Working Group Two proposals in order to incorporate the results of the Integration Capacity Analysis into Rule 21: 8a; a modified 8b; 8c; Modification 1 of 8f, 8g, 8h, and 8j; Option B of 8i; Option C of 8k; 8l, in concept, with testimony submitted in phase two of this proceeding; a modified Option B of 8m; 8n; 8q; and 8r. As described further below, adoption of these proposals will inform interconnection siting decisions, streamline the Fast Track process for projects that are proposed below the integration capacity at a particular point on the system, and facilitate interconnection process automation. While we do not adopt proposal 8t, we find merit in the discussion regarding queue management. Hence, we authorize the Director of the Energy Division to facilitate a workshop on queue management and continue the discussion of Options A and B. We also address other proposals to resolve Issue 8 and why they should not be adopted. Below we present the background for this issue, a description of each proposal and the proposal's support and opposition, and a discussion of the resolution of the issue.

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[12] *Id*. at 34-35.

#### 4.2.1. Issue 8: Background

The Integration Capacity Analysis[13] provides information on the distribution system's hosting capacity and informs interconnection applicants about project siting and sizing. The Distribution Resources Plan Working Group anticipate that, with the Integration Capacity Analysis, developers should be able to submit a Rule 21 Fast Track application for distributed energy resource interconnection up to the identified Integration Capacity Analysis value at the proposed point of interconnection and bypass those Screens representing criteria the Integration Capacity Analysis has already evaluated.[14] Further, the values identified at a point of connection are expected to replace and/or supplement the size limitations in the Fast Track eligibility criteria and be able to address and/or improve upon the Fast Track technical Screens, which are now included in the Integration Capacity Analysis method. Hence, Interconnection customers should be able to use the Integration Capacity Analysis value at their point of interconnection to establish whether a proposed project will pass these technical Screens.[15]

In developing proposals for changes to Rule 21, Working Group Two identified three threshold considerations: 1) the reasonableness of proposal

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[13] D.17-09-026, in the Distribution Resources Plan proceeding (R.14-08-013), adopted the use of the Integration Capacity Analysis for online maps, interconnection streamlining and automation, and distribution planning. The Commission authorized system-wide implementation of the Integration Capacity Analysis across the Utilities' territories.

[14] Working Group Two Report at 42, citing The Integration Capacity Analysis Working Group Final Report at 8-9.

[15] *Id*. at 41-42

costs; 2) the tools and processes needed to implement the proposals; and 3) the outcomes of the Integration Capacity Analysis quality control and assurance tests, including validation of data.[16]

#### 4.2.2. Issue 8: Proposal 8a

The Working Group Two Report highlights that current eligibility for Fast Track review is dependent upon a project's size.[17] Proposal 8a, supported by all members of the working group, removes the existing Fast Track eligibility size limits.[18] The result of removing the size limits is that any applicant can choose to select Fast Track as their preferred study track regardless of the project size. No party or other stakeholder opposes this proposal.

While supporting Proposal 8a, working group participants identify three caveats: 1) because the Integration Capacity Analysis only evaluates certain technical criteria, projects that are below the Integration Capacity Analysis may still be required to go to Supplemental Review or Detailed Study if they fail Screens not evaluated by the Integration Capacity Analysis; 2) elimination of the size limit does not increase chances of passing through Initial or Supplemental Review if the project is sized above the Integration Capacity Analysis value; and 3) the Commission should continue to allow Net-Energy Metering projects under 30 kVA to use the Fast Track process regardless of the Integration Capacity Analysis.

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[16] *Id*. at 42 – 43.

[17] *Id*. at 44.

[18] *Ibid*.

#### 4.2.3. Issue 8: Proposal 8b

Proposal 8b would allow Utilities to incorporate an additional run of the specific node/feeder Integration Capacity Analysis into the Initial Review process when updated Integration Capacity Analysis values may be required. This proposal, supported by Utilities, would also require Utilities to provide an explanation of the update when necessary. As described below, with certain caveats, the proposal is supported by IREC, Public Advocates Office, Green Power Institute, TURN, and Clean Coalition.

The Working Group Two Report explains that the Integration Capacity Analysis is updated on a monthly basis where significant system changes have occurred, and the frequency of updates would lead to Interconnection Requests based upon out-of-date Integration Capacity Analysis values.[19] Utilities propose two different processes for determining whether it is necessary to update the values:

1) SDG&E and SCE recommend using the Initial Review process to determine if the Integration Capacity Analysis values at the proposed Point of Interconnection need to be updated. SDG&E and SCE propose using the Integration Capacity Analysis tool on the specific electrical node or running the Integration Capacity Analysis on all the electrical nodes in the circuit; and
2) PG&E proposes that verification of the Integration Capacity Analysis within the Initial Review processes can be accomplished through existing 15 percent of peak load

[19] (*Id*. at 45.) The report provides several examples of why the values may have changed from the latest update.

calculations, which avoids rerunning the Integration Capacity Analysis.

Utilities emphasize that if certain other proposals are adopted by the Commission (*e.g.*, Proposals 8f, 8g, 8h, and 8j), additional analyses of Interconnection Requests with less than 30 kVA nameplate capacity will not be necessary. Further, Utilities assert that implementation of Proposal 8b will not impact existing timelines for the Initial Review.

All working group participants agree that in the event disclosing the results of the Integration Capacity Analysis conflicts with confidentiality requirements, Utilities will present the results in a manner that complies with current Commission data redaction policies.[20]

Additionally, SCE states in the report that it will consider future implementation of a system for "flagging" Integration Capacity Analysis values that will likely need an update.

According to the Working Group Two Report, several participants object to PG&E's approach to determining whether the values need to be updated. While a lack of time to review the proposal was the basis for the objection, the opposition also cautions that interconnection applicants may not understand how the screening limit is derived and applied. Participants further contend that using the 15 percent screen would undermine the use of the Integration Capacity Analysis.[21]

[20] *Id*. at 46.

[21] *Ibid*.

From a broader perspective, Green Power Institute asserts that outdated Integration Capacity Analysis values will be a large problem and an automated Integration Capacity Analysis is necessary. Green Power Institute supports 8b until alternatives delineated in 8v below can be developed and adopted.[22]

Public Advocates Office also supports 8b, stating the proposal will "ensure the online Integration Capacity Analysis tool is as accurate and as reflective of real-time conditions as possible."[23] Public Advocates Office requests the Commission include a review of the costs of these updates as part of the long-term Integration Capacity Analysis refinements to determine whether the ratepayer costs are commensurate with the benefits.[24]

#### 4.2.4. Issue 8: Proposal 8c

Proposal 8c requires Utilities to track Integration Capacity Analysis updates outside the required monthly updates. Supporters of this proposal submit the tracking of this information will inform future discussions of the frequency of and process for Integration Capacity Analysis updates.[25] For example, Green Power Institute asserts that tracking Integration Capacity Analysis posted value deviations "is the first step in collecting the required diagnostic data to improve the system overtime."[26] Public Advocates Office's support is contingent upon a review of the costs and benefits. Only PG&E

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[22] *Id*. at 47.

[23] *Ibid*.

[24] *Ibid*.

[25] *Ibid*.

[26] *Id*. at 48.

expressed opposition to this proposal. PG&E's opposition is procedurally-based; PG&E contends such tracking should be addressed in the Distributed Resources Planning proceeding during the long-term Integration Capacity Analysis refinement discussion.

#### 4.2.5. Issue 8: Proposal 8d

Proposal 8d would provide an opportunity for applicants, who apply based on the posted Integration Capacity Analysis values, to modify their application if they fail any Initial Review Screens because the Integration Capacity Analysis values have changed by the time the application is reviewed. The proposal allows ten business days to modify the application or turn to Supplemental Review; no response would result in an automatic Supplemental Review. Proposal 8d is supported by CALSSA, Green Power Institute, and Clean Coalition. Utilities and TURN oppose Proposal 8d.

The Working Group Two Report explains that the current Fast Track process does not allow an applicant to reduce the size of a proposed project without resubmittal. D.19-03-013 adopted a definition of material modifications that would allow a proposed project to be reduced in size by up to 20 percent if it does not impact any other project lower in the queue.[27] Proposal 8d. would address situations not contemplated by Working Group One and allow an interconnecting customer to maintain its position in the Fast Track process queue when it would impact another applicant lower in the queue.

[27] D.19-03-013 at Ordering Paragraph 5.

Utilities assert Proposal 8d would add complexity and defeat the purpose of a Fast Track process.[28] Notably, Utilities contend the proposal would also complicate the monthly update to the Integration Capacity Analysis values.[29] Despite supporting the proposal, CALSSA points out that the proposal would add ten days to the interconnection process, which would slow the process without any benefit.[30]

#### 4.2.6. Issue 8: Proposal 8f1

Proposal 8f1 would add Screen F1 to determine whether the generating system's short circuit contribution exceeds 1.2 per unit. This is a consensus proposal.

The Working Group Two Report explains that generating systems with 1.2 per unit short circuit contribution can reference the Integration Capacity Analysis value for meeting the reduction of reach[31] Integration Capacity Analysis Protection Screen. For generating facilities exceeding the 1.2 per unit short circuit contribution, a utility would use the protection Integration Capacity Analysis value at the point of interconnection and the project specific per unit short circuit contribution to determine whether the facility passes Screen F1.

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[28] Working Group Two Report at 49.

[29] *Id*. at 49-50.

[30] *Id*. at 49.

[31] Reduction of Reach occurs when distribution relays are rendered less able to sense a faulted condition as a consequence of increased generation on a distribution line. (*See* Padullaparti, H.V. *et al*. (2016).) Analytical Approach to Estimate Feeder Accommodation Limits Based on Protection Criteria. IEEE Access. 4. 1-1. 10.1109/ACCESS.2016.2589545.

The Working Group Two Report points out that synchronous or induction generators cannot use the Integration Capacity Analysis to determine a specific value. Instead, the Integration Capacity Analysis automatically assigns a value of 1.2 per unit short circuit contribution for inverter-based technology. Thus, to evaluate an inverter-based project's short circuit duty contribution, Screen F1 is proposed. If the project's short circuit duty contribution is less than 1.2, the project passes Screen F1. If the project's contribution is greater than 1.2, the project would fail Screen F1. The Working Group Two Report underscores that if the projects' nameplate value multiplied by its per unit contribution is less than or equal to the Integration Capacity Analysis value multiplied by 1.2 per unit, the project will still pass Screen F1. Simply put, projects would fail Screen F1 because the project's nameplate capacity is greater than the Project Specific Protection Integration Capacity Analysis value. Projects failing Screen F1 would be evaluated under Supplemental Review for impacts to reduction in reach.

#### 4.2.7. Issue 8: Proposal 8f, 8g, 8h, and 8j

This combination of proposals has two versions. Modification 1 would allow that projects less than 30 kVA would bypass Screens F, G, H, and J; this version is supported by all working group participants. Modification 2 would require Utilities to provide the earliest available indication where Screens F[32] and G[33] failure is likely; this proposal has mixed positions as discussed further below.

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[32] Screen F identifies whether a project may have an impact on system's short circuit duty, fault detection sensitivity, relay coordination, or fuse-saving schemes.

With respect to Modification 1, existing tariff language allows generating facilities with a Gross Rating of 11 kVA or less to bypass Screens F, G, H, and J.[34] While some working group participants believe the threshold could be higher, all participants agree that raising the threshold to 30 kVA to bypass these Screens is an improvement for streamlining the Fast Track process for small projects and would not raise any safety or reliability concerns.[35]

Modification 2 involves Screens F and G. The working group discovered that all elements of the tests conducted under Screens F and G are not evaluated within the Integration Capacity Analysis. Participants considered whether and how Utilities could provide an early indication of whether a project is likely to face hurdles in passing Screens F and G. Some parties propose that Utilities update the Integration Capacity Analysis maps to indicate at what locations these Screens could be hurdles. Noting that distributed generation screening tools are able to quickly analyze Screens F and G, PG&E and SDG&E propose to provide the results of Screen F in the pre-application report. Public Advocates Office supports Modification 2 but only if it can be applied across all Utilities.[36]

SCE opposes Modification 2 and, instead, is investigating whether it can determine and flag locations on the Integration Capacity Analysis map where

[33] Screen G identifies whether a generating facility, in aggregate with other generating facilities on the distribution circuit, cause disturbances to protective devices and equipment, risking overstressing the equipment.

[34] Working Group Two Report at 51.

[35] *Id.* at 51-52.

[36] *Id*. at 53.

projects would most likely fail Screens F and G. Green Power Institute does not support PG&E and SDG&E's proposal to use the pre-application report option, because, from Green Power Institute's perspective, it adds considerable expense and time. Instead, Green Power Institute prefers SCE's flagging solution, noting that the flagging solution should be a temporary solution to proposal 8v.[37]

IREC, CALSSA and Clean Coalition propose that the Commission require Utilities to submit an Advice Letter 120 days after issuance of this decision recommending one proposal and including an analysis of the costs.

#### 4.2.8. Issue 8: Proposal 8i

Participants offer two options to the resolution of Proposal 8i. Option A, supported by Utilities and TURN, would relocate Screen I[38] to the Rule 21 technical framework overview whereby all non-exporting projects above 30 kVA would be reviewed under all Screens. Option B, supported by CALSSA, IREC, Green Power Institute, Clean Coalition, Stem, and Public Advocates Office, would continue the current practice of permitting all non-exporting projects of all sizes to skip Screens K, L, and M[39] but review the issue in Phase 2 of this proceeding, to allow discussion of costs.

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[37] *Ibid*.

[38] Screen I asks whether power will be exported across the Point of Common Coupling.

[39] Screen K asks whether a generating facility is a net energy metering project with a nameplate capacity equal to 500 kW or less. Screen L reviews where the distribution project is big enough, and/or if there are different projects, whether the project may impact transmission interconnected projects. It can be very costly and require a lot of time to mitigate in order to pass this Screen. Screen M asks whether the total generation capacity on the line section is less than 15 percent of line section peak load for all time sections bounded by automatic sectionalizing devices.

The objective of Issue 8 is to determine how the Commission should incorporate the results of the Integration Capacity Analysis into Rule 21. Proposal 8i, Option A, emanates from the Utilities' perspective that as distributed energy resources penetration increases, the level of Integration Capacity Analysis margin at various parts of the distribution system are diminishing "to the point at which non-export projects can potentially adversely affect the safety and reliability of the distribution grid by causing overvoltage conditions and possible overloads."[40] Utilities explain that an adequate level of technical evaluation is needed to prevent these conditions, which includes evaluating how non-export projects may affect the Integration Capacity Analysis parameters.[41]

Opposition to this technical evaluation proposal includes Public Advocates Office, which contends the Utilities' proposal with its insufficiently detailed technical justification makes the Fast Track process less efficient; and CALSSA and IREC, which highlight that Utilities have indicated that, up to now, the overvoltage and overloads situation has never arisen. Green Power Institute suggests that since the situation has not occurred, the issue should be tabled and re-visited in the future. [42]

[40] Working Group Two Report at 55.

[41] *Ibid*.

[42] *Id*. at 56.

#### 4.2.9. Issue 8: Proposal 8k

Proposal 8k, involving Screen L,[43] comprises three options: Option A, supported by Utilities, modifies the screen to include a transmission overvoltage[44] and transmission anti-islanding[45] test from Screen M; Option B, supported by CALSSA, modifies the Screen to include only the transmission overvoltage test; and Option C, supported by IREC, Green Power Institute, and Clean Coalition, modifies the Screen to temporarily allow application of anti-islanding tests until Issue 18 can be resolved in Working Group Four.

Screen L determines whether the Interconnection Request is made in an area where there are known transient stability limitations, or the proposed generating facility has interdependencies known to the utility with transmission system Interconnection Requests already in the queue.[46] Screen M evaluates whether there is a risk that aggregate generation could exceed 15 percent of peak load and, if so, identifies which projects require Supplemental Review.[47]

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[43] Screen L is the Transmission Independence Screen. This Screen reviews where the distribution project is big enough, and/or if there are different projects, whether the project may impact transmission interconnected projects. It can be very costly and require a lot of time to mitigate in order to pass this Screen.

[44] Transmission overvoltage is considered possible when a transmission breaker opens on a substation that has an ungrounded high side and aggregate generation is greater than 50 percent of minimum load. 15 percent of peak load is used as the initial screen or filter to conduct additional screening on projects that exceed 15 percent of peak load.

[45] Islanding is considered possible when the ratio of machine-based synchronous generation to inverter-based generation is more than 40 percent and aggregate generation is greater than 50 percent of minimum load. Again, 15 percent of peak load is used as the initial screen or filter to conduct additional screening on projects that exceed 15 percent of peak load.

[46] Working Group Two Report at 57.

[47] *Ibid*.

To identify when projects should undergo more detailed protection tests, PG&E currently utilizes a value of 15 percent of peak load in Initial Review and 50 percent of minimum load calculations in Supplemental Review together with data on the presence of synchronous generations and substation grounding.[48] According to PG&E, these transmission protection screens are not included in the Integration Capacity Analysis. PG&E submits that if the Commission adopts the proposal to revise Screen M (discussed below) by replacing the current approach of using 15 percent of peak load to using the Integration Capacity Analysis, these transmission protections screens should be performed within Screen L, because Screen L also evaluates transmission impacts.[49] Relatedly, the Working Group Two Report also points out a relationship with Working Group Four Issue 18, which considers changes to the existing anti-islanding test.

PG&E's Option A would require Screen L to look at whether the Interconnection Request is in an area where islanding conditions are possible based on currently adopted and published screen policies with respect to anti-islanding screening.[50] If the answer is yes, Supplemental Review is required; otherwise the Interconnection Request moves on to Screen M. Supported by Utilities, Option A is opposed by TURN and CALSSA.

CALSSA opposes PG&E's proposal to replace the use of Integration Capacity Analysis values with an anti-islanding test. CALSSA contends that the

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[48] *Ibid*.

[49] *Id*. at 57-58.

[50] *Id*. at 58.

issue of anti-islanding should be addressed in Issue 18, as laid out in the scoping memo. CALSSA highlights that the intent of Issue 8 is to coordinate the implementation of the Integration Capacity Analysis and not add an unsubstantiated technical review measure.[51] CALSSA recommends Option B, that there should be no changes to the Rule 21 anti-islanding policy. This option is opposed by Utilities.

Option C, proposed by IREC, would allow PG&E to utilize the current screening practices that look at whether a project has failed 50 percent of minimum load and where 40 percent or more of the generation on the substation comes from rotating machines and allow SCE and SDG&E to screen for anti-islanding but on a temporary basis until Issue 18 is resolved. IREC explains that Option C would require a guidance document to be published identifying the specific screening approach SCE and SDG&E would use, similar to that of PG&E. The subtle but important difference in Option C is that the customer will identify the specific screening approach that will apply to them.[52] Option C is supported by IREC, Clean Coalition, and Green Power Institute but opposed by Utilities.

#### 4.2.10. Issue 8: Proposal 8l

Proposal 8l would require Utilities to post an indication of potential Screen L results on Integration Capacity Analysis maps. This proposal is supported by PG&E, TURN, Clean Coalition, Green Power Institute, IREC, and SCE, but opposed by SDG&E.

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[51] *Id*. at 61.

[52] *Id*. at 63.

The Working Group Two Report describes the importance of identifying locations where pre-existing grid conditions could lead to projects failing Screen L.[53] This proposal would provide more information for developers. PG&E and SCE offer different fields/information to help identify locations that could be of concern for Screen L. IREC, Clean Coalition, and Green Power Institute support requiring Utilities to post information on their maps that helps identify known conditions that might indicate whether a proposal may fail Screen L.[54]

#### 4.2.11. Issue 8: Proposal 8m

Proposal 8m has two options and two implementation variations.

First, Option A, supported by Utilities and TURN, would apply a 10 percent buffer to the Integration Capacity Analysis Static Grid (SG) profile[55] and no buffer to the Integration Capacity Analysis Operational Flexibility (OF) profile.[56] In Option A, if the Interconnection Request is greater than Integration Capacity Analysis OF, further evaluation in Supplemental Review is required. If the Interconnection Request crosses the 10 percent buffer in the Integration Capacity Analysis SG, the necessary upgrades would be implemented to

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[53] *Id*. at 64.

[54] *Id*. at 64-65.

[55] The Integration Capacity Analysis Static Grid (SG) 576 profile is the minimum Integration Capacity Analysis values at each of the 576 hours for the most limiting of these categories: thermal, voltage, power quality, and protection.

[56] The Integration Capacity Analysis Operational Flexibility (OF) 576 profile is the same as the static grid profile but includes safety as one of the categories. Where the safety Integration Capacity Analysis value is not the lowest of all the categories, the two profiles are the same.

maintain the 10 percent buffer at minimum.[57] Additionally, if the project is interconnecting to an area of the system without an Integration Capacity Analysis, the project is evaluated against 15 percent peak load using the current process.

Option B, proposed by IREC, Clean Coalition, Stem, CALSSA, Tesla, Sunrun, and Public Advocates Office, is the same as Option A except for the treatment of Integration Capacity Analysis OF.[58] Language in Option A asks whether the PV Interconnection Request real power production based on PV Watts or equivalent is greater than 100 percent of the lowest value in the Integration Capacity Analysis-OF 576 profile.[59] Language in Option B asks whether the PV Interconnection Request real power production based on PV Watts or equivalents is greater than 100 percent of the Integration Capacity Analysis-OF 576 values in any hour.[60] Contending it is incorrect to view Option A as having a buffer on the Integration Capacity Analysis-SG and no buffer on Integration Capacity Analysis-OF, Public Advocates Office submits this will get the most value out of Integration Capacity Analysis while maintaining grid safety and reliability.[61] Utilities argue that using the lowest value Integration Capacity Analysis-OF is essential to ensure that the internal system can be

[57] Working Group Two Report at 67.

[58] *Id*. at 69.

[59] *Id*. at 68.

[60] *Id*. at 70.

[61] *Id*. at 69.

reviewed as part of the interconnection process the ensure the safety and reliability for the distributed energy resources connection up to Integration Capacity Analysis-OF can be maintained during normal operations of the grid.[62]

Opposing applying the buffer to the protection constraint, CALSSA, IREC, and Clean Coalition contend the need for a buffer does not apply to protection because the ratio of load to generation does not determine whether a protection issues will arise. Hence, for Options A and B, these participants recommend comparing the aggregate generating facility capacity on the line section with 100 percent of the protection Integration Capacity Analysis value rather than 90 percent.[63] This variation is supported by Clean Coalition, IREC, CALSSA, and SCE but opposed by SDG&E and PG&E.

A second implementation variation recommended by CALSSA and IREC would incorporate the buffer into the Integration Capacity Analysis values on the back end.[64] These entities suggest that if the thermal and voltage Integration Capacity Analysis values are de-rated by 10 percent before posting, it would be more user-friendly and straightforward. Clean Coalition, IREC, and CALSSA support this variation. Utilities express concern over whether they have the ability to include this before mapping the Integration Capacity Analysis.[65]

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[62] *Id*. at 70.

[63] *Id*. at 72.

[64] *Ibid*.

[65] *Ibid*.

However, if the first implementation variation is adopted, Utilities support this variation.[66]

#### 4.2.12. Issue 8: Proposal 8n

Proposal 8n would update Screen N to allow the evaluation of thermal overload, steady state voltage deviation, and protection reduction-of-reach when the Interconnection Request fails Initial Review due to exceeding the Integration Capacity Analysis values or Screen F1. This proposal is supported by Utilities, IREC, Public Advocates Office, Green Power Institute, Clean Coalition, TURN, and CALSSA.

Screen N, which tests the level of distributed energy resources penetration, ask whether the aggregate generating facility capacity on the line section is less than 100 percent of the minimum load.[67] If yes, the project passes Screen N. If no, the project is reviewed to determine the requirements to address the failure. If the failure cannot be addressed through this review, Electrical Independence Tests and Detailed Studies are required.

To address Issue 8, Screen N needs to be updated to a method based on the Integration Capacity Analysis. The Working Group Two Report explains that Screen N was designed to determine possible negative impacts of a project (*e.g.*, thermal overloads or overvoltage) by verifying whether flow of electrical power from the distribution circuit to the low side bus of the substation would occur

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[66] *Ibid*.

[67] *Id*. at 73.

under typical distributed energy resources' operating conditions.[68] According to the report, maintaining a verifiable minimum load greater than the resource's real power output would prevent an overload of electrical distribution systems or overvoltage in the distribution circuit.[69]

With the implementation of Integration Capacity Analysis values, the participants agree that the Screen N needs to be adjusted for three scenarios: a) Screen N can be bypassed if the Interconnection Request is below the updated Integration Capacity Analysis and has passed Screen F1; b) when the Interconnection Request is above the updated Integration Capacity Analysis or fails Screen F1, the utility will determine if a quick review can determine interconnection requirements or if Electrical Independence Tests and Detailed Studies are required; and c) the utility will use the existing tariff language when Integration Capacity Analysis information is not available.[70]

#### 4.2.13. Issue 8: Proposal 8q

Proposal 8q, supported by all participants, updates Screen P to account for new smart inverter capabilities. Specifically, Rule 21 at Section G.2.c would be amended to add the following example of an item that may be considered under Screen P: "Will the proposed system cause any voltage impacts considering the settings of the Volt-Var function and the characteristics of the circuit segment?"

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[68] *Id*. at 74.

[69] *Ibid*.

[70] *Id*. at 75.

Working Group Two Report explains that Screen P in Supplemental Review is used to determine whether a project is required to be moved to Detailed Study. Therefore, the report contends the list of mitigations to avoid a Detailed Study should be expanded to include advanced smart inverters.[71] Rule 21 currently requires that all new interconnections must have certain smart inverter functions enabled, including the Volt-Var function.[72] While the voltage restraint may cause a project to fail Initial Review, in the Supplemental Review Utilities will consider the impact of Volt-Var. Proposal 8q allows Utilities to account for adjustments in the standard Volt-Var settings when determining whether Detailed Study is needed.[73]

#### 4.2.14. Issue 8: Proposal 8r

Proposal 8r, supported by all working group participants, would add an upfront option to allow a customer to pre-pay for Supplemental Review when paying for Initial Review and opt to proceed straight to Supplemental Review without the optional Initial Results meeting, thus combining the two processes. The Working Group Two Report submits that providing the option to combine the two processes benefits applicants and Utilities and meets the main objective of this proceeding: streamlining the Rule 21 process.[74]

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[71] *Ibid*.

[72] *Id*. at 76.

[73] *Id*. at 76.

[74] *Id*. at 77.

#### 4.2.15. Issue 8: Proposal 8s

Proposal 8s would reduce the interconnection application fee for non-net energy metering systems. CALSSA offers Option A, which would align the application fee for non-net energy metering systems smaller than 1 MW with the application fee for net energy metering systems. Option B, supported by Clean Coalition and IREC, proposes Utilities review actual costs and determine whether a $300 fee is appropriate for significant application categories. Utilities oppose both options of Proposal 8s.

The Working Group Two Report states that an $800 application fee applies to non-net energy metering systems of any size; whereas, the net energy metering tariff requires net energy metering systems to pay an application fee based on actual utility costs to process the applications.[75]

CALSSA contends that as energy storage becomes more common, there are applications for non-net energy metering systems far smaller than 1MW that are proposing to interconnect, which resemble small solar projects more than large wholesale projects.[76] CALSSA submits that because applications for non-net energy metering systems less than 1MW require the same amount of work to process as a net energy metering system, the application fees should be similar.[77] CALSSA suggests that, by using Integration Capacity Analysis data, the

[75] *Id*. at 78.

[76] *Ibid*.

[77] *Ibid*.

Commission could determine that smaller non-net energy metering applications result in average costs of less than half of the standard $800 application fee.[78]

Utilities assert it is not appropriate to establish the same fee for non-net energy metering and net energy metering projects. First, Utilities contend that the sheer number of applications for small residential systems cause the average study cost to be much lower for all net energy metering systems.[79] Further, Utilities maintain the technical review for net energy metering systems cannot be compared to non-export storage projects up to 1MW because non-export storage projects require an evaluation of Screens F, G, H, and E and potentially an evaluation of loading profiles, all of which are bypassed for small residential net energy metering projects.[80] Utilities disagree with CALSSA's contention that Integration Capacity Analysis data indicates smaller non-net energy metering projects result in study costs less than $400. Utilities argue that the Integration Capacity Analysis does not evaluate all screens that require evaluation under the $800 application fee, including Screens F, G, H, and E.[81]

Clean Coalition and IREC propose an alternative to CALSSA's proposal, whereby the fee would reflect actual average costs. Moreover, Clean Coalition suggests that if a defined class of applicants has substantially lower average actual costs for Initial Review, these applications should be subject to a lower fee.

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[78] *Ibid*.

[79] *Ibid*.

[80] *Ibid*.

[81] *Ibid*.

Utilities opposed inclusion of this option in Working Group Two Report stating that they had insufficient time to review. The Working Group Two Report explains that while consideration of the option was limited, including both options was prudent.

#### 4.2.16. Issue 8: Proposal 8t

Proposal 8t addresses a situation that CALSSA calls queue sitting, whereby a developer of wholesale, front-of-the-meter distributed energy resources projects, that must apply for interconnection before they have buyers, may hold the reserved grid capacity for as long as it takes to find a buyer. CALSSA asserts that queue sitting impacts wholesale projects who are further behind in the queue as well as the customers that want to invest in behind-the-meter distributed energy resources.[82] Participants do not agree on the magnitude of this queue sitting but agree that it may be a bigger problem with the integration of the Integration Capacity Analysis.[83] Participants offer two options, both of which are opposed by Utilities and TURN.

In Option A, offered by CALSSA, the proposal requires that 1) the commercial operation date be set by mutual agreement and any extension of the date be justified; 2) current milestones dates for wholesale projects in Rule 21 would be tightened; and 3) small projects be allowed to interconnect if they do not impact larger projects in front of them in the queue. Clean Coalition, who supports Option A, contends that some of the new timelines may impose

[82] *Id*. at 80.

[83] *Id*. at 79-80.

reporting and enforcement burdens not warranted. IREC also supports Option A. The Working Group Two Report indicates that a small number of Rule 21 projects currently come online after the planned Commercial Operation Date, and there is no evidence of either increasing delays or a "land rush" (in which developers race to obtain available hosting capacity) associated with the Integration Capacity Analysis.[84] Green Power Institute offers Option B, which is identical to Option A but permits Utilities to continue to rely on the negotiation phase of the interconnection process.[85] Option B's only other support comes from Tesla.

#### 4.2.17. Issue 8: Proposal 8v

Proposal 8v, supported by Green Power Institute, Clean Coalition, and Stem, is a draft Interconnection Automation and Streamlining report that provides guidance on further action regarding automation opportunities, likely costs and benefits of automated data processes, and coordination of related Utility investments.[86] The adoption of this report is opposed by Utilities and TURN.

Green Power Institute and Clean Coalition explain that the intent of the appended report is to form a starting point for an actionable "roadmap" for further automation and streamlining of the interconnection process for adoption

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[84] *Id.* at 83.

[85] *Id*. at 84.

[86] *Id*. at 84-85 and Appendix A. The report was drafted by Green Power Institute and Clean Coalition, with assistance by Smarter Grid Solutions, Inc.

by the Commission.[87] TURN opposes inclusion and adoption of the report because it does not have a high-level cost estimate of automation opportunities, only a relative cost-benefit analysis.[88] SCE cautions that scoping, development and implementation of IT tools [for automation] require time and cost; the funding for the costs requires Commission authorization in a general rate case proceeding.[89] Like SCE, PG&E points out that funding for costs requires Commission authorization, typically in a general rate case. PG&E also expresses concern that Rule 21 compliance timelines should reflect what the manual process of performing the task entails, with the volume of projects in mind.[90]

#### 4.2.18. Resolving Issue 8

The purpose of Issue 8 is to integrate the Integration Capacity Analysis into Rule 21. As discussed further below, the proposals we adopt to resolve Issue 8 address the objectives of integration as well as further automation and improved streamlining.

First, we conclude that proposal 8a, which removes existing Fast Track process eligibility limits, should be adopted. As explained in the Working Group Two Report, the Integration Capacity Analysis provides an estimation about the size of a project that can be interconnected at a specific point in a circuit and not require distribution upgrades.[91] By incorporating the Integration Capacity

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[87] *Id*. at 85.

[88] *Id*. at 86.

[89] *Id*. at 87.

[90] *Id*. at 88.

[91] *Id*. at 44.

Analysis data into Rule 21, we no longer need the eligibility limits. In the past, eligibility for the Fast Track process depended upon the size of the project. Eliminating the size restriction allows any applicant to select the Fast Track process, as their preferred study track. Proposal 8a, which is unopposed, will streamline the Fast Track process. Proposal 8a should be adopted with the three caveats listed in the Working Group Two Report: 1) projects that are below the Integration Capacity Analysis values may still be required to go to Supplemental Review or Detailed Study even if they fail the other screens not evaluated by the Integrated Capacity Analysis; 2) elimination of the Fast Track process eligibility limit does not increase an interconnecting generator's chances of passing through Initial or Supplemental Review if the project is sized above the Integrated Capacity Analysis value; and 3) net energy metering projects under 30 kVA are currently processed as Fast Track projects and will continue to do so regardless of the Integrated Capacity Analysis value.

Because an objective for Issue 8 is to incorporate the Integration Capacity Analysis while streamlining the Fast Track process, we adopt proposal 8b using SCE and SDG&E's implementation process. This proposal provides that Utilities use the Initial Review process to determine if the Integration Capacity Analysis values at the proposed Point of Interconnection need to be updated. If updated values are needed, the proposal requires Utilities to use the Integration Capacity Analysis tool on the specific electrical node or run the Integration Capacity Analysis on all the electrical nodes in the circuit, depending on future Integration Capacity Analysis tool capabilities. This proposal will ensure use of the most recent Integration Capacity Analysis values without impacting timelines for

Initial Review. Hence, this proposal addresses the objectives of integration, further automation, and maintaining a streamlined process.[92] Because we are adopting proposals 8f, 8g, 8h, and 8j below, Utilities will not need to perform additional Integration Capacity Analyses as part of the interconnection process of Interconnection Requests with less than 30 kVA nameplate capacity,[93] which further supports our objective of streamlining. Advocated by all participants, we agree that this proposal should help ensure that the online Integration Capacity Analysis tool is accurate and reflective of real-time conditions to the extent possible.[94] Proposal 8b, as described herein, should be adopted.

In addition to implementing Proposal 8b, as described above, we require Utilities to share the results of any Integration Capacity Analysis updates with the interconnecting generator and explain any grid condition or interconnection queue changes. Utilities shall also comply with confidentiality provisions by following current Commission data reduction policies, as recommended in the Working Group Two Report.[95]

In the Working Group Two Report, SCE agreed to consider future implementation of a system for "flagging" Integration Capacity Analysis values needing to be updated. We direct SCE to move forward on developing this

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[92] *Id*. at 46.

[93] *Ibid*.

[94] *Ibid*.

[95] *Ibid*.

system and provide a report on its status to the Director of the Energy Report within 6 months of the issuance of this decision.

With respect to the matter of updated Integration Capacity Analysis values, we are faced with competing priorities: having the most updated values and ensuring the costs to maintain these values are reasonable. In order to balance these two priorities, the Commission should collect the relative data, including tracking when the Integration Capacity Analysis values are updated outside of the standard monthly updates and the costs associated with the updates. Hence, we should adopt Proposal 8c, which requires Utilities to track when the Integration Capacity Analysis updates lead to Interconnection Requests failing the Initial Review. We agree with participants that the tracking of this information will inform future discussions of the frequency of and process for Integration Capacity Analysis updates.[96] We note that only PG&E expressed opposition to this proposal, contending that such tracking should be addressed in the Distribution Resources Plans proceeding. We disagree. While we acknowledge that the Integration Capacity Analysis was created in the Distribution Resources Plans proceeding, we agree with Green Power Institute that the tracking of the updates is a first step to improve the interconnection system over time.

Relatedly, we decline to adopt Proposal 8d, the CALSSA proposal to allow additional time for applicants to modify applications in response to failed Screens due to outdated Integration Capacity Analysis values. We find the

[96] *Ibid*.

proposal does not meet the objectives of Issue 8 in that it does not streamline the process but, more significantly, it adds time to the process. Further, we are concerned about the Utilities' contention that the proposal would complicate the Integration Capacity Analysis monthly update. We recognize that the proposal provides an opportunity to applicants to modify the application when outdated values lead to Initial Review Screen failure; unfortunately, the proposal would add ten business days for the applicant to modify the application or turn to Supplemental Review. Even the supporter of the proposal underscores that the ten days provides no additional benefit. Proposal 8d does not meet the streamlining objective of Issue 8 and, therefore, should not be adopted.

Our focus in this proceeding is streamlining Rule 21 but Issue 8 focuses the streamlining attention on integrating the Integration Capacity Analysis. We adopt Proposal 8f1, which adds a new Screen, F1, to determine whether the generating systems' short circuit contribution exceeds 1.2 per unit. Integration with the Integration Capacity Analysis requires this additional Screen. As noted in the Working Group Two Report, synchronous or induction generators cannot use the Integration Capacity Analysis to determine a specific value and are automatically assigned a value of 1.2 per unit short circuit contribution. Thus, in order to properly evaluate an inverter-based project's short circuit duty contribution, Screen F1 is necessary. As no party opposes this needed proposal, we find it reasonable to adopt proposal 8f1.

We now address a group of proposals: 8f, 8g, 8h, and 8j. As previously stated, existing tariff language allows generating facilities with a Gross Rating of 11 kVA or less to bypass Screens F, G, H, and J. All participants agree that raising the threshold to 30 kVA to bypass these Screens improves streamlining and would not raise any safety or reliability concerns. Hence, we find it reasonable to adopt Modification 1 of Proposals 8f, 8g, 8h, and 8j. However, the costs of Modification 2 have not been identified and therefore we cannot determine the overall value of Utilities providing an early indication of hurdles in passing Screens F and G. Accordingly, we should not adopt Modification 2.

We turn to Proposal 8i, which considers the applicability of Screen I for Non-exporting projects above 30 kVA. We maintain the current process which allows non-exporting projects of all sizes to skip Screens K, L, and M. Utilities contend that relocating Screen I to the Rule 21 technical framework overview (Option A) is necessary to evaluate how non-export projects may affect the Integration Capacity Analysis parameters. However, this option would result in unknown additional costs and would make the Fast Track process less efficient. Furthermore, while Utilities contend this change is necessary because distributed energy resources penetration increases can lead to overvoltage conditions and possible overloads, they acknowledge, and others agree, that this situation has not occurred. Accordingly, we should adopt Option B of Proposal 8i and retain the status quo whereby non-exporting projects of all sizes skip Screens K, L, and M. However, we will revisit Option A of Proposal 8i in the ratesetting phase of this proceeding.

Proposal 8k overlaps with Issue 18, which asks whether the Commission should adopt changes to anti-islanding screen parameters; Issue 18 is currently being addressed by Working Group 4. At this time, we find it reasonable to adopt Option C and modify Screen L to include the transmission overvoltage and transmission anti-islanding tests currently in Screen M. As noted by PG&E, changing the current 15 percent of peak load value in Screen M to Integration Capacity Analysis values results in Screen M not including the transmission overvoltage and transmission anti-islanding tests because these tests are not incorporated in the Integration Capacity Analysis.[97] However, we are cognizant of the remaining factual dispute regarding anti-islanding screening standards. Hence, we should adopt Option C as a temporary solution until Issue 18 is considered by the Commission. We should also adopt the language revision for Screen L, as proposed by IREC, to take into account that SCE and SDG&E do not currently screen for anti-islanding but may decide to do so in the future.

Continuing with revisions to Screen L, we decline to adopt the non-consensus Proposal 8l, at this time. The record in this proceeding is limited with respect to technology solutions, tools needed, and implementation costs. However, we adopt the proposal's concept that Utilities should identify where projects are likely to fail Screen L, as we agree that this will facilitate the transparency, predictability, and streamlining of the Fast Track process. Accordingly, we direct Utilities to continue to develop proposals for implementing the conceptual proposal. Utilities, either individually or together, shall submit testimony proposing approaches to implement the proposal. The testimony shall include details regarding the necessary technology solutions and tools, and proposed implementation costs. Consideration of this testimony will

[97] *Id*. at 57.

be conducted in the next phase of this proceeding, which will address costs and cost allocation issues. Utilities will receive further instructions in a future ruling.

Moving on to revisions to Screen M, the purpose of Screen M is to maintain generation and load balance in case of load changes on a circuit. As previously discussed, all parties agree that Screen M should be modified to reflect the Integration Capacity Analysis. We adopt Proposal 8m with a modified Option B that requires a 10 percent buffer be applied to both Integration Capacity Analysis-SG and Integration Capacity Analysis-OF curves. We agree with Public Advocates Office that this option, as modified, will get the most value out of the ratepayer-funded Integration Capacity Analysis while maintaining grid safety and reliability. We underscore that the working group acknowledges that the load on a circuit might change after a project is interconnected, which could pose safety and reliability risks. Hence, as proposed by the working group, we agree that integrating a buffer into Screen M would effectively leave space between the amount of expected interconnecting generation and the Integration Capacity Analysis value.[98] The utility proposal, Option A, recommends a 10 percent buffer for the Integration Capacity Analysis-SG.[99] Given the working group acknowledgement that a buffer can reduce risk due to changing circuit characteristics, we find it prudent to apply a similar buffer to Option B to ensure safety and reliability. In comments to the proposed decision, CALSSA and IREC recommend that instead of a 10 percent buffer to the

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[98] *Id*. at 67.

[99] *Ibid*.

Interconnection Capacity Analysis-OF, the Commission track the frequency of mitigation requirements based on operational flexibility constraints and host a workshop after one year after the implementation of Interconnection Capacity Analysis to determine if the buffer is necessary.[100] SDG&E, CALSSA, and IREC contend the buffer should be removed as it is overly conservation. In response, PG&E maintains that this view assumes that PG&E establishes alternative circuit configurations with SCADA-enabled devices, whereas the majority of its switching devices are non-SCADA-enabled switching devices.[101] Because the Integrated Capacity Analysis is a new tool for the interconnection process, we maintain the current buffer to ensure reliability. We will revisit this buffer in the future. In the near term, we require Utilities to collect data and report on the effectiveness of this buffer within the reporting requirements for the buffers adopted in Issue 9 below.

Similar to Screen M above, Screen N also requires alignment with the Integration Capacity Analysis. We adopt the consensus proposal to update Screen N to allow the evaluation of thermal overload, steady state voltage deviation, and protection reduction-of-reach when the Interconnection Request fails Initial Review due to exceeding the Integration Capacity Analysis values or Screen F1. As noted in the Working Group Two Report, alignment to account for thermal overload, overvoltage conditions and protection requires adjustment for

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[100] CALSSA Opening Comments on Proposed Decision at 1-3, IREC Opening Comments on Proposed Decision at 2 and IREC Reply Comments on Proposed Decision at 3.

[101] PG&E Reply Comments on Proposed Decision at 2. See also SCE Reply Comments on Proposed Decision at 2.

the following three scenarios: 1) when the Interconnection Request is below the updated Integration Capacity Analysis value and passes Screen F1; 2) when the Interconnection Request is above the updated Integration Capacity Analysis value or fails Screen F1; and 3) when Integration Capacity Analysis information is not available.[102] This uncontested proposal addresses these three scenarios and should be adopted.

Also a consensus proposal, we adopt Proposal 8q, but we revise it to update Screen O, not Screen P, to account for new smart inverter capabilities. Working Group Two Report described Screen P as being in Supplemental Review and used to determine if there are mitigations that can avoid having a project move to Detailed Study. Rule 21 requires that all new interconnections must have certain smart inverter functions enabled. Adoption of the proposal will allow a utility to consider these additional functions as potential mitigations. Avoidance of the Detailed Study maintains efficiency of the Fast Track process. However, in comments to the proposed decision, PG&E argues that smart inverter capabilities should be evaluated in Screen O, given that Screen O covers power quality and voltage tests.[103] No party presented opposition to this revision in reply comments. Proposal 8q, modified to revise Screen O instead of Screen P, meets the objective of Issue 8 and this proceeding and should be adopted.

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[102] *Id*. at 75.

[103] PG&E Opening Comments on Proposed Decision at 2.

Proposal 8r would provide the option to combine Initial Review and Supplemental Review. All parties support this proposal. As noted in the Working Group Two Report, applicants and Utilities benefit from additional time savings by opting to skip the Initial Results meeting. Proposal 8r meets the Issue 8 objective of streamlining the Fast Track process. Proposal 8r should be adopted.

As further described below, we decline to adopt the other proposals to address Issue 8: 8s, 8t, and 8v. We discuss each individually.

Proposal 8s would reduce the interconnection application fee for non-net energy metering systems. Parties disagree on the data that claims the need for fee reduction. Parties also disagree on whether it is appropriate to compare small net energy metering projects to large non-export projects up to 1 MW. We find that the record does not support fee reduction. Thus, Proposal 8s should not be adopted. However, in comments to the proposed decision, parties continue to express support for this proposal. In response, PG&E expressed support of reporting actual costs. We find the collection of data regarding actual costs will lead to better transparency in the streamlining process. Accordingly, we direct Utilities to track the actual costs associated with the processing of interconnection applications and report the data in the reporting document discussed in Issue 12 below.

With respect to the proposal on queue management, Proposal 8t, there is disagreement on the necessity of the proposal and, pertinent to the intent of Issue 8, whether the introduction of the Integration Capacity Analysis will make much difference. The record of this proceeding does not support adoption of Proposal 8t.

The final Issue 8 proposal addresses an *Interconnection Automation and Streamlining* report written by Green Power Institute and Clean Coalition with support from Smarter Grid Solutions, which identifies additional automation and streamlining opportunities for the Rule 21 process. Proposal 8v recommends that the Commission consider this report and provide guidance on further action within the proceeding on future Working Group schedules, review of likely costs and benefits of automated data processes, and coordination of related utility investments.

Supporters of the proposal, Green Power Institute and Clean Coalition, state that the intent of the report is to form the starting point for an actionable roadmap for further automation and streamlining of the interconnection process for adoption by the Commission. The supporters underscore that the report was informed by other stakeholders but is not a comprehensive reflection of input received.[104] The proposal is opposed by Utilities and TURN. TURN opposes inclusion of the report on the basis that it is not supported by a high level cost estimate of automation opportunities. TURN recommends the report be seen as identification of potential opportunities to be analyzed later.

We consider this proposal to be out of scope for Issue 8, which specifically focuses on the integration of the Integration Capacity Analysis with Rule 21. Accordingly, we decline to adopt Proposal 8v.

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[104] *Id*. at 85.

### 4.3. Issue 9: Conditions That Allow Distributed Energy Resources to Perform While Avoiding Upgrades

We adopt a modified version of the Utilities' proposal to address Issue 9. As discussed further below, we modify the Utilities' proposal such that the frequency of changes is expanded to monthly limits to align with the Integration Capacity Analysis. Within 120 days of the issuance of this decision, Utilities shall file a Tier 3 Advice Letter describing implementation of the proposal. We note that implementation cannot occur until a certification scheme for the Limited Generation Profile has been developed and adopted.

#### 4.3.1. Issue 9: Background

Issue 9 looks at the conditions of operations the Commission should adopt to allow distributed energy resources to perform within existing hosting capacity constraints and avoid triggering upgrades. These conditions would be included in interconnection applications and agreements. The purpose of resolving Issue 9, as highlighted by IREC, is to utilize the Integration Capacity Analysis data to allow modern inverters, storage, and other technologies to confidently respond to grid conditions while ensuring safety and reliability.[105] IREC notes that the solution should allow customers to use existing grid capabilities to deploy distributed energy resources at a lower cost.[106] Referencing the Integration Capacity Analysis Working Group, IREC quotes the vision for the Integration Capacity Analysis as providing "hourly data about hosting capacity

[105] IREC Opening Comments to December 12, 2019 Ruling at 12.

[106] *Ibid*.

limitations that enables a developer to design a system that takes full advantage of the available hosting capacity at their proposed point of interconnection."[107] The Integration Capacity Analysis Working Group found that the data also required verification that proposed operational profiles meet the Integration Capacity Analysis hourly limitations.[108]

#### 4.3.2. Issue 9: Proposals and Positions

Supported by CalCom and CALSSA, Proposal 9 would modify interconnection procedures to allow a distributed energy resources customer to include a "Limited Generation Profile" with their application, require the customer to enable generation profile limiting functionality, and allow a utility limited opportunity to alter that profile if circumstances warranted. CALSSA states that this proposal builds on Proposal 8m and applies to distributed energy resources which would accept certain conditions of operation as follows:

1) Customer submits a Limited Generation Profile as part of their application and may include generation up to the Integration Capacity Analysis -SG value published by the utility at the time of the application, submitted in a standard 288-hour format;
2) Customer agrees to enable smart inverter functionality and local controls to ensure actual operations conform with the applications' Limited Generation Profile; and
3) Customer agrees to allow future reductions to the generation profile up to the minimum Integration Capacity

[107] *Id*. at 12-13 citing the March 3, 2017 Final Integration Capacity Analysis Working Group Report at 8-9.

[108] *Ibid*.

Analysis – SG typical PV profile published by the utility at the filing of the application.

In the Working Group Two Report, Utilities presented several uncertainties with the proposal: a) whether an actual generator profile may be represented by the forecasted Limited Generation Profile; b) whether the Integration Capacity Analysis – SG will reflect actual grid conditions; c) whether the inverter and Data Acquisition System controls will meet expectations; d) whether and how the utility knows if and when the generator's output needs to be reduced and communicate any needed chance to the customer and whether the customer would respond timely; e) impacts on subsequent interconnections and the domino effect on operational constraint; f) complexity of Limited Generation Profiles to modeling; and g) customer, project size, and project asset applicability.

While recognizing the concerns of Utilities, TURN and Public Advocates Office offer support for the CALSSA proposal, with contingencies. TURN's support depends upon the Commission: 1) ordering that smart inverters be tested and added to a list of certified inverters deemed able to effectively and reliably limit output and 2) monitoring and measuring generation in real-time; because a measurement over a period of time would likely lead to underestimates.[109] Public Advocates Office submits that the CALSSA proposal "fits squarely within the [Integration Capacity Analysis] use cases identified in

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[109] Working Group Two Report at 123-124.

the Integration Capacity Analysis Working Group's Final Report."[110] Highlighting implementation challenges, the Public Advocates Office offers two recommendations to address such challenges: 1) incorporate the findings of the Smart Inverter Working Group to support the Issue 9 Proposal; and 2) encourage Utilities to develop verification processes for generator profiles.[111]

Following the completion of the Working Group Two meetings, Utilities filed a counter proposal to the CALSSA proposal, which applies the work from the Smart Inverter Working Group and its recommendation to include a Real Power Limiting Function on Smart Inverters. The counter proposal allows a customer to utilize a smart inverter's ability to increase its output during seasons of the year where a higher level of Interconnection Capacity is available based on the Integration Capacity Analysis, while still operating in a safe and reliable manner. The seasonal real power limit would include a 20 percent buffer. Similar to the CALSSA proposal, the Utility counter proposal has three parts: 1) Customer submits a Limited Generation Profile with their application, which may include generation up to the 80 percent Integration Capacity Analysis-SG value published by the utility and submitted in a standard 288-hour format; 2) customer agrees to enable smart inverter functionality to ensure actual operations conform to submitted Limited Generation Profile; and 3) customer

[110] *Id*. at 124.

[111] *Ibid*.

agrees to follow future reductions to generation profile, with the utility determining such reductions within defined circumstances.[112]

#### 4.3.3. Resolving Issue 9

One of the major objectives of this proceeding is to incorporate the Integration Capacity Analysis results into Rule 21. Accordingly, we adopt the Utilities' counter proposal to resolve Issue 9, with the modification to allow the frequency of changes to be monthly versus seasonal, which will take advantage of the Integration Capacity Analysis. Allowing a customer to establish scheduled outputs aligns the Issue 9 proposal with the Integration Capacity Analysis. Further, as described below, allowing a customer to establish monthly scheduled output limits strikes a balance between the proposed schedule and the more conservative seasonal schedule recommended in the counter proposal.

We highlight that implementation of this proposal cannot occur until a certification scheme for the Limited Generation Profile has been developed and adopted. In comments to the proposed decision, PG&E, SDG&E, and SCE underscore the interdependencies between this proposal and Proposal A-B 3 (discussed below in Section 5.9).[113] SCE asserts that in addition to the need for the development of the Limited Generation Profile, other complex technical issues need resolution including determination of how to best utilize smart inverter functions to achieve limited export schedules and identification of

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[112] Parties were given the opportunity to comment on the counter proposal in comments to the Working Group Three Report.

[113] PG&E Opening Comments to the Proposed Decision at 3, SDG&E Opening Comments to the Proposed Decision at 3 and SCE Opening Comments to the Proposed Decision at 3-4.

necessary modification to standards (such as UL 1741) to allow limited exports. All three utilities request the Commission to allow additional discussions between the parties focused on implementing the two proposals.

Accordingly, within 90 days, the Utilities shall commence such discussions with the Smart Inverter Working Group. Further, within six months of the issuance of this decision, the Utilities shall submit a Tier 3 Advice Letter providing the recommendations from these discussions, and include standard review, certification requirements, and interconnection processes necessary for implementing this proposal. Within 60 days of adoption of a certification scheme for the Limited Generation Profile, Utilities shall modify the Rule 21 Interconnection Application Process to allow a distributed energy resources customer to include a Limited Generation Profile with their application, require the customer to enable generation profile limiting functionality, and allow Utilities opportunity to alter the profile if circumstances warranted.

As noted by CALSSA, the core concepts and functionality of the CALSSA and Utilities' proposals are the same.[114] The Utilities' proposal differs in that the proposed buffer is 20 percent instead of 10 percent, the frequency of changes is limited to seasonal, and it allows an open-ended reduction in generation if system conditions change. We discuss each of these differences below and describe our final determination.

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[114] CALSSA Opening Comments to December 7, 2018 Ruling at 9-11. (*See* also Tesla Opening Comments to December 7, 2018 Ruling at 7.)

With respect to the proposed buffer, CALSSA and Tesla support a 10 percent buffer. CALSSA contends that a 10 percent buffer is adequate, noting that Utilities are comfortable with a 10 percent buffer when the system relies on the nameplate inverter size to limit production.[115] Public Advocates Office offers that the buffer should be developed as part of real-world tests of the Integration Capacity Analysis' accuracy, rather than arbitrarily determined beforehand.[116] PG&E supports Public Advocates Office's assertion, contending it is too early to rely on the Integration Capacity Analysis.[117] We agree that a final buffer should be based on real-world tests of the effectiveness of the use of Integration Capacity Analysis values within the interconnection process.

In comments to the proposed decision, several parties reiterate support for a 10 percent buffer, arguing that a 20 percent buffer is unreasonably conservative. SDG&E also supports the 10 percent buffer, stating that it would be sufficient. We adopt a 10 percent buffer, given the utilities ability to reduce the Interconnection Capacity Analysis values where safety and reliability of the grid are concerned.. We will revisit the size of the buffer, 18 months after implementation of this proposal. This will provide adequate data collection on the effectiveness of the use of Integration Capacity Analysis values within the interconnection process. As suggested by SCE in comments to the proposed decision, data obtained from Proposals 8b and 8c, adopted above, should

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[115] *Id*. at 10.

[116] Public Advocates Office Opening Comments to December 7, 2018 Ruling at 9.

[117] PG&E Reply Comments to December 7, 2018 Ruling at 9.

indicated how well the Interconnection Capacity Analysis values measure real world conditions.[118] Utilities shall file a Tier 3 Advice Letter 18 months after the implementation of this proposal providing data obtained from Proposals 8b and 8c, to assess the effectiveness of the use of the Integration Capacity Analysis values within the interconnection process and a proposal as to whether the Commission should continue use of the 10 percent buffer or adjust it, based on the data.

Turning to the matter of the frequency of customer output changes, we revise the Utilities' proposal to allow customers to utilize a smart inverter's ability to increase its output on a monthly basis. The Utilities' counter proposal offers changes on a seasonal basis. We find that allowing a customer to establish scheduled output limits aligns the proposal with the Integrated Capacity Analysis. In comments to the Working Group Two Report, CALSSA underscores that if seasonable changes work, monthly should work just as well and, if monthly works, daily or hourly should work.[119] In response, SCE argues that hourly profiles compared to seasonal profiles have a much higher risk of exceeding the Integrated Capacity Analysis value each hour.[120] Our modification of allowing to increase the output on a monthly basis strikes a balance between the original proposal and the Utilities' proposal.

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[118] SCE Opening Comments on Proposed Decision at 10-11.

[119] CALSSA Opening Comments to Working Group Two Report at 10.

[120] SCE Reply Comments to Working Group Two Report at 11-12.

The last point of contention relates to the amount of control Utilities should have over reductions to customer generation profiles. Both the CALSSA proposal and the Utilities counter proposal acknowledge that future grid conditions could result in actual hosting capacity being below the published Integration Capacity Analysis-SG and that the utility may need to reduce generation to ensure safe and reliable service without grid upgrades. The CALSSA proposal recommends that the "interconnecting generator would agree to generation reductions down to a pre-defined static level."[121] The CALSSA proposal notes that the specifics of whether and how Utilities make the determination that reductions are necessary have not been determined.[122] The Utilities' counter proposal mirrors the CALSSA proposal on this element, except that "determinations of such reductions would be made by Utilities under defined conditions."[123] Neither proposal offers defined conditions. Accordingly, we adopt the element that the utility may need to reduce generation to ensure safe and reliable service without grid updates. In comments to the proposed decision, CALSSA, IREC and Tesla argues that the language allowing retroactive changes is broad.[124] PG&E and SDG&E contend the retroactive limitations are

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[121] Working Group Two Report at 121.

[122] *Ibid*.

[123] *Id*. at 126.

[124] CALSSA Opening Comments to the Proposed Decision at 4, IREC Opening Comments to the Proposed Decision at 10, and Tesla Reply Comments to the Proposed Decision at 2

necessary for safety.[125] We reiterate that profile reductions may only be allowed for safety and reliability reasons. Furthermore, retroactive alterations to generation profiles shall not reduce generation to below a pre-defined static level, i.e., the lowest Integrated Capacity Analysis – Static Grid typical profile value identified at the time of the Interconnection Application. Utilities will provide the proposed specifics of whether and how reductions are determined in a Tier Three Advice Letter submitted no later than 120 days from the issuance of this decision.

### 4.4. Issue 10: Coordination of Integration Capacity Analysis and Rule 21 with Rules 2, 15, and 16

We conclude that the Commission should adopt the following proposals to better coordinate the Integration Capacity Analysis and each Utility's Rule 21 processes with processes in Rules 2, 15, and 16: Proposals 2, 3, 4, 5, and 8. As discussed below, adoption of these proposals will improve the efficiency of the overall interconnection process and increase transparency for customers. We provide an overview and background material of Issue 10, followed by a description and party positions for each proposal, and a discussion of our consideration of each of the proposals.

#### 4.4.1. Issue 10: Overview and Background

Issue 10 asks the parties to propose options to coordinate the Integration Capacity Analysis and Rule 21 with Rules 2, 15, and 16 processes to improve the efficiency of the overall interconnection process. The Working Group Two

[125] PG&E Reply Comments to the Proposed Decision at 3 and SDG&E Reply Comments to the Proposed Decision at 3.

Report explains that if a generator has applied for interconnection through Rule 21, the utility may require a service upgrade under Rules 2, 15, and 16. The Working Group Two Report described each of the rules:[126]

- Rule 2 addresses special facilities that may be installed, owned, and maintained or allocated by a utility as an accommodation to the Rule 21 applicant.
- Rule 15 addresses new distribution facilities, which are a continuation of, or branch from, the nearest available existing permanent Distribution Line to the point of connection of the last service.
- Rule 16 addresses overhead and underground primary or secondary facilities extending from the point of connection at the Distribution Line to the Service Delivery Point.

The Working Group Two Report further explains that when a new service request occurs simultaneously with a Rule 21 generator application, the utility first requires a review of the retail load elements eligible for Rules 2, 15, and 16. This review determines the scope and cost related to the new service and load request, which is then followed by a Rule 21 scope and cost evaluation. The Working Group Two Report highlights that projects requiring work performed by the utility leads to a complex interconnection process that can differ by utility.

In the Working Group Two Report, solar providers assert that the transition from Rule 21 to one or more of the other rules "has often not been smooth and there is very little visibility into the status of a project outside of the

[126] *Id*. at 128-129.

interconnection review under Rule 21."[127] Underscoring that the other three rules lack the details and timelines provided in Rule 21, the developers provide several examples of resulting concerns including inconsistency across Utilities.[128]

CALSSA proposes eight opportunities to standardize utility processes and timelines that are reviewed under Rules 2, 15 and 16. We describe each of these in the following eight sections and provide party positions for each.

#### 4.4.2. Issue 10: Proposal 1

In Proposal 1, the Commission would require Utilities to assign a project manager to all projects larger than 100 kilowatts (kW). The project manager would be responsible for managing the project through the Rule 21 process as well as the transition to study under Rules 2, 15, or 16. Opposed by Utilities, SCE and SDG&E assert the Commission should not mandate how Utilities should manage the interconnection process. Further, PG&E contends that current practice depends upon the nature of the project, *e.g.*, more complex projects currently have a project manager assigned. Proposal 1 is supported by CALSSA with qualified support from Clean Coalition and TURN.

#### 4.4.3. Issue 10: Proposal 2

A consensus proposal, Proposal 2 would require a single Project Identification Number for a project, which would apply from receipt of an interconnection application through permission to operate and would be used in Rules 2, 15, 16, and 21. PG&E highlights that the issue of multiple Project

[127] *Id*. at 129.

[128] *Ibid*.

Identification Numbers has limited PG&E personnel from being able to access project history and background when responding to customer inquiries.

#### 4.4.4. Issue 10: Proposal 3

Also a consensus proposal, Proposal 3 would inform the customer of the start date of a study when a project is studied under Rules 2, 15 and 16. Each of the Utilities state that a similar practice is in place at their respective company.

#### 4.4.5. Issue 10: Proposal 4

Proposal 4 would require a utility to send an invoice for the engineering advance or the facility cost within five business days of execution of the Interconnection Agreement unless the request for payment is contained within the agreement. This proposal is supported by CALSSA with qualified support from Clean Coalition, TURN, and SCE. PG&E and SDG&E oppose the proposal.

#### 4.4.6. Issue 10: Proposal 5

Proposal 5 would require the utility to attempt to contact the customer or its representative, within five business days of receiving payment for the engineering advance or upgrade costs, to schedule a mitigation work scoping meeting. Supported by CALSSA, this proposal also has qualified support from SCE, Clean Coalition, TURN, and PG&E. Only SDG&E opposes this proposal.

#### 4.4.7. Issue 10: Proposal 6

Proposal 6 would require that design and cost estimation for interconnection facilities and minor distribution upgrades be completed within 60 business days of: 1) receipt of funds for the engineering advance or upgrade costs; or 2) receipt of the Utility approved necessary customer site information as required for the design of the facilities that meets the utility technical requirements, whichever occurs later. This proposal would allow parties to agree upon a different timeline by mutual consent. Further, if the utility anticipates exceeding the deadline, this proposal would require the utility to inform the Energy Division and the customer or its representative, with an explanation for the delay. Proposal 6 is supported by CALSSA but also has qualified support from SCE, Clean Coalition, TURN, and PG&E. SDG&E opposes Proposal 6.

#### 4.4.8. Issue 10: Proposal 7

Proposal 7 would require that construction of interconnection facilities and minor distribution upgrades be completed within 60 business days of 1) a customer's election to proceed after facility design, or 2) after the customer has completed their portion of civil work, whichever occurs later. Similar to Proposal 6, Proposal 7 would allow parties to agree upon a different timeline by mutual consent. Again, if the utility anticipates exceeding the deadline, this proposal would require the utility to inform the Energy Division and the customer or its representative, with an explanation for the delay. Proposal 7 is supported by CALSSA but also has qualified support from SCE, Clean Coalition, and TURN. SDG&E and PG&E oppose Proposal 7.

#### 4.4.9. Issue 10: Proposal 8

Proposal 8 would require the utility to send, within 6 months of project completion, a detailed reconciliation of the costs of interconnection facilities and distribution updates, with a refund of any amount paid in excess of actual costs. Proposal 8 is supported by CALSSA and Clean Coalition, with qualified support from TURN. All three Utilities oppose Proposal 8.

#### 4.4.10. Resolving Issue 10

We conclude that the following proposals should be adopted because they improve coordination of the Integration Capacity Analysis and each utility's Rule 21 process with processes in Rules, 2, 15, and 16:

- Proposal 2: use of a single project identifier number;
- Proposal 3: notification by the utility of the study start date for projects studied under these rules;
- Proposal 4: invoicing of the engineering advance by the utility within 5 business days;
- Proposal 5: scheduling of a mitigation work scoping meeting process; and
- Proposal 8: delivery of a detailed reconciliation of the costs within 12 months.

We discuss each of the adopted proposals individually below, as well as those proposals we decline to adopt. We defer consideration of Proposals 6 and 7 to our discussion of Issue 12 in Section 5.1.12 below.

We begin with Proposals 2 and 3, which are consensus proposals. Proposal 2 recommends the use of a single Project Identification Number from the receipt of an interconnection application through permission to operate; this number shall also be the identifier used for interconnection review under Rule 21 and study under Rules 2, 15, and 16. No one opposes this proposal.[129] Working Group Two Report highlights the barriers and hurdles that arise without implementation of this proposal. For example, PG&E notes that multiple identification numbers for one project "has limited certain PG&E personnel from

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[129] *Id*. at 131.

being able to access project history and background when responding to customer inquiries."[130] We find that assigning one single identification number to a project through all of these processes will make the interconnection process easier to navigate for the developers and easier to manage for the utility. As the purpose of this proceeding is refinement and streamlining of Rule 21, it is prudent that the overlapping rules coordinate to further the streamlining. We should adopt Proposal 2, with the caveat that this is a project identification number, which is not meant to replace the meter number or service account number. Nor would this identifying number be used for other separate work, such as an upgrade or work requested prior to interconnection, as these are not considered part of the same project.

Proposal 3 requires a utility to inform an interconnection customer of the start date for a project studied under Rules 2, 15, and/or 16. The Working Group Two Report indicates that each of the Utilities currently have a similar practice in place. Implementation of this requirement would provide customers and developers with more visibility and transparency into the interconnection process. We conclude the Commission should adopt this consensus proposal to improve visibility and transparency.

Proposals 4 through 8 address Rule 21 timelines. TURN highlights that its support for all Issue 10 proposals is contingent upon the Utilities' determination of the additional costs incurred as a result of implementing these proposals. Clean Coalition's support for these proposals is also qualified. Agreeing that the

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[130] *Ibid*.

solutions are headed in the right direction, Clean Coalition cautions that modifications in line with feedback from Utilities may be necessary and underscores that timelines should be reasonable and allow for extenuating circumstances. Utilities oppose the addition of timelines in Rule 21, stating they are not supported, but do not point to a reason for not including them. PG&E agrees to provide written information regarding the timelines and will inform customers when the timelines cannot be met. SCE supports the contents of the timeline proposals but contends the timelines should be in the interconnection agreement and not part of the actual tariff. Similarly, SDG&E asserts that the interconnection agreement should outline the applicable milestones.

Continuing with our objective of transparency, we adopt Proposal 4, which requires a utility to send an invoice for the engineering advance or the facility costs within five business days of execution of the Interconnection Agreement, unless the request for payment is contained within the agreement. Knowing when to expect the invoice provides certainty to the customer, thus improving transparency of the interconnection process. As previously noted, PG&E agrees in principle that the invoice should be sent to the customer as soon as practical but contends that an executed agreement should be in place prior to invoicing for capital work.[131] None of the Utilities justify their opposition to the inclusion of timelines in the tariff. Hence, we find no reason why we should deny the adoption of Proposal 4 and its improved transparency to the customers. Proposal 4 should be adopted.

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[131] *Id*. at 132.

Proposal 5 should also provide more certainty to customers. This proposal is a next step after receiving payment for the engineering advance discussed in Proposal 4. Proposal 5 would require that Utilities attempt to contact the customer to schedule a mitigation work scoping meeting no later than five business days after receiving the payment for the engineering advance. Only SDG&E opposes this proposal. SCE offers that 10 days is a more realistic expectation for this next step but contends that its current process for the scoping meeting seems to be working and, therefore, a change is not necessary. PG&E agrees to contact the customer within the five-day timeframe. Again, all three Utilities oppose the inclusion of timelines in the Rule 21 tariff. We find that customers should know when to expect this next step of contact to occur. Again, the Commission's objectives in this streamlining process are to increase efficiency and improve transparency. Proposal 5 addresses these objectives and should be adopted. However, we are cognizant of the concern regarding realistic timelines. Hence, we modify Proposal 5 to require a 10-business day customer contact.

Further certainty will be provided to customers through the adoption of a modified Proposal 8, revised to allow Utilities 12 months to provide customers with a detailed reconciliation of the costs of interconnection facilities and distribution upgrades. This timeline aligns with the timeline adopted by the FERC for its Wholesale Distribution Access Tariff and Transmission Owner Tariff.[132] Here again, Utilities recommend the timeline not be included in the

[132] *Id*. at 136.

Rule 21 tariff but we find that inclusion of the timeline provides certainty and transparency to the customer.

We turn to Proposal 1, which we decline to adopt. This proposal recommends assigning a project manager for interconnection requests greater than 100 KW. We decline to adopt Proposal 1 for multiple reasons. First, as noted in the Working Group Two Report, Rule 21 gives Utilities the flexibility to determine the most efficient way to allocate resources.[133] We agree that the Commission should not mandate how Utilities should effectively manage the process to meet customer needs. Second, the Working Group Two Report does not contain data regarding the cost of such a mandate. We note that TURN expressed concern regarding the costs of Issue 10 proposals and highlighted that its support for the proposals was contingent on the determination of such costs. For these reasons, we should not adopt Proposal 1. However, we emphasize that Section E.2.a. of Rule 21 requires "an individual as a single point of contact" for each application above 100 kw.[134]

We defer the consideration of Proposals 6 and 7 to our discussion of Issue 12 in Working Group 3.

### 4.5. Issue 11: Non-Exporting Storage Systems: Using a Notification Approach or an Interconnection Application

We conclude that, at this time, the Commission should not adopt a specific proposal for a notification-based approach for non-exporting storage systems

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[133] *Id*. at 130-131.

[134] See CALSSA Opening Comments on the Proposed Decision at 6.

with negligible impact on the distribution system. There remain many unanswered questions the Commission needs to consider in order to adopt a particular proposal. However, we find value in the concept of the notification approach and will continue to explore the concept and related proposals in this proceeding. In the meantime, we adopt two proposals for streamlining the processes for these non-exporting energy storage projects. We adopt Proposal A, which directs each utility to formally incorporate into the Rule 21 Fast Track process all successful process improvements tested in the Utilities' non-exporting energy storage pilot (Pilot), and Proposal B1, which makes all non-exporting storage less than or equal to 30 kVA eligible for the same process used by standard net energy metering projects less than 30 kVA. Below we provide an overview and background information on Issue 11, followed by a description of each proposal to address this issue, and a discussion of our determinations.

#### 4.5.1. Issue 11: Overview and Background

Issue 11 involves storage interconnections with inadvertent to no export to the grid. The Working Group Two Report explains that, in the past, most interconnections involved either generating facilities with no export or distributed energy resources with the express purpose of export. Now, projects with a mix of export with non-export, as well as non-export stand-alone storage projects, are more common. Recognizing this, this proceeding inquires whether we should develop and adopt a notification-based approach in lieu of an interconnection application for non-exporting storage systems that have a negligible impact on the distribution system and what the approach should entail. (Hence, requiring a developer to notify the utility versus requiring a developer to submit an application.) Because of the negligible impact on the distribution system, it is thought that that this type of interconnection offers the most opportunities for streamlining.

In exploring this question, the working group reviewed the definitions of notification-based, non-exporting, and negligible; considered the eligibility criteria for an expedited process for non-exporting storage systems; and discussed: 1) the potential advantages and disadvantages of a notification-only system for non-exporting storage projects, 2) barriers in the current process that resolution of Issue 11 should address; and 3) the number of projects that could benefit from addressing the barriers.

In developing the proposals below, the working group discussed the overlap between this issue and Issue 25, which asks whether any revisions to the expedited process for non-exporting storage systems could be revised to support tariff principles of technological neutrality and consistency across Utilities.

The Working Group Two Report underscored that there was no consensus on whether the Commission should adopt a notification-based approach in lieu of an interconnection application. The group agrees that the focus should be on how the interconnection application could be expedited to reduce the time and costs of interconnecting non-export storage systems.[135] However, in the end, several parties assert that this process need not be limited just to non-exporting

[135] *Id*. at 140.

storage projects because the technical characteristics enabling streamlining are not specific to non-export or storage projects.[136]

Below is a description of proposals to streamline the processes for non-export storage system applications, which are meant to expedite the applications. The Working Group Two Report notes that these proposals are limited to interconnection of standalone storage systems that will be non-exporting under one of the Rule 21 Screen I options identified in Issue 8, Proposal 8i. This position is in contention. CALSSA, Clean Coalition, IREC, and Tesla assert that none of the steps outlined in the proposals below need to be limited to storage projects. These parties maintain the only process step that is different for non-exporting and exporting systems is whether Screen D can apply to both. These parties highlight that Screen D is applied for net energy metering projects under 30 kVA and argue Screen D should be applied to any inverter-based export project below 30 kVA as well, as there is no technical basis not to apply the same process to both types of projects.[137] Utilities oppose including non-net energy metering 30 kVA or less exporting inverter-based systems as applicable systems in the proposals listed below. Utilities contend the presence of jurisdictional conflicts and key interconnection program differences indicate that these systems should not be treated the same.

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[136] *Ibid*.

[137] *Id*. at 140-141.

Each proposal for Issue 11 includes a high-level discussion of the resources required to implement the proposal but does not discuss whether the benefits are worth the investment.

#### 4.5.2. Issue 11: Proposal A

Proposal A, a consensus proposal, would require each utility to formally implement all successful process improvements tested in the Pilot into the standard Fast Track process flow for all storage applications that fit the pilot criteria.

The Pilot, approved by the Commission through Advice Letter 4941-E, proposed to continue to build on significant process improvements underway, specifically the building of the modular tool to streamline interconnection application submission. Advice Letter 4941-E described the scope of the software platform effort as the collection of equipment descriptions from applicants, acceptance of online payments, and the leveraging of other PG&E databases. The Advice Letter noted that PG&E anticipated the average timeline for a storage interconnection application process would decrease as each new component came online.[138] A subsequent Advice Letter filing by PG&E provided a report on the outcomes of the pilot. The Working Group Two Report highlights that interconnection time reductions reported in the Advice Letter ranged from 30 to 40 percent with the expectation that trends would continue to show additional improvement.[139]

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[138] *Id*. at 142 citing Advice Letter 4941-E, February 1, 2017 at 8.

[139] *Id*. at 142 citing Advice Letter 5371-E, August 31, 2018 at 6.

### 4.5.3. Issue 11: Proposal B

The foundation of Proposal B, which has three subproposals, is the concept of a Lightning Review. As described in the Working Group Two Report, the Lightning Review concept is predicated on an interconnection review process streamlined to the maximum extent possible for the broadest range of applications for non-exporting energy storage installations. The genesis of the Lightning Review process is the Standard net energy metering process.

There are four areas of process improvement opportunities in the Lighting Review: 1) Application Submittal to Deemed Complete; 2) Fully Frontloading an executable Generator Interconnection Agreement; 3) Technical Review Screens; and 4) Inspection/Testing for Permission to Operate. The Working Group Two Report describes in detail each of the areas and the potential process improvements.

The proposed design and implementation plan for the Lightning Review has three phases; each of these phases equate to a separate proposal.

- Proposal B1 would require Utilities to implement Phase 1 of the Lightning Review. This would include making all non-exporting storage less than or equal to 30 kVA generating facility aggregate nameplate rating eligible for effectively the same process that applications for Standard net energy metering projects less than 30 kVA proceed through, subject to fees commensurate with those processes. Proposal B1 would also require qualifying projects to be exempt from the queueing procedures that non-net energy metering and net energy metering greater than 1 MW projects experience. Proposal B1 is supported by Stem, Green Power Institute, Clean Coalition, CALSSA, and IREC. Utilities offer qualified support. Several of the proposed process improvements have already been implemented by one or more of the Utilities.

- Proposal B2, developed by Stem, recommends the Commission direct Utilities to undertake the study and design of Phase 2 of Lightning Review, which increases the project size eligibility for the Lightning Review to a number greater than 30 kVA as the new standard that applies to most areas of the grid. This proposal recommends that projects below 30 kVA would be eligible anywhere on the grid. The Working Group Two Report notes that the working group did not evaluate or take positions on the specifics of Proposal B2.
- Proposal B3, also developed by Stem, recommends the Commission expand the scope of R.17-07-007 to include the study and design of Lightning Review Phase 3, which entails developing the next set of Integration Capacity Analysis-related Rule 21 improvements beyond those listed in the scope for Working Group Two. Here again, the participants of the working group did not have an opportunity to discuss the details of this proposal.

#### 4.5.4. Issue 11: Proposal C

Proposal C recommends that, in lieu of addressing Issue 25, the scope of Working Group 4 should be amended to research and report what circumstances, configurations, lessons, and changes would need to be adopted in Rule 21 to effectuate a notification-based approach. Issue 25 asks whether the Commission should make any revisions to the expedited process for eligible non-exporting storage facilities in response to pilot program data collected by Utilities between July 1, 2017 and June 30, 2018, in order to support tariff principles of technological neutrality and consistency across Utilities. Proposal C is supported by Stem, Green Power Institute, Clean Coalition, CALSSA, and IREC. Utilities oppose Proposal C. Since the filing of the Working Group Two Report, Issue 25 has been re-assigned to the Interconnection Discussion Forum by the Amended Scoping Memo.

#### 4.5.5. Resolving Issue 11

We conclude that, at this time, the Commission should not adopt a specific proposal for a notification-based approach for non-exporting storage systems with negligible impact on the distribution system. There remain many unanswered questions the Commission needs to consider in order to adopt a particular proposal, in lieu of an application process. However, we find value in the concept and will continue to explore the concept and develop proposals in this proceeding. Further, given the objective of this proceeding is streamlining the interconnection process, we find it reasonable to adopt proposals that look at alternative streamlining approaches for the same class of projects—non-exporting storage systems. We adopt Proposal A as it streamlines the interconnection process for this class of projects. Similarly, we also adopt the concept of Proposal B1 but will address the specifics, including costs in Phase II of this proceeding. We decline to adopt the other options for Proposal B, as the working group did not complete its review of the proposals. Lastly, we decline to adopt Proposal C, which seeks to expand the scope of this proceeding prior to its completion. We should review the results of adopted changes in this decision and the decision on Working Group One proposals to ascertain whether additional changes are warranted. We discuss each of our determinations below.

We begin with the heart of this issue, whether the Commission should adopt a notification-based approach for non-exporting storage systems. The

Working Group Three Report underscores that there was a breadth of perspective, substantial differences of opinion, and many unanswered questions needing to be considered to resolve these differences.[140] While we cannot make a determination based on the record of this proceeding, we note that the Working Group Three Report is over a year old and technology has improved. Furthermore, in light of public safety power shut-offs to prevent wildfires in California, the Commission has increased the importance of the availability of resiliency options. There are policy and technology perspectives with respect to this subject matter that the Commission should consider in this proceeding. Hence, a ruling asking parties to respond to questions on this matter will be issued in this proceeding in the near future.

Despite not coming to a consensus on whether the Commission should adopt a notification-based approach for non-exporting storage systems, we find it valuable that the working group participants were able to find common ground in their examination of the procedures for non-exporting storage systems interconnection applications. Furthermore, we find streamlining these procedures, in lieu of the notification-based approach, to be a related extension of this issue and practical to consider in this decision.

We begin with the threshold question of whether the Commission should limit the proposals to applications for the interconnection of non-exporting standalone storage systems or expand the applicability to other projects in a technology-neutral manner. IREC, CALSSA, Tesla, and Clean Coalition contend

[140] *Id*. at 140.

the Commission should expand the applicability to include all generating facility aggregate nameplate inverter rating under 30 kVA, regardless of whether those systems are exporting or non-exporting. As previously noted, they assert there is no technical basis not to apply the same process to the two systems. However, Utilities argue that there are jurisdictional, contractual, and processing differences that exist. Utilities presented a list of those differences in the Working Group Two Report.[141] We agree that that these differences exist and impact the ability to treat all systems in a similar streamlined manner. Further, as discussed below, the foundation of the proposals is the Pilot, which is focused on non-exporting storage systems and has been largely successful in decreasing interconnection application processing times for these systems.[142] Accordingly, we find it prudent to limit the applicability of the streamlining proposals to non-exporting standalone storage systems. Hence, we should adopt proposals that comply with this limitation.

We turn to Proposal A, which is a consensus proposal. As previously described, the proposal would implement, in the Rule 21 Fast Track process, all successful process improvements tested in the Pilot for non-exporting standalone storage projects. These improvements have been shown to be successful in the Pilot and should be implemented solely for the same group of projects as

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[141] *Id*. at 141. See also PG&E Opening Comments to Administrative Law Judge Ruling, February 1, 2019 at 27-28.

[142] *Id*. at 142.

previously tested.[143] We agree that the improvements would create a more streamlined interconnection process for this class of projects. Furthermore, as indicated in the Working Group Two Report, given the lower volume of the non-export storage projects compared with net energy metering projects, Proposal A would be the most cost-effective approach for reducing interconnection application processing time for this class of projects.[144] Utilities are directed to revise the Rule 21 Fast Track process, implementing the same procedures and criteria as the Pilot.

Proposal B1, also a consensus proposal, renders all non-exporting storage less than or equal to 30 kVA generating facility aggregate nameplate rating eligible for the same process as applications for standard net energy metering projects less than 30 kVA and subject to fees commensurate with that process. In our review of the proposed enhancements for the Lightning Review process, which mirrors the standard net energy metering process, we find that many of the enhancements have already been implemented by Utilities. For example, both PG&E and SDG&E have deployed an auto-validation of required fields as well as the web portal which checks technical eligibility criteria and prevents submission to the Lightning Review process if those criteria are not met.[145] We find that adoption of the concept of the Lightning Review process supports these

[143] *Ibid*.

[144] *Ibid*.

[145] *Id*. at 145-146.

prior process improvements in anticipation of future growth of storage interconnection applications.

The Working Group Two Report lists four principles for developing enhancements for streamlining and the Lightning Review process: a) design for the most common cases; b) minimize roundtrips between utility and applicant by frontloading information exchange; c) remove the need for engineering technical review by using a checkbox or lookup verification; and d) create standard templates for required documents.[146] No participant expressed opposition to these principles. We find the principles reasonable as they should further the streamlining of the process. We should adopt the four principles for developing enhancements for the Lightning Review Process.

The Working Group Two Report identifies proposed enhancements for Proposal B1.[147] At this time, we decline to deliberate on each enhancement due to an insufficient record, including unknown costs for these proposals. Furthermore, we find that requiring Utilities to serve testimony on these enhancements in Phase II of this proceeding is the more appropriate regulatory approach to address these processes and their costs. Accordingly, we direct Utilities to serve testimony in Phase II of this proceeding, providing a detailed proposal for the implementation of the Lightning Review process and the proposed enhancements, in compliance with the principles listed in the Working Group Two Report and adopted herein, and in consideration of the positions

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[146] *Id*. at 144.

[147] *Id*. at 145-153.

described in the Working Group Two Report. Furthermore, the testimony shall include an analysis of the costs and benefits for Proposal B1. While we adopt the concept of Proposal B1, we confirm SDG&E's comments to the proposed decision that in order to implement this proposal, the benefits of Proposal B1 must outweigh the costs.[148] Accordingly, we address this in Phase II of the proceeding, which will address cost related issues including cost recovery.

We decline to adopt Proposals B2, B3, or C. First, participants did not discuss Proposals B2 and B3 during the working group meetings; thus the record is insufficient to determine whether to adopt these two proposals. Furthermore, we find that these proposals, as well as Proposal C, extend beyond the scope of this proceeding. The purpose of Issue 11 is to look at non-exporting storage systems, both Proposals B2 and B3 go well beyond this issue. Proposal C explicitly requests the Commission to expand the scope of this proceeding prior to its resolution and completion. The results of adopted changes in this decision and the decision on Working Group One proposals should be implemented and then evaluated to ascertain whether additional changes are warranted. Hence, we should not adopt Proposals B2, B3 and C.

## 5. Working Group Three Adopted Recommendations

In this section, we describe each of the Working Group Three Issues, the proposals to resolve the issues and positions of parties, and the resolution of the issues. The Commission can choose to adopt none or all of the proposals for each

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[148] See SDG&E Opening Comments to the Proposed Decision at 6.

issue. Again, in limited cases, adoption of one proposal is dependent upon adoption of other proposals.

### 5.1. Issue 12: Improving Timeline Certainty

We adopt all of the proposals recommended to address Issue 12, with the exception of 12g. As discussed further below, we find the adopted proposals foster transparency and accountability. We modify proposal 12i, which calls for a workshop to discuss the two years of tracking and reporting; instead, we require Utilities to host the proposed workshop. Further, we reject the request to "clearly indicate that financial penalties" are on the table. We decline to adopt Proposal 12g; the goals of this proposal are addressed by the adoption of proposals 12f, 12h, and 12i. Below, we describe the background of this issue, followed by a description of each proposal and party positions, and a discussion of our determinations.

#### 5.1.1. Issue 12: Overview

The purpose of Issue 12 is to improve certainty regarding timelines for distribution upgrade planning, cost estimation, and construction. In the Working Group Three Report, parties claim timelines for these three elements of interconnection are not being set, communicated, and/or adhered to in a predictable and consistent manner.[149] These same parties contend that as a result, developers cannot give reliable estimates to customers; customers may be

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[149] Working Group Three Report at 11.

required to carry their own facilities' loan or leasing costs for longer than reasonable or expected; and Utilities are not being held accountable.[150]

Working group participants all agree that in order to improve accountability, transparency, communication, and consistency around these times, additional data is needed along with better data collection. Over the course of the working group meetings, participants acknowledged that the Commission was in the process of conducting an independent study review of interconnection timelines in 2019.[151]

During the working group meetings, Utilities discussed current practices with respect to timeline setting, communication, and adherence. SDG&E states that agreed-upon specific timelines for each project are included in interconnection agreements and discussed and updated throughout the life of the project. Relatedly, SCE asserts that it provides best-practice upgrade times, which are included in interconnection agreements. PG&E notes that it uses a centralized work group to address all generation interconnection requests. All three entities employ a different method for timeline tracking.

Utilities explained to participants that variability and uncertainty can be created when there is a need to coordinate with other agencies, if there are land rights or permitting issues, if the customer had done necessary construction preparation work, or there was unfamiliarity with new technologies. Non-utility participants acknowledged that exceptions will always be needed for

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[150] *Ibid*.

[151] *Id*. at 12.

emergencies, delays from other agencies, and other reasons, but the Commission should establish standard expectations.

Parties developed several consensus and non-consensus proposals. These are discussed in the following subsections.

#### 5.1.2. Issue 12: Proposal 12a

Proposal 12a would establish a framework for quarterly tracking and reporting on timelines for the interconnection application review process and the design and construction of interconnection-related distribution upgrades. The participants agreed upon 12 timelines applicable for the quarterly tracking and reporting:

1) Time from submission of Interconnection Request to the utility's acknowledgement of receipt;
2) Time from submission of Interconnection Request to time deemed complete;
3) Time from Interconnection Request 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 start date to its completion;
6) Time from Electrical Interdependence Test completion to EIT results scoping meeting held;
7) Time from study scoping meeting until study agreement provided;
8) Time from System Impact Study start date to its completion date;
9) Time to provide Draft Generator Interconnection Agreement 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 notifies 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; and

12) Total time from submission of Interconnection Request to Permission to Operate (Not in Rule 21, tracked for informational purposes.)

This is a consensus proposal with one caveat. Utilities requests the timeline tracking be on a future basis as they assert the establishment of retroactive baseline data is too great a burden.[152]

#### 5.1.3. Issue 12: Proposal 12b

Proposal 12b is supplemental to Proposal 12a and would require that in addition to the 12 timelines tracked and reported, seven other timelines be included:

1) Time from request to consider modification to determination whether modification is material (F.3.b.v);
2) Time for responding to line-side taps variance requests (for Utilities that require a variance request);
3) Design and invoice of net generation output meter;
4) Installation of net generation output meter;
5) Time from customer agreement to proceed to final design and issuance of invoice;

[152] *Id*. at 14.

6) Time from customer payment of invoice and completion of customer work to completion of upgrade construction; and
7) Time for scheduling of Commissioning Test.

This proposal is supported by CALSSA, Clean Coalition, Green Power Institute, IREC, and JKB Energy. Supporters contend these additional timelines are an interim step to begin tracking the process and construction timelines in Rule 21.[153] Utilities, who oppose this proposal, consider some of these timelines to be more of a process issue and not a tracking issue and could be addressed in the Interconnection Discussion Forum.[154]

### 5.1.4. Issue 12: Proposal 12c

Also a consensus proposal, Proposal 12c would establish standard timelines for design and construction of interconnection-related distribution upgrades as follows: (i) 60 business days for design and 60 business days for construction; or (ii) design and construction timelines as agreed with the customer. Parties agree that the 60-day clock would commence upon payment and after the customer has done everything necessary on their end to prepare for construction.[155]

### 5.1.5. Issue 12: Proposal 12d

Proposal 12d would establish standard timelines for the installation of Net Generation Output Meters as follows: (i) 20 business days for design and invoicing, and 20 days for construction or (ii) design and construction timelines

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[153] *Id*. at 15,

[154] *Id*. at 15-16.

[155] *Id*. at 16.

as agreed with the customer. CALSSA, Clean Coalition, Green Power Institute, IREC, JKB Energy, SDG&E and Tesla support this proposal. CALSSA highlights the importance of timelines for Net Generation Output Meters.[156]

Neither SCE nor PG&E support the proposal. SCE says it currently achieves a one to two month installation time for the vast majority of its Net Generation Output Meter installations, but process improvements are in development.[157] While open to developing IT infrastructure to track timelines, PG&E opposes establishing a 20-day timeline requirement given "these timelines can vary across the service territory based on local needs."[158]

#### 5.1.6. Issue 12: Proposal 12e

Another consensus proposal, Proposal 12e would require that customers be notified when a timeline is not met, or at risk of not being met. Further, the proposal would require notification to include the category of delay, the reason for the delay, and a new expected deadline.

While the proposal in concept is agreed to by all participants, there are two areas of non-agreement: 1) whether it is necessary to include the detailed reason for the delay and 2) whether to notify the Energy Division.

With respect to the question of whether to require a detailed reason for the delay, CALSSA and IREC contend that a generic auto-generated response does

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[156] *Ibid*.

[157] *Id*. at 17.

[158] *Ibid*.

not accomplish the goal of accountability or transparency.[159] PG&E argues that the workflow management databases are separate between Electric Grid Interconnection and Service Planning and the former does not have a line of sight into the step-by-step construction process.[160]

Regarding notification to Energy Division, SDG&E contends the process would be overly burdensome. PG&E and SCE offer work arounds to ease the notification burden.

#### 5.1.7. Issue 12: Proposal 12f

Continuing on the issue of timelines, Proposal 12f would establish an overall goal that 95 to 100 percent of projects meet all timelines in the tracking and reporting framework, within two years after the start of tracking.

Parties discussed the concept of timeline goals. PG&E and SCE agreed to begin tracking timelines in July 2019, such that any goal would be set for July 2021.[161] PG&E and SCE also agreed to provide quarterly progress reports toward compliance in 2021.[162] However, the Working Group Three Report underscores that PG&E withdrew its support of this proposal immediately before the report was filed, with no discussion.

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[159] *Ibid*.

[160] *Ibid*.

[161] *Id*. at 18.

[162] *Ibid*.

In opposition to the concept of setting an overall goal, SDG&E underscores that Rule 21 applications account for less than 0.1 percent of all applicants. SDG&E contends setting timeline goals is not beneficial to SDG&E ratepayers.[163]

### 5.1.8. Issue 12: Proposal 12g

Proposal 12g builds on Proposals 12a, 12b, and 12f and requires adoption of 12a and 12f. Proposal 12g would require that if a utility is not meeting the goal established by Proposal 12f through the tracking established in 12a/12b, the Utility would first set intermediate goals within the first two years of commencement of tracking and then establish a process to achieve compliance within the first two years of commencement. This proposal is supported by CALSSA, Clean Coalition, Green Power Institute, IREC, JKB Energy, and Tesla and opposed by Utilities.

The supporters of the proposal assert that the purpose of establishing intermediate goals is to set Utilities on a path towards all projects being completed within the Rule 21 timeline.[164] Further, the supporters also submit that incremental goals will ensure that when there are delays, the delays are not unreasonable.

PG&E and SDG&E are not amenable to intermediate goals. SCE prefers to use the Interconnection Discussion Forum to discuss timeline tracking and quarterly reporting. PG&E recommends leveraging collective stakeholder expertise to analyze collected data and collaborate on identifying and closing

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[163] *Id*. at 19.

[164] *Ibid*.

gaps. SDG&E reiterates that interconnection applications account for less than 0.1 percent of all applications and setting goals for timelines is not beneficial to SDG&E ratepayers.[165]

#### 5.1.9. Issue 12: Proposal 12h

Proposal 12h would determine which projects the goals established in 12f and 12g apply. Here again, Proposal 12 h builds upon and is dependent upon the adoption of other Issue 12 proposals: 12a, 12f, and 12g. Supported by CALSSA, Clean Coalition, Green Power Institute, IRE, JKB Energy, SCE and Tesla, the proposal recommends that the reporting requirements and goals established in previous Issue 12 proposal are applicable to all projects except for net energy metering projects less than 30 kW, which are standard net energy metering projects. Parties generally agreed that standard net energy metering projects are interconnected quickly; hence the volume of projects would complicate reporting.[166]

PG&E and SDG&E dispute the need for Proposal 12h. PG&E opposes applying the timelines and goals to any subset of projects based on size. Instead, PG&E recommends the Commission prioritize improvements based on data indicating where the most need is. For example, PG&E asserts that standard net energy metering and net energy metering paired storage are the projects with the

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[165] *Id*. at 20.

[166] *Id*. at 21.

highest volume of applications and the Commission should focus application improvements on these projects.[167]

#### 5.1.10. Issue 12: Proposal 12i

Proposal 12i is a next step should the Commission choose to adopt proposals 12a and 12f. Supported by CALSSA, Clean Coalition, Green Power Institute, IREC, and JKB Energy, this proposal would require Energy Division to hold a meeting of the parties after two years of timeline tracking and reporting. The purpose of the meeting would be to discuss whether the goals have been achieved and, if not, what steps should the Commission take. In addition, the proposal requests the Commission to apply financial penalties if goals are not met. Utilities oppose the financial penalties portion of this proposal. TURN also recommends that any financial penalties be paid by shareholder dollars, not ratepayer dollars.

#### 5.1.11. Issue 12: Proposal 12j

Proposal 12j would require Utilities to provide quarterly updates on substation upgrades to applicants whose projects are dependent upon a given substation upgrade. Supported by CALSSA, Clean Coalition, Green Power Institute, IREC, and JKB Energy, this proposal is requested because long delays and revised timelines association with substation upgrades create a strong customer dissatisfaction. The proponents of Proposal 12j recognize that

[167] *Ibid*.

substation upgrades cannot be subject to standard benchmark timelines due to their complexities and related uncertainties.[168]

Utilities oppose Proposal 12j. While not opposed to providing quarterly updates as a business practice, PG&E does not support the inclusion of this requirement in Rule 21. SDG&E also opposes adding this requirement to Rule 21, stating that it would prefer to continue to create two-way transparency based on design and construction milestones tracked by the developer and utility. SCE asserts ample opportunity already exists to have regular status updates with interconnection customers about substation upgrades.[169]

#### 5.1.12. Resolving Issue 12

We adopt all proposals recommended in the Working Group Three Report, with the exception of Proposal 12g. Further, we modify Proposal 12i. We find that the proposals address the objective of improving certainty with timelines, cost estimation and construction. We discuss each of these determinations below.

We begin with the consensus proposals: 12a, which creates a framework for timeline tracking and reporting; 12c, which establishes a standard timeline for design and construction of upgrades; and 12e, which requires customer notification when a timeline is not met. As discussed in Sections 5.1.2, 5.1.4, and 5.1.6 above, all three of these proposals have agreement of the entire working group. All three specifically address the objective of this issue: improving

[168] *Id*. at 23.

[169] *Ibid*.

certainty with respect to timelines. We conclude the Commission should adopt Proposals 12a, 12c, and 12e.

For Proposal 12a, Utilities will track the 12 timelines discussed in Section 5.1.2 above. We find that tracking these timelines will provide the data necessary for future, data-driven considerations of process improvements. Parties agree that the reporting should be on a quarterly basis: we find this frequency of reporting reasonable, at this time. We will monitor to determine if the Commission should have more or less frequent reports.

With respect to Proposal 12c, we highlight that adoption of these design and construction timelines aligns with the design and cost estimation timelines recommended in Proposal 10.6, as discussed in Sections 4.4.7 and 4.4.10 above. Hence, we find it reasonable to likewise adopt Proposal 6 from Working Group Two, Issue 10. Parties disagreed on the Proposal 10.6 timeline during discussions in Working Group Two but were able to come to a consensus on a timeline in Working Group Three.

For Proposal 12e, there is one point of contention regarding whether the Commission's Energy Division should be simultaneously notified when notifying a customer of a delay in the timeline. Opposing parties state this additional simultaneous notification is burdensome. We find it reasonable to instead require Utilities to include a tally of the notifications on a quarterly basis, with the report adopted in Proposal 12a. The quarterly tally shall also include the associated data required in Proposal 12e: new expected date, category of delay, and reason for delay. Utilities shall meet with stakeholders to develop a standard set of categories of delay, as required by Proposal 12e. A final set of agreed-upon delay categories shall be provided to Energy Division no later than six months from the issuance of this decision.

We move on to those proposals where consensus was not reached.

Proposal 12b would add seven other timelines to the framework adopted in Proposal 12a. As noted in Section 5.1.3 above, supporters maintain that these additional timelines are an interim step to begin tracking the process and construction timelines in Rule 21. However, Utilities consider some of these timelines to be more of a process issue and not a tracking issue. We disagree. We find that tracking and reporting on these seven additional timelines should result in a more transparent process. Again, the objective of Issue 12 is to improve certainty; a more transparent process should help improve certainty. Furthermore, tracking these additional timelines should also result in increased accountability. We conclude Proposal 12b should be adopted.

With respect to the reporting requirements of Proposal 12b, as well as 12 a, we recognize that differences in utility timeline tracking could result in reporting discrepancies between the three Utilities.[170] Hence, we direct Utilities to confer with Energy Division to ensure reporting consistency. In comments to the proposed decision, SDG&E and SCE request the Commission establish a sunset date for these reporting requirements.[171] We address below this in our discussion regarding Proposal 12i.

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[170] See SCE Opening Comments to the Proposed Decision at 6-9 and SDG&E Opening Comments to the Proposed Decision at 7-8.

[171] SDG&E Opening Comments on Proposed at 7-8 and SCE Opening Comments on Proposed Decision at 6-9.

We turn to Proposal 12d, which establishes a 20 business day timeline for the design of net generation output meters and a 20 business day timeline for construction. Tesla highlights that the amount of time for the design and invoice and installation steps for net generation output meters has historically posed significant challenges for developers.[172] SCE says it currently achieves a one to two month timeline for these installations. However, PG&E reports that it completed 5500 such installations in 2019, with 99 percent of those installations completed in 10 calendar days.[173] While, PG&E argues that "these timelines can vary across the service territory based on local needs," PG&E's own records show that this is not the case in the vast majority of installations.[174] Given that net generation output meters can add tens of thousands of dollars to project costs and delays of six months or more, as highlighted by Tesla,[175] we find it reasonable to adopt these 20-day timelines.

The next proposals focus on setting goals for meeting the timelines we establish here: Proposals 12f, 12g, 12h and 12i.

We adopt Proposal 12f, which would establish a goal that 95 to 100 percent of projects meet all timelines adopted in Proposals 12a and 12b within two years upon the commencement of tracking. We are not persuaded by SDG&E's contention that the timeline goals are not beneficial to its ratepayers based on the

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[172] *Id*. at 15.

[173] PG&E Comments to November 27, 2019 Ruling at 3.

[174] *Ibid*.

[175] Tesla Comments to November 27, 2019 Ruling at 3.

volume of applications.[176] We find adoption of this proposal would provide a benchmark by which to assess our adopted tracking procedures, which would benefit ratepayers. Again, the objective in this procedure is streamlining Rule 21 and the objective of Issue 12 is improving certainty around timelines. Establishing timeline benchmarks should help us achieve both of these objectives. Thus, Proposal 12f should be adopted. We direct note

Relatedly, we adopt Proposal 12h, which limits the applicability of Proposal 12f to non-net energy metering projects and net energy metering projects greater than 30 kW. As we previously pointed out in Section 5.1.9 above, parties agree that the volume of standard net energy metering projects would complicate reporting.[177] PG&E and SDG&E dispute the need for Proposal 12h, but we find that adoption of this proposal will target the project types that are of most concern to stakeholders, without an undue administrative burden.[178] We agree with PG&E that we should target projects based on where the most need is but that need is not necessarily based on a location but rather based on a project type. Therefore, Proposal 12h should be adopted.

We decline to adopt Proposal 12g, which would establish additional intermediate goals if tracking reveals that Utilities are not meeting the 95 to 100 percent goal. Adoption of Proposals 12f, 12h and 12i sufficiently address the need for benchmarks to assess the results of the timeline tracking. Furthermore,

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[176] Working Group Three Report at 19.

[177] *Id*. at 21.

[178] *Ibid*.

Proposal 12g would add a level of unnecessary administration. Hence, Proposal 12g should not be adopted.

Instead of Proposal 12g, we find that a modified Proposal 12i is a more reasonable and effective approach for determining whether the objective of Issue 12 is being achieved. Proposal 12i, as modified, would require Utilities—with oversight by the Energy Division—to organize and host a workshop to discuss whether, after two years of tracking, 95 to 100 percent of the timelines being tracked and reported on have been met. If the benchmark has not been met, the participants should discuss what steps are needed. If the benchmark has been met, the participants shall discuss a sunset date for the reporting requirements, as suggested by SDG&E.[179] Proponents of this proposal also recommend that financial penalties should be discussed by parties. Utilities oppose the inclusion of financial penalties but otherwise support this proposal. We find the issue of financial penalties premature, at this time. The Commission must first determine whether timeline certainty is improving. Accordingly, the modified Proposal 12i should be adopted to determine whether timeline certainty is improving. The Commission may consider establishing a penalty structure in the future if it determines such a construct would support timely interconnection.

We also adopt Proposal 12j, to require Utilities to provide quarterly updates on substation upgrades to applicants whose projects are dependent on a substation upgrade. We find this proposal also meets the objective of Issue 12

[179] See SDG&E Opening Comments at 8.

and provides additional transparency. Utilities argue that including the requirement in Rule 21 is unnecessary and should solely be a business practice. We find that a Rule 21 requirement will create better transparency and improve timeline certainty for customers. Proposal 12j should be adopted.

### 5.2. Issue 15: Itemized Billing

We adopt both proposals recommended to address Issue 15. As discussed further below, we find both consensus proposals continue our movement toward greater transparency. Below, we present a discussion of the need for resolving this issue, a description of the two consensus proposals, and a discussion of the resolution of the issue.

#### 5.2.1. Issue 15: Overview

Issue 15 asks whether the Commission should require itemized billing for distribution upgrades. Developers asked the Commission to address this issue because they contend there is no consistency across Utilities regarding the level of detail provided in the final accounting invoice to customers. Developers submit that more detail in billing would allow customers to compare final costs with the estimated costs.

The Working Group Three Report explains that developers provide customers project estimates based on the Unit Cost Guide, which was approved in concept by the Commission in D.16-06-052, along with principles for developing the Guide.[180] According to the adopted principles, the Guide will include the anticipated cost of procuring and installing such facilities during the

[180] D.16-06-052 at Ordering Paragraph 1.

current year and may vary among Utilities and within an individual Utility's service territory.[181]

While the Guide does not govern actual costs,[182] developers stressed the need to know the actual costs incurred for certain separate components of total costs. This, the developers maintain, would lead to improved estimations for their customers. Currently, however, customers' bills show lump sums for the entire upgrade project without substantive information detailing what they have been charged. Further, the developers contend the lump sum billing reduces the ability to compare costs with third-party contractors doing distribution upgrades. Parties agreed that the billing cost categories could be based on the level of detail provided in the Guide.[183]

Parties discussed the difficulty for Utilities to provide the level of detail requested given current Utilities' information and management systems. Utilities stated a willingness to discuss solutions within the capabilities of existing systems.[184]

Parties also discussed two types of billing: i) "bill on estimate" requires the interconnection customer's cost responsibility to be equal to the estimated cost provided by a utility before construction begins—a utility would not reconcile the estimate with the actual and the cost estimate is itemized; and

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[181] *Id*. at Appendix A.

[182] In D.16-06-052, the Commission specifically stated that the Cost Guide will not be binding for actual facility costs.

[183] Working Group Three Report at 24-25.

[184] *Id*. at 25.

ii) reconciled billing requires the customer to pay a deposit and make payments at certain milestones—a utility reconciles based on actual costs and the final bill is not itemized. Utilities contend it is difficult to itemize bills simultaneous with reconciled billing. Only PG&E stated an ability to provide cost itemization without the need to charge customers additional costs.

Two independent proposals were presented during the working group meetings. These are both consensus proposals.

#### 5.2.2. Issue 15: Proposal 15a

Proposal 15a would direct Utilities to do what is immediately possible to provide cost itemization based on existing system capabilities. In addition, the proposal would require Utilities to strive to improve their itemized billing processes for further clarity to the customer and developer or applicant.

Given the current system, only SDG&E is able to adhere to this proposal without additional cost to the customer. PG&E and SCE assert that they would incur additional costs, which would be charged to the customer.

#### 5.2.3. Issue 15: Proposal 15b

In Proposal 15b, the Commission would consider the details for the bill on estimate approach in a future working group or rulemaking. As previously described, the bill on estimate approach would eliminate the need for an itemized final bill, as the customer’s cost responsibility is equal to the estimated cost provided by a utility prior to construction.

#### 5.2.4. Resolving Issue 15

It is reasonable to adopt Proposal 15a and a modified Proposal 15b; both of these are consensus proposals. As noted by Public Advocates Office, both proposals will provide greater cost transparency.[185]

With respect to Proposal 15a, we find that Utilities should strive to improve their itemized billing process for clarity and transparency. We anticipate that this improved clarity and transparency will also limit future disputes, which improves regulatory efficiency. Proposal 15a should be adopted.

We agree that Utilities should continue to improve billing practices into the future. Participants recommend a future working group or rulemaking to continue looking at billing practices, including bill on estimate cost estimates.[186] The Commission always looks to improve processes, including billing practices. However, we do not think it is necessary to require a future rulemaking at this time. Instead we adopt the CALSSA recommendation to have Utilities prepare and present a bill on estimate proposal in a future Interconnection Discussion Forum; this is a more timely approach.[187] Utilities are directed to present such a proposal during an Interconnection Discussion Forum, no later than January 31, 2021.

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[185] Public Advocates Office Comments to November 27, 2019 Ruling at 6.

[186] Public Advocates Office Comments to November 27, 2019 Ruling at 6-7.

[187] CALSSA Comments to November 27, 2019 Ruling at 3-4.

### 5.3. Issue 16: Third Party Construction of Upgrades

We adopt the three consensus proposals recommended to address Issue 16, proposals 16a, 16b, and 16c. The purpose of these proposals is to encourage third party construction of upgrades so as to support timely and more cost-effective interconnection. As discussed further below, we find the consensus proposals promote regulatory simplicity for third-party providers and lead to increased participation by these providers. However, we decline to adopt Proposal 16d because no such upgrade scenarios were identified. Below, we provide an overview of this issue, followed by a description of each proposal and party positions, and a discussion of our determinations.

#### 5.3.1. Issue 16: Overview

Supporters for encouraging third-party upgrade construction assert several benefits including increased competition, improved timelines, and cost certainty.[188] Supporters contend that the use of third-party providers for upgrades will give developers more control over timing, costs, and contractor choice. Parties express safety and reliability concerns.

Parties reference two points. First, Rule 21 currently permits third-party construction on interconnection facilities, subject to approval by the distribution provider.[189] Second, use of third-party providers does not necessarily equate to lower costs when considering initial and ongoing costs.[190]

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[188] Working Group Three Report at 27.

[189] *Id*. at 27.

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

Over the course of the working group meetings, parties reviewed eligibility rules and competitive bidding language and discussed the qualification and selection process for third-party providers. Parties also discussed proposed changes to Rule 21 and developed four proposals as described below.

#### 5.3.2. Issue 16: Proposal 16a

Proposal 16a, a consensus proposal, would incorporate by reference Rule 15 eligibility requirements into Rule 21, specifically minimum contractor qualifications, other contractor qualifications, and facility relocation or rearrangement.[191] Additionally, this proposal would also require existing warranty requirements from SCE's *Terms and Conditions Agreement for Installation of Distribution Line Extension by Applicant* to be incorporated into Rule 21 by reference.[192] Parties agreed that incorporation of these sections by reference eliminates the need to develop and adopt new language in Rule 21.[193] All parties further agree that eligibility rules will ensure the third-party upgrade providers are sufficiently qualified to provide an appropriate level of safety and reliability.[194]

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[191] Rule 15 sections G.2, G.3, and I.1.

[192] Working Group Three Report at 29, footnote 4.

[193] *Id*. at 29.

[194] *Ibid*.

### 5.3.3. Issue 16: Proposal 16b

Also a consensus proposal, Proposal 16b would include a reference, in Rule 21, to the applicable competitive bidding language from Rule 15. Specifically, Rule 21 would be revised to refer to the following three statements:

- *Upon completion of Applicant's installation and acceptable by [utility], ownership of all such facilities will transfer to [utility].*[195]
- *Applicant shall pay to [utility] the estimated cost of [utility's] inspection, which shall be a fixed amount not subject to reconciliation.*[196]
- *Only duly authorized employees of [utility] are allowed to connect to, disconnect from, or perform any work upon [utility's] facilities.*[197]

Similar to Proposal 16a, parties agree that a reference to the Rule 15 language eliminates the need to develop and adopt new language for Rule 21.[198] Furthermore, as stated in the Working Group Three Report, only qualified contractors would be able to participate in the bidding, consistent with existing bidding and qualification practices.[199]

### 5.3.4. Issue 16: Proposal 16c

Proposal 16c would modify Rule 21 by revising the language: "Subject to the approval of Distribution Provider, a Producer may, at its option…" to

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[195] *Ibid*. referencing Rule 15 Section G.1.a.

[196] *Ibid*. referencing Rule 15 Section G.1.e. (part a).

[197] *Ibid*. referencing Rule 15 Section G.1.f.

[198] *Ibid*.

[199] *Ibid*.

"Subject to/consistent with Rule 15 contractor selection rules, a Producer may, at its option..." Green Power Institute and Clean Coalition contend removing the discretion language, "*Subject to the approval of Distribution Provider*" is needed in order to achieve the benefits of promoting regulatory simplicity for third-party providers and increased participation by these providers.[200] Utilities agree with the language revision.[201]

#### 5.3.5. Issue 16: Proposal 16d

Proposal 16d would allow third-party providers to work on existing de-energized systems under specified scenarios, such as on dedicated lines and in other specified situations. However, parties could not agree on what circumstances third-party providers could work on existing de-energized facilities.[202]

Green Power Institute and Clean Coalition contend Utilities generally disallow third-party electrical upgrades, which Utilities did not contradict.[203] Utilities support the use of current facility practices allowed under Rules 15 and 16 for the construction of new interconnection non-energized facilities.[204]

#### 5.3.6. Resolving Issue 16

We find adoption of the three consensus proposals for Issue 16 would directly address the objective of the issue: the encouragement of third-party

[200] *Id*. at 30.

[201] *Ibid*.

[202] *Ibid*.

[203] *Id*. at 31.

[204] *Ibid*.

construction of upgrades. These three proposals: 16a, 16b, and 16c, would promote regulatory simplicity and lead to more timely and cost-effective interconnections. However, given the absence of any identified upgrade scenarios relevant to the subject of de-energized systems, we decline to adopt Proposal 16d, which would encourage third-parties to work on existing de-energized systems. We discuss each of these separately below.

Working group participants agree that Proposal 16a, which incorporates tariff Rule 15 by reference, would ensure that third-party upgrade providers are sufficiently qualified for safety and reliability purposes.[205] As discussed in the Working Group Three Report, participants discussed contractor qualifications and the selection process, realizing that referencing the Rule 15 provisions addresses the safety and reliability concerns while simultaneously simplifying the process. Hence, Proposal 16a achieves the objective of Issue 16 and should be adopted.

Similarly, Proposal 16b, which proposes to reference Rule 15 competitive bidding provisions, would lead to the promotion of third-party construction of upgrades while addressing safety and reliability concerns. Working group participants agree that referencing competitive bidding language from Rule 15 in Rule 21 resolves concerns about contractor eligibility.[206] We agree. Thus, we find Proposal 16b meets the intention of Issue 16 and should be adopted.

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[205] *Id*. at 29.

[206] *Id*. at 28.

Proposal 16c would align the contractor selection provisions of Rule 21 with Rule 15 while encouraging third-party construction of upgrades by eliminating certain "discretion" language. Participants submit that removing language requiring third-party construction to be subject to the approval of the Distribution Provider would create a more competitive environment that also improves costs and timelines.[207] We find that the alignment of the contractor selection provisions and the elimination of the "discretion" language achieves many benefits: improves consistency between rules, promotes regulatory simplicity, and meets the objective of Issue 16. Hence, Proposal 16c should be adopted.

Proposal 16d recommends allowing third parties to work on existing de-energized systems under specific scenarios. As noted in the Working Group Three Report, participants could not agree on any scenarios in which third parties could work on existing de-energized facilities.[208] Without any identified scenarios, it is not prudent to adopt Proposal 16d. Proposal 16d should not be adopted.

### 5.4. Issue 20: Coordination of Commission and FERC Rules for Behind-the-Meter Distributed Energy Resources

We adopt the three consensus proposals recommended to address Issue 20: proposals 20a, 20b, and 20c. Issue 20 asks how the Commission should coordinate its interconnection rules with federal rules for behind-the-meter

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[207] *Id*. at 27.

[208] *Id*. at 30.

distributed energy resources. As discussed further below, we agree with the working group that no modification to the rules are necessary to improve the coordination of the two sets of rules. Rather, education through additional information provided through the internet should improve access to clarifying information. Below, we describe the issue and each proposal, and provide a discussion of our determinations.

#### 5.4.1. Issue 20: Overview

The Working Group Three Report explains that customer-sited and distribution-connected energy storage resources are generally interconnected under Rule 21, but opportunities exist for certain resources to participate in the wholesale market using the federal WDAT process. Some participants contend that these resources would benefit from clarifying and streamlining transfers from Rule 21 to WDAT and understanding how to minimize re-studies.

Working Group Three participants discussed the requirements for the WDAT interconnection process and when a project/resource must be re-studied for transfer to the WDAT process. Utilities discussed past experiences with transitions from Rule 21 to WDAT. Participants also discussed related CAISO tariffs and Commission resource adequacy requirements.

Participants developed three consensus proposals, which are discussed below.

#### 5.4.2. Issue 20: Proposal 20a

Proposal 20a would use Frequently Asked Questions on utility websites to clarify the transfer processes and permission-to-operate rules for Rule 21 projects transferring to the WDAT interconnection process and for eligible Rule 21 resources to begin the New Resource Implementation process at the CAISO.

Utilities provided a table of existing procedures to enable transitions from Rule 21 to WDAT.[209] PG&E and SCE both state they have instructional language on their web sites but highlight that projects already granted a permit to operate, which have proposed changes, would require a new interconnection request.[210]

CESA and Green Power Institute believe that customers transferring from Rule 21 to the WDAT process could benefit from clarifications to and guidance on these processes.[211] Further, CESA recommended that the high-level overview page could be provided within the applicable Frequently Asked Questions documentation and webpages.[212]

### 5.4.3. Issue 20: Proposal 20b

Proposal 20b is an all participant agreement that no modification is necessary to the queuing rules for Rule 21 and WDAT projects seeking to interconnect at the same location.

### 5.4.4. Issue 20: Proposal 20c

Also a consensus proposal, Proposal 20c depends upon the adoption of Proposal 20a and would require the addition of reference language or a soft link within the Rule 21 tariff to the Frequently Asked Questions web pages recommended in Proposal 20a.

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[209] *Id*. at 35-36.

[210] *Id*. at 36.

[211] *Ibid*.

[212] *Id*. at 38.

The Working Group Three Report explains that a soft link would provide a shortcut to relevant information for contractors and interconnection applicants. The inclusion and use of a soft link would enable contractors and applicants to find answers quickly, while decreasing the need to contact utility personnel for this same information.

CESA proposes that as the volume of requests increases, Utilities could use these soft links to address specific use cases, as provided in the Working Group Three Report. Participants agreed that posting of these cases may not be necessary at this time but should be considered in the future.[213]

#### 5.4.5. Resolving Issue 20

The purpose of Issue 20 is to coordinate Commission and federal interconnection rules for behind-the-meter distributed energy resources. We find that the three consensus proposals recommended in the Working Group Three Report resolve the issue. Proposal 20a would use information web pages to educate customers on the transfer processes between the Commission and federal interconnection processes. We find Proposal 20a provides customers and other interconnection stakeholders with easy access to clarifying information. Proposal 20b recommends maintaining the current queuing rules for Rule 21 and federal interconnection processes seeking to interconnect at the same location. We agree that no modification is necessary. Similar to Proposal 20a, Proposal 20c provides customers and other interconnection stakeholders access to existing

[213] *Id*. at 39, Annex B.

information resulting in better informed customers and stakeholders. Proposals 20a, 20b, and 20c should be adopted.

### 5.5. Issue 22: Improving Interconnection Application Portals

We conclude that the Commission should allow continued discussion of the 18 subproposals for portal improvements. While we determine that Utilities should improve interconnection application portals, we find that the participants did not have time to sufficiently discuss each of the 18 subproposals developed by the working group. For each of the subproposals, Utilities are directed to develop and present cost recovery mechanisms where approved mechanisms do not already exist. We discuss the additional development of the subproposals, the recommendations of the working group, and provide additional details regarding these determinations.

#### 5.5.1. Issue 22: Overview

Working Group Three participants recognize and agree that there are opportunities for immediate and ongoing improvements to the Utilities' interconnection application portals, which should lead to streamlining the interconnection application process.[214] The working group discussed the capabilities and problems of the current interconnection portals, efforts for improvements, as well as planned improvements. A subworking group developed a list of 18 proposed improvements to the portals, as indicated in Table 1 below, which were then prioritized by importance to developers and

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[214] *Id*. at 40.

support by Utilities. As described below, participants developed two proposals with respect to the issue of whether the Commission should require Utilities to make improvements to the interconnection application portals.

#### 5.5.2. Issue 22: Proposal 22a

Proposal 22a recommends the Commission provide direction on the 18 subproposals for portal improvements, as listed in Table 1 below.

After a subworking group developed the Table 1 subproposals and the prioritizations, participants provided comments on the subproposals. Green Power Institute contends that limited discussion of the subproposals occurred resulting in potential misunderstanding of the subproposals in the comments or inaccurate comments due to evolving sub proposals. Green Power Institute maintains that additional discussion is warranted.[215] However, if the Commission were to move forward, Green Power Institute recommends the Commission determine whether each of the subproposals should be adopted either as a principle or as a directive to Utilities.[216] Tesla recommends the Commission adopt the subproposals and direct Utilities to develop an implementation plan for the subproposals.[217]

| **Table 1[218]** | |
|---|---|
| **Subproposals** | |
| **1** | Question-response facility with 24-hour turnaround, ***or*** online chat box. |

[215] *Id*. at 41.

[216] *Ibid*.

[217] *Ibid*.

[218] *Id*. at 43.

| | |
|---|---|
| **2** | Include an option for transmission or distribution interconnection in the online application. |
| **3** | Provide an Application Programming Interface that is harmonized across Utilities. |
| **4** | Add V2G-DC interconnection options to portal. |
| **5** | Add automated Pre Application Report (PAR) option to portals. This would allow applicants to apply for, pay for, and receive PAR reports almost instantaneously. |
| **6** | Automate the "deemed complete" process for standardized or template-based single-line diagram projects. |
| **7** | Online signature option for all required interconnection application and related signatures such as Generator Interconnection Agreements. |
| **8** | Add link in Integrated Capacity Analysis maps that allows applicant to jump from the Integrated Capacity Analysis map to the online interconnection portal, location-specific info automatically populated. |
| **9** | Eliminate manual data entry as much as possible by integrating with applicant databases or allowing batch uploads. |
| **10** | Eliminate requirement to provide existing system info when applying for additional interconnection capacity (either solar or storage). |
| **11** | Automated data validation check when submitting application. |
| **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. |
| **14** | Create one-click "Authority Having Jurisdiction" approval process, possibly app-based or web-based. |
| **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. |

| | |
|---|---|
| **16** | Online payments for all payments, including standard payments such as NGOMs[219] for residential storage systems or meter socket adapters. |
| **17** | Allow contractors to generate forms for standard agreements like the Interconnection Facilities Financing and Ownership Agreement, NGOM, etc. |
| **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. |

#### 5.5.3. Issue 22: Proposal 22b

Proposal 22b recommends that, for any of the listed subproposals that require improvements to the Utilities' 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, where approved recovery does not already exist. This is a consensus proposal with caveats, as described below.

First, pointing to the Commission's objective in this proceeding of streamlining the interconnection process, Green Power Institute supports consideration of costs for these subproposals, but without a cost-benefit analysis.[220] Second, TURN maintains that if only a small group of developers benefit from the subproposal, the costs associated with the subproposal should not be rate-based.[221] Third, PG&E supports the recovery of costs for the implementation of any of these subproposals be from the Interconnection

[219] NGOM is an acronym for the net generation output meters.

[220] *Working Group Three Report* at 45.

[221] *Ibid*.

Request Fee. PG&E asserts this would allow that costs are recovered from the set of customers who benefit.[222] Fourth, stating that the existing application processes are adequate to facilitate the interconnection requests and review processes, SDG&E asserts the Commission should evaluate whether the benefits to the public outweigh the costs of any subproposal implemented and ensure that those who benefit from the subproposal are appropriately paying for the costs.[223]

#### 5.5.4. Resolving Issue 22

We find that improvements to the Utilities' interconnection application portals should be made based upon the list of 18 subproposals in Section 5.5.2 above and the expressed support by all working group participants for some of these subproposals (e.g. subproposals 2, 7, 9, 10, 11, and 15). We agree with the participants that additional discussion is needed regarding the 18 subproposals, especially with respect to cost and cost recovery methods. However, there is insufficient record to determine which of the 18 subproposals should be adopted. As described in the Working Group Three Report, the subproposals have varying degrees of support, but the lack of support could "reflect misunderstandings about a sub proposal."[224] We agree with Utilities that further discussion should and could occur through a workshop.[225]

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[222] *Ibid*.

[223] *Ibid*.

[224] *Id*. at 41.

[225] PG&E comments to November 27, 2019 Ruling at 11, SCE comments to November 27, 2019 Ruling at 10.

Accordingly, we direct Utilities to host an Interconnection Portals Workshop on the subproposals. The workshop shall be held no later than six months following the issuance of this decision. Utilities shall coordinate this workshop with other proceedings considering or implementing improvements to interconnection portals, especially R.14-07-002 and its successor, and ensure the workshop is noticed on those proceedings' service lists.[226] During the workshop, Utilities shall identify and describe the portal improvements they have implemented or plan to implement. Interconnection stakeholders should also discuss the 18 subproposals, focusing on those where there is utility support and high proponent ranking, as indicated by Tiers A and B of Table 1 in the Working Group Three Report. Part of the workshop should be dedicated to a presentation by Utilities of costs and proposed cost recovery for Tiers A and B sub proposals. Should additional portal issues arise between the issuance of this decision, and the Interconnection Portal Workshop, Utilities shall work with Energy Division to incorporate the new topics into the workshop agenda.

No later than 45 days following the workshop, Utilities shall submit testimony proposing a set of portal improvements as well as the costs and cost recovery. The testimony will be considered in the second phase of this proceeding, which will address costs and cost allocation matters.

[226] R.14-07-002 is the Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Codes Section 2827.1 and to Address Other Issues Related to Net Energy Metering.

While we do not have the record to approve a specific list of subproposals and the associated cost recovery methods, we provide some policy direction to Utilities in their preparation for the workshop and the subsequent testimony submission and to parties participating in the workshop. First, we agree with Green Power Institute that the Commission has made it clear that we encourage both the growth of the use of distributed energy resources and, as indicated by the objective of this proceeding, the streamlining of the interconnection application process, including the portals.[227] However, we also have a responsibility to ratepayers and hence conclude that the costs for implementing a subproposal should be recovered from the set of customers who benefit.[228]

Relatedly, in comments to the proposed decision, CALSSA references working group discussions regarding utility responsiveness to customer queries.[229] CALSSA highlights the following commitments made by the Utilities during Issue 22 discussions, which we memorialize here:

- SDG&E states that its "Customer Generation's business policy is to return all emails and phone calls within the same business day."[230]
- PG&E states that a "three-business day turnaround as a compliance timeline, with a goal of answering simple requests within one-

[227] Working Group Three Report at 45.

[228] *See Id*. at 45 discussing TURN's position and PG&E's position.

[229] CALSSA Opening Comments to Proposed Decision at 7-8.

[230] *Id*. at 7 citing Working Group Three Report at 51.

business day would be more reasonable" to answer questions that may or may not come during the time period.[231]

- SCE states that Utilities "collectively agree that improved response time to customer inquiries is an important aspect of customer service.

### 5.6. Issue 23: Interconnection of Electric Vehicles and Related Charging Infrastructure

We find it reasonable to consider issues related to the interconnection of electric vehicles and related charging infrastructure and devices, as the current Rule 21 language allows such interconnections. The proposals we adopt in this decision include this recognition, especially Proposal 23c. Other proposals that we adopt, 23a, 23b, 23d, 23e, and 23i, establish certain interconnection criteria. We also adopt Proposal 23f, which tracks vehicle to grid interconnections, given the Commission's pursuit of these types of interconnections. Further, the Commission previously approved the establishment of a Vehicle to Grid Alternating Current Subgroup, rendering Proposal 23g moot. Finally, we decline to adopt 23h, as we find it duplicative of existing rules.

Below, we provide a brief description of Working Group Three's review of electric vehicle technology and policies; this includes a discussion of related pilots. We also describe each of the proposals and discuss our resolution of this issue.

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[231] Id. at 8 citing Working Group Three Report at 50.

### 5.6.1. Issue 23: Overview

The Working Group Three Report presents the foundation for the relevance of this issue, noting the California objective of having 5 million zero emission vehicles on the road by 2030 and 250,000 vehicle charging stations by 2025.[232] Along with the Commission, the CAISO and California Energy Commission have moved toward the achievement of this objective by developing and issuing a Vehicle-Grid Integration Roadmap.[233] The Working Group Three Report defines several relevant terms, which we include here:

- V1G: one-way managed or "smart" charging
- V2G AC: charging systems that utilize bidirectional onboard inverters within the electric vehicle
- V2G DC: charging systems that utilize bidirectional inverters within the Electric Vehicle Supply Equipment (EVSE).[234]

The Working Group Three Report establishes several facts and assertions. First, in R.16-02-007, the Commission found that flexible electric vehicle charging could reduce the amount of renewable generation and energy storage selected to meet 2030 greenhouse gas planning targets.[235] The Working Group Three Report

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[232] *Id*. at 63.

[233] *Id*. at 63, citing *California Vehicle-Grid Integration (VGI) Roadmap: Enabling vehicle-based grid services*, February 2014. This report is available at http://www.caiso.com/document/vehicle-gridintegrationroadmap.pdf

[234] This may also be referred to as electric vehicle charging stations, electric recharging points or charging points.

[235] *Id*. at 63. *See* Footnote 8.

asserts that while V1G can help manage customer bills and provide load response, V2G may be able to provide additional customer and grid services.[236]

The working group makes note of current pilots that aim to demonstrate the viability of V2G use cases.[237] Relevant to Issue 23, the working group warns that issues and barriers, including those related to the technical components of V2G systems and interconnection technical requirements, limit market opportunities for V2G systems.[238]

The working group discussed and agreed upon the scope of this issue. Looking at V1G and V2G systems, the group agrees that basic electric vehicle charging load and V1G systems are not Rule 21 applicable. The working group further explored V2G systems and developed several categories, as shown in the Working Group Three Report.[239] The group agrees that the interconnections of V2G systems have been done on a case-by-case basis to date.

In the end, the group agrees that the scope of Issue 23 and the related proposals includes the following:

- Applicability of Rule 21 to V2G capable systems;
- Interconnection processes and pathways for V2G AC Non-Export and Export EVSE (stationary inverter, V2G DC) configurations;
- Single-site V2G Non-Export interconnections under Rule 21;

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[236] *Id*. at 63.

[237] *Id*. at 64-65.

[238] *Id*. at 65.

[239] *Id*. at 67, Table 1.

- Applicability of UL[240] 1741 SA, SAE[241] J-3072, IEEE[242] 1547 and other standards/certifications to enable V2G AC and V2G DC interconnections; and
- Coordination of finding and proposals for Issue 23 with all relevant agencies, stakeholders, and proceedings.

#### 5.6.2. Issue 23: Proposal 23a

Proposal 23a would recognize that Rule 21 does not apply to V1G with no discharge capability. Instead, V1G must comply with Rules 2, 15, and 16. The Working Group Three Report explains that adoption of this proposal would remove any uncertainty about its applicability. All participants agree with this proposal due to the fact that V1G is considered to be load and not generation.[243] Furthermore, participants also agree that V1G must comply with Rules 2, 15, and 16 because these are load interconnection requirements.[244]

#### 5.6.3. Issue 23: Proposal 23b

Proposal 23b would clarify that Rule 21 applies to the interconnection of stationary and mobile energy storage systems. This proposal would modify Section B.4 of Rule 21 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*

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[240] UL is the acronym representing Underwriter Laboratories, a standards body.

[241] SAE is the acronym representing Society of Automotive Engineers, another standards body.

[242] IEEE is the acronym representing the Institute of Electrical and Electronics Engineers, another standards body.

[243] Working Group Three Report at 69.

[244] *Ibid*.

*other load, using the incremental net load for non-residential customers, if any, of the storage devices."*

All Working Group Three participants agree that the modified language proposed in Proposal 23b, which clarifies that Rule 21 applies to mobile and stationary energy storage systems, would remove uncertainty or ambiguity.[245] Proposal 23b is a consensus proposal.

#### 5.6.4. Issue 23: Proposal 23c

Also a consensus proposal, Proposal 23c would recognize that Vehicle to Grid Electric Vehicle Supply Equipment with stationary inverter for direct current charging of vehicles (V2G DC EVSE) may be interconnected under the current Rule 21 language, if the EVSE meets Rule 21 requirements including UL 741 SA and other updated smart inverter standards. Proposal 23c maintains the status quo but, similar to Proposal 23b, adoption of this proposal results in a policy that removes uncertainty and ambiguity.[246]

#### 5.6.5. Issue 23: Proposal 23d

Proposal 23d would allow V2G DC EVSE to connect as V1G, load-only, and operate in unidirectional (charge-only) mode if the system's UL Power Control System Certification Requirements Decision (CRD) and UL 1741 SA certification testing demonstrates that: i) the electric vehicle will not discharge if the EVSE is set to unidirectional mode; ii) the EVSE will not inadvertently change to bidirectional mode; and iii) factory default settings are set to unidirectional

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[245] *Id*. at 70.

[246] *Ibid*.

mode. Additionally, this proposal would also require that the operational mode cannot be changed without utility authorization.

This proposal evolved from the Utilities' desire for assurance and confidence that a V2G DC EVSE in charge-only mode would not discharge. After forming a subgroup to review technical requirements, evaluations, and processes to allay these concerns, the working group agreed upon the following criteria:

*All V2G capable EVSEs used for V2G-DC shall:*

*a) Be evaluated and listed under UL 1741 SA through an Occupational Safety and Health Administration-approved Nationally Recognized Testing Laboratory and be evaluated using UL 1741 that replaces the Supplement A with IEEE P1547.1-2019, expected to be approved by the end of 2019.*[247]

*b) Be evaluated, using the UL CRD for Power Control System to:*

*i) Demonstrate that EVSE set to unidirectional will not discharge*

*ii) Prevent inadvertent change in operational mode.*

*c) Be configured such that EVSE factory default mode is unidirectional (charging only).*

With these criteria in mind, the working group agreed upon the recommendations and language set forth above in Proposal 23d.

#### 5.6.6. Issue 23: Proposal 23e

Proposal 23e would allow bidirectional mode to be enabled for a V2G-DC EVSE (stationary inverter) system only upon receiving permission to operate

[247] Since the issuance of the Working Group Three Report, IEEE 1547.1-2020 was published on May 21, 2020. A publication delay negated the need for IEEE 1547.1-2019.

from a utility. Further, this proposal would require owners of these systems who wish to switch to bidirectional mode, to complete the Rule 21 interconnection process and receive the permission to operate. Once permission is received, the manufacturer or approved third-party installer would then be able enable bidirectional operation. Proposal 23e is a consensus proposal.

#### 5.6.7. Issue 23: Proposal 23f

Proposal 23f would modify the interconnection portals to enable tracking of V2G interconnections. The modifications could entail adding new EVSE inverter types in drop-down menu or flagging interconnections as V2G. This proposal is supported by CESA, Clean Coalition, eMotorWerks, Fiat-Chrysler, Green Power Institute, Honda, Nuuve, PG&E and SCE, with caveats. Only SDG&E opposes this proposal.

In support of this proposal, Green Power Institute urges the Commission to be proactive and prepare for the V2G need. While supporting the proposal, Tesla questions the degree of urgency given the nascent state of V2G.[248] SCE notes that it has not seen any current V2G projects but supports the inclusion of EVSE inverters in future updates of its Generation Interconnection Processing Tool discussed in Issue 22. SCE anticipates this tool being able to incorporate a drop down menu.[249]

Furthering the argument of lack of need, SDG&E states that it has only ever processed one interconnection application for a Demonstrated

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[248] Working Group Three Report at 72.

[249] *Id*. at 73.

Capacity-coupled V2G facility. SDG&E cautions that the scope and cost to revise its web portal is unknown, because of the lack of applicable projects. SDG&E asserts the existing processes are adequate, given the low volume of related projects.[250]

#### 5.6.8. Issue 23: Proposal 23g

Proposal 23g requests the Commission to establish a subgroup inviting stakeholders from the Smart Inverter Working Group and SAE to develop and present recommendations on the technical requirements to enable V2G AC (mobile inverter) interconnections. The recommendations would be provided to the Commission six months after the issuance of the Working Group Three Report if consensus can be reached, or six months after a Commission decision on the Working Group Three Report if parties cannot reach consensus.

A tentative agreement was reached to create an informal technical subgroup to address V2G interconnection issues and develop recommendations to be introduced into the record in time for the adoption of the Working Group Three decision. Discussion took place with respect to whether this issue should be addressed in the vehicle electrification proceeding (R.18-12-006). While not disagreeing, CESA warns that the vehicle electrification proceeding "is already overloaded with a wide range of issues."[251] Others suggest the use of the Smart Inverter Working Group, but CESA similarly cautions that the Smart Inverter Working Group also has a heavy agenda. CESA contends that this proceeding is

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

[251] *Id*. at 74

more appropriate because the Utilities' interconnection engineers are participants in this rulemaking and the results would require Rule 21 tariff changes.[252]

PG&E argues that V2G AC issues should be addressed as part of a broader vehicle grid integration effort. Equally important, PG&E also asserts that the need and/or value of V2G AC needs to be clearly articulated to justify launching dedicated efforts to address the technical aspects of V2G AC.[253] Furthermore, PG&E supports the continuation of private industry efforts to address the V2G AC issues as the Smart Inverter Working Group may not have the expertise.[254]

SDG&E highlights that a draft motion to separately create this subgroup is in circulation; the motion proposes the subgroup be established in Q2-Q3 2019. SDG&E contends that changes to SAE J3072 must occur before Utilities will agree to participate in the subgroup.[255]

#### 5.6.9. Issue 23: Proposal 23h

Proposal 23h would modify Section N of Rule 21 to allow streamlined study process for V2G DC EVSE interconnection. CESA, Clean Coalition, eMotorWerks, Fiat-Chrysler, Green Power Institute, Honda, Nuuve, and SDG&E (with a caveat) support this proposal. PG&E and SCE oppose the proposal.

CESA suggests that a recently-approved one-year pilot for expedited interconnection review could be modified to establish a performance based

[252] *Ibid*.

[253] *Ibid*.

[254] *Id*. at 74-75

[255] *Id*. at 76.

interconnection review process. The pilot looked at non-export, standalone energy storage systems that meet specific eligibility criteria. CESA proposes the Commission could revise existing Section N Criteria to comport with the pilot criteria.[256] Alternatively, CESA contends a new subsection of Section N could be created for V2G DC systems and broadly for V2G systems in general.[257]

SCE opposes the proposal and the related revisions to Section N. SCE points out that Section N was adopted for the very specific use case of expanding the interconnection of non-export energy storage projects.[258] SCE argues that the Fast Track process is sufficient to meet the needs of V2G-DC EVSEs, if Proposal 23d is adopted.[259] PG&E also opposes the modifications to Section N. PG&E contends that an electric vehicle with energy storage meets the Rule 21 definition of a generator, thus no changes to Section N are required.[260] While supporting the proposal to include non-exporting V2G-DC systems, SDG&E disagrees with the modifications to Section N. SDG&E asserts that if a V2G-DC system applies to interconnect behind a meter where there are other meters, Utilities need the full review time provided under the Fast Track process and not the expedited timelines prescribed in Section N. SDG&E argues the presence of other generators will require engineering review.[261]

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[256] *Id*. at 76-77.

[257] *Id*. at 78.

[258] *Id*. at 80.

[259] *Id*. at 81.

[260] *Id*. at 83.

[261] *Ibid*.

### 5.6.10. Issue 23: Proposal 23i

Proposal 23i would clarify a pathway for parties to interconnect V2G AC systems on a timely basis for experimental and/or temporary use until the appropriate rules are updated in the future. Opposed by all three Utilities, Proposal 23i is supported by CEC, CESA, eMotorWerks, EPRI, Fiat-Chrysler, Ford, Green Power Institute, Honda, Kitu Systems, and Nuuve.

This proposal grew out of concern that a lack of a Rule 21 interconnection process for V2G AC systems could create a barrier to implementing pilots for V2G AC systems. Parties identified four existing pilots requiring V2G AC interconnection.[262] The Working Group Three Report explains that there are no non-pilot deployments of V2G AC systems on California's distribution grid.[263] Supporters contend that a temporary exemption from Rule 21 smart inverter requirements should be considered while being supplemented by SAE J3072 certification. Further, these supporters argue that already approved and funded pilot projects should be allowed to interconnect in order to provide data and real-world use cases to inform policymaking.[264]

Utilities oppose this exemption. SDG&E maintains that any exemption or deviation from Rule 21 could compromise safety or deprive Utilities of adequate time to review projects to ensure safety requirements are met.[265] SDG&E adds

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[262] *Id*. at 84, Table 3.

[263] *Id*. at 84.

[264] *Ibid*.

[265] *Id*. at 85.

that the requirements of Rule 21 protect utility workers and the public. However, SCE notes that to the extent that certification compliance to UL 1741 standard is part of the experimental pilot, SCE can work to develop a temporary interconnection.[266] PG&E contends the request is premature, since the SAE standard is not ready for this application at this time.[267]

#### 5.6.11. Resolving Issue 23

The Rule 21 language currently allows the interconnection of electric vehicles and related charging infrastructure and devices. Hence, we find consideration of the Issue 23 proposals to be appropriate.

We begin with a discussion of the consensus proposals: 23a, 23b, 23c, 23d, and 23e.

Proposal 23a recognizes that, in the case of unidirectional charge-only V1G, Rule 21 does not apply but Rules 2, 15, and 16 are applicable. As noted in the Working Group Three Report, this is consistent with current rules and practice[268] and should be affirmed in this decision.

Proposal 23b would modify Rule 21 to clarify that the rule applies to the interconnection of both stationary and mobile energy storage systems. Parties agree that Rule 21 applies to the interconnection of stationary and mobile storage systems, but do not agree on the proposed modifications, as noted by comments

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[266] *Ibid*.

[267] *Ibid*.

[268] *Id*. at 68.

to the Working Group Three Report.[269] Several parties express concern that without this clarity, customers are left with regulatory and market uncertainty.[270] We conclude that clarity is necessary. Hence, we adopt the proposal and direct Utilities to meet and confer to develop clarifying language for Section B.4 of Rule 21.

Similar to the first two proposals, Proposal 23c would clarify that the current practice, as set forth in Rule 21, is to allow the interconnection of V2G DC EVSE systems. Specifically, Proposal 23c asks the Commission to affirm this practice. The Working Group Three Report confirms that V2G DC EVSE systems may be interconnected under the exiting Rule 21 tariff, provided that the EVSE meets all Rule 21 requirements, including UL 1741 SA.[271] We affirm this as part of the current Rule 21 tariff.

Proposal 23d would allow V2G DC EVSE systems with bidirectional capability to connect as V1G, load-only, and operate in unidirectional (charge only) mode upon certifying that: i) the electric vehicle will not discharge if the EVSE is set to unidirectional model; ii) the EVSE will not inadvertently change to bidirectional mode and iii) factory default settings are set to unidirectional mode. While this is a consensus proposal, there are differing opinions with respect to the need for language changes in the Rule 21 tariff. Nuvve, CESA, and PG&E

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[269] PG&E Comments to November 27, 2019 Ruling at 12, stating that the suggested changes are not necessary.

[270] CESA Comments to November 27, 2019 Ruling at 2, Nuvve Comments to November 27, 2019 Ruling at 2, and Working Group Three Report at 70.

[271] Working Group Three Report at 70.

state that no changes to Rule 21 are required.[272] However, SCE contends that minor changes to Section C of Rule 21, Certification and Testing Criteria, and interconnection forms are necessary.[273] The proposal should be adopted as we find it necessary for safety and clarity, but we also require Utilities to meet and confer with respect to the need for language changes in Rule 21. Any recommended language change shall be included in the Tier 2 Advice Letter implementing the adopted proposals in this decision, which shall be submitted 60 days following the issuance of this decision.

The final consensus proposal for Issue 23 is Proposal 23e, which would allow bidirectional mode to be enabled for a V2G DC EVSE system only upon receiving permission to operate from the utility. The Working Group Three Report underscores that current Rule 21 tariff language allows this; hence, no change to the tariff is necessary.[274] This being a consensus proposal, we find it should be adopted. However, SCE and Public Advocates Office both contend that implementation details need to be resolved.[275] This can be accomplished with the following steps. After consulting with the parties, Utilities shall meet and confer to develop a consistent, to the extent possible, set of implementation steps for Proposal 23e. No later than six months from the issuance of this

[272] CESA Comments to November 27, 2019 Ruling at 4, Nuvve Comments to November 27, 2019 Ruling at 4, and PG&E Comments to November 27, 2019 Ruling at 13.

[273] SCE Comments to November 27, 2019 Ruling at 12.

[274] Working Group Three Report at 71.

[275] SCE Comments to November 27, 2019 Ruling at 13 and Public Advocates Office Comments to November 27, 2019 Ruling at 11.

decision, Utilities shall facilitate a workshop on V2G issues, where they shall present and discuss the proposed implementation steps for Proposal 23e. If Commission approval is needed for the implementation steps, Utilities shall request that approval in an Advice Letter submitted no later than 60 days following the workshop.

Moving on to proposals where parties did not reach consensus, we first address Proposal 23f. This proposal would require the modification of the Utilities' interconnection portals to enable simple tracking of V2G interconnections. We find this tracking will assist the Commission and California in knowing the extent to which our policies are achieving the goal of increasing vehicle to grid interconnections. Only SDG&E voiced opposition to this proposal, contending that the need for this tracking is minimal.[276] Agreeing that the need is minimal now, SCE supports the inclusion of tracking in future updates.[277] We direct Utilities to develop the timeline, costs, and cost recovery method to implement this proposal and discuss these elements during the workshop to address Issue 22 subproposals (Interconnection Portal Workshop). Following the Interconnection Portal Workshop, Utilities shall submit testimony in the second phase of this proceeding regarding the timeline, costs, and cost recovery method for Proposal 23f, modified in response to the workshop discussion.

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[276] Working Group Three Report at 73.

[277] *Ibid*.

We find it prudent to adopt Proposal 23i, which would clarify a pathway for parties to interconnect V2G AC systems on a timely basis for experimental, pilot, and/or temporary use until the appropriate rules are updated in the future. Specifically, this proposal would allow V2G AC system pilots to be exempt, on a temporary basis, from Rule 21 smart inverter requirements. As noted in the Working Group Three Report, the Commission is currently addressing V2G AC Interconnection issues through four existing pilots.[278] Parties contend that without a pathway to interconnect, these four pilots face barriers to operate, gather data, and learn.[279] Utilities oppose allowing a temporary exemption from Rule 21 smart inverter requirements stating that such deviations could compromise safety.[280] We find it necessary to create a pathway to interconnection to enable the Commission to learn from these and other future V2G AC interconnection pilots. Accordingly, we direct Utilities to work with stakeholders to develop a temporary interconnection pathway for pilots seeking V2G AC Interconnection that will provide the necessary safety precautions. Utilities shall host a series of meetings, with the first to begin no later than 30 days from the issuance of this decision. In response to Utilities' concerns, the discussion should include developing a definition for "pilot."[281] As a result of these meetings, Utilities shall develop a proposed temporary pathway to be

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[278] *Id*. at 84.

[279] *Ibid*.

[280] *Id*. at 85.

[281] SCE Opening Comments on the Proposed Decision at 13-14.

discussed during the V2G Workshop, discussed above. Utilities shall consider comments of workshop participants and propose a temporary pathway in a Tier 3 Advice Letter submitted 60 days following the V2G Workshop.

We decline to adopt Proposals 23g and 23h, which we discuss separately.

As described in the procedural background for this decision, the Administrative Law Judges for this proceeding and R.18-12-006 established a Vehicle to Grid Alternating Current Subgroup. Hence Proposal 23g, which would establish a group to develop technical recommendations to enable V2G AC interconnection, is no longer necessary.

Finally, we decline to adopt Proposal 23h, as we find it duplicative of existing language in Rule 21. Proposal 23h would modify Section N of Rule 21 to allow streamlined study process for V2G DC EVSE interconnections. As noted by Public Advocates Office, a specific reference to V2G DC within Rule 21 is not necessary as the Rule 21 definition of a generator captures V2G DC capability as a generator.[282] PG&E agrees, noting that electric vehicles with energy storage meet the Rule 21 definition of a generator, making this modification to the rule duplicative.[283]

### 5.7. Issue 24: Cost-of-Ownership Charges Formula

We conclude that the Commission should not modify the formula for calculating the cost-of-ownership charge at this time because there is concern that adoption could result in unfair cost shifts. We also find there is uncertainty

[282] Public Advocates Office Comments to November 27, 2019 Ruling at 11.

[283] PG&E Comments to November 27, 2019 Ruling at 14.

regarding accounting practices of the cost-of-ownership charge. As discussed below, we decline to adopt Proposals 24a, 24b, or 24c as recommended by some parties in the Working Group Three Report. Further, we decline to determine, at this time, whether it is appropriate to make changes to the cost-of-ownership in this proceeding or a general rate case. We find that additional information on the cost-of-ownership from Utilities, followed by a workshop, would be helpful to the Commission, parties, and other interconnection stakeholders.

Below we provide a brief description of the issue and each of the proposals and a discussion of our determination, with further details and instructions to Utilities.

#### 5.7.1. Issue 24: Overview

Working Group Three reviewed cost-of-ownership charges to determine whether they are being appropriately applied to generator interconnection applicants, identify best practices and inconsistencies across Utilities, and recommend or propose changes to reflect those best practices. As noted in the Working Group Three Report, parties agree that the purpose and intent of cost-of-ownership charges on interconnection applicants is to prevent costs from being shifted from one customer class to the broader class of ratepayers as a result of the new interconnection and simultaneously not transfer costs to the generation applicant that the utility would have incurred.[284] In developing proposals, the working group focused on a review of the types of costs and cost components that should be subject to the standardized cost-of-ownership rates.

[284] Working Group Three Report at 100.

### 5.7.2. Issue 24: Proposal 24a

Proposal 24a would require that, when applying the cost-of-ownership rates to new facilities, Utilities and ratepayers will not be subject to additional costs resulting from the new generator interconnection nor will a utility transfer costs to the generation applicant that the utility would have otherwise normally incurred. Further, this proposal would allow Utilities, at their discretion, to determine that the facility replacement is "like-for-like" in terms of cost-of-ownership implications thereby eliminating a cost-of-ownership rate allocated to the applicant. This proposal is supported by CALSSA, Clean Coalition, Green Power Institute, and Tesla and opposed by Utilities and TURN.

Supporters of Proposal 24a state that two examples of common distribution facilities upgrades where like-for-like comparability exists are: 1) existing pole or equipment not upgraded but relocated and continued in use for same and new customers; and 2) minor pole upgrade where the existing single wood pole is replace with next size larger wood pole. Supporters contend the following are examples where like-for-like comparability could exist, depending upon the details: 1) major pole upgrade where four existing wooden poles are replaced with two steel poles; 2) transformer upgrade where the existing transformer is upgraded to a higher capacity to serve the same customers and a new generation/storage application; 3) single customer upgrade where the existing distribution system line extension and transformer provide load service to a single customer is upgraded to accommodate a new generation interconnection request; and 4) a single customer update where the existing customer service line drop provides load service (load side of point of common coupling with utility grid, utility side of meter) is upgraded to accommodate a new generation interconnection request.

The point of contention in this proposal is the definition of the term, like-for-like. PG&E asserts "like-for-like" should be defined as equivalent facilities in terms of cost and function. Based on this definition, PG&E contends there are no cases in interconnection where a generator would be assigned a like-for-like upgrade.[285] PG&E maintains the list of proposed like-for-like upgrades are not like-for-like because there is a cost increase associated with relocation or upgrade.[286] SDG&E underscores that like-for-like replacements only achieve ratepayer indifference if the existing assets are at the very end of life and fully depreciated. If the Commission approves this proposal and the asset being replaced has remaining undepreciated costs, SDG&E contends ratepayers will continue to pay for both the removed and the replacement assets.[287]

Separately, SCE argues that any issue related to the cost-of-ownership should be addressed within a general rate case. SCE explains that cost-of-ownership rate rules are established under Rule 2 and apply to all facilities requested by an applicant that are in addition to or substitution for standard facilities.[288]

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[285] *Id*. at 101.

[286] *Id*. at 102.

[287] *Id*. at 103.

[288] *Id*. at 102.

### 5.7.3. Issue 24: Proposal 24b

Proposal 24b would make available to the interconnection applicant the following three cost-of-ownership replacement cost options, while maintaining ratepayer indifference: i) charge for replacement in perpetuity; ii) charge for replacement for fixed term in 10-year increments ; and iii) customer responsibility for actual cost of replacement if and when needed. CALSSA, Clean Coalition, and Green Power Institute support this proposal, while Utilities and TURN are opposed to Proposal 24b.

Following a discussion regarding the impact of replacement costs on cost-of-ownership charges, Clean Coalition surmises that replacement coverage options can greatly affect interconnection customer costs without affecting ratepayers.[289] SCE notes that ongoing operations and maintenance cost is relatively steady from year to year, but replacement cost is charged on a constant recurring annual basis, even though one would expect the replacements to come later in an asset's life.[290] Based on the working group discussion, Clean Coalition asserts 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 cost-of-ownership is greatly reduced and the remaining components of cost-of-ownership may be significantly reduced.[291] Clean Coalition further asserts that if replacement cost charges are

[289] *Id*. at 104.

[290] *Ibid*.

[291] *Ibid*.

not aligned with actual replacement costs, there is a cost shift between the interconnection customer and other ratepayers.[292]

Utilities oppose the separation of the replacement cost from the cost-of-ownership rate. PG&E explains that the replacement cost is a component of the cost-of-ownership, which is determined in general rate cases.[293] PG&E contends having separate components for replacement would create excessive administration burden.[294] SDG&E and SCE assert that the governing rules of cost-of-ownership, which includes replacement cost, impact customer classes beyond interconnecting customers. Utilities agree that cost-of-ownership related issues are better suited for review within a general rate case.[295]

#### 5.7.4. Issue 24: Proposal 24c

Proposal 24c focuses on the replacement of existing facilities with new facilities that are not like-for-like. In this proposal, the interconnection applicant would be credited for the utility cost-of-ownership of the equipment that was replaced and only be charged any net-additional cost-of-ownership. Proposal 24c defines net-additional cost-of-ownership as the cost-of-ownership that would not have otherwise occurred if no interconnection request had been made. Net-additional cost-of-ownership excludes the portion of cost-of-ownership of the replacement equipment that represents the continued share or

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[292] *Id*. at 105.

[293] *Ibid*.

[294] *Ibid*.

[295] *Ibid*.

obligation of ratepayers for that equipment. As was the case with the prior Issue 24 proposals, Issue 24c is supported by CALSSA, Clean Coalition, JKB Energy, and Tesla and opposed by Utilities and TURN.

This net additional proposal evolved from a method used by PG&E for Rules 15 and 16 to reflect costs for the whole system without the upgrade. The Working Group Three Report explains that these costs are compared to the system with the upgrade and the difference is calculated. Supporters assert that this method, if used for Rule 21 interconnections, could produce a net-additional cost-of-ownership for the following common distribution facilities upgrades: major pole upgrade where four existing wooden poles are replaced with two steel poles; transformer upgrade where the existing transformer is upgraded to higher capacity to serve the same customers and a new generation/storage application; single-customer upgrade where the existing distribution system line extension and transformer is providing load service to a single customer and upgrades to accommodate a new generation interconnection request; and a single customer upgrade where the existing customer service line drop providing load service is upgraded to accommodate a new generation interconnection request.[296]

Utilities state that, using their current accounting practices, if the customer is only charged for the net-additional cost-of-ownership resulting from the interconnection request, an under-collection of cost-of-ownership would

[296] *Id*. at 107.

result.[297] Here again, Utilities contend any discussion of modifications to the cost-of-ownership should be addressed in a general rate case.[298] TURN opposes this proposal as it could result in a potential subsidy of the interconnecting project by ratepayers.

#### 5.7.5. Resolving Issue 24

We decline to modify the formula for calculating the cost-of-ownership charge. We discuss our rejection of each of the proposals below, but we find that, overall, the record for Issue 24 contains inconsistencies. Moreover, there is uncertainty regarding accounting practices. Hence, we also decline to determine whether it is appropriate to make changes to the cost-of-ownership charge in this proceeding or a general rate case. We find that additional information on the cost-of-ownership from Utilities, followed by a workshop, would be helpful to the parties in this proceeding, other interconnection stakeholders, as well as the Commission, in understanding the accounting of this charge.

Proposal 24a would treat certain new facilities upgrades as like-for-like upgrades in terms of applying the cost-of-ownership charge and result in a zero cost-of-ownership charge. Utilities contend the proposed like-for-like scenarios do not consider all relevant cost associated with the upgraded facility.[299] As explained by SCE, the purpose of the cost-of-ownership charge is to offset a utility's revenue requirement for operating and maintaining the underlying

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[297] *Id*. at 108.

[298] *Id*. at 108-109.

[299] *Id*. at 101-103.

asset, as well as any applicable capital related revenue requirement.[300] We agree that ratepayers and Utilities should not pay for the operation and maintenance of an interconnection project. However, the accounting practices of Utilities with respect to the cost-of-ownership charge remain unclear in the record. Hence, while we do not adopt Proposal 24a due to cost shift concerns, we do require Utilities to provide additional insight on the cost-of-ownership charge and related accounting practices. We provide further direction to Utilities below.

Proposal 24b would create three cost-of-ownership replacement cost options for an interconnection applicant. Supporters of this proposal explain that replacement cost charges should be aligned with actual replacement costs to ensure no cost shifts occur between the interconnection customer and other ratepayers.[301] We are concerned about the lack of certainty in the form, method, and application of accounting practices used by Utilities. For example, SCE highlights that replacement cost is charged on a constant recurring annual basis (straight-line basis); however, the Working Group Three Report points out that Utilities differ in how they address replacement charges.[302] The Working Group Three Report also notes that the Utilities' practices avoid under collection but do not avoid over-collection. While the purpose of the cost-of-ownership charge is to prevent cost shifts occurring between ratepayers and interconnection applicants, we do not have a sufficient understanding of the cost-of-ownership

[300] *Id.* at 102.

[301] *Id*. at 105.

[302] *Id*. at 104.

practices in this record to know whether this proposal will achieve such prevention. Furthermore, SDG&E and PG&E oppose separating the replacement charge from the cost-of-ownership charge. SDG&E and SCE underscore that the replacement charge is one of several elements of the cost-of-ownership charge, which is ultimately determined in a utility's general rate case.[303] We make no determination as to whether we should separately identify any element of the cost-of-ownership charge outside of a utility's general rate case until we better understand the cost-of-ownership charge and its relationship with the general rate case and interconnection. We provide further direction to Utilities below to improve our understanding of the cost-of-ownership charge.

Proposal 24c would replace the cost-of-ownership charge with a charge similar to a net-additional cost-of-ownership charge, which would result in the difference between the system without the upgrade and the costs with the upgrade, including operating and maintenance costs. Proponents state this is similar to a method used by PG&E for Rules 15 and 16. We are concerned by opponents' warnings that this could result in a cost shift or subsidy.[304] Utilities, noting a lack of visibility into applicants' asset costs, caution that this proposal would shift more costs to existing ratepayers and benefit only the interconnection applicant.[305] We decline to adopt Proposal 24c due to the potential for cost shifts between interconnection customers and other ratepayers.

[303] *Id*. at 105-106.

[304] *See* Turn Comments, *Id*. at 108.

[305] Working Group Three Report at 108.

However, here again, we consider the record to be insufficient to understand the Utilities' accounting practices of the cost-of-ownership charge.

To ensure that we have a complete understanding of the cost-of-ownership charge, we direct Utilities to develop a report to include a step-by-step description of the cost-of-ownership charge and the determination of the value of each element. As suggested by SBUA in comments to the proposed decision, Utilities shall include in the report a discussion of the potential cost shifts between ratepayers and interconnection applicants, if modifications are made to those values and the cost-of-ownership method.[306] Utilities shall seek input from the Commission's Energy Division regarding a side-by-side comparison of each of the Utilities and other related content. The final report shall be submitted to the Energy Division no later than March 31, 2021. No later than 60 days following the submission of the report, Utilities shall host a workshop to present the contents of the report to parties and other stakeholders.

### 5.8. Issues 27 and 28: Operational Requirements of Smart Inverters and Coordinating the Requirements with Valuation Mechanisms Adopted in the Integrated Distributed Energy Resources Proceeding

We agree with parties that Rule 21 currently requires customers to maintain the default settings for smart inverter functions unless different settings are approved. We therefore adopt Proposal 27a, which provides further clarification regarding default settings, as well as providing instruction

[306] SBUA Opening Comments to the Proposed Decision at 5.

regarding the full range of smart inverter capabilities. We also adopt Proposal 27c, which would convene the Smart Inverter Working Group to refine technical specifications for the Set Active Power Mode function. We find this proposal presents a coordinated effort to align existing and developing inverter standards. Relatedly, we adopt Proposal 28a, which instructs Energy Division to determine whether the Smart Inverter Working Group should be reconvened for technical work following the adoption of any sourcing or valuation mechanism in R.14-10-003, the proceeding addressing the integration of distributed energy resources. We decline to adopt Proposal 27b, which would require Utilities to convene a workshop to present their distributed energy resources management systems (DERMS) roadmaps. Utilities will present these roadmaps during Working Group 4 discussions. Below, we present an overview of Issue 27 and the related Issue 28, describe each of the recommendations from the working group, and discuss our determinations.

#### 5.8.1. Issue 27 and 28: Overview

Issue 27 focuses on the operational requirements of smart inverters and the rules and procedures for adjusting smart inverter functions through communication controls. Issue 28 asks how the Commission should ensure these operational requirements are aligned with any valuation mechanism adopted in the Integrated Distributed Energy Resources proceeding.

During the course of Working Group Three meetings, the group considered the functional capabilities of smart inverters.[307] The working group and the Smart Inverter Working Group looked at the operational requirements of smart inverters and the procedures for changing settings, including regulatory needs, technical work, and customer and utility benefits.

Parties agree that Rule 21 requires customers to maintain the default settings for smart inverter functions unless different settings are approved.[308] Hence, parties focused on proposals for non-default settings.

Working Group Three and the Smart Inverter Working Group developed operational categories (within which changes to smart inverter default settings can be considered) and defined a series of use cases that could be operationalized in the future.[309] The working group is not recommending any specific Commission action regarding the use cases.[310]

With respect to the rules and procedures for adjusting smart inverter functions via communication controls, the working group discussed the need for Utilities to send signals to distributed energy resources based on grid conditions and react to data received from distributed energy resources through the

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[307] The three Phases of the Smart Inverter Working Group: Phase I- Autonomous Functions, mandatory as of 2017; Phase II – Communication Capabilities, mandatory as of June 22, 2020; and Phase III- Advanced Functions, mandatory as of June 22, 2020. Working Group Three Report at 111 and Commission Executive Director Alice Stebbins Letter, March 20, 2020.

[308] Working Group Three Report at 111.

[309] *Id*. at Annex F and Annex G.

[310] *Id*. at 112.

development of DERMS. The Working Group Three Report explains that DERMS are software platforms that control or send signals to distributed energy resources over a variety of different time intervals to perform actions for grid reliability management and/or grid services.[311] While most working group participants agree that DERMS will become widespread, there are differing opinions regarding the speed of the growth.[312]

Finally, participants looked at the aforementioned use cases to consider the relevance to sourcing and valuation mechanisms being developed in the Integrated Distributed Energy Resources proceeding, R.14-10-003. The group discussed how and when technical assistance could be provided to R.14-10-003 in order to set operational requirements for those mechanisms.

#### 5.8.2. Issue 27: Proposal 27a

Proposal 27a would add language to Rule 21 to clarify that "with mutual agreement, changes to default settings are allowed." Further, the proposal would also allow for a revision to Rule 21 to account for IEEE 1547-2018 and IEEE 1547.1-2020 updated requirements and a process for requesting and approving non default inverter settings. Proposal 27a is a consensus proposal.

The Working Group Three Report explains that this proposal would clarify that Utilities may approve the full range of alternative smart inverter settings that could be useful for facilitating interconnection or providing grid services.[313]

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[311] *Ibid*.

[312] *Ibid*.

[313] *Id*. at 113.

This proposal recognizes that there is no current process to request and receive permission for non-default settings to provide these grid services and thus allows for a future process to occur.

#### 5.8.3. Issue 27: Proposal 27b

Proposal 27b would set a 90-day deadline to hold a workshop at which time Utilities would present their DERMS roadmaps including the vision, milestones, and challenges for the roadmaps. The proposal would allow parties to comment on the roadmaps.

CALSSA, Clean Coalition, Green Power Institute, JKB Energy, PG&E, Sunrun, and Tesla support this proposal. CALSSA explains that several of the case uses developed by the working group for Issue 27 require DERMS to make full use of advanced functionality of the smart inverters.[314] CALSSA recommends that DERMS' pilots previously conducted by Utilities should be part of a larger plan vetted through a public process. SCE supports Proposal 27b, on the condition that it be understood that further modifications would not be considered, since SCE's DERMS has already been reviewed by the Commission in its recent general rate case.[315]

SDG&E opposes Proposal 27b, suggesting instead that a workshop be convened to assess the maturity of the DERMS commercial software. Pointing to a presentation by the Energy Division, SDG&E argues that "the state of DERMS

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[314] *Ibid*.

[315] *Id*. at 114.

is nascent" and "making any substantive development timelines…is problematic."[316]

TURN also opposes the adoption of Proposal 27b, asserting that a "showing needs to be made" to show that the benefits will offset the costs of building systems to utilize Phase 3 functions.[317]

#### 5.8.4. Issue 27: Proposal 27c

Proposal 27c would convene the Smart Inverter Working Group to refine technical specifications for the Set Active Power Mode function. CALSSA, Clean Coalition, Green Power Institute, Nuuve, and SCE support the proposal; PG&E and SDG&E oppose it.

Supporters of Proposal 27c state that Set Active Power Mode (Function 4 of the Advanced Smart Inverter functions, has been delayed until after implementation of IEEE 1547-2018. CALSSA asserts that Set Active Power Mode will likely be valuable for enabling customers to provide capacity as a grid service and should be reprioritized.[318]

PG&E argues that the Set Active Power Mode will not be useful until the grid sees higher storage penetration and the Utilities' grid control systems are upgraded with DERMS.[319] SDG&E contends there is no value to modify the tariff to incorporate IEEE 1547-2018 if there is no use for this function at this time.

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[316] *Id*. at 115.

[317] *Id*. at 114.

[318] *Id*. at 115.

[319] *Id*. at 115-116.

Further, SDG&E agrees with PG&E that the technology and industry are too undeveloped for any proposed tariff change.[320] Relatedly, SDG&E also asserts that the Smart Inverter Working Group is not an official entity empowered by the Commission to take on the tasks of refining technical specifications for the Set Active Power Mode function; work on these functions should wait until compensation issues have been addressed in R.14-10-003.[321]

#### 5.8.5. Issue 28: Proposal 28a

Proposal 28a would instruct the Energy Division to decide on the need to convene the Smart Inverter Working Group to determine if technical work is needed following the issuance of a decision adopting a distributed energy resources tariff in R.14-10-003. This is a consensus proposal.

In the Working Group Three Report, supporters of Proposal 28a underscore that because proposals in Issue 27 reference use cases relevant to sourcing and valuation mechanisms being developed in R.14-10-003, it is important to look at how and when the working group and the Smart Inverter Working Group could provide technical assistance to R.14-10-003 in setting operational requirements for those mechanisms. PG&E and SDG&E support future work by the Smart Inverter Working Group on technical specifications, but only after tariffs are adopted in R.14-10-003.[322]

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[320] *Id*. at 116.

[321] *Ibid*.

[322] *Ibid*.

#### 5.8.6. Resolving Issues 27 and 28

Issue 27 asks what the operational requirements of smart inverters should be and what rules and procedures should be adopted for adjusting smart inverter functions through communication controls. Relatedly, Issue 28 asks how to coordinate with R.14-10-003, to ensure that these operational requirements align with valuation mechanisms adopted in that proceeding. As discussed below, we find that Proposals 27a and 27c appropriately establish the operational requirements of smart inverters. Further, Proposal 28a provides a pathway to ensure that operational requirements align with any adopted distributed energy resources valuation mechanism.

Proposal 27a, a consensus proposal, would add language to Rule 21 specifically allowing smart inverter default settings to be changed and establishes a process to update Rule 21 when additional smart inverter standards are developed. The Working Group Three Report highlights that currently there are no rules regarding alternative settings for smart inverters. We find this proposal provides additional clarity for Utilities and customers and allows for alternative settings that are useful for facilitating interconnection or providing grid services. As noted in the report, this clarity will allow Utilities to use the full range of smart inverter settings.[323] In comments to the proposed decision, SCE request the Commission to take into consideration a prior Commission directive

[323] *Id*. at 113.

in Resolution E-5000 to update the Rule 21 tariff with updated IEEE 1547 and 1547.1 standards,[324]

Proposal 27c would convene the Smart Inverter Working Group to refine technical specifications for the Set Active Power Mode function. There are two points of contention that we address here.

First, SDG&E argues that the Smart Inverter Working Group is not an official entity empowered by the Commission to take on these tasks. We disagree. The Commission and the California Energy Commission established the Smart Inverter Working Group to pursue the development of advanced smart inverter functionality. Furthermore, in D.16-06-052, parties of the previous Rule 21 proceeding and other interested stakeholders were encouraged to continue to participate in this working group. We also authorized the Energy Division to continue to monitor emerging issues as improved inverters are deployed and communication protocols developed. Hence, we find it logical to assign the refinement of the Set Active Power Mode function technical specifications to the Smart Inverter Working Group.

Second, SDG&E recommends a single process for updating Rule 21 to align with IEEE 1547 and UL 1741. SDG&E argues it would be more efficient and provide certainty to the inverter manufacturers to only have one update. We agree.

Accordingly, we adopt Proposal 27c and direct the Smart Inverter Working Group to convene within six months of the publication of 1547.1 or within three

[324] SCE Opening Comments to the Proposed Decision at 14.

months of the adoption of this decision, whichever comes later. The Smart Inverter Working Group will then refine the technical specifications for the Set Active Power Mode function for recommendation to the Commission.

Recognizing that R.14-10-003 is considering proposals for a distributed energy resources tariff, Working Group Three participants agreed that if new technical needs arise for smart inverter functions as a result of any approved distributed energy resources tariff, the Smart Inverter Working Group would be available.[325] SDG&E underscores that a regulatory pathway needs to be established for implementation of any proposals from the Smart Inverter Working Group.[326] We agree. Accordingly, we find Proposal 28a should be approved. Given its prior technical work, we find the Smart Inverter Working Group should be reconvened by the Energy Division if and when the Commission adopts a distributed energy resources tariff. Further, the Smart Inverter Working Group is tasked with reviewing the tariff to determine if any technical changes to smart inverters are necessary and making any associated recommendations to the Commission through an Advice Letter submission from Utilities on behalf of the Smart Inverter Working Group.

### 5.9. Issues A and B: System Design Approval Parameters and Generating Capacity for Behind-the-Meter Paired Solar and Storage Systems

We agree with the working group that Issues A and B are interrelated and should be addressed together. We adopt Proposals A-B 1 and A-B 2. We find

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[325] *Id*. at 116.

[326] *Ibid*.

that adoption of these recommendations allows the Commission to maintain technology neutrality, while fully utilizing new technologies that can safely and reliably substitute non-export relays and limit the grid impacts of interconnecting generation. We also adopt Proposal A-B 3 but modified to require that nine months after technical specifications and standards for Functions 3 and 8 have been approved by the appropriate standards approving bodies, Utilities shall make this capability available for use. Lastly, we adopt Proposal A-B 4, which applies to SCE customers only.

Below we provide a technical overview to better understand these two issues, followed by a description of each proposal, and our resolution.

#### 5.9.1. Issue A: Overview

Issue A asks what changes are needed to clarify the parameters for approving the design of systems for non-export and limited export. We begin with non-export systems. Non-export systems are designed to prevent the transfer of electrical energy from the generating facility to the distribution or transmission system. The Working Group Three Report explains that when an interconnection customer chooses to operate as non-export, Utilities must determine whether a system has the potential to export and, if so, determine the magnitude of safety and reliability impacts to the grid.[327] Rule 21 currently contains provisions that recognize that systems that do not export power have different grid impacts compared to full export systems.[328] Rule 21 also addresses

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[327] *Id*. at 126.

[328] *Ibid*. See also Rule 21, Sections N and G.1.

systems that may inadvertently export energy, which may have potential safety and reliability impacts on the grid, depending upon the frequency and duration of the inadvertent export.[329] As indicated in Table 2 below, 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.

| **Table 2[330]** | | |
|---|---|---|
| **Qualifications for Non-Exporting and Inadvertent Exporting Systems** | | |
| **System** | **Option** | **Option Description** |
| Non-Export | 1 | Reverse Power Relay |
| | 2 | Minimum Power Relay (Continuous Import) |
| | 3 | Certified Non-Islanding Protection<br>(Small System Compared to Service) |
| | 4 | Relative Generating Facility Rating<br>(Small System Compared to Load) |
| Inadvertent Export | 5 | Inadvertent Export (Rule 21, Section M) |
| | 6 | Inadvertent Export (Rule 21 Section Mm) – Designed for small UL 1741 SA inverter-based generating facilities |

Focusing on Option 1, the working group highlights that customers choosing this option must install a relay to automatically disconnect the system if reverse power flow occurs for longer than 2 seconds; this relay is considered a backstop to power control systems, a safety backup.[331] As described in the Working Group Three Report, the relay only acts in unexpected circumstances, when generating facility controls deviate from normal. Participants express a

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[329] *Ibid*. See also Rule 21, Sections M and Mm.

[330] *Id*. at 127.

[331] *Ibid*.

concern that a non-export relay can be prohibitively expensive.[332] Furthermore, IREC and CALSSA contend that if a Power Control System is capable of providing the same functionality, the cost burden of the relay is unnecessary.

The Working Group Three Report points to the Underwriters Laboratory (UL) Power Control Systems CRD test protocol, which provides a way for inverters and power control systems to be tested and certified for non-export and limited export.[333] This protocol was developed to create a framework for limited export systems. The Working Group Three Report points to the pros and cons of relays versus the certified power control systems. Relays have the ability to measure system frequency, voltage, and phase rotation, which can be used to satisfy other interconnection protection requirements, while power control systems need only monitor current to satisfy the UL CRD.[334] A relay only operates when generating facility controls deviate from normal, but a power control system satisfying the UL CRD may operate more frequently to regulate system output under normal conditions.[335] Finally, Utilities have a great deal of experience using relays, but very little experience exists with control systems approved under the UL CRD.

We turn to an overview of limited export systems. Limited export systems are designed and set to limit the level of export to some specified amount less

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[332] *Ibid*.

[333] *Ibid*.

[334] *Id*. at 128, Technical Insert 1.

[335] *Ibid*.

than the nameplate capacity of the system.[336] The UL CRD power control system can provide limited export to a value below nameplate capacity and within some time interval characteristic of that device.[337] The Working Group Three Report highlights that Rule 21 does not explicitly recognize the concept of limited export. In order to study limited export projects for grid reliability and for the safety of utility customers and employees, Utilities must ensure that intended limits will not be exceeded, which requires a review of system response time and ensuring system constraints can only be changed as provided in the UL CRD.[338]

### 5.9.2. Issue B: Overview

Issue B asks how Utilities should treat generating capacity for behind-the-meter paired solar and storage systems that are not certified non-export. The Working Group Three Report explains that, currently in Rule 21, a system that does not qualify for non-export is studied using the maximum nameplate rating. The report highlights that this is interpreted differently depending upon the situation and the utility. Until the approval of the UL CRD, discussed above, the Working Group Three Report states that there were no standards for the control of power output for non-export or limited export systems, which has led to Utilities interpreting the maximum nameplate rating conservatively.[339] In particular, PG&E and SCE equate the maximum nameplate rating of the

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[336] *Id*. at 129.

[337] *Ibid*.

[338] *Id*. at 129-130.

[339] *Id*. at 130.

combined system with the sum of the individual nameplate ratings of the solar-connected-inverter and the storage-connected-inverter.[340] This "nameplate plus nameplate" method could lead to significant financial consequences for the applicant.[341]

#### 5.9.3. Issue A-B: Proposal A-B 1

Proposal A-B 1 requires Rule 21 to be modified to specifically allow the use of a power control system for non-export and limited export interconnection applications and establishes five specifications that generating facilities must meet to be treated as non-export or limited export:

- Use a power control system that passes the requirements of the UL CRD;
- Use a power control system that has an open-loop response time of no more than 2 seconds, as provided in the control systems specification data sheets, and must be able to reduce export power to the approved export limit within 2 seconds of exceeding the approved export limit;
- Use only UL 1741 certified and/or UL 1741 SA listed grid-support non-islanding inverters;
- Set the power control system to zero-export or some non-zero controlled maximum export value; and
- Maintain voltage fluctuations at the limits specified in Rule 2.

Furthermore, if the facility meets these five specifications, Utilities shall adhere to the following steps to evaluate the application.

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[340] *Ibid*.

[341] *Ibid*.

- For non-export interconnection applications, a power control system can demonstrate non-export operation under Screen I; Screen D shall be omitted; and Screens F and G are reviewed based on the generating facility's gross nameplate rating.
- For limited-export interconnection applications, the limited export value determines the impacts to the grid, in accordance with Rule 21 tariff procedures and will be used in Screens D, I, J, K, M, N, O, and P (other screens will be applied as relevant); and Screens F and G will be based on the generating facility's nameplate rating.

This is a consensus proposal. CALSSA maintains that if a non-export or limited export resource using a power control system that responds within the same timeframe as the current Rule 21 requires for relays, (*i.e.*, two seconds), the resource should be treated the same as a resource using a relay.[342] SDG&E supports the proposal with the caveat that only certified inverter-based generation devices are applicable.[343] Also providing qualified support, PG&E recommends the CRD should be able to replace the need for discrete directional power relays and streamline the process.[344] Further, PG&E also proposes to use the certified preset export value in its load flow interconnection studies and the nameplate rating for fault studies.[345]

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[342] *Id*. at 132.

[343] *Ibid*.

[344] *Ibid*.

[345] *Ibid*.

### 5.9.4. Issue A-B: Proposal A-B 2

Proposal A-B 2 is also a consensus proposal addressing a project in interconnection review with inadvertent export. First, like Proposal A-B 1, this proposal would update Rule 21 language to allow the use of a power control system for non-export and limited-export applications. Further, Proposal A-B 2 would require that, to be treated as inadvertent export, a generating facility must meet all six of the following specifications:

- Use a power control system that passed testing in conformance with the UL CRD;
- Use a power control system with an open-loop response time of no more than ten seconds as provided in the control systems' specification data-sheets;
- Use only UL 1741 certified and/or UL 1741 SA listed grid-support non-islanding inverters;
- Use a power control system set to zero-export or some non-zero controlled maximum export value;
- Maintain voltage fluctuations to the limits specified in Rule 2; and
- Have a nameplate capacity equal to or less than 1000 kVA.

Upon meeting the six specifications, Utilities would be required to review the facility as follows: apply Screens A-M using the aggregate nameplate inverter rating; during Supplemental Review the applicant would be required to identify, within 15 days, the frequency of inadvertent export, the real power level in watts of inadvertent export and the time duration of inadvertent export; if distribution upgrades are identified then Screen P would recognize power control parameters taking into account local feeder conditions; and only the largest facility in the line section would be used for aggregate evaluation for subsequent interconnection requests. Proposal A-B 2 would also require Utilities to consider during Screen P review, to the extent feasible, the customer's operating profile and the magnitude, duration, and frequency of anticipated export.

In the Working Group Three Report, CALSSA states that with the introduction of the UL CRD, the review process can be revised to be more pragmatic. CALSSA highlights that, in the future, engineers may be able to develop tools to incorporate new customer capabilities and the industry may improve the ability to limit response time and frequency. However, for now, CALSSA contends this proposal would allow Utilities to exercise their engineering judgement to determine whether the uncontrolled inadvertent export between 2 to 10 seconds would cause equipment overload or other negative system impacts.[346] CALSSA asserts this proposal would implement an interim solution that recognizes that studying projects at full nameplate capacity may not be appropriate in all cases and allow Utilities to use information about the expected performance, as well as knowledge of local grid conditions, to make that assessment.[347]

This is a consensus proposal with no conditions placed upon participant support. However, Tesla does consider this proposal to be conservative.[348] Further, Utilities support use of a 10-second delay instead of the current 30-second delay, as the 10-second delay should lower potential system impacts and

[346] *Id*. at 134.

[347] *Ibid*.

[348] *Ibid*.

help to reduce the amount of review time.[349] PG&E notes that it is open to considering minor adjustments if there are specific gaps that need to be addressed.

#### 5.9.5. Issue A-B: Proposal A-B 3

Proposal A-B 3 is dependent upon the adoption of A-B 1 and/or A-B 2. This proposal would allow an inverter approved for non-export and limited-export to be set using different maximum export value settings at different times of the year and at the discretion of the utility until a future scheduling standard is released. Proposal A-B 3 would require the inverter to meet the qualifications for non-export or limited-export under Proposal A-B 1 or A-B 2. This proposal is supported by CALSSA, Clean Coalition, Green Power Institute, IREC, Nuuve, and Tesla. Utilities oppose Proposal A-B 3.

CALSSA maintains that Smart Inverter Phase II Function 8 will allow power control systems to have different maximum export values at different times of the year. Distributed energy resources are required to have this advanced functionality, as of June 2020. It should be noted that the deadline for implementation of the smart inverter advanced functionality was extended to June 22, 2020.

SCE contends this proposal cannot be adopted until standards to test control systems have been adopted. Further, SCE also argues that the UL CRD must be updated to include the temporal testing procedures for which work has

[349] *Id*. at 135.

not commenced.[350] SCE surmises this proposal is premature. However, SCE submits that nine months after these specifications and standards have been approved, Utilities could adopt tools, forms, and technical evaluation methods in order to make this various scheduling capability available for use.[351] SDG&E and PG&E agrees that the proposal is premature but would consider the proposal once the standards and specifications are in place.[352]

#### 5.9.6. Issue A-B: Proposal A-B 4

A consensus proposal, Proposal A-B 4 would apply solely to customers of SCE. This proposal would require customers applying for interconnection with a power control system to use a system already on the approved list. This proposal would not become applicable until six months from the approval of the Advice Letter implementing this decision. SCE contends that requiring customers to submit applications with pre-approved power control systems will maximize efficiency.[353] The six months will provide time for power control system manufacturers to certify equipment.[354]

#### 5.9.7. Resolving Issues A and B

Issue A ask what specifications should be required for a system to be non-export, inadvertent export, or limited export. Relatedly, Issue B asks how to treat generating capacity for behind-the-meter paired solar and storage certified not to

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[350] *Id*. at 136-137.

[351] *Ibid*.

[352] *Id*. at 137.

[353] *Id*. at 138.

[354] *Ibid*.

export more than a preset value. We find Proposals A-B 1 and A-B 2, which are consensus proposals, both appropriately address Issues A and B. Proposals A-B 1 and A-B 2 define the specifications required for a generating facility to be considered non-export, limited export, and inadvertent export. These new specifications address concerns regarding the high cost of the current relay options by providing the option of the less costly power control system in compliance with UL CRD as described above.[355] Furthermore, the inclusion of the UL CRD compliance as a specification option also addresses the concern regarding the lack of standards for the control of power output for non-export or limited export for inverters and power control systems, while eliminating the need for the controversial nameplate plus nameplate maximum nameplate rating.[356] Using the UL CRD will give assurance to the utility that a system will always operate within set parameters, including an appropriate response time.[357] The adopted specifications also address utility concerns that generating facilities use only certified inverters.[358]

We find that Issues A and B can also be addressed through the adoption of a modified Proposal A-B 3, which allows an inverter approved for non-export and limited export to be set using different maximum export value settings at different times of the year, when meeting the qualifications for either

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[355] *Id*. at 127-128.

[356] *Id*. at 130.

[357] *Ibid*.

[358] *Id*. at 132.

Proposal A-B 1 or A-B 2. As noted by CALSSA, Smart Inverter Phase III Function 8 enables systems to have different export values at different parts of the year and could vary seasonally, monthly, or hourly. [359] While not disagreeing with CALSSA's statement, Utilities contend the proposal is premature since no standards have been developed to test control systems.[360] We recognize that such standards are not approved at this time. While we find it reasonable to adopt Proposal A-B 3, we modify the proposal and require Utilities to wait to implement this proposal nine months after technical specifications standards and a certification scheme for Limited Generation Profiles have been approved by the standards approving bodies.

Proposal A-B 4 is a consensus proposal applying only to SCE customers. This proposal would require SCE customers applying for interconnection with a power control system to use only the systems on a pre-approved list. We find this would streamline the application process, which is the objective of the proceeding.[361] Since all relevant parties agree to this proposal and the proposal would ensure safety and reliability through the certified control information, we conclude Proposal A-B 4 should be adopted.

## 6. V2G AC Subgroup Adopted Recommendations

In this section, we describe the issues assigned to the V2G AC Subgroup, the proposals to resolve the issues and positions of parties, and the resolution of

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[359] *Id*. at 136.

[360] *Id*. at 136-137.

[361] *Id*. at 137.

the issues. The Commission can choose to adopt none or all of the proposals for each issue. Again, in limited cases, adoption of one proposal is dependent upon adoption of other proposals.

### 6.1. V2G AC Subgroup Issues: Overview

The V2G AC Subgroup evolved from Working Group Three discussions and discovery that there was a general lack of understanding of the V2G AC use cases in the electric industry. The subgroup, a joint effort between this proceeding and R.18-12-006, reviewed and assessed the ability of current standards to ensure safe interconnection of V2G AC systems. The subgroup's objectives were to understand the application of existing standards to create interconnection at one fixed point for one or more plug-in electric vehicles and present recommendations, if existing standards are sufficient; and, if not sufficient for safe interconnection, identify the gaps in the standards to ensure a future pathway to safe interconnection.

After considering that a mobile inverter has two primary components: i) a computer that implements the smart inverter functions and ii) a power conversion device that creates an AC current, the subgroup looked at single onboard inverter configuration and split inverter configuration approaches for V2G AC interconnections.[362] From there, the subgroup discussed different use cases for V2G AC interconnections but focused the scope on the technical discussions to the interconnection of a mobile inverter at one fixed point.

[362] V2G AC Subgroup Report at 17.

The subgroup also discussed the role of smart inverter requirements in Rule 21. The subgroup report highlights that since 2005, UL 1741 has been the certification standard for IEEE 1547 and IEEE 1547.1 and is used by Nationally Recognized Testing Laboratories to verify that equipment meets Rule 21 and National Electric Code requirements.[363] Hence, the group discussed the applicability and appropriateness of the current UL 1741 requirements to V2G AC Systems.

The subgroup determined that there were gaps in the existing standards, but if the standards were revised or updated to fill the gaps, the standards could be combined to fulfill interconnection requirements for a mobile inverter at one fixed point. The subgroup agrees on the following eight gaps in the current standards.[364]

- Updates are needed to UL 1741[365] to make it applicable to vehicles.
- Updates are needed to SAE J3072[366] and other applicable automotive standards to align with IEEE 1547-2018 and IEEE 1547.1 – 2020.
- Standards and certifications for SAE J3072 mobile inverters to receive default settings at each site need to be defined.
- IEEE 1547 and IEEE 1547.1 do not account for default Rule 21 settings to be delivered to the inverter at each site.

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[363] *Id*. at 21.

[364] *Id*. at 2 through 5.

[365] UL 1741 is the testing standard that applies more reasonable to stationary inverters.

[366] SAE J3072 is the standard that establishes interconnection requirements for a utility-interactive inverter system, which is integrated into a Plug-In electric vehicle.

- Lists to authenticate and authorize certified plug-in electric vehicles for discharge are needed.
- Updates are needed to UL 9741[367] (2014) to align with UL 1741.
- Matched pair certification for EVSEs presents business and implementation challenges that require further consideration.
- Utility process for third-party certification for storage and generation resource interconnection does not align with automotive industry norms for internal testing, which presents a key barrier to V2G AC Interconnections.

### 6.2. V2G AC Subgroup: Recommendations

The subgroup report presented one consensus recommendation and two non-consensus recommendations.

Recommendation 1, consensus support: Reconvene subgroup or some other group upon completion of updates to automotive and other applicable standards to assess gaps and consider Rule 21 changes to interconnect V2G AC systems, if such standards have been updated.[368] The scope of this new group will be to re-assess the updated national standards and determine whether these standards can be combined to fulfill safety requirements for interconnection of a mobile inverter at one fixed point. Upon completion of this review and if gaps are not identified, the group shall recommend language citing existing standards to enable Rule 21 interconnection.

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[367] UL 9741 is the standard that covers testing requirements for bidirectional plug-in electric vehicle charging equipment.

[368] *Id*. at 49-50.

Recommendation 2a, supported by plug-in electric vehicle industry stakeholders: Consider the jurisdictional question of plug-in electric vehicle equipment requirements, as well as self-certification policy issues.[369]

Recommendation 2b, supported by Utilities: Identify, evaluate, and determine solutions to the challenges faced by the plug-in electric vehicle industry that prevents it from complying with third-party testing, which the stationary inverter manufacturers now perform.[370]

### 6.3. Resolving V2G AC Subgroup Issues

Participants of the subgroup conclude that there are gaps in the existing standards and thus do not provide in the subgroup report any recommended changes to Rule 21 needed to enable V2G AC interconnection. Instead, the subgroup agrees on a procedural recommendation to ensure next steps to build on the efforts of the subgroup.[371]

The subgroup recommends reconvening the subgroup or another group when automotive and other applicable standards are updated.[372] The subgroup would reassess the updated standards to determine whether standards can be combined to fulfill safety requirements for interconnection of a mobile inverter at one fixed point. The subgroup would assess any gaps and, if no gaps are found, consider Rule 21 changes to allow for the interconnection of V2G AC Systems.

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[369] *Id*. at 51.

[370] *Ibid*.

[371] *Id*. at 6 and 49.

[372] *Id*. at 49-50.

Subgroup members disagree on when such a subgroup should reconvene. Plug-in electric vehicle stakeholders support a commencement date of July 2020. Utilities recommend waiting until testing has been performed to determine which part of UL 1741 cannot be met by V2G AC inverters and after the IEEE 1547.1 has been updated.

In comments to the subgroup report, PG&E and SDG&E contend it would not be effective to set a firm start date to reconvene the V2G AC Subgroup.[373] The VGIC recommends maintaining momentum through the use of a one-day workshop as this would not prematurely overcommit resources to the effort.[374] We agree that reconvening the subgroup without revised standards in place would be premature. We also see value in holding a brief meeting of the subgroup on a routine basis to provide the members of the subgroup with any news on the status of V2G AC interconnection standards update. Hence, we direct Utilities to host such a meeting, no later than six months from the issuance of this decision and continue to hold such a meeting every six months until updated standards have been tested and approved. The meeting should be noticed to the service lists of this proceeding and R.18-12-006. -Furthermore, we direct Utilities to actively participate in the committees that update the standards in order to ensure that the standards bodies understand what is needed for V2G AC Interconnection and the Utilities are well apprised of the standards update status. Once standards have been tested and approved, Utilities shall inform the

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[373] PG&E and SDG&E Comments to V2G AC Subgroup Report at 4.

[374] VGIC Comments to V2G AC Subgroup Report at 3.

Smart Inverter Working Group and the Director of the Energy Division. We authorize the Director of the Energy Division to reconvene the V2G AC Subgroup no later than 90 days from the issuance of approved updated standards that show progress towards V2G AC electric vehicle interconnection whether that be standards in the automotive industry or the interconnection industry..

In addition to the consensus procedural recommendation above, plug-in electric vehicle industry stakeholders request that the Commission consider the jurisdictional question of plug-in electric vehicle equipment requirements, as well as self-certification policy issues. Supporters of this recommendation suggest that the scope of this effort could be considered in this rulemaking and in R.18-12-006.[375] Utilities oppose this proposal recommending, instead, that the Commission identify, evaluate, and determine solutions to the challenges faced by the plug-in electric vehicle industry that prevents it from complying with third-party testing.[376] Utilities maintain that if the challenges remain then it may be appropriate to consider the jurisdictional question. We decline to adopt this recommendation at this time. We agree with PG&E and SDG&E that we should have standards in place prior to considering this issue.

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[375] V2G AC Subgroup Report at 51.

[376] *Ibid*.

## 7. Comments on Proposed Decision

The proposed decision of Commissioner Martha Guzman Aceves in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on September 9, 2020 by CESA, CALSSA, Clean Coalition, Green Power Institute, IREC, Nuvve, PG&E, Public Advocates Office, SDG&E, SBUA, SCE, Tesla, and Vehicle-Grid Integration Council. Reply comments were filed on September 14, 2020 by CESA, Clean Coalition, IREC, Green Power Institute, PG&E, SDG&E, SCE, Tesla, and TURN. In response to the comments, corrections and clarifications have been made throughout the Decision. We address certain comments here.

Several parties request the Commission to revise timelines for implementation of certain proposals. First, PG&E requests to extend the implementation time from two to nine months for proposals 8f1, 8f, 8g, 8h, 8j, 8k, 8l, and 8m.[377] SDG&E and SCE also asks for nine months to implement proposal 8m Option B.[378] Second, with respect to the Advice Letter required for Issue 11, CESA requests the Commission to accelerate the filing to 60 days, arguing the implementation details are largely administrative improvements.[379] On the other end of the spectrum, SCE requests a delay of 60 days, to provide time for stakeholder outreach.[380] We decline to shorten the schedule, as the scope of full implementation is unknown at this time. We also decline to delay the timeline, as 180 days should provide sufficient time for stakeholder outreach. Second, CALSSA, Tesla and Green Power Institute all object to the timing for implementing portal improvements, while SDG&E requests an additional 90 days to submit testimony.[381] Here again, we decline to revise the schedule. We recognize Utilities have a variety of current and planned portal upgrades and the current timeline will allow time for tracking and coordination.

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[377] PG&E Opening Comments on Proposed Decision at 2.

[378] SDG&E Opening Comments on Proposed Decision at 1 and SCE Opening Comments on Proposed Decision at 5.

[379] CESA Opening Comments on Proposed Decision at 5-6.

[380] SCE Opening Comments on Proposed Decision at 6

[381] See CALSSA Opening Comments on Proposed Decision at 7, Tesla Opening Comments on Proposed Decision at 5, Green Power Institute Opening Comments on Proposed Decision at 9-10, and SDG&E Opening Comments on Proposed Decision at 9.

Green Power Institute requests a correction on the contents of the report, *Interconnection Automation and Streamlining,* stating that the proposed decision mischaracterizes the report as solely focused on automation and streamlining opportunities for Rule 21 process. Rather, Green Power Institute asserts the report proposes a number of detailed solutions for Incorporating the Interconnection Capacity Analysis into the Fast Track process and proposes further automation and streamlining options for the Rule 21 process.[382] Further, Green Power Institute argues the Commission should consider this report in the record of this proceeding, pointing to a scoping memo provided by the working group facilitator.[383] In response, TURN contends that Green Power Institute mischaracterizes working group discussions, noting that the inclusion of Proposal 8v and the report was objected to repeatedly by every party other than Green Power Institute and Clean Coalition.[384] TURN also highlights that the facilitator of the working group had no official capacity nor authority to determine which issues were in scope and appropriate to be discussed.[385] We confirm that Assigned Commissioner's Scoping Memos and any amendments determine the scope of a proceeding, not working group facilitators and not parties. The *Interconnection Automation and Streamlining* report is outside the scope of Issue 8.

[382] Green Power Institute Opening Comments on Proposed Decision at 4.

[383] Green Power Institute Opening Comments on Proposed Decision at 6.

[384] TURN Reply Comments on Proposed Decision at 1.

[385] *Id*. at 2.

CESA and VGIC request the Commission clarify the applicability of the UL PCS CRD referenced in Proposal 23d and recommend the Commission allow for an option that the V2G DC systems pursue Rule 21-approved bidirectional mode from the outset.[386] SCE opposed this option arguing that the option was not discussed in the working group and noting that it raises resale concerns.[387] We agree that this information is not in the record. Hence, we decline to adopt the proposed option.

VGIC disagrees with Finding of Fact 263, contending it reflects a subjective determination rather than a finding of fact. VGIC recommends a new finding, contending that it is "well within Commission's power to adopt a general policy that self-certification processes could be considered an acceptable approach to V2G AC Interconnection."[388] In response, SCE opposes VGIC's recommendation noting that the members of the V2G AC Subgroup did not agree that either third-party or self-certification for plug-in vehicle equipment Is acceptable.[389] We decline to revise the finding of fact. This issue requires further discussion and record development In the V2G AC Subgroup.

## 8. Assignment of Proceeding

Martha Guzman Aceves is the assigned Commissioner and Kelly A. Hymes is the assigned Administrative Law Judge in this proceeding.

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[386] CESA Opening Comments on Proposed Decision at 3-4 and VGIC Opening Comments on Proposed Decision at 2.

[387] SCE Reply Comments on Proposed Decision at 3.

[388] VGIC Opening Comments on Proposed Decision at 5.

[389] SCE Reply Comments on Proposed Decision at 5.

**Findings of Fact**

1. Resolution E-5000 rejected the argument that the lack of a standard aggregator agreement should preclude aggregators from providing communications capabilities.

2. Issue 6 is moot and, as a result, resolved.

3. The Integration Capacity Analysis provides an estimation about the size of a project that can be interconnected at a specific point in a circuit and not require distribution upgrades.

4. By incorporating the Integration Capacity Analysis data into Rule 21, we no longer need the project size eligibility limits.

5. Eliminating the size restrictions allows any applicant to select the Fast Track process.

6. Proposal 8a is unopposed.

7. Proposal 8a will streamline the Fast Track process.

8. Proposal 8b will ensure use of the most recent Integration Capacity Analysis values without impacting timelines for Initial Review.

9. Proposal 8b addresses the objectives of integration, further automation, and maintaining a streamlined process.

10. Because we also adopt proposals 8f, 8g, 8h, and 8j in this decision, Utilities do not need to perform additional Integration Capacity Analyses as part of the interconnection process of projects with less than 30 kVA nameplate capacity.

11. Proposal 8b should help ensure that the online Integration Capacity Analysis tool is accurate and reflective of real-time conditions to the extent possible.

12. Tracking when the Integration Capacity Analysis values are updated outside of the standard monthly updates balances the competing priorities of having the most updated values and ensuring costs to maintain the values are reasonable.

13. Tracking when Integration Capacity Analysis outdated values lead to Interconnection Requests failing the Initial Review will inform future discussions of the frequency of and process for Integration Capacity Analysis updates.

14. Proposal 8c, which tracks when Integration Capacity Analysis values are updated outside of the standard monthly updates, is a first step to improving the Interconnection Application system over time.

15. Proposal 8d does not streamline the interconnection process.

16. Proposal 8d adds an additional 10 business days of time to the interconnection process, with no additional benefit.

17. Proposal 8d could complicate the Integration Capacity Analysis monthly update.

18. Synchronous or induction generators cannot use the Integration Capacity Analysis to determine a specific value and are automatically assigned a value of 1.2 per unit short circuit contribution.

19. Proposal 8f1 would add Screen F1 to the interconnection process, which would determine whether the generating system's short circuit contribution exceeds 1.2 per unit.

20. Proposal 8f1, with its new Screen F1, is needed in order to integrate the Integration Capacity Analysis tool with Rule 21.

21. Existing tariff language allows generating facilities with a Gross Rating of 11 kVA or less to bypass Screens F, G, H, and J.

22. All working group participants agree that Modification 1 for Proposals 8f, 8g, 8h, and 8j, which would raise the threshold to 30 kVA to bypass Screens F, G, H, and J, would improve streamlining and not raise any safety or reliability concerns.

23. It is reasonable to adopt Modification 1 for Proposals 8f, 8g, 8h, and 8j.

24. Modification 2 for Proposals 8f, 8g, 8h, and 8j would require Utilities to provide an early indication of an applicant confronting problems with passing Screens F and G.

25. The costs related to Modification 2 for Proposals 8f, 8g, 8h, and 8j have not been identified.

26. The value of Utilities providing an early indication of hurdles in passing Screens F and G cannot be determined at this time.

27. Option A of Proposal 8i, which would relocate Screen I to the Rule 21 technical framework overview, would result in unknown additional costs and would make the Fast Track process less efficient.

28. Utilities contend Option A of Proposal 8i is necessary because distributed energy resources penetration increases could lead to overvoltage conditions and possible overloads but acknowledge, along with other parties, that this situation has not occurred.

29. Option B of Proposal 8i would retain the status quo whereby non-exporting projects of all sizes skip Screens K, L, and M.

30. The transmission overvoltage and transmission anti-islanding tests are not incorporated in the Integration Capacity Analysis.

31. Replacing the current 15 percent of peak load value in Screen M with the Integration Capacity Analysis values results in Screen M no longer including the transmission overvoltage and transmission anti-islanding tests.

32. Option C of Proposal 8k would modify Screen L to include the transmission overvoltage and transmission anti-islanding tests that had been included in Screen M.

33. There is an unresolved factual dispute regarding anti-islanding screening standards.

34. Issue 18, which asks whether the Commission should adopt changes to anti-islanding screen parameters, will be addressed by Working Group 4.

35. SCE and SDG&E do not currently screen for anti-islanding but may do so in the future.

36. The proposed language from IREC would require a guidance document to be published identifying the specific screening approach SCE and SDG&E would use.

37. The record does not contain sufficient information regarding the technology solutions, tools needed and implementation costs for adopting Proposal 8l.

38. The concept of Proposal 8l, requiring Utilities to identify where projects are likely to fail Screen L, will facilitate the transparency, predictability, and streamlining of the Fast Track process.

39. The purpose of Screen M is to maintain generation and load balance in case of load changes on a circuit.

40. All parties agree that Screen M should be modified to reflect the Integration Capacity Analysis.

41. The modified Proposal 8m, Option B, will get the most value out of the ratepayer-funded Integration Capacity Analysis while maintaining grid safety and reliability.

42. The load on a circuit might change after a project is interconnected, which could pose safety and reliability risks.

43. Integrating a buffer into Screen M would leave space between the amount of expected interconnecting generation and the Integration Capacity Analysis value.

44. Applying a buffer to Proposal 8m, Option B, to ensure safety and reliability is prudent.

45. Screen N requires alignment with the Integration Capacity Analysis.

46. Alignment with the Integration Capacity Analysis, to account for thermal overload, overvoltage conditions and protection, requires adjustment for three scenarios: 1) when the Interconnection Request is below the updated Integration Capacity Analysis value and passes Screen F1; 2) when the Interconnection Request is above the updated Integration Capacity Analysis value or fails Screen F1; and 3) when Integration Capacity Analysis information is not available.

47. Proposal 8n is uncontested.

48. Proposal 8n makes the necessary adjustments for: 1) when the Interconnection Request is below the updated Integration Capacity Analysis

value and passes Screen F1; 2) when the Interconnection Request is above the updated Integration Capacity Analysis value or fails Screen F1; and 3) when Integration Capacity Analysis information is not available.

49. Proposal 8q, involving Screen P, is uncontested.

50. Screen P is in Supplemental Review and is used to determine if there are mitigations that can avoid having a project move to Detailed Study.

51. Rule 21 requires that all new interconnections must have certain smart inverter functions enabled.

52. Adoption of Proposal 8q would allow a utility to consider these additional functions as potential mitigations.

53. Avoidance of the Detailed Study maintains efficiency of the Fast Track process.

54. Proposal 8q meets the objective of this proceeding, streamlining, and of Issue 8, integrating the Integration Capacity Analysis tool.

55. Proposal 8r provides the option to combine the Initial Review and Supplemental Review processes.

56. Proposal 8r is supported by all parties.

57. Proposal 8r would benefit Applicants and Utilities by providing additional time savings through the option to skip the Initial Results meeting.

58. Proposal 8r meets the Issue 8 objective of streamlining the Fast Track process.

59. Proposal 8s would reduce the interconnection application fee for non-net energy metering systems.

60. Parties disagree on the data that claims the need for fee reduction.

61. Parties disagree on whether it is appropriate to compare small net energy metering projects to large non-export projects up to 1MW.

62. The record does not support fee reduction, as recommended in Proposal 8s.

63. The record regarding Proposal 8t, which addresses queue management, indicates disagreement on the necessity of the proposal and whether the integration of the Integration Capacity Analysis will make a difference.

64. The record does not support adoption of Proposal 8t.

65. Proposal 8v recommends consideration of the *Interconnection Automation and Streamlining Report.*

66. Supporters of the *Interconnection Automation and Streamlining Report* state the report was informed by other stakeholders but is not a comprehensive reflection of input received.

67. Proposal 8v is out of scope for Issue 8, which focuses on the integration of the Integration Capacity Analysis with Rule 21.

68. The CALSSA and Utilities' proposals for resolving Issue 9 differ in three ways: proposed buffer size, frequency of changes, and breadth of Utility control over reductions to customer generation profiles.

69. A final buffer for resolving Issue 9 should be based on real-world tests of the Integration Capacity Analysis.

70. An interim 10 percent buffer for the Issue 9 proposal will ensure the safety and reliability of the grid while we gather data on the accuracy of the Integration Capacity Analysis.

71. Eighteen months after implementation of the Issue 9 proposal should provide adequate data collection on the accuracy of the Integration Capacity Analysis.

72. The Utilities' proposal for addressing Issue 9 allows a customer to change its output on a seasonal basis.

73. The Integration Capacity Analysis has the ability to make monthly changes.

74. Allowing a customer to establish scheduled output limits aligns the Issue 9 proposal with the Integration Capacity Analysis.

75. Allowing a customer to establish monthly scheduled output limits strikes a balance between the initial proposed schedule and the seasonable schedule proposed by Utilities.

76. Future grid conditions could result in actual hosting capacity being below the published Integration Capacity Analysis-SG and the utility may need to reduce generation to ensure safe and reliable service without grid upgrades.

77. The record of this proceeding does not contain information regarding whether and how Utilities determine that generation reductions are necessary.

78. No party opposes Proposal 2 for Issue 10, which recommends the use of a single Project Identification Number.

79. There are barriers and hurdles that rise without the use of a single Project Identification Number.

80. Assigning one single identification number to a project will make the interconnection process easier to navigate for the developers and easier to manage for Utilities.

81. Because the purpose of this proceeding is the refinement and streamlining of Rule 21, coordinating the overlapping Rules 2, 15, 16, and 21 is prudent.

82. Proposal 3 for Issue 10 would require a utility to inform an interconnection customer of the start date for a project studied under Rule 2, 15, and/or 16.

83. Each of the Utilities currently have a practice similar to Proposal 3 for Issue 10.

84. Implementation of Proposal 3 for Issue 10 would provide customers and developers with more visibility and transparency into the interconnection process.

85. Proposal 4 for Issue 10 would require a utility to send an invoice for the engineering advance or the facility costs within five business days of execution of the Interconnection Agreement.

86. Knowing when to expect an invoice provides certainty to the customer and improves the transparency of the interconnection process.

87. None of the Utilities justified their opposition to the inclusion of timelines in the tariff.

88. Proposal 5 for Issue 10 would provide more certainty to customers by requiring Utilities to attempt to contact the customer to schedule a mitigation work scoping meeting no later than five business days after receiving payment for the engineering advance.

89. The Commission's objectives in this streamlining process are to increase efficiency and improve transparency.

90. All three Utilities oppose the inclusion of timelines in the Rule 21 tariff.

91. Proposal 5 for Issue 10 addresses the Commission's objectives of increasing efficiency and improving transparency.

92. There is concern about Proposal 5 for Issue 10 with respect to realistic timelines.

93. Proposal 8 would require the utility to send a detailed reconciliation of the costs of interconnection facilities and distribution updates within 6 months.

94. The inclusion of a timeline in the Rule 21 tariff provides certainty and transparency to the customer.

95. A 12-month timeline to provide customers a detailed reconciliation of the costs aligns with the timeline adopted by the FERC for its Wholesale Distribution Access Tariff and Transmission Owner Tariff.

96. The adoption of a modified Proposal 8 for Issue 10 will provide further certainty to customers.

97. Proposal 1 for Issue 10 recommends assigning a project manager for interconnection requests greater than 100 kW.

98. Rule 21 gives Utilities the flexibility to determine the most efficient way to allocate resources.

99. The Commission should not mandate how Utilities should effectively manage the process to meet customer needs.

100. The Working Group Two Report does not contain data regarding the costs of implementing Proposal 1 for Issue 10.

101. There remain many unanswered questions the Commission needs to consider in order to adopt a particular notification process proposal, in lieu of the application process.

102. There is value in the concept of a notification-based approach for non-exporting storage systems.

103. It is valuable that the working group participants were able to find common ground in procedures for non-exporting storage systems interconnection applications.

104. Streamlining procedures for non-exporting storage systems interconnection applications is a related extension of Issue 11 and practical to consider.

105. There are jurisdictional, contractual, and processing differences between non-exporting standalone storage systems and non-net energy metering below 30 kVA exporting systems.

106. The differences between non-exporting standalone storage systems and non-net energy metering below 30 kVA exporting systems impact the ability to treat all systems in a similar streamlined manner.

107. The foundation of the three proposals for Issue 11 is a non-exporting energy storage pilot (Pilot), which is focused solely on non-exporting storage systems.

108. The Pilot has been largely successful in decreasing interconnection application processing times for non-exporting storage systems.

109. Proposal A for Issue 11, which would implement in Rule 21 all process improvements tested in the Pilot, is a consensus proposal.

110. The improvements tested in the Pilot have been shown to be successful for non-exporting storage systems.

111. The improvements would create a more streamlined interconnection process for this class of projects.

112. Given the low volume of the non-export storage projects, Proposal A would be the most cost-effective approach for reducing interconnection application processing time for this class of projects.

113. Proposal B1, which would require Utilities to implement Phase I of the Lightning Review, is a consensus proposal.

114. The Lightning Review process would mirror the standard net energy metering process.

115. Many of the enhancements proposed for the Lightning Review process have already been implemented by Utilities.

116. Adoption of the concept of the Lightning Review process supports these prior process improvements in anticipation of future growth of storage interconnection applications.

117. The Working Group Two Report proposes four principles for developing enhancements for streamlining and the Lightning Review process to which no party expressed opposition.

118. The four principles should further the streamlining of the Lightning Review process.

119. The record is insufficient for deliberating on the enhancements identified in Proposal B1 of Issue 11 and the related costs.

120. The filing of testimony in Phase II of this proceedings is the more appropriate regulatory vehicle to address the technical processes identified in Proposal B1 for Issue 11 and their related costs.

121. Participants did not discuss Proposal B2 or B3 (for Issue 11) in the working group meetings.

122. Proposals B2, B3 and C for Issue 11 extend beyond the scope of the issue, which is focused on non-exporting storage systems.

123. Proposal C explicitly requests the Commission to expand the scope of this proceeding prior to its resolution and completion.

124. The results of adopted changes in this decision and the decision on the recommendations of Working Group 1 should be implemented and reviewed to ascertain whether additional changes are warranted.

125. Proposals 12a, 12c, and 12e have agreements of the entire working group.

126. Proposals 12a, 12c, and 12e address the objective of improving timeline certainty.

127. Tracking of the 12 timelines recommended in Proposal 12a will provide the data necessary for future, data-driven considerations of process improvements.

128. Reporting the tracking of the 12 timelines recommended in Proposal 12a on a quarterly basis is a reasonable frequency.

129. Adoption of the design and construction timelines recommended in Proposal 12c aligns with the design and cost estimation timelines recommended in Proposal 10.6.

130. Parties disagreed on the Proposal 10.6 timeline during Working Group Two discussions but were able to come to a consensus on a timeline in Working Group Three.

131. Parties oppose the simultaneous notification of Energy Division in Proposal 12e and consider it burdensome.

132. It is reasonable to require Utilities to include a tally of the notifications on a quarterly basis for Proposal 12e.

133. It is reasonable to require Utilities, as part of Proposal 12e, to report the reason for delay.

134. Proposal 12b would add seven other timelines to the framework recommended in Proposal 12a.

135. The tracking and reporting on the seven additional timelines, as recommended in Proposal 12b, should result in a more transparent process.

136. The objective of Issue 12 is to improve certainty and a more transparent process should help improve certainty.

137. Tracking the seven additional timelines, as recommended in Proposal 12b, should result in increased accountability.

138. Proposal 12d establishes a 20 business day timeline for the design of net generation output meters and a 20 business day timeline for construction.

139. 99 percent of installations completed by PG&E in 2019 were completed in 10 calendar days.

140. Net generation output meters can add tens of thousands of dollars to project costs and delays of six months or more.

141. It is reasonable to require 20 business day timelines for designing net generation output meters and for construction of the net generation output meters.

142. Proposal 12f would establish a goal that 95 to 100 percent of projects meet all timelines adopted in Proposal 12a and 12b within two years upon commencement of tracking.

143. Adoption of Proposal 12f would provide a benchmark by which to assess our adopted tracking procedures, which would benefit ratepayers.

144. Establishing timeline benchmarks should help us achieve our objectives of streamlining Rule 21 and improving timeline certainty.

145. Proposal 12h would limit the applicability of Proposal 12f to non-net energy metering projects and net energy metering projects greater than 30 kW.

146. The volume of standard net energy metering projects would complicate reporting.

147. Adoption of Proposal 12h will target the project types that are of most concern to stakeholders, without an undue administrative burden.

148. Project targeting should be based on project type and need, but not necessarily location need.

149. Proposal 12g would establish intermediate goals if tracking reveals Utilities are not meeting the 95 to 100 percent goal required by Proposal 12f.

150. Adoption of Proposals 12f, 12h, and 12i sufficiently address the need for benchmarks to assess the results of the timeline tracking.

151. Proposal 12g would add a level of unnecessary administration.

152. A modified Proposal 12i is a more reasonable and effective approach than Proposal 12g to determine whether the objective of Issue 12 is being achieved.

153. The modified Proposal 12i would require Utilities to organize and host a workshop to discuss whether the timelines being tracked and reported on have been met.

154. The modified Proposal 12i will ascertain whether timeline certainty is improving.

155. Proposal 12j would require Utilities to provide updates on substation upgrades to applicants whose projects depend on such an upgrade.

156. Proposal 12j meets the objective of Issue 12 – improving timeline certainty—and provides additional transparency.

157. Including the requirements of Proposal 12j in Rule 12 will create better transparency and improve timeline certainty.

158. Proposals 16a, 16b, and 16c are consensus proposals.

159. The objective of Issue 16 is the encouragement of third-party construction of upgrades.

160. Proposals 16a, 16b, and 16c would promote regulatory simplicity and lead to more timely and cost-effective interconnections.

161. Proposal 16a would incorporate tariff Rule 15 by reference in Rule 21.

162. Proposal 16a would ensure that third-party upgrade providers are sufficiently qualified for safety and reliability purposes.

163. Proposal 16a achieves the objective of Issue 16.

164. Proposal 16b would reference Rule 15 competitive bidding language in Rule 21.

165. Proposal 16b would resolve concerns about contractor eligibility.

166. Proposal 16b meets the intention of Issue 16.

167. Proposal 16c would align contractor selection provisions of Rule 21 with Rule 15.

168. Proposal 16c would encourage third-party construction of upgrades by eliminating specific "discretion" language.

169. The alignment of the contractor selection provisions and the elimination of the "discretion" language in Proposal 16c improves consistency between rules, promotes regulatory simplicity, and meets the objective of Issue 16.

170. Proposal 16d would allow third parties to work on existing de-energized systems under specific scenarios.

171. Working Group Three participants could not agree on any scenarios in which third parties could work on existing de-energized facilities.

172. Without identified scenarios, it is not prudent to adopt Proposal 16d.

173. The purpose of Issue 20 is to coordinate Commission and federal interconnection rules for behind-the-meter distributed energy resources.

174. Proposals 20a, 20b and 20c are consensus proposals.

175. Proposal 20a would use information web pages to educate customers on the transfer processes between the Commission and federal interconnection processes.

176. Proposal 20a provides customers and other interconnection stakeholders with easy access to clarifying information.

177. Proposal 20b recommends maintaining the current queuing rules for Rule 21 and federal interconnection processes seeking to interconnect at the same location.

178. No changes are necessary for Rule 21 and federal interconnection processes seeking to interconnect at the same location.

179. Proposal 20c provides customers and other interconnection stakeholders access to existing information.

180. Proposal 20c would result in better informed customers and stakeholders.

181. Proposals 20a, 20b, and 20c resolve Issue 20.

182. For Issue 22, Working Group Three participants developed a list of proposed improvements to the Utilities' interconnection application portals, i.e. 18 subproposals.

183. Working Group Three participants have varying degrees of support for the 18 subproposals developed for Issue 22.

184. There is insufficient record to determine which of the 18 subproposals, developed for Issue 22, should be adopted.

185. Additional discussion is needed regarding Issue 22's 18 subproposals, including costs and cost recovery methods.

186. The Commission encourages the growth of the use of distributed energy resources and the streamlining of the interconnection application process, including the portals.

187. The Commission has a responsibility to protect ratepayers.

188. Rule 21 language currently allows the interconnection of electric vehicles and related charging infrastructure and devices.

189. The consideration of the Issue 23 proposals is appropriate.

190. Proposal 23a recognizes that, in the case of unidirectional charge-only V1G, Rule 21 does not apply but Rules 2, 15, and 16 are applicable.

191. Current Rules and practice confirm that, in the case of unidirectional charge-only V1G, Rule 21 does not apply but Rules 2, 15, and 16 are applicable.

192. Proposal 23a is consistent with current rules and practice.

193. Proposal 23b would modify Rule 21 to clarify that the rule applies to the interconnection of stationary and mobile energy storage systems.

194. Rule 21 currently applies to the interconnection of stationary and mobile storage systems.

195. Clarity in Rule 21 is necessary.

196. Proposal 23c would clarify that the current practice set forth in Rule 21 is to allow the interconnection of V2G DC EVSE systems.

197. The existing Rule 21 tariff allows V2G DC EVSE systems to be interconnected if the EVSE meets all Rule 21 requirements, including UL 1741 SA.

198. Proposal 23d would allow V2G DC EVSE systems with bidirectional capability to connect as V1G, load-only, and operate unidirectional mode with specific certifications.

199. Proposal 23d is a consensus proposal but parties disagree on the need for language changes in the Rule 21 tariff.

200. Adoption of Proposal 23d is necessary for safety and clarity.

201. Proposal 23e would allow bidirectional mode to be enabled for a V2G DC EVSE system upon receiving permission to operate from the utility.

202. Proposal 23e is a consensus proposal.

203. The current Rule 21 tariff allows bidirectional mode to be enabled for a V2G DC EVSE system upon receiving permission to operate from the utility.

204. Implementation details for Proposal 23e need to be resolved.

205. Proposal 23f would modify the Utilities' interconnection portals to enable simple tracking of V2G interconnections.

206. Tracking V2G interconnections will assist the Commission and California in knowing the extent to which policies are achieving the goal of increasing vehicle to grid interconnections.

207. Proposal 23f is not urgently needed.

208. The implementation details of Proposal 23f need to be resolved: timeline, costs, and cost recovery methods.

209. Proposal 23i would clarify a pathway for parties to interconnect V2G AC systems on a timely basis for experimental, pilot, and/or temporary use until the appropriate rules are updated in the future.

210. Proposal 23i would allow V2G AC system pilots to be exempt, on a temporary basis, from Rule 21 smart inverter requirements.

211. The Commission is currently addressing V2G AC interconnection issues through four existing pilots.

212. It is necessary to create a pathway to interconnection to enable the Commission to learn from these and other future V2G AC interconnection pilots.

213. Administrative Law Judges from this proceeding and R.18-12-006 established a Vehicle to Grid Alternating Current Subgroup.

214. Proposal 23g, which would establish a group to develop technical recommendations to enable V2G AC interconnections, is no longer necessary.

215. Proposal 23h would modify Section N of Rule 21 to allow streamlined study process for V2G DC EVSE interconnections.

216. The Rule 21 definition of a generator captures V2G DC EVSE capability as a generator.

217. A specific reference to V2G DC EVSE within Rule 21 is not necessary.

218. Proposal 24a would treat certain new facilities upgrades as like-for-like upgrades in terms of applying the cost-of-ownership charge and result in a zero cost-of-ownership charge.

219. The purpose of the cost-of-ownership charge is to offset a utility's revenue requirement for operating and maintaining the underlying asset, as well as any applicable capital related revenue requirement.

220. Ratepayers and Utilities should not pay for the operation and maintenance of an interconnection project.

221. The accounting practices of Utilities, with respect to the cost-of-ownership charge, remain unclear in the record.

222. Proposal 24b would create three cost-of-ownership replacement cost options for an interconnection applicant.

223. There is a lack of certainty in the form, method, and application of accounting practices used by Utilities.

224. Utilities' practices avoid undercollection but do not avoid overcollection.

225. We do not have a sufficient understanding of the cost-of-ownership accounting practices to determine whether Proposal 24b will prevent cost shifts occurring between ratepayers and interconnection applicants.

226. Proposal 24c would replace the cost-of-ownership charge with a charge similar to a net-additional cost-of-ownership charge, which would result in the

difference between the system without the upgrade and the costs with the upgrade, including operating and maintenance costs.

227. Proposal 24c could result in a cost shift or subsidy.

228. A Utility report including a step-by-step description of the cost-of-ownership charge and the Utility determination of the value of each element of the charge should provide the Commission with a complete understanding of the cost-of-ownership charge.

229. Proposal 27a would add language to Rule 21 allowing smart inverter default settings to be changed and would establish a process to update Rule 21 when additional smart inverter standards are developed.

230. Proposal 27a is a consensus proposal.

231. There are no rules regarding alternative settings for smart inverters.

232. Proposal 27a would provide additional clarity to Utilities and customers and would allow for alternative settings useful for facilitating interconnection or providing grid services.

233. The clarity provided by Proposal 27a would allow Utilities to use the full range of smart inverter settings.

234. Proposal 27a would achieve the intention of Issue 27, establishing operational requirements for smart inverters.

235. Proposal 27c would convene the Smart Inverter Working Group to refine technical specification for the Set Active Power Mode function.

236. The Commission and the California Energy Commission established the Smart Inverter Working Group to pursue the development of advanced smart inverter functionality.

237. D.16-06-052 encouraged parties and other interested stakeholders to continue to participate in the Smart Inverter Working Group.

238. It is logical to assign the refinement of the Set Active Power Mode function technical specifications to the Smart Inverter Working Group.

239. A single process for updating Rule 21 to align with IEEE 1547 and UL 1741 is efficient and would provide certainty to the inverter manufacturers in the form of one update process.

240. R.14-10-003 is considering proposals for a distributed energy resources tariff.

241. A regulatory pathway needs to be established for implementation of any proposals adopted.

242. Proposal 28a would instruct the Energy Division to decide on the need to convene the Smart Inverter Working Group to determine if technical work is needed following the adoption of a distributed energy resources tariff in R.14-10-003.

243. Issue A asks what specifications should be required for a system to be non-export, inadvertent export, or limited export.

244. Issue B asks how to treat generating capacity for behind-the-meter paired solar and storage that are certified not to export more than a preset value.

245. Proposals A-B 1 and A-B 2 are consensus proposals.

246. Proposals A-B 1 and A-B 2 define the specifications required for a generating facility to be considered non-export, limited export, and inadvertent export.

247. The specifications provided in Proposals A-B 1 and A-B 2 address concerns regarding the high cost of the current option of relays by providing the option of the less costly power control system in compliance with UL CRD as described in this decision.

248. The inclusion of UL CRD compliance as a specification option addresses the concern regarding the lack of standards for the control of power output for non-export or limited export for inverters and power control systems and eliminates the need for the controversial nameplate plus nameplate maximum nameplate rating.

249. Using the UL CRD will give assurance to Utilities that a system will always operate within set parameters, including an appropriate response time.

250. The specifications in Proposals A-B 1 and A-B 2 address the Utilities' concerns that generating facilities use only certified inverters.

251. Proposals A-B 1 and A-B 2 appropriately resolve Issues A and B.

252. Proposal A-B 3 would allow an inverter approved for non-export and limited export to be set using different maximum export value settings at different times of the year, when meeting the qualifications of Proposal A-B 1 or A-B 2.

253. Smart Inverter Phase III Function 8 enables systems to have different export values at different parts of the year and can vary seasonally, monthly, or hourly.

254. Standards to test control systems are not approved at this time.

255. Proposal A-B 3 addresses Issues A and B.

256. Proposal A-B 4 is a consensus proposal that applies only to SCE customers and requires SCE customers applying for interconnection with a power control system to use only the systems on a pre-approved list.

257. Proposal A-B 4 would streamline the application process, an objective of this proceeding, and would ensure safety and reliability through the certified control information.

258. There are gaps in the existing standards to create interconnection at one fixed point for one or more plug-in electric vehicles.

259. The V2G AC Subgroup recommends reconvening the subgroup when automotive and other applicable standards are updated.

260. Reconvening the V2G AC Subgroup without revised standards in place would be premature.

261. There is value in holding a meeting of the subgroup on a routine basis to provide the members of the subgroup with news on the status of the V2G AC Interconnection standards.

262. Utility participation in committees that update V2G AC interconnection standards will apprise Utilities of any standards updates and ensure the committee understands what is needed for V2G AC interconnection from the Utilities' perspective.

263. V2G AC interconnection standards need to be adopted prior to the Commission considering the jurisdictional question of plug-in electric vehicle equipment requirements or self-certification policy issues.

## Conclusions of Law

1. Proposal 8a should be adopted.

2. Proposal 8b should be adopted.
3. Proposal 8c should be adopted.
4. Proposal 8d should not be adopted.
5. Proposal 8f1 should be adopted.
6. Modification 1 for Proposals 8f, 8g, 8h, and 8j should be adopted.
7. Modification 2 for Proposals 8f, 8g, 8h, and 8j should not be adopted.
8. Option A of Proposal 8i should not be adopted.
9. Option B of Proposal 8i should be adopted.
10. Option C of Proposal 8k should be adopted as a temporary solution until Issue 18 is resolved.
11. The concept of proposal 8l should be adopted but Utilities should continue to develop proposals to implement the concept.
12. Proposal 8m. Option B should be adopted with the modification of a ten percent buffer.
13. Proposal 8n should be adopted.
14. Proposal 8q should be adopted.
15. Proposal 8r should be adopted.
16. Proposal 8s should not be adopted.
17. Proposal 8t should not be adopted.
18. Proposal 8v should not be adopted.
19. The Utilities' counter proposal to resolve Issue 9, with the modifications of the required buffer and to allow monthly customer changes, should be adopted.
20. Proposal 2 for Issue 10 should be adopted.
21. Proposal 3 for Issue 10 should be adopted.

22. Proposal 4 for Issue 10 should be adopted.

23. Proposal 5 for Issue 10 should be adopted with a modification to require a 10 business day customer contact.

24. Proposal 8 for Issue 10 should be adopted but modified to allow Utilities 12 months to provide customers a detailed reconciliation of the costs of interconnection facilities and distribution upgrades.

25. Proposal 1 for Issue 10 should not be adopted.

26. The notification-based approach should continue to be explored in this proceeding.

27. Streamlining process for non-exporting storage systems interconnection applications should be considered in this decision.

28. We should limit the applicability of the streamlining proposals for Issue 11 to non-exporting standalone storage systems.

29. Proposal A for Issue 11 should be adopted.

30. The concept of the Lightning Review process recommended in Proposal B1 for Issue 11 should be adopted.

31. The four principles for developing the Lightning Review process should be adopted.

32. Utilities should file testimony in Phase II of this proceeding to seek approval of the proposed enhancements discussed in Proposal B1 and their related costs.

33. Proposals B2, B3 and C of Issue 11 should not be adopted.

34. Proposal 12a should be adopted.

35. The tracking of timelines in Proposal 12a should be done on a quarterly basis.

36. Proposal 12c should be adopted

37. Proposal 6 from Working Group Two Issue 10 should be adopted.

38. Proposal 12e should be modified to require a tally of the notifications on a quarterly basis to the Energy Division.

39. Proposal 12e, as modified, should be adopted.

40. Proposal 12b should be adopted.

41. Proposal 12d should be adopted.

42. Proposal 12f should be adopted.

43. Proposal 12h should be adopted.

44. Proposal 12g should be adopted.

45. Proposal 12i should be modified.

46. Proposal 12i, as modified, should be adopted.

47. Proposal 12j should be adopted.

48. Proposal 16a should be adopted.

49. Proposal 16b should be adopted.

50. Proposal 16c should be adopted.

51. Proposal 16d should not be adopted.

52. Proposals 20a, 20b, and 20c should be adopted.

53. Improvements to the Utilities' interconnection application portals should be made.

54. A workshop to discuss the 18 subproposals should be held.

55. The costs for implementing any of the 18 subproposals should be recovered from the set of customers who benefit.

56. It should be affirmed that Proposal 23a is consistent with current rules and practice.

57. Rule 21 should specifically state that V2G DC EVSE systems may be interconnected if the EVSE meets all Rule 21 requirements, including UL 1741 SA.

58. Proposal 23d should be adopted.

59. Proposal 23e should be adopted.

60. Implementation details for 23e should be resolved through a collaborative effort of the parties and stakeholders.

61. Proposal 23f should be adopted following the development of implementation details: timeline, costs, and cost recovery method.

62. Proposal 23g should not be adopted.

63. Proposal 23h should not be adopted.

64. Proposal 24a should not be adopted.

65. Proposal 24b should not be adopted.

66. Proposal 24c should not be adopted.

67. Utilities should provide additional insight on the cost-of-ownership charges and related accounting practices.

68. Proposal 27a should be adopted.

69. Proposal 27c should be adopted.

70. Proposal 28a should be adopted.

71. Proposals A-B 1 and A-B 2 should be adopted.

72. Proposal A-B 3 should be modified to require Utilities to wait for control system testing standards to be approved.

73. Proposal A-B 3, as modified, should be adopted.

74. Proposal A-B 4 should be adopted.

75. Utilities should host a meeting of the V2G AC Subgroup on a routine basis to update the members of the subgroup on the status of V2G AC interconnection standards.

76. Utilities should actively participate in standards committees that address V2G AC interconnection standards.

77. R.17-07-007 should remain open to consider Working Group Four issues and subsequent phases.

**O R D E R**

**IT IS ORDERED** that:

1. Proposal 8a is adopted. The Fast Track eligibility size is eliminated from Electric Rule 21. An Interconnection project that is sized below the Integration Capacity Analysis value may still be required to go through Supplemental Review or Detailed Study, if the project fails the Screens not evaluated by the Integration Capacity Analysis. The elimination of size eligibility shall not increase chances of passing through Initial Review or Supplemental Review if the projects is sized above the Integration Capacity Analysis value. Net energy metering interconnection projects under 30 kilovolt amperes may use the Fast Track process regardless of the Integration Capacity Analysis value.

2. Proposal 8b is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall

use the Initial Review process to determine if Integration Capacity Analysis values at the proposed Point of Interconnection need to be updated using the Integration Capacity Analysis tool on the specific electrical node into the Initial Review process or running the Integration Capacity Analysis on all the electrical nodes in the circuit. Utilities shall not perform additional Integration Capacity analyses as part of the interconnection process of projects with less than 30 kilovolt amperes nameplate capacity. Utilities shall share the results of any Integration Capacity Analysis updates with the interconnecting generator and provide an explanation of changes to grid conditions or the interconnection queue. Utilities shall comply with confidentiality provisions and data reduction policies.

3. Southern California Edison Company (SCE) shall develop a system for labeling Integration Capacity Analysis values that need to be updated. No later than six months from the issuance of this decision, SCE shall submit a report on the status of this work to the Director of the Commission's Energy Division.

4. Proposal 8c is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall track when the Integration Capacity Analysis outdated values lead to Interconnection Requests failing the Initial Review. Utilities shall provide the results of the tracking required in Proposal 8c with the Issue 12 reporting required by Ordering Paragraph 22 below. Additionally, Utilities shall also track the costs associated with the updates necessitated by the outdated values and provide the data in the same Issue 12 reporting document. Furthermore, Utilities

shall include the actual costs associated with the processing of interconnection applications as referenced in the discussion on Proposal 8s.

5. Proposal 8f1 is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall include a new Screen in the Interconnection Rule 21 process, to be named Screen F1, which will determine whether a generating system's short circuit contribution exceeds 1.2 per unit.

6. Modification 1 of Proposals 8f, 8g, 8h, and 8j is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall modify Interconnection Rule 21 to allow interconnection projects less than 30 kilowatt volt amperes to bypass Screens F, G, H, and J.

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

8. Option C of Proposal 8k is adopted on an interim basis until resolution of Issue 18 in Working Group Four. Pacific Gas and Electric Company shall: modify Screen L in Interconnection Rule 21 to include the transmission overvoltage and transmission anti-islanding tests currently in Screen M.

9. The concept of Proposal 8l, identifying where interconnection projects are likely to fail Screen L of the Rule 21 Interconnection Application process, is adopted for future use.

10. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall develop proposals for implementing the concept of Proposal 8l, identifying where interconnection

projects are likely to fail Screen L of the Rule 21 Interconnection Application process. Utilities (either individually or together) shall submit testimony, in phase two of this proceeding, proposing concept implementation approaches with details to include the necessary technology solutions and tools, estimated costs, and proposed cost recovery method.

11. Option B of Proposal 8m is adopted with modification. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall apply a 10 percent buffer to the Integration Capacity Analysis-Static Grid profile and to the Integration Capacity Analysis-Operational Flexibility profile during review of Screen M of the Rule 21 Interconnection Application Process. The need for the 10 percent buffer to the Integration Capacity Analysis-Operational Flexibility profile will be revisited by the Commission. Utilities shall collect data on the effectiveness of the 10 percent Integration Capacity Analysis-Operational Flexibility buffer (after consulting with the Commission's Energy Division) and provide the data and a recommendation on whether to retain the buffer or adjust it, in the Advice Letter on buffers for Issue 9, as required by Ordering Paragraph 15.

12. Proposal 8n is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall update Screen N of the Rule 21 Interconnection Application Process to account for thermal overload, while adjusting for the following three scenarios: i) when the Interconnection Request is below the updated Integration Capacity Analysis value and passes Screen F1; ii) when the Interconnection Request is above the

updated Integration Capacity Analysis value or fails Screen F1; and iii) when Integration Capacity Analysis information is not available.

13. Proposal 8q is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall update Screen P of the Rule 21 Interconnection Application Process to account for new smart inverter capabilities.

14. Proposal 8r is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall revise the Rule 21 Interconnection Application Process to allow a customer to pre-pay for Supplemental Review when paying for Initial Review.

15. The counter proposal from Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) to resolve Issue 9 is adopted with modification. Within 90 days of the issuance of this decision, Utilities shall commence discussions with the Smart Inverter Working Group focused on implementing the proposal. Within six months of issuance of this decision, Utilities shall submit a Tier 3 Advice Letter providing recommendations (as applicable) regarding the standard review, certification requirements, and interconnection processes necessary for implementation of the proposal. Within 60 days of adoption of a certification scheme for the Limited Generation Profile, Utilities shall modify the Rule 21 Interconnection Application Process to allow a distributed energy resources customer to include a Limited Generation Profile with their application, require the customer to enable generation profile limiting functionality, and allow Utilities opportunity to alter the profile if safety and reliability concerns warrant it. Retroactive alterations to

generation profiles shall not reduce generation to below a pre-defined static level, i.e., the lowest Integrated Capacity Analysis – Static Grid typical profile value identified at the time of the Interconnection Application. As part of the proposal, Utilities shall: i) allow customers to utilize a smart inverter's ability to increase its output on a monthly basis; and ii) use a 10 percent buffer, which shall be revisited. No later than 18 months after the implementation of this proposal, Utilities shall submit a Tier 3 Advice Letter providing data obtained from Proposals 8b and 8c, adopted below, assessing the effectiveness of the use of the Integration Capacity Analysis values within the interconnection process and addressing whether the Commission should continue use of the 10 percent buffer or adjust it, based on the data.

16. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall submit a Tier 3 Advice Letter no later than 120 days from the issuance of this decision providing the specifics of whether and how reductions to a customer's Limited Generation Profile are determined. The Advice Letter shall include a description of how the Utilities will implement Ordering Paragraph 15. The final resolution of the Advice Letter will be implemented simultaneously with the counter proposal for Issue 9, adopted in Ordering Paragraph 15.

17. The following proposals are adopted to resolve Issue 10: a) Proposal 2, which requires Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) to use a single project identifier number from receipt of an interconnection request through permission to operate and applicable for Rules 2, 15, 16 and 21; b) Proposal 3,

which requires Utilities to notify the Interconnection customer of the study start date for projects studied under these rules; c) Proposal 4, which requires Utilities to invoice the engineering advance within five business days of execution of the Interconnection Agreement; d) Proposal 5, which requires Utilities to schedule a mitigation work scoping meeting no later than ten business days after receiving the payment for the engineering advance; and e) Proposal 8, which requires Utilities to provide a customer a detailed reconciliation of the costs of interconnection facilities and distribution upgrades within 12 months of project completion.

18. Proposal A of Issue 11 is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall modify the Rule 21 Fast Track process to include all successful process improvements tested in the Utilities' non-exporting energy storage pilot (Pilot). These improvements shall be applicable to non-exporting standalone storage system projects only.

19. The concept of the Lightning Review Process, as described in Proposal B1 of Issue 11, is adopted.

20. The following four principles for developing enhancements for streamlining and the Lightning Review Process are adopted: i) design for the most common cases; ii) minimize roundtrips between utility and applicants by frontloading information exchange; iii) remove the need for engineering technical review by using a checkbox or lookup verification; and iv) create standard templates for required documents.

21. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall serve testimony in Phase II of this proceeding providing a detailed proposal, the related costs, and a cost-benefit analysis for implementation of the Lightning Review Process, in compliance with the principles adopted in Ordering Paragraph 20, and in consideration of the positions described in the Working Group Two Report.

22. Proposals 12a and 12b are adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall track the 19 timelines listed below, beginning 90 days from the issuance of this decision. No later than 120 days from the issuance of this decision, and once every quarter thereafter, Utilities shall provide the results of the tracking to the Director of the Energy Division and the service list for this proceeding, or its successor. Where discrepancies exist, Utilities shall confer with the Commission's Energy Division to ensure reporting consistency.

a) Time from submission of Interconnection Request to the utility's acknowledgement of receipt;

b) Time from submission of Interconnection Request to time deemed complete;

c) Time from Interconnection Request deemed complete to completion of initial review and provision of results;

d) Time from Supplemental Review start date to completion of Supplemental Review;

e) Time from Electrical Interdependence Test start date to its completion;

f) Time from Electrical Interdependence Test completion to Electrical Interdependence Test results scoping meeting held;

g) Time from study scoping meeting until study agreement provided;

h) Time from System Impact Study start date to its completion date;

i) Time to provide Draft Generator Interconnection Agreement applicable milestone;

j) Time from Draft Generator Interconnection Agreement provided or Final Study Report date for Detailed Study to date Generator Interconnection Agreement executed;

k) Time from when the customer notifies 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;

l) Total time from submission of Interconnection Request to Permission to Operate (Not in Rule 21, tracked for informational purposes.)

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

n) Time for responding to line-side taps variance requests (for Utilities that require a variance request);

o) Design and invoice of net generation output meter;

p) Installation of net generation output meter;

q) Time from customer agreement to proceed to final design and issuance of invoice;

r) Time from customer payment of invoice and completion of customer work to completion of upgrade construction; and

s) Time for scheduling of Commissioning Test.

23. Proposal 12c is adopted, establishing a standard timeline for design and construction of interconnection-related distribution upgrades as follows: i) 60 business days for design and 60 business days for construction, or ii) design

and construction timelines as agreed with the customer. The 60-day clock commences upon payment and after the customer has done everything necessary on their end to prepare for construction.

24. Proposal 12d is adopted, establishing a standard timeline for installation of Net Generation Output Meters as follows: i) 20 business days for design and 20 business days for construction, or ii) design and construction timelines as agreed with the customer. The 20-day clock commences upon payment and after the customer has done everything necessary on their end to prepare for construction.

25. Proposal 12e is adopted. Beginning no later than six months from the issuance of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall notify interconnection customers when a timeline will not be met or is at risk of not being met. The notification shall include the category of delay, the reason for the delay and the new expected deadline.

26. As part of Proposal 12e adopted in Ordering Paragraph 26, no later than nine months from the issuance of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall include with the reports directed in Ordering Paragraph 23, a quarterly tally of customer notifications when timelines have not been met or were at risk of not being met. The quarterly tally shall include the category of delay, reason for delay, and new expected date.

27. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall meet with stakeholders

to develop a standard set of categories of delay, needed to implement Ordering Paragraphs 26 and 27. No later than six months from the issuance of this decision, Utilities shall provide a set of agreed-upon delay categories to the Director of the Commission's Energy Division.

28. Proposals 12f and 12h are adopted. Within two years of the commencement of tracking required by Ordering Paragraph 23, no less than 95 percent of non-net energy metering projects and net energy metering projects greater than 30 kilowatts shall meet all timelines listed in Ordering Paragraph 23, except (f), (j), (l), and (s), which are not stipulated in Rule 21.

29. Proposal 12i is adopted with modification. No later than 30 months following the commencement of timeline tracking, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, with oversight by the Commission's Energy Division, shall organize and host a workshop to discuss whether timelines have been met for at least 95 percent of the applicable interconnection projects, as required by Ordering Paragraph 29, and the steps necessary to make the 95 percent benchmark. The workshop discussion shall also include a discussion of a sunset date for the timeline tracking if the benchmark has been met.

30. Proposal 12j is adopted. Rule 21 shall be revised to require Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company to provide quarterly updates on substation upgrades to applicants whose projects are dependent on a substation upgrade.

31. Proposals 15a and 15b are adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company

(Utilities) shall do what is immediately possible to provide cost itemization based on existing system capabilities and strive to improve itemized billing processes. No later than January 31, 2021, Utilities shall develop and present a proposal for improving their billing practices during an Interconnection Discussion Forum meeting.

32. Proposals 16a, 16b, and 16c are adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall revise Rule 21 Interconnection Application Processes as follows: i) incorporate, by reference, Rule 15 eligibility requirements, specifically minimum contractor qualifications, other contractor qualification, and facility relocation or rearrangement; ii) incorporate, by reference, Southern California Edison's *Terms and Conditions Agreement for Installation of Distribution Line Extension by Applicant*; iii) incorporate, by reference, Rule 15 competitive bidding provisions Section G.1.a., G.1.e. (part a), and G.1.f.; and iv) revise the language: "*Subject to the approval of Distribution Provider, a Producer may, at its option…*" to "*Subject to / consistent with Rule 15 contractor selection rules, a Producer may, at its option…*"

33. Proposals 20a, 20b, and 20c are adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall use information web pages to educate customers on the transfer processes between the Commission and federal interconnection processes. Utilities shall add reference language or a soft link within the Rule 21 tariff to these information web pages.

34. No later than six months following the issuance of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall host a workshop regarding improvements to the Utilities' interconnection application portals (Interconnection Portals Workshop). The agenda for the Interconnection Portals Workshop shall include: i) identification and description by Utilities of implemented and planned portal improvements; and ii) discussion of 18 subproposals provided in Table 1 of this decision, focusing on those supported by Utilities and proponents. The discussion shall include estimated costs and proposed cost recovery methods for the implemented and planned portal improvements and the 18 subproposals.

35. No later than 45 days after the Interconnection Portals Workshop required by Ordering Paragraph 35, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall submit testimony addressing Issue 22, to include a set of portal improvement proposals, improvement costs, and cost recovery proposals. The proposals contained in the testimony shall adhere to two policies: i) the Commission encourages the growth of the use of distributed energy resources, and ii) costs for implementing a subproposal should be recovered from the set of customers who benefit from the subproposal. The testimony will be addressed in the second phase of this proceeding.

36. Proposal 23a is adopted, confirming that in the case of unidirectional charge-only V1G (one-way managed or smart charging), Electric Rule 21 (Interconnection) does not apply but Rules 2 (Special Facilities),

15 (New Distribution Facilities), and 16 (Overhead and Underground Primary or Secondary Facilities) are applicable.

37. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall meet and discuss the need for Rule 21 language changes to implement Proposal 23a. Utilities shall include any necessary language changes in the Tier 2 Advice Letter required by Ordering Paragraph 56 below.

38. Proposal 23b is adopted clarifying that Rule 21 applies to the interconnection of stationary and mobile energy storage systems. Section B.4 of Rule 21 is modified 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."

39. Proposal 23c is adopted. Vehicle to Grid Electric Vehicle Supply Equipment with stationary inverter for direct current charging of vehicles (V2G DC EVSE) may be interconnected under the current Rule 21 language if the EVSE meets Rule 21 requirements, including UL 1741 SA and other updated smart inverter standards.

40. Proposal 23d is adopted. Vehicle to Grid Electric Vehicle Supply Equipment (EVSE) with stationary inverter for direct current charging of vehicles (V2G DC EVSE) with bidirectional capability may connect as one way managed or smart charging (V1G), load-only, and operate in unidirectional (charge only) mode upon certifying the V2G DC EVSE through applicable UL Power Control

Systems and UL 1741 certification testing to ensure that: i) the electric vehicle will not discharge if the V2G DC EVSE is set to unidirectional charging model; ii) the V2G DC EVSE will not inadvertently change to bidirectional mode; and iii) factory default settings are set to unidirectional charging mode and cannot be changed without utility authorization.

41. Proposal 23e is adopted. Interconnection applicants with a Vehicle to Grid Electric Vehicle Supply Equipment with stationary inverter for direct current charging of vehicles (V2G DC EVSE) system may request permission to switch to bidirectional mode after completing the Rule 21 interconnection process and receiving permission to operate from a utility. Only the manufacturer or approved third-party installer may program or enable bidirectional operation after the permission to operate is given by a utility.

42. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall meet and confer to develop a consistent, to the extent possible, set of implementation steps for Proposal 23e, as required by Ordering Paragraph 42. No later than six months from the issuance of this decision, Utilities shall present and discuss the proposed implementation at a Vehicle-to-Grid workshop, facilitated by Utilities. If Commission approval is needed for the implementation steps, Utilities shall request approval in a Tier 3 Advice Letter submitted no later than 60 days following the workshop.

43. Proposal 23f is approved, in concept. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall develop the timeline, costs, and cost recovery method to

implement Proposal 23f , which would modify interconnection portals to enable simple tracking of vehicle-to-grid projects. Utilities shall discuss these elements during the Interconnection Portals Workshop, as directed in Ordering Paragraph 35 above. Utilities shall include the details of these elements in the submitted testimony required by Ordering Paragraph 36.

44. Proposal 23i is adopted. Vehicle to Grid Alternating Current (V2G AC) system pilots are exempt, temporarily, from Rule 21 smart inverter requirements. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall host a series of meetings with stakeholders to develop a temporary interconnection pathway for pilots seeking V2G AC interconnection that will ensure the necessary safety precautions. The first of these meetings shall begin no later than 30 days from the issuance of this decision. Following these meetings, Utilities shall propose a temporary pathway in the same Vehicle-to-Grid Workshop directed in Ordering Paragraph 43. Utilities shall request approval of the pathway in the Tier 3 Advice Letter submitted no later than 60 days following the workshop.

45. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall develop a Cost-Of-Ownership Charge report to include a step-by-step description of the charge and the determination of the value of each element. Utilities shall seek input from the Commission's Energy Division regarding a side-by-side comparison of each of the Utilities' processes and other related content. Utilities shall submit a final report to the Director of the Energy Division no later than March 31, 2021. No

later than 60 days following the submission of the report, Utilities shall host a workshop to present the contents of the report to parties and other stakeholders.

46. Proposal 27a is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall revise Rule 21 to: i) specifically allow smart inverter default settings to be changed; ii) account for IEEE 1547 and IEEE 1547.1 updates being developed by the Smart Inverter Working Group; and iii) establish a process for requesting and approving non default inverter settings. Utilities shall include Rule 21 language changes necessary to implement Proposals 27a.i) and 27a.iii) as directed in Ordering Paragraph 56 below.

47. Proposal 27c is adopted. The Smart Inverter Working Group shall refine the Set Active Power Mode function technical specifications. The group shall convene to refine the technical specifications, no later than nine months after the final approval of standards for IEEE 1547 and UL 1741. No later than 15 months following the publication of IEEE 1547.1, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall jointly seek approval of the technical specifications, on behalf of the Smart Inverter Working Group, through submission of a Tier 3 Advice Letter.

48. Proposal 28a is adopted. The Director of the Energy Division is authorized to reconvene the Smart Inverter Working Group if, and when, the Commission adopts a distributed energy resources tariff. The Smart Inverter Working Group shall review the tariff to determine if any technical changes to smart inverters are necessary and make any associated recommendations to the Commission through a Tier 3 Advice Letter submission from Pacific Gas and Electric

Company, San Diego Gas & Electric Company, and Southern California Edison Company on behalf of the Smart Inverter Working Group.

49. Proposal A-B 1 is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall modify their Rule 21 tariffs to allow the use of a power control system for non-export and limited export interconnection applications. Rule 21 shall be modified to establish the following five specifications that generating facilities must meet to be treated as non-export or limited export: i) use a power control system that passes the requirements of the Underwriters Laboratory (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol; ii) use a power control system that has an open-loop response time of no more than two seconds, as provided in the control systems specification data sheets, and must be able to reduce export power to the approved export limit within two seconds of exceeding the approved export limit; iii) Use only UL 1741 certified and/or UL 1741 SA listed grid-support non-islanding inverters; iv) set the power control system to zero-export or some non-zero controlled maximum export value; and v) maintain voltage fluctuations at the limits specified in Electric Rule 2. Once meeting these five specifications, Utilities shall evaluate non-export interconnection applications as such: a power control system can demonstrate non-export operations under Screen I; Screen D shall be omitted; and Screens F and G shall be reviewed based on the generating facility's gross nameplate rating. Once meeting these five specifications, Utilities shall evaluate limited-export interconnections applications as such: limited export value can determine

the impacts to the grid and in Screens D, I, J, K, M, N, O, and P; and Screens F and G will be based on the generating facility's nameplate rating.

50. Proposal A-B 2 is adopted. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall modify their Rule 21 tariffs to allow the use of a power control system for non-export and limited-export applications. Rule 21 tariffs shall be modified to require that, to be treated as inadvertent export, a generating facility must meet the following six specifications: i) use a power control system that passed testing in conformance with the Underwriters Laboratory (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol; ii) use a power control system with an open-loop response time of no more than ten seconds as provided in the control systems' specification data-sheets; iii) use only UL 1741 SA certified and/or UL 1741 SA listed grid-support non-islanding inverters; iv) use a power control system set to zero-export or some non-zero controlled maximum export value; v) maintain voltage fluctuations to the limits specified in Electric Rule 2; and vi) have a nameplate capacity equal to or less than 1,000 kilovolt amperes. Upon meeting the six specifications, the Utilities shall review the facility as such: apply Screens A through M using the aggregate nameplate inverter rate; during Supplemental Review the applicant shall identify, within 15 days, the frequency of inadvertent export, the real power level in watts of inadvertent export and the time duration of inadvertent export; if distribution upgrades are identified, Screen P shall recognize power control parameters taking into account local feeder conditions; and only the largest facility in the line section shall be used for aggregate evaluation for subsequent

interconnection requests. Utilities shall consider a customer's operating profile and the magnitude, duration, and frequency of anticipated export during the review of Screen P.

51. A modified Proposal A-B 3 is adopted but shall not be implemented until nine months after technical specifications standards, and a certification scheme for a Limited Generation Profile have been approved by the standards approving bodies. Within 90 days of such approval, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall submit a Tier 2 Advice Letter seeking to modify their Rule 21 tariffs to allow an inverter approved for non-export and limited export to be set using different maximum export value settings at different times of the year, when meeting the qualifications for either Proposal A-B 1 or A-B 2. Within 90 days of the issuance of this decision, Utilities shall commence discussions with the Smart Inverter Working Group focused on implementing the proposal. Within six months of issuance of this decision, Utilities shall submit a Tier 3 Advice Letter providing recommendations (as applicable) regarding the standard review, certification requirements, and interconnection processes necessary for implementation of the proposal. The discussions and Tier 3 Advice Letter required in this ordering paragraph may be combined with those required in Ordering Paragraph 15.

52. Proposal A-B 4 is adopted for customers of Southern California Edison (SCE) only. SCE shall revise its Rule 21 tariff to require SCE customers applying for interconnection with a power control system to use only the systems on a pre-approved list.

53. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall hold a meeting of the Vehicle-to-Grid Alternating Current Subgroup (V2G AC Subgroup) on a routine basis to provide the members of the subgroup updates on the status of the V2G AC interconnections standards update. The first meeting shall be held no later than six months from the issuance of this decision and every six months thereafter until updated standards have been tested and approved. The meeting shall be noticed to the service lists of this proceeding, Rulemaking 17-07-007, and Rulemaking 18-12-006, the Transportation Electrification proceeding.

54. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall actively participate in the committees that update the vehicle to grid alternating current interconnection standards. When standards have been approved, Utilities shall inform the Director of the Energy Division, who is authorized to reconvene the Vehicle to Grid Alternating Current Subgroup no later than 90 days from the issuance of approved updated standards.

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

required to be Tier 1 or Tier 2 and provides the deadline for submitting the Advice Letter.

| OP | Tier 1<br>Submit 30 days after issuance of decision | Tier 2<br>Submit 60 days after issuance of decision | Tier 2<br>Submit 120 days after issuance of decision |
|---|---|---|---|
| 1 | | X | |
| 2 | | X | |
| 3 | | X<br>(if tariff changes are needed) | |
| 4 | | X<br>(if tariff changes are needed) | |
| 5 | | | X |
| 6 | | | X |
| 7 | X | | |
| 8 | | | X |
| 11 | | | X |
| 12 | | X | |
| 13 | X | | |
| 14 | X | | |
| 17 | | X | |
| 18 | | X | |

| OP | Tier 1<br>Submit 30 days after issuance of decision | Tier 2<br>Submit 60 days after issuance of decision | Tier 2<br>Submit 120 days after issuance of decision |
|---|---|---|---|
| 24 | | X<br>(if tariff changes needed) | |
| 25 | | X<br>(if tariff changes needed) | |
| 31 | | X | |
| 33 | | X | |
| 34 | | X | |
| 38 | | X | |
| 39 | | X | |
| 41 | | X | |
| 47 | X<br>(for 27a.i) | X<br>(for 27a.iii) | |
| 50 | X | | |
| 51 | X | | |
| 53 | X | | |

56. Rulemaking 17-07-007 remains open.

This order is effective today.

Dated September 24, 2020, at San Francisco, California

MARYBEL BATJER

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

# Exhibit C

**(Excel File Filed Via CD-ROM)**

# Exhibit D

**(Excel File Filed Via CD-ROM)**

# Exhibit E

# VNM-A/NEM-V/NEM Aggregation (Option 2 NGOM Method) Checklist

1) FIELD MEETING REQUIRED
   a) ☐ Contact SDG&E at 858-636-5585 to schedule field meeting.
   b) ☐ A single line drawing (SLD) showing proposed interconnection is required.
   c) ☐ SDG&E to review whether project qualifies for requested program.
   d) ☐ SDG&E to review/approve proposed Net Generator Output Meter (NGOM) location(s).
   e) ☐ Review Service Standards and requirements for project.
   f) ☐ Discuss project timelines.
2) CUSTOMER REQUESTED OUTAGE
   a) ☐ If Customer Requested Outage is required, a second meeting will be scheduled with a SDG&E Customer Project Planner. (Planner is responsible for scheduling of outage request)
   b) ☐ A 4 week minimum lead time to schedule Customer Requested Outage is required.
   c) ☐ Customer/Contractor is responsible for outage costs.
   d) ☐ Customer/Contractor must fill out Customer Requested Outage Form and submit to SDG&E Customer Project Planner along with electric single line drawing and approved bus tap drawing
   e) ☐ Inspection release to re-energize from Authority Having Jurisdiction (AHJ) is required. Coordinate with SDG&E Customer Project Planner.
3) CREATE ADDRESS/ACCOUNT FOR Net Generation Output Meter (NGOM)(s)
   a) ☐ SDG&E creates new address and account number for proposed NGOM(s) and sends to Customer/Contractor via e-mail.
4) NEM APPLICATION
   a) ☐ Customer/Contractor submits application online through DIIS for each NGOM.
   b) ☐ For applications >30 kW, submit two signed copies of Interconnection Agreement. For <30 kW, terms and conditions are required.
   c) ☐ For projects with bus taps, an approved bus tap drawing is required.
5) APPLICATION REVIEW
   a) ☐ Once T's and C's or Interconnection Agreements are received, SDG&E to review application and single SLD.
   b) ☐ If corrections need to be made, Customer/Contractor to be notified by e-mail through DIIS. Contractor will make corrections and resubmit SLD through DIIS.
   c) ☐ After application has been reviewed and accepted, SDG&E to send e-mail to Customer/Contractor with the following information:
      i) ☐ Cost Letter

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  ii) ☐ Customer Payment Remittance Form
  iii) ☐ Rule 2 Contract(s)
  iv) ☐ Allocation Form or Aggregation From
  v) ☐ Continuity of Service Form

6) CUSTOMER/CONTRACTOR PAYMENT/FORMS
   a) ☐ Submit Payment
   b) ☐ Return signed and dated Rule 2 Contract(s) (by mail or e-mail)
   c) ☐ Return Allocation Form(s) or Aggregation Form(s) (by mail or e-mail)
   d) ☐ Return Continuity of Service Form (Optional) (by mail or e-mail)
7) INSTALLATION COMPLETED BY CUSTOMER/CONTRACTOR
   a) ☐ Customer/Contractor to follow job requirements per NGOM Inspection Checklist.
   b) ☐ The following inspection releases must be received from the AHJ:
      i) ☐ PV Inspection Release(s) for each NGOM (address must match exactly)
      ii) ☐ Meter Inspection Release(s) for each NGOM (address must match exactly)
8) SDG&E FIELD INSPECTION
   a) ☐ SDG&E Field Inspector to complete inspection per NGOM Inspection Checklist.
   b) ☐ SDG&E will notify Customer/Contractor of any corrections that need to be made by e-mail through DIIS.
   c) ☐ Meters scheduled to be set after Customer/Contractor passes field inspection.
9) APPLICATION COMPLETED/PTO
   a) ☐ SDG&E verifies meter has been set.
   b) ☐ SDG&E verifies payment and all forms have been received.
   c) ☐ PTO e-mail sent next business day to Customer/Contractor.


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# Exhibit F

Outlook

## 563 GREENBRIER DR CG, OC - CG ACCT # 210001445909

**From** VNMApplications <VNMApplications@sdge.com>
**Date** Tue 9/17/2024 3:05 PM
**To** Richard Thompson <richard.thompson@sunrun.com>

1 attachment (134 KB)
Allocation Form NBT-V.pdf;

Hello Richard,
Below is the CG account number. Please proceed to submit an application in DIIS within 2 weeks from this email. Attached is a blank NBT-V allocation form that will need to be filled out before uploading to the application in step 6.
**Reply to the email with the DIIS Application ID number once the application has been completed.**
Below is the virtual process for your notes.

| CG ACCOUNT # | CG ADDRESSS |
|---|---|
| 210001445909 | 563 GREENBRIER DR CG, OC |

**Virtual Contractor Process**

1. Contractor submits a complete Virtual request per this process **prior to construction:**
   a. *Email all new Virtual requests to vnmapplications@sdge.com Please do not combine multiple requests for different sites. (Multiple installations located on one property can be combined in one email submission.)*
   b. ***A complete submittal includes:***
      i. *Site map identifying electric panel location(s) and all POI's.*
      ii. *Complete SLD to include: address, existing SDG&E HM meter number, NGOM meter amperage, serving phase, voltage, and system size in AC CEC KW. Disconnects to be labeled as "VISIBLE LOCKABLE" and to be located adjacent to the NGOM meter panel as per SDG&E Service Guide page 806.6. https://www.sdge.com/sites/default/files/SGe%20%284%29.pdf*
      iii. *Confirm customer name as shown on their most recent SDGE bill.*
2. **SDG&E Advisor will **review** the submittal:*
   a. Upon confirming a complete and accurate submittal, the contractor will receive an Initial Site Meeting via Outlook Calendar notice.
      1. Outlook Calendar notice will be emailed to the email address referenced in the submittal email.
   b. If deficiencies are identified in the virtual submittal, the contractor will be advised, and revisions will be required.
      i. Once the corrections are resubmitted using the process above, the review lead time resets.
2. * **Initial Joint Meet (Site Meeting)** is scheduled to establish an approved NGOM meter location, verify field conditions, discuss installation requirements and establish CG address.
3. SDG&E then provides a **CG account number** via email, approximately within 5-10 business days of the Initial Joint Meet.
4. Solar contractor **submits application via DIIS** using provided CG account number. (Note: CG Meter number is not required to submit application). The completed Virtual Allocation form is

uploaded to step 6 of DIIS. **Customer/Contractor to email application ID number to VNMApplications@sdge.com to proceed.**

   a. The uploaded Virtual Allocation to specify assigned CG address and CG number the generator account.
   b. Correct DIIS application needs to be completed either < 30kW or >30kW must be completed.

5. SDG&E will forward allocation form for review to the Billing team to determine eligibility.
   a. Issues will be added as applicable throughout the application process.
6. Once allocation eligibility is confirmed from Billing team, the application will proceed to **Initial Review status:**
   a. The Distribution Planning Review will be initiated to verify transformer is adequate for new PV system. Required necessary upgrades will be identified at this stage of the application.
   b. The Secondary Service Assessment Review will be initiated to verify Secondary/Service is adequate for new PV system. Required necessary upgrades will be identified at this stage of the application.
7. Upon passing the Distribution Planning Review, Customer Generation will create & email all required customer documents: NGOM Rule 2, and NGOM payment invoice.
   a. Please note the application status will only change upon passing both the Distribution Planning Review and Secondary Service Assessment Review. Application will be moved to **Pending AHJ** status in DIIS upon completion of both reviews. Keep checking DIIS for updates on the application.
8. Contractor to complete all Issues in DIIS ISSUE tab.
9. DIIS application will automatically change to **Pending SDG&E Inspection** status once AHJ for PV is posted. Please note, two AHJ inspection releases are required: **PV and CG to the CG Address.**

- Example:
  - Assigned CG Address:

123 Main St CG

  - Required AHJ releases:

123 Main St CG “PV release”
123 Main St CG “CG release”

11. Contractor to request **FINAL SDG&E inspection** via email to VNMApplications@sdge.com.
    a. Email request to include **Final NGOM Photo Packet** as follows:
       1. Entire NGOM installation in one frame with STO letter displayed (both disconnects, NGOM panel, working space showing ground in front of meter).
       2. Individual photo of NGOM meter panel showing required CG address placard.
       3. Photos of each disconnect showing required placards with correct verbiage.
       4. Photo of site map placard installed at main switchgear. (Note: Second placard on NGOM meter panel if not within line of sight of main switchgear.)
       5. Photo of inside of NGOM panel in one frame clearly displaying conductor labels and current flow sticker* (*for CT rated installations).
    b. Photos to be attached individually as PDF or JPG format. Zip files also acceptable.
    c. Contractor to verify all items on checklist are completed and ensure a qualified electrical worker is present for a voltage test at the final inspection.
12. **Final Joint Meet (Site Meeting)** will be scheduled at the first available appointment. Meeting notice will be sent to the email address requesting the **FINAL SDG&E Inspection.** SDG&E Advisor will **review** the submittal:
    a. Upon confirming a complete and accurate submittal, the contractor will receive a Final Joint Meeting via Outlook Calendar notice.
       1. Outlook Calendar notice will be emailed to the email address referenced in the submittal email.
    b. If deficiencies are identified in the final virtual submittal, the contractor will be advised, and revisions will be required.
       i. Once the corrections are resubmitted using the process above, the review lead time resets.
12. Upon FINAL SDGE inspection passing, **a meter set will be scheduled**. Please see CG Meter Set issue in DIIS for the schedule ETA meter set date. Typically the meter sets are completed within 10 Business Days of passing the **FINAL SDG&E Inspection.**
13. **PTO to follow once the meter set has been completed and all Issues are closed in DIIS.

- *Submittal review and site meeting lead times are subject to current workload.

- All Virtual application inquiries are to be submitted to VNMApplications@sdge.com. Please include site address and app ID (if available) in subject line.

Thank you,

**Berenice McNamara**
Net Energy Metering Specialist
Customer Generation Team
E netmetering@sdge.com

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# Exhibit G

Outlook

## Initial Site Walk Request - 414 N Santa Fe Ave CG, Vista, CA 92083 - Santa Fe Senior Village

**From** VNMApplications <VNMApplications@sdge.com>
**Date** Thu 5/29/2025 7:42 AM
**To** MF Interconnection <mf_interconnection@sunrun.com>
**Cc** Richard Thompson <richard.thompson@sunrun.com>

4 attachments (6 MB)

Santa Fe Senior Village_SLD_414 N Santa Fe Ave_vB.pdf; SANTA FE SENIOR_SDG&E ELECTRICAL SERVICE_Rev0.pdf; Santa Fe Senior Village_Plot Plan_vB.pdf; Vista Santa Fe Senior Village_POI ProposalsEEstamp_vB.pdf;

Good morning Richard,

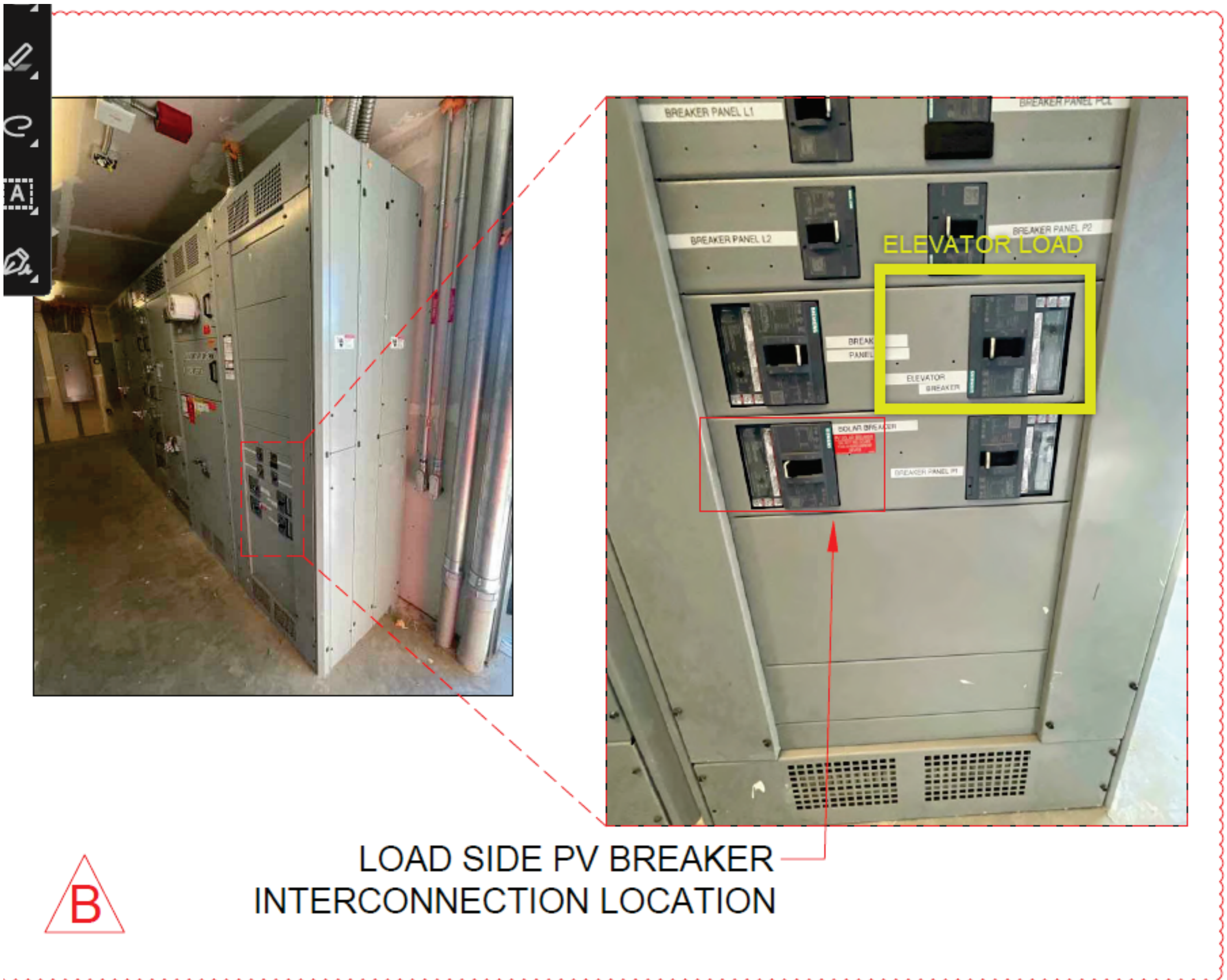
There is an issue with the proposed POI on this submittal. I reviewed this with our Standards department and confirmed the following:

The breaker identified as the interconnection location is questionable. This breaker appears to be on the customer load side as the elevator is served from this section, along with what may be customer subpanels (L1, L2, etc). Since there is load identified in this section, this would not be an acceptable location for a Virtual interconnection. So, either…

The elevator and subpanels are not wired correctly to an UNMETERED section. (Customer load cannot be in an unmetered section.)

OR

The Virtual POI is to be relocated so it is BEFORE any meters or customer load.




Please submit a revised SLD once you work through this with the customer.

**Rosie**
Customer Generation Advisor
**E** VNMApplications@sdge.com

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**From:** richard.thompson@sunrun.com <richard.thompson@sunrun.com> **On Behalf Of** MF Interconnections Inbox
**Sent:** Thursday, April 10, 2025 10:06 AM
**To:** VNMApplications <VNMApplications@sdge.com>
**Cc:** Richard Thompson <richard.thompson@sunrun.com>
**Subject:** [EXTERNAL] Initial Site Walk Request - 414 N Santa Fe Ave CG, Vista, CA 92083 - Santa Fe Senior Village

**CAUTION! External Sender**

This email came from outside the company. If you're unsure whether this message is harmless, click the "Report Suspicious" button.

Report Suspicious

Hello,

Our design team has made updates to the plan set after the original comments provided on our previous submission for initial site walk on this property. I am reaching out today to request an initial site walk for **(1)** POI:

**414 N Santa Fe Ave CG, Vista, CA 92083**
***(House Meter #: 6948451)***

**Customer Account:** Santa Fe Senior Village LP

Attached to this email are the SLD, Plot Plan, POI Proposal, and the Electrical Service planning map for the main electrical system being installed at this site.

Appreciatively,
Richard Thompson

**Multifamily Interconnection**
*Multifamily* | Preinstall Operations

On Fri, Jan 17, 2025 at 4:16 PM VNMApplications <VNMApplications@sdge.com> wrote:

> Hello Richard,
>
> Per the SLD, I see there is a PV breaker at the main panel being utilized as one of the PV disconnects. Reaching out to ensure this meets SDGE requirements as specified on page 806.7 of the SDGE Service & Standards Guide:
>
> SDGE Service & Standards guide page 806.7 states:
>
> The service sections must be designed so that the metering section can be isolated by a lockable open or rackable circuit breaker and a visibly open and lockable disconnect switch. (The lockable open devices need to be located on each side of the metering section.)
>
> Once confirmed, please resubmit the SLD specifically labeling the breaker as "LOCKABLE OPEN" or "RACKABLE CIRCUIT BREAKER" to proceed with an initial site meeting.
>
> Thank you.
>
> **Rosie**
> Customer Generation Advisor
> **E** VNMApplications@sdge.com
>
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**From:** richard.thompson@sunrun.com <richard.thompson@sunrun.com> **On Behalf Of** MF Interconnections Inbox
**Sent:** Wednesday, January 8, 2025 12:09 PM
**To:** VNMApplications <VNMApplications@sdge.com>
**Subject:** [EXTERNAL] Initial Site Walk Request

Hello,

I am reaching out today to request an initial site walk for **(1)** POI:

**414 N Santa Fe Ave CG, Vista, CA 92083**
***(House Meter #: 6948451)***

**Customer Account:** Santa Fe Senior Village LP

Attached to this email are the SLD, Plot Plan, POI Proposal, and the Electrical Service planning map for the main electrical system being installed at this site.

Appreciatively,
Richard Thompson

**Multifamily Interconnection**
*Multifamily* | Preinstall Operations

This email originated outside of Sempra. Be cautious of attachments, web links, or requests for information.

# Exhibit H

Customer Generation Team
San Diego Gas & Electric ®
8316 Century Park Court, CP52F
San Diego, CA 92123
Phone (858) 636-5585
netmetering@sdge.com

Date: 07/23/2025

Application ID: 489891
Service Address: 563 GREENBRIER DR, CG, OCEANSIDE, CA 92054

Dear SDG&E ® Customer / Contractor,

Your application for interconnection has been reviewed by SDG&E's Customer Generation Team. The next step in the interconnection process is for your City/County Inspector to conduct an electrical inspection of the installed generation equipment at the premise noted above. After we receive notification from the City/County that your system has passed their inspection, your application will be reviewed to determine if any outstanding requirements exist for your project.

**Customer must not operate the Generating Facility in parallel with SDG&E's Distribution System until Customer receives written authorization for Parallel Operation from SDG&E.**

Please continue to monitor your email for updates. If you have any questions, please contact us.

Thank you,

Customer Generation Team
San Diego Gas & Electric

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# Exhibit I

Outlook

## [EXTERNAL] Re: APP 489891 - 563 GREENBRIER DR CG, OC

**From** Richard Thompson <richard.thompson@sunrun.com>
**Date** Wed 10/30/2024 12:43 PM
**To** VNMApplications <VNMApplications@sdge.com>

**CAUTION! External Sender**
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Report Suspicious

Hello Berenice,

I have resubmitted this application **(APP# 489891)** today. I confirmed the SLD we have for 563 Greenbrier (Oceanside, 92054) is the one I have uploaded today, and also uploaded the customer signed prevailing wage form.

For the VNM form, we do not have the meter numbers yet as this is a new construction, but have updated the form as much as we can at the moment. I will be able to provide a completed version before we take on the PTO process.

Appreciatively,
Richard Thompson

sunrun
[sunrun.com]

**Richard Thompson**
**Interconnection Analyst, Multifamily**
**P** (407) 669-6575
PowerThrough

On Fri, Oct 4, 2024 at 12:19 PM VNMApplications <VNMApplications@sdge.com> wrote:

> Hello Richard,
>
> Thank you for submitting the application. Please see the corrections requested for the application.
>
> 1. The wrong SLD was uploaded. Please upload the correct SLD for this project in step 6 of DIIS application.
> 2. Prevailing Wage document must be signed by the customer of record, upload corrected doc in step 6 of DIIS application.
> 3. The allocation form must list the Generator meter and address. The CG address and meter # must be listed as the generator on the Allocation form. Upload corrected allocation form in step 6 of DIIS application.

| CG ACCOUNT # | CG ADDRESSS |
|---|---|
| 210001445909 | 563 GREENBRIER DR CG, OC |

Thank you,

**Berenice McNamara**

Net Energy Metering Specialist

Customer Generation Team
E netmetering@sdge.com

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---

**From:** Richard Thompson <richard.thompson@sunrun.com>
**Sent:** Monday, September 23, 2024 3:26 PM
**To:** VNMApplications <VNMApplications@sdge.com>
**Subject:** [EXTERNAL] Re: 563 GREENBRIER DR CG, OC - CG ACCT # 210001445909

Hello,

This application has now been submitted with **APP ID# 489891**

Thank you,
Richard Thompson

sunrun [sunrun.com]

**Richard Thompson**

**Interconnection Analyst, Multifamily**

**P** (407) 669-6575

PowerThrough

On Tue, Sep 17, 2024 at 6:04 PM VNMApplications <VNMApplications@sdge.com> wrote:

Hello Richard,

Below is the CG account number. Please proceed to submit an application in DIIS within 2 weeks from this email. Attached is a blank NBT-V allocation form that will need to be filled out before uploading to the application in step 6.

**Reply to the email with the DIIS Application ID number once the application has been completed.**

Below is the virtual process for your notes.

| CG ACCOUNT # | CG ADDRESSS |
|---|---|
| 210001445909 | 563 GREENBRIER DR CG, OC |

**Virtual Contractor Process**

1. Contractor submits a complete Virtual request per this process **prior to construction:**

a. *Email all new Virtual requests to vnmapplications@sdge.com Please do not combine multiple requests for different sites. (Multiple installations located on one property can be combined in one email submission.)*

b. ***A complete submittal includes**:*

i. *Site map identifying electric panel location(s) and all POI's.*

ii. *Complete SLD to include: address, existing SDG&E HM meter number, NGOM meter amperage, serving phase, voltage, and system size in AC CEC KW. Disconnects to be labeled as "VISIBLE LOCKABLE" and to be located adjacent to the NGOM meter panel as per SDG&E Service Guide page 806.6. https://www.sdge.com/sites/default/files/SGe%20%284%29.pdf*

iii. *Confirm customer name as shown on their most recent SDGE bill.*

2. **SDG&E Advisor will **review** the submittal:*

a. Upon confirming a complete and accurate submittal, the contractor will receive an Initial Site Meeting via Outlook Calendar notice.

1. Outlook Calendar notice will be emailed to the email address referenced in the submittal email.

b. If deficiencies are identified in the virtual submittal, the contractor will be advised, and revisions will be required.

i. Once the corrections are resubmitted using the process above, the review lead time resets.

3. *** Initial Joint Meet (Site Meeting)** is scheduled to establish an approved NGOM meter location, verify field conditions, discuss installation requirements and establish CG address.

4. SDG&E then provides a **CG account number** via email, approximately within 5-10 business days of the Initial Joint Meet.

5. Solar contractor **submits application via DIIS** using provided CG account number. (Note: CG Meter number is not required to submit application). The completed Virtual Allocation form is uploaded to step 6 of DIIS. **Customer/Contractor to email application ID number to VNMApplications@sdge.com to proceed.**

a. The uploaded Virtual Allocation to specify assigned CG address and CG number the generator account.

b. Correct DIIS application needs to be completed either < 30kW or >30kW must be completed.

6. SDG&E will forward allocation form for review to the Billing team to determine eligibility.

   a. Issues will be added as applicable throughout the application process.

7. Once allocation eligibility is confirmed from Billing team, the application will proceed to **Initial Review status:**

   a. The Distribution Planning Review will be initiated to verify transformer is adequate for new PV system. Required necessary upgrades will be identified at this stage of the application.

   b. The Secondary Service Assessment Review will be initiated to verify Secondary/Service is adequate for new PV system. Required necessary upgrades will be identified at this stage of the application.

8. Upon passing the Distribution Planning Review, Customer Generation will create & email all required customer documents: NGOM Rule 2, and NGOM payment invoice.

   a. Please note the application status will only change upon passing both the Distribution Planning Review and Secondary Service Assessment Review. Application will be moved to **Pending AHJ** status in DIIS upon completion of both reviews. Keep checking DIIS for updates on the application.

9. Contractor to complete all Issues in DIIS ISSUE tab.

10. DIIS application will automatically change to **Pending SDG&E Inspection** status once AHJ for PV is posted. Please note, two AHJ inspection releases are required: **PV and CG to the CG Address.**

- Example:
    - Assigned CG Address:

123 Main St CG

- Required AHJ releases:

123 Main St CG “PV release”

123 Main St CG “CG release”

11. Contractor to request **FINAL SDG&E inspection** via email to VNMApplications@sdge.com.

    a. Email request to include **Final NGOM Photo Packet** as follows:

       1. Entire NGOM installation in one frame with STO letter displayed (both disconnects, NGOM panel, working space showing ground in front of meter).

       2. Individual photo of NGOM meter panel showing required CG address placard.

3. Photos of each disconnect showing required placards with correct verbiage.

4. Photo of site map placard installed at main switchgear. (Note: Second placard on NGOM meter panel if not within line of sight of main switchgear.)

5. Photo of inside of NGOM panel in one frame clearly displaying conductor labels and current flow sticker* (*for CT rated installations).

b. Photos to be attached individually as PDF or JPG format. Zip files also acceptable.

c. Contractor to verify all items on checklist are completed and ensure a qualified electrical worker is present for a voltage test at the final inspection.

12. **Final Joint Meet (Site Meeting)** will be scheduled at the first available appointment. Meeting notice will be sent to the email address requesting the **FINAL SDG&E Inspection.** SDG&E Advisor will **review** the submittal:

a. Upon confirming a complete and accurate submittal, the contractor will receive a Final Joint Meeting via Outlook Calendar notice.

1. Outlook Calendar notice will be emailed to the email address referenced in the submittal email.

b. If deficiencies are identified in the final virtual submittal, the contractor will be advised, and revisions will be required.

i. Once the corrections are resubmitted using the process above, the review lead time resets.

13. Upon FINAL SDGE inspection passing, **a meter set will be scheduled**. Please see CG Meter Set issue in DIIS for the schedule ETA meter set date. Typically the meter sets are completed within 10 Business Days of passing the **FINAL SDG&E Inspection.**

14. **PTO to follow once the meter set has been completed and all Issues are closed in DIIS.

- ***Submittal review and site meeting lead times are subject to current workload.
- All Virtual application inquiries are to be submitted to VNMApplications@sdge.com. Please include site address and app ID (if available) in subject line.

Thank you,

**Berenice McNamara**

Net Energy Metering Specialist

Customer Generation Team
E netmetering@sdge.com

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# Exhibit J

SDGE™

Customer Generation Team
San Diego Gas & Electric ®
8316 Century Park Court, CP52F
San Diego, CA 92123
Phone (858) 636-5585
netmetering@sdge.com

Date: 11/01/2024

Application ID: 489891
Service Address: 563 GREENBRIER DR, CG, OCEANSIDE, CA 92054

Dear SDG&E ® Customer / Contractor,

This e-mail is to inform you that SDG&E reviewed your interconnection application and determined a revision is required.

Below is a description of the action(s) needed to the application. Please make the requested revision(s) and then resubmit your application via our Distribution Interconnection Information System.

| Item | Date Identified |
|---|---|
| CONTRACTOR ACTION REQUIRED | 11/01/2024 |

Comments
SLD document has poor quality and we are unable to zoom into the document to read all the details of the project. Please either upload a better quality SLD or email the document to VNMapplications@sdge.com

If you have any questions, please contact us.

Thank you,

Customer Generation Team
San Diego Gas & Electric

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# Exhibit K

Outlook

## Corrections Required for Virtual Allocation Form - APP 489891 - 563 GREENBRIER DR CG

**From** VNMApplications <VNMApplications@sdge.com>
**Date** Mon 5/5/2025 1:57 PM
**To** Richard Thompson <richard.thompson@sunrun.com>
**Cc** MF Interconnections Inbox <mf_interconnection@sunrun.com>

1 attachment (452 KB)

Greenbrier Village SDGE_ELEC-SF_142-02770_vnm allocation standard_4-3-25.pdf;

Hello,
Please see the Billing team's response below regarding this allocation form review. The attached allocation form is **ineligible** due to the following:

- *There are no meters listed on the application. Meters must be listed for the benefitting meters/accounts to confirm eligibility*

Please make necessary changes/ corrections and email the allocations form back to VNMApplications@sdge.com to send for review again.
For questions regarding this notification or for assistance with resolving the issues noted above, please contact **SDG&E's Customer Care Center at 1-800-411-7343.**

@Richard Thompson Customer Generation cannot move forward until the allocation form is demed complete.

Thank you,

**Berenice McNamara**
Customer Generation Team
Virtual Applications
**E** VNMApplications@sdge.com

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Exhibit L

Outlook

# Follow Up- Virtual Allocation Form - APP 489891 - 563 GREENBRIER DR CG

**From** VNMApplications <VNMApplications@sdge.com>
**Date** Fri 5/2/2025 9:31 AM
**To** NEMAGG <NEMAGG@semprautilities.com>

1 attachment (462 KB)
Greenbrier Village SDGE_ELEC-SF_142-02770_vnm allocation standard_4-3-25.pdf;

Hello NEMAGG,
Following up per the contractor request. Please review the NBT-V allocation form for eligibility.

Thank you,

**Berenice McNamara**
Net Energy Metering Specialist
Customer Generation Team
E netmetering@sdge.com
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**From:** VNMApplications
**Sent:** Friday, April 11, 2025 2:30 PM
**To:** NEMAGG <NEMAGG@semprautilities.com>
**Subject:** Virtual Allocation Form - APP 489891 - 563 GREENBRIER DR CG

Hello NEMAGG,
Please review the NBT-V allocation form for eligibility.

Thank you,

**Berenice McNamara**
Net Energy Metering Specialist
Customer Generation Team
E netmetering@sdge.com
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**From:** Richard Thompson <richard.thompson@sunrun.com>
**Sent:** Thursday, April 3, 2025 10:05 AM
**To:** VNMApplications <VNMApplications@sdge.com>
**Subject:** [EXTERNAL] Re: Virtual Allocation Form - APP 489891 - 563 GREENBRIER DR CG

**CAUTION! External Sender**

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Hello Berenice,

I have made updates to the form with the information we have available at this new construction site **(App 489891)**. The only items we do not have information on yet from your notes would be "Section E", while we are unable to obtain this yet, we will provide a completed version with the information for review before we engage final inspection down the road for PTO. May we proceed with the updates made for now to engage the necessary reviews for this application?

Thank you,
Richard Thompson

[sunrun.com]

**Richard Thompson**

**Interconnection Analyst, Multifamily**

**P** (407) 669-6575

PowerThrough

On Wed, Feb 26, 2025 at 9:35 AM VNMApplications <VNMApplications@sdge.com> wrote:

> Hello Richard,
> Before I can send this allocation form to the Billing team to review for eligibility. Some corrections need to be made.
>
> 1. Please complete section E.
> 2. Please list the Generator address as 563 GREENBRIER DR **CG**, OCEANSIDE CA 92054
>
> Email the corrected allocation form to VNMApplications@sdge.com once corrections are completed.
>
> Thank you,
>
> **Berenice McNamara**
> Net Energy Metering Specialist
> Customer Generation Team
> E netmetering@sdge.com

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Exhibit M

Customer Generation Team
San Diego Gas & Electric ®
8316 Century Park Court, CP52F
San Diego, CA 92123
Phone (858) 636-5585
netmetering@sdge.com

Date: 02/26/2025

Application ID: 489891
Service Address: 563 GREENBRIER DR, CG, OCEANSIDE, CA 92054

Dear SDG&E ® Customer / Contractor,

This e-mail is to inform you that SDG&E reviewed your interconnection application.

Below is a description of the actionable item(s) required to interconnect.

| Issues | Date Identified |
|---|---|
| VNM Allocation Form Required | 02/26/2025 |
| Allocation Eligibility Required from Billing | 02/26/2025 |
| Allocation Form Sent to Billing | 02/26/2025 |

Comments:

Please submit a completed NEM-V Credit Allocation Form 142-02770. The form can be downloaded from here: www.sdge.com/nemdocs Email completed form to us at: VNMApplications@sdge.com Reference the Application ID Number in the subject line.

The previously identified item(s) listed below have been resolved.

| Closed Issues | Date Resolved |
|---|---|
| Waiting for payment | 09/23/2024 |

Comments:

Waiting for Payment NEM Application Fee

If you have any questions, please contact us.

Thank you,

Customer Generation Team
San Diego Gas & Electric

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# Exhibit N

Customer Generation Team
San Diego Gas & Electric ®
8316 Century Park Court, CP52F
San Diego, CA 92123
Phone (858) 636-5585
netmetering@sdge.com

Date: 07/23/2025

Application ID: 489891
Service Address: 563 GREENBRIER DR, CG, OCEANSIDE, CA 92054

Dear SDG&E ® Customer / Contractor,

This e-mail is to inform you that SDG&E reviewed your interconnection application.

Below is a description of the actionable item(s) required to interconnect.

| Issues | Date Identified |
|---|---|
| Rule 2 Required | 07/17/2025 |
| Waiting for NGOM Payment | 07/17/2025 |
| NBT Virtual Interconnection Agreement Required | 07/17/2025 |
| Bus Tap Drawings Required | 07/17/2025 |
| CG Meter Release Required | 07/17/2025 |

Comments:

Please submit the Virtual NBT-V Metering Interconnection Agreement. This form is available at www.sdge.com/nemdocs. Please email completed form to us at: vnmapplications@sdge.com. Reference the Application ID Number and address in the subject line of the email. Please submit VNM-ST Interconnection Agreement Form 142-02779.5

Please submit your Bus Tap drawing to drawingsubmittals@sdge.com. Bus Tap information can be found on pages 517.1 & 517.2 for Bus Tap information. Reference the Application ID Number and address in the subject line. Please refer to SDGE Service Standards here: https://www.sdge.com/sites/default/files/SG2025v0321e.pdf

CR# 1000023366

The previously identified item(s) listed below have been resolved.

| Closed Issues | Date Resolved |
|---|---|
| Secondary Service Assessment Required | 07/22/2025 |
| VNM Allocation Form Required | 06/30/2025 |
| Allocation Eligibility Required from Billing | 07/02/2025 |
| Allocation Form Sent to Billing | 06/30/2025 |
| Distribution Planning Review | 07/16/2025 |
| Waiting for payment | 09/23/2024 |

Comments:

Waiting for Payment NEM Application Fee

Please submit a completed NEM-V Credit Allocation Form 142-02770. The form can be downloaded from here: www.sdge.com/nemdocs Email completed form to us at: VNMApplications@sdge.com Reference the Application ID Number in the subject line.

Virtual allocation form is ineligible due to the following: • There are no meters listed on the application. Meters must be listed for the benefitting meters/accounts to confirm eligibility

Revised Virtual Allocation form required. Application cannot move forward until allocation form is deemed eligible

Revised form sent to Billing

Revised form

Review conducted by SDG&E. No contractor/customer action required.

Review conducted by SDG&E. No contractor/customer action required.

If you have any questions, please contact us.

Thank you,

Customer Generation Team
San Diego Gas & Electric

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Exhibit O

Outlook

## FOLLOW UP ITEMS VNM: 439513 - 337 E VALLEY PKWY, ES

**From** VNMApplications <VNMApplications@sdge.com>
**Date** Tue 1/9/2024 12:26 PM
**To** Adam Hammill <adam@aliveindustries.com>
**Bcc** Kissinger, Nicole M <NKissinger@sdge.com>

Hello Adam,

Reaching out regarding a couple of follow-up items after the initial site meeting:

1. Please confirm the customer's name as it appears on their most current SDGE bill. The application specifies "National Community Renaissance." This does not match current SDGE records. This information is necessary to proceed with the application.

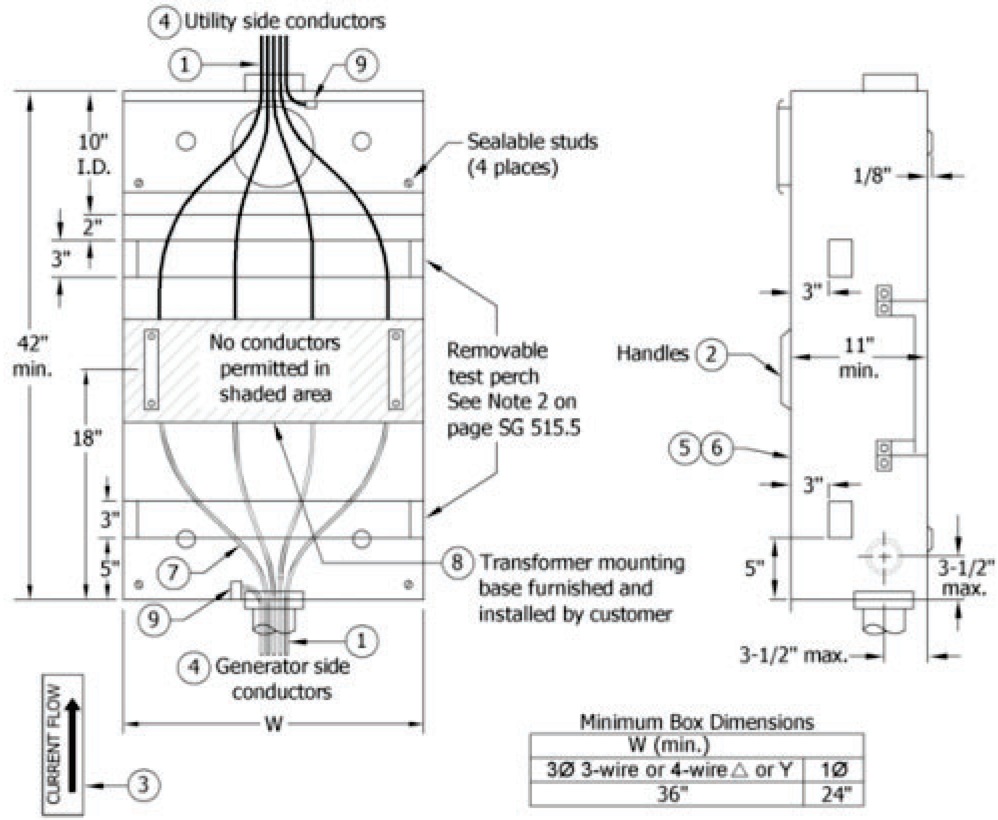
2. Please submit a completed NEM-V Credit Allocation Form 142-02770. The form can be downloaded from here: www.sdge.com/nemdocs. Email completed form to VNMApplications@sdge.com. Reference the application ID number and address in the subject line.

3. Email completed form to us at: VNMApplications@sdge.com Reference the Application ID Number in the subject line.

4. One major item found while I was at the site is the current position of the conduits entering the NGOM panel. Both conduits enter the panel at the top left corner. This is not installed per SDGE standards. Per SDGE Service Guide page 806.11, the conductors are to enter above the test perch and below the CT mounting base:

TABLE OF CONTENTS

**NET GENERATION OUTPUT METERING (NGOM) ONLY – COMBINATION CURRENT TRANSFORMER & METER SOCKET CAN, 0 – 600 VOLTS, 800 AMPS MAXIMUM**




Minimum Box Dimensions

| W (min.) | |
|---|---|
| 3Ø 3-wire or 4-wire △ or Y | 1Ø |
| 36" | 24" |

Notes:

(1) Generator and Utility side conductors must enter above the test perch and below the CT mounting base. See page SG 515.4 for overhead-fed can and page SG 515.5 for underground-fed cans.

(2) Cover shall have two lifting handles, be a maximum of 9 square feet, and a caution sign that reads, "DO NOT BREAK SEALS, NO FUSES INSIDE."

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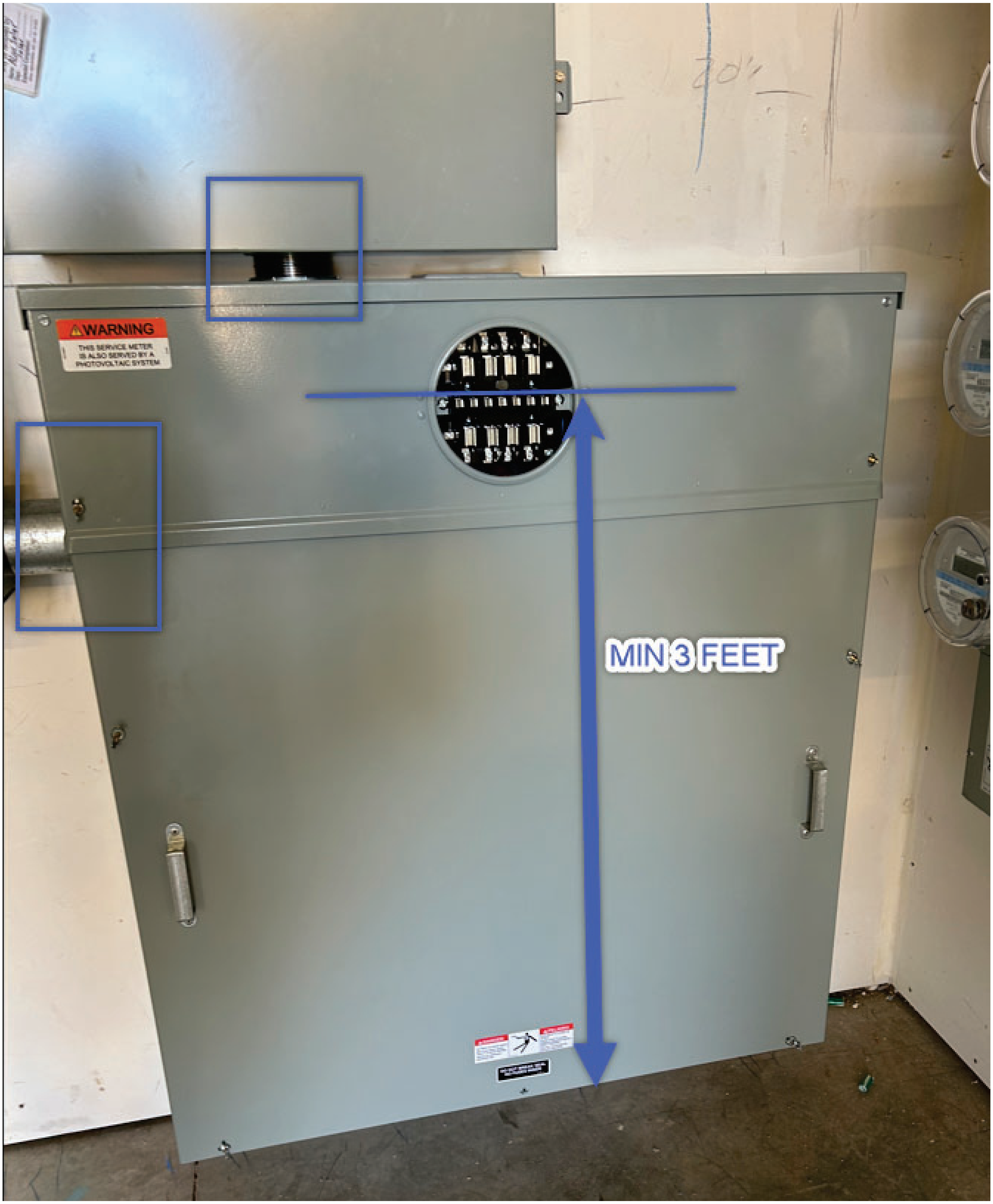
| REV | CHANGE | BY | DSGN | APPV | DATE | REV | CHANGE | BY | DSGN | APPV | DATE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | Editorial Changes | LSM | IPJ | TPM | 11/01/17 | D | | | | | |
| B | | | | | | E | | | | | |
| C | | | | | | F | | | | | |

Indicates Latest Revision | X Completely Revised | New Page | Information Removed

SHEET 11 OF 16 | SDG&E SERVICE STANDARDS & GUIDE | **DISTRIBUTED GENERATION** | SG 806.11

This correction will be required prior to the SDGE final inspection.

In addition, the minimum meter height to center line of the meter is 3 feet when inside a meter room (Service Guide page 504.1). Please ensure this is met as well prior to final SDGE inspection:




All other items were listed on the checklist I provided to Dan at our site meeting. Please let me know if you have any further questions.

Thank you.

**Rosie**

Customer Generation Advisor
**E** VNMApplications@sdge.com

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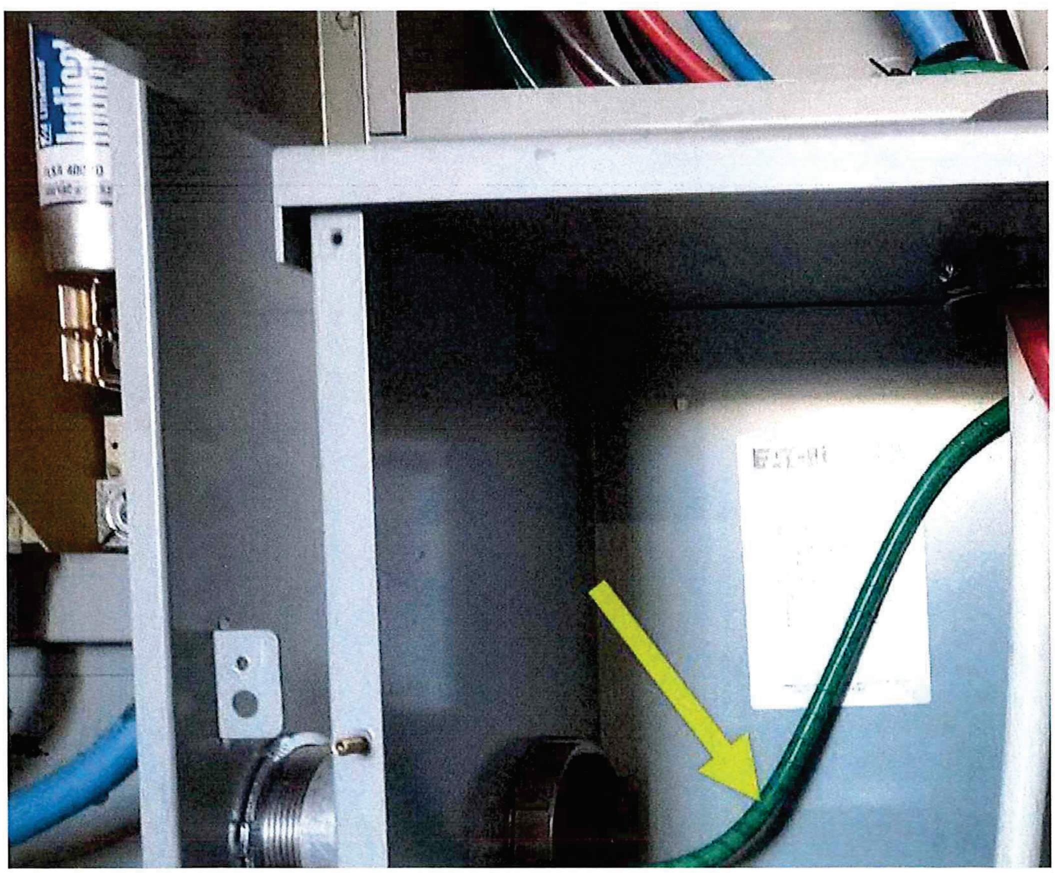
# Exhibit P

| | |
|---|---|
| **From:** | VNMApplications <RMatanane@sdge.com> |
| **Sent on:** | Friday, February 21, 2025 8:28:31 PM |
| **To:** | Dan Wert <danw@aliveindustries.com> |
| **CC:** | adam@aliveindustries.com |
| **BCC:** | McNamara, Berenice <Berenice.McNamara@sdge.com> |
| **Subject:** | CORRECTIONS #2: REQ FOR FINAL: App 439513 photo packet - 337 E VALLEY PKWY CG, ES |
| **Attachments:** | 9153978001031998516.JPG (315.14 KB), 7124122626217559022.JPG (256.16 KB), 5822637517683370900.JPG (406.78 KB), 9154838145262603706.JPG (440.95 KB), 2348631292702995175.JPG (377.58 KB) |

Hi Dan,

There are still issues with the installation listed here. I also included a couple of photos below of a couple approved CT installations for reference.

1. The ground wire is to TERMINATE at the bushing.
2. The current flow placard is to be ON THE PANEL; not the test perch.
3. The conductors are to be labeled. Not the landing lugs.



# Exhibit Q

Outlook

## RE: VNEM for Valley Senior Village 337 E. Valley Pkwy., Escondido 92025 APP # 439513

**From** VNMApplications <VNMApplications@sdge.com>
**Date** Thu 6/20/2024 8:43 AM
**To** Aaron Spoelhof <aspoelhof@nationalcore.org>; Adam Hammill <adam@aliveindustries.com>
**Cc** Dan Wert <danw@aliveindustries.com>; Patrick Meredith <pmeredith@nationalcore.org>; Paige Jodoin <pjodoin@nationalcore.org>; Randy Slabbers <rslabbers@nationalcore.org>

Good morning,

The allocation form issue was added following the initial joint meet. It reads as follows and contains specific information as to your next steps:

Please submit a completed NEM-V Credit Allocation Form 142-02770. The form can be downloaded from here: www.sdge.com/nemdocs. Email completed form to us at: VNMApplications@sdge.com Reference the Application ID Number in the subject line.

SDGE has not received the required completed allocation form to proceed.

As far as the required inspections, they should be released utilizing the SDGE-assigned CG address:

337 E Valley Pkwy CG – CG release (for the NGOM panel)
337 E Valley Pkwy CG – PV release (for the PV system)

The house meter address should not be used as this project does not involve that meter.

Please submit the requested allocation form to proceed. The DP review will commence once the allocation form is approved. Current lead times for allocation form approval is up to 6 weeks.

Thank you.

**SDGE VNM Team**
**E** VNMApplications@sdge.com

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---

**From:** Aaron Spoelhof <aspoelhof@nationalcore.org>
**Sent:** Wednesday, June 19, 2024 2:41 PM
**To:** Adam Hammill <adam@aliveindustries.com>; VNMApplications <VNMApplications@sdge.com>; Netmetering <netmetering@sdge.com>
**Cc:** Dan Wert <danw@aliveindustries.com>; Patrick Meredith <pmeredith@nationalcore.org>; Paige Jodoin <pjodoin@nationalcore.org>; Randy Slabbers <rslabbers@nationalcore.org>
**Subject:** [EXTERNAL] Re: VNEM for Valley Senior Village 337 E. Valley Pkwy., Escondido 92025 APP # 439513

**CAUTION! External Sender**

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Report Suspicious

Adding Paige Jodoin and Randy Slabbers for National Core information purposes.

Thank you,

Get Outlook for iOS [aka.ms]

**Aaron Spoelhof** | Construction Superintendent | (951) 265-0538
**National Community Renaissance** |9692 Haven Avenue Suite 100 |Rancho Cucamonga, CA 91730 |www.nationalcore.org [nationalcore.org]

National CORE is Hiring! Check open positions

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---

**From:** Adam Hammill <adam@aliveindustries.com>
**Sent:** Wednesday, June 19, 2024 13:03
**To:** VNMApplications <VNMApplications@sdge.com>; Netmetering <netmetering@sdge.com>
**Cc:** Dan Wert <danw@aliveindustries.com>; Aaron Spoelhof <aspoelhof@nationalcore.org>; Patrick Meredith <pmeredith@nationalcore.org>
**Subject:** Re: VNEM for Valley Senior Village 337 E. Valley Pkwy., Escondido 92025 APP # 439513

EXTERNAL EMAIL - This email was sent by a person from outside your organization. Exercise caution when clicking links, opening attachments or taking further action, before validating its authenticity.

**Secured by Check Point [checkpoint.com]**

Hello!

We have passed our final inspection with the City of Escondido for this project. The inspector is unclear as to which meter he is to release, but I'm assuming it is the house meter / account number listed below: "06892738." Could you please confirm?

Secondly, I also see this is still stuck in "issues" with the allocation form having been sent to billing on January 4th, with distribution planning review started at that time as well.

Could you please let us know the next steps toward getting this signed off and VNM placed so the system can begin operation?

Sincerely,
Adam Hammill

**Adam Hammill**
Owner/President

**ALIVE Industries, Inc.**
P: (760) 892-5483 x 1M: (760) 877-4759F: (760) 892-5483
A: 2557 Dundee Glen, Escondido, CA 92026
W: www.aliveindustries.com [protect.checkpoint.com]E: adam@aliveindustries.com
CA Lic.: #983966
[protect.checkpoint.com] [protect.checkpoint.com]
[protect.checkpoint.com] [protect.checkpoint.com]
GET QUOTE [PROTECT.CHECKPOINT.COM]

On Nov 9, 2023, at 1:18 PM, Adam Hammill <adam@aliveindustries.com> wrote:

Yes, my previous emails specified that the account holder on the bill is indeed IVY VALLEY HOUSING PARTNERS LP. This was different from the information we had received from the customer when we originally applied for interconnection, so it will need to be changed on our application. I have attached this bill for your reference.

Sincerely,
Adam Hammill

**Adam Hammill**
Owner/President
**ALIVE Industries, Inc.**
P: (760) 892-5483 x 1M: (760) 877-4759F: (760) 892-5483
A: 2557 Dundee Glen, Escondido, CA 92026
W: www.aliveindustries.com [protect.checkpoint.com]E: adam@aliveindustries.com
CA Lic.: #983966
[protect.checkpoint.com]
[protect.checkpoint.com]
[protect.checkpoint.com]
[protect.checkpoint.com]
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# Exhibit R

Outlook

## RE: [EXTERNAL] Re: App 439513

**From** VNMApplications <VNMApplications@sdge.com>
**Date** Thu 8/8/2024 11:16 AM
**To** 'Adam Hammill' <adam@aliveindustries.com>
**Cc** 'Paige Jodoin' <pjodoin@nationalcore.org>; 'Aaron Spoelhof' <aspoelhof@nationalcore.org>; 'Randy Slabbers' <rslabbers@nationalcore.org>; 'Patrick Meredith' <pmeredith@nationalcore.org>; 'Dan Wert' <danw@aliveindustries.com>

1 attachment (308 KB)
ELEC_ELEC-SF_142-02770 (Edited 1-10-24) copy 2.pdf;

Hello Adam,
Please add the CG address and CG account number to the Generator on the allocation form. Leave the CG meter number blank.

Thank you,

**Berenice McNamara**
Net Energy Metering Specialist
Customer Generation Team
E netmetering@sdge.com
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---

**From:** VNMApplications
**Sent:** Thursday, August 8, 2024 11:15 AM
**To:** Adam Hammill <adam@aliveindustries.com>
**Cc:** Paige Jodoin <pjodoin@nationalcore.org>; Aaron Spoelhof <aspoelhof@nationalcore.org>; Randy Slabbers <rslabbers@nationalcore.org>; Patrick Meredith <pmeredith@nationalcore.org>; Dan Wert <danw@aliveindustries.com>
**Subject:** RE: [EXTERNAL] Re: App 439513

Hello Adam,
This form was requested on 1/4/24. We have sent this form to the Billing team to review for eligibility. Please keep in mind that we cannot move forward with the application until eligibility is confirmed from Billing. Please see the process outlined below.
Once the Billing team confirms eligibility, we will update the Issues in DIIS and proceed with the process.

**Virtual Customer/Contractor Process**

1. Contractor submits a complete Virtual request per this process **prior to construction:**
   a. *Email all new Virtual requests to vnmapplications@sdge.com Please do not combine multiple requests for different sites. (Multiple installations located on one property can be*

*combined in one email submission.)*

b. ***A complete submittal includes****:*
   i. *Site map identifying electric panel location(s) and all POI's.*
   ii. *Complete SLD to include: address, existing SDG&E HM meter number, NGOM meter amperage, serving phase, voltage, and system size in AC CEC KW. Disconnects to be labeled as "VISIBLE LOCKABLE" and to be located adjacent to the NGOM meter panel as per SDG&E Service Guide page 806.6.* *https://www.sdge.com/sites/default/files/SGe%20%284%29.pdf*
   iii. *Confirm customer name as shown on their most recent SDGE bill.*

2. **SDG&E Advisor will* ***review*** *the submittal:*
   a. Upon confirming a complete and accurate submittal, the contractor will receive an Initial Site Meeting via Outlook Calendar notice.
      1. Outlook Calendar notice will be emailed to the email address referenced in the submittal email.
   b. If deficiencies are identified in the virtual submittal, the contractor will be advised, and revisions will be required.
      i. Once the corrections are resubmitted using the process above, the review lead time resets.
2. *** Initial Joint Meet (Site Meeting)** is scheduled to establish an approved NGOM meter location, verify field conditions, discuss installation requirements and establish CG address.
3. SDG&E then provides a **CG account number** via email, approximately within 5-10 business days of the Initial Joint Meet.
4. Solar contractor **submits application via DIIS** using provided CG account number. (Note: CG Meter number is not required to submit application). The completed Virtual Allocation form is uploaded to step 6 of DIIS. **Customer to email application ID number to VNMApplications@sdge.com to proceed.**
   a. The uploaded Virtual Allocation to specify assigned CG address and CG number the generator account.
5. SDG&E will forward allocation form for review to the Billing team to determine eligibility.
   a. Issues will be added as applicable throughout the application process.
6. Once allocation eligibility is confirmed from Billing team, the application will proceed to **Initial Review status:**
   a. The Distribution Planning Review will be initiated to verify transformer is adequate for new PV system. Required necessary upgrades will be identified at this stage of the application.
   b. The Secondary Service Assessment Review will be initiated to verify Secondary/Service is adequate for new PV system. Required necessary upgrades will be identified at this stage of the application.
7. Upon passing the Initial Review stage, Customer Generation will create & email all required customer documents: NGOM Rule 2, and NGOM payment invoice. Application will be moved to **Pending AHJ** status in DIIS.
8. Contractor to complete all Issues in DIIS ISSUE tab.
9. DIIS application will automatically change to **Pending SDG&E Inspection** status once AHJ for PV is posted. Please note, two AHJ inspection releases are required: **PV and CG to the CG Address.**
   - Example:
      - Assigned CG Address:

123 Main St CG

      - Required AHJ releases:

123 Main St CG "PV release"
123 Main St CG "CG release"

11. Contractor to request **FINAL SDG&E inspection** via email to VNMApplications@sdge.com.
    a. Email request to include **Final NGOM Photo Packet** as follows:
       1. Entire NGOM installation in one frame with STO letter displayed (both disconnects, NGOM panel, working space showing ground in front of meter).

2. Individual photo of NGOM meter panel showing required CG address placard.
3. Photos of each disconnect showing required placards with correct verbiage.
4. Photo of site map placard installed at main switchgear. (Note: Second placard on NGOM meter panel if not within line of sight of main switchgear.)
5. Photo of inside of NGOM panel in one frame clearly displaying conductor labels and current flow sticker* (*for CT rated installations).

b. Photos to be attached individually as PDF or JPG format. Zip files also acceptable.

c. Contractor to verify all items on checklist are completed and ensure a qualified electrical worker is present for a voltage test at the final inspection.

12. **Final Joint Meet (Site Meeting)** will be scheduled at the first available appointment. Meeting notice will be sent to the email address requesting the **FINAL SDG&E Inspection.** SDG&E Advisor will **review** the submittal:
    a. Upon confirming a complete and accurate submittal, the contractor will receive a Final Joint Meeting via Outlook Calendar notice.
        1. Outlook Calendar notice will be emailed to the email address referenced in the submittal email.
    b. If deficiencies are identified in the final virtual submittal, the contractor will be advised, and revisions will be required.
        i. Once the corrections are resubmitted using the process above, the review lead time resets.
12. Upon FINAL SDGE inspection passing, **a meter set will be scheduled**. Please see CG Meter Set issue in DIIS for the schedule ETA meter set date. Typically the meter sets are completed within 10 Business Days of passing the **FINAL SDG&E Inspection.**
13. **PTO to follow once the meter set has been completed and all Issues are closed in DIIS.

- *Submittal review and site meeting lead times are subject to current workload.
- All Virtual application inquiries are to be submitted to VNMApplications@sdge.com. Please include site address and app ID (if available) in subject line.

Thank you,

**Berenice McNamara**
Net Energy Metering Specialist
Customer Generation Team
E netmetering@sdge.com
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**From:** Adam Hammill <adam@aliveindustries.com>
**Sent:** Monday, August 5, 2024 11:56 AM
**To:** VNMApplications <VNMApplications@sdge.com>
**Cc:** Paige Jodoin <pjodoin@nationalcore.org>; Aaron Spoelhof <aspoelhof@nationalcore.org>; Randy Slabbers <rslabbers@nationalcore.org>; Patrick Meredith <pmeredith@nationalcore.org>; Dan Wert <danw@aliveindustries.com>
**Subject:** [EXTERNAL] Re: App 439513

Hello Berenice and Net Metering Team,

Please find attached the generation credit allocation request form that should complete the application for VNEM for app 439513.

Could you also please confirm that the PV and CG releases were received for 377 E Valley Pkwy?

Please let us know if anything else is needed. Everything is inspected and up and ready to go as soon as you can get our CG meter installed.

Thanks very much for your assistance with this.

Sincerely,
Adam Hammill

upload image

**Adam Hammill**

Owner/President

**ALIVE Industries, Inc.**

P: (760) 892-5483 x 1M: (760) 877-4759F: (760) 892-5483

A: 2557 Dundee Glen, Escondido, CA 92026

W: www.aliveindustries.comE: adam@aliveindustries.com

CA Lic.: #983966

**GET QUOTE**

---

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# Exhibit S

**From:** VNMApplications <RMatanane@sdge.com>
**Sent on:** Tuesday, April 22, 2025 10:13:56 PM
**To:** adam@aliveindustries.com
**CC:** Dan Wert <danw@aliveindustries.com>
**Subject:** PHOTO REQUEST: CORRECTIONS #3: REQ FOR FINAL: App 439513 photo packet - 337 E VALLEY PKWY CG, ES
**Attachments:** Screenshot 2025-02-25 at 3.40.54 PM.png (3.04 MB), Screenshot 2025-02-25 at 3.38.17 PM.png (3.2 MB), Screenshot 2025-02-25 at 3.37.52 PM.png (3.21 MB)

Hi Adam,

I am unable to see the required correction of the ground wire at the bushings in the photo you submitted below. Was it completely removed? The ground wire is <u>required</u>.

Please reply to this email by attaching (.pdf or .jpg) photos clearly displaying the ground wire at the bushings. Thank you.

# Exhibit T

Outlook

## RE: Pre PTO VNM App ID 463973

**From** NEMAGG <NEMAGG@semprautilities.com>
**Date** Tue 12/19/2023 1:26 PM
**To** Kissinger, Nicole M <NKissinger@sdge.com>; NEMAGG <NEMAGG@semprautilities.com>
**Cc** Grace, Jocelyn M <JMGrace@sdge.com>

1 attachment (1 MB)
463973-allocation.pdf;

Hello,

The attached application is ineligible due to the following:

- No meter numbers are included in the application.

Please make any needed changes and resubmit an updated application for approval.

Thank you,
Ruben

---

**From:** Kissinger, Nicole M <NKissinger@sdge.com>
**Sent:** Tuesday, December 19, 2023 1:09 PM
**To:** NEMAGG <NEMAGG@semprautilities.com>
**Cc:** Grace, Jocelyn M <JMGrace@sdge.com>
**Subject:** FW: Pre PTO VNM App ID 463973

Hi NEM AGG,
Do you know if this review will be completed soon?

Thank you,
**Nicole Kissinger**
**Customer Generation Department**

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**From:** VNMApplications
**Sent:** Tuesday, November 21, 2023 11:45 AM
**To:** NEMAGG <NEMAGG@semprautilities.com>
**Subject:** Pre PTO VNM App ID 463973

Hi NEM AGG!
Please advise if this meets eligibility.

Thank you,
**Customer Generation Department**

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# Exhibit U

Outlook

## REQUEST FOR FINAL IS PREMATURE: App ID: 463973; Nestor Senior

**From** VNMApplications <VNMApplications@sdge.com>
**Date** Thu 2/22/2024 2:57 PM
**To** John Young <JohnIX@calsolarinc.com>
**Cc** Stuart McFarland <stuart.mcfarland@calsolarinc.com>; Solomon Gill <solomon.gill@calsolarinc.com>

Hello John,

This request for final is premature. Please resubmit later in the process once all issues have been resolved.

The DIIS application status shows SDGE is waiting for a revised allocation form due to the submitted form missing meter numbers. The application will not proceed to transformer review or costing until this is completed.

In the future, please ensure all customer issues are resolved in DIIS prior to requesting a final SDGE inspection.

Thank you.

**Rosie**
Customer Generation Advisor
**E** VNMApplications@sdge.com

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---

**From:** John Young <JohnIX@calsolarinc.com>
**Sent:** Friday, February 16, 2024 4:17 PM
**To:** VNMApplications <VNMApplications@sdge.com>
**Cc:** Stuart McFarland <stuart.mcfarland@calsolarinc.com>; Solomon Gill <solomon.gill@calsolarinc.com>
**Subject:** [EXTERNAL] Re: [Request for FINAL] App ID: 463973; Nestor Senior

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Hi Rosie,

The files attached in the previous email are .jpg files.
Please see attached for the .pdf versions of each photo attached below.

On Fri, Feb 16, 2024 at 3:18 PM VNMApplications <VNMApplications@sdge.com> wrote:

> Hello John,
>
> This request for final SDGE inspection is premature. The revised allocation form requested was received by SDGE yesterday afternoon. It is in the queue for processing.
>
> Once the allocation form is approved, the transformer review will be initiated and costing docs will be sent out within 15 business days of the allocation form approval. Prior to submitting the request for final SDGE inspection, please review the DIIS application to ensure all issues are completed.
>
> Also, as the verbiage reads, please submit photos in .jpg or .pdf format. This way I can zoom in to confirm placard verbiage and conductor labels and wiring (I am unable to do so in the manner they are attached below).
>
> Contractor to request FINAL SDGE inspection via email to VNMApplications@sdge.com. Contractor to ensure all DIIS issues are closed. Prior to scheduling final inspection, contractor to submit photos (.jpg or .pdf) of the installation for review to VNMApplications@sdge.com. Photos to include: 1) Entire NGOM installation in one frame with STO letter displayed (both disconnects, NGOM panel, working space showing ground in front of meter). 2) Individual photo of NGOM meter panel showing required CG address placard. 3) Photos of each disconnect showing required placards with correct verbiage. 4) Photo of site map placard installed at main switchgear. (Note: Second placard on NGOM meter panel required if not within line of sight of main switchgear.) 5) Photo of inside of NGOM panel in one frame clearly displaying conductor labels and current flow sticker* (*for CT rated installations). Customer to verify all items on checklist are completed and ensure a qualified electrical worker is present for a voltage test at the final inspection.
>
> Thank you.
>
> **Rosie**
> Customer Generation Advisor
> **E** VNMApplications@sdge.com
>
> Follow Us:
> [facebook.com] [twitter.com]
> [linkedin.com]
> [instagram.com]
>
> For more information about privacy at SDG&E visit sdge.com/privacy.

**From:** John Young <JohnIX@calsolarinc.com>
**Sent:** Thursday, February 15, 2024 4:32 PM
**To:** VNMApplications <VNMApplications@sdge.com>
**Cc:** Stuart McFarland <stuart.mcfarland@calsolarinc.com>; Solomon Gill <solomon.gill@calsolarinc.com>
**Subject:** [EXTERNAL] [Request for FINAL] App ID: 463973; Nestor Senior

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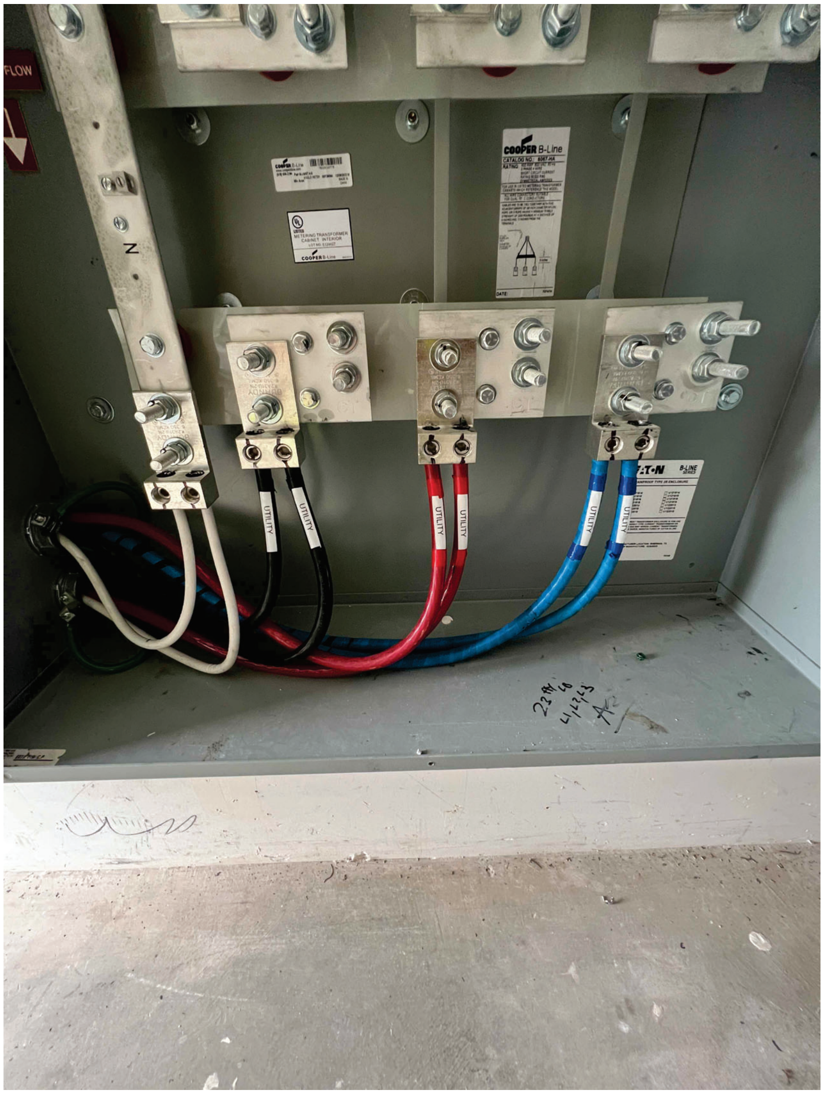
Hi SDGE VNEM Team,
Please let us know your availability to schedule the FINAL NGOM inspection for the following application:

| Project | Utility App ID | Service Address |
|---|---|---|
| Nestor Senior | 463973 | 1120 Nestor Way CG, San Diego, CA 92154 |

Attached are the following:
Photos of:
- NGOM Installation in one frame (Both Disconnects and NGOM Panel)
- NGOM Meter Panel showing required CG Address Placards
- Inside NGOM Panel in one frame
- Conductor Labels (Utility & Generator)
- Current Flow Sticker
- Each Disconnect showing the required Placards:
  - PV Disconnect: "PV SYSTEM DISCONNECT FOR UTILITY OPERATION GENERATOR SIDE"
  - Utility Disconnect: "PV SYSTEM DISCONNECT FOR UTILITY OPERATION UTILITY SIDE"
- Site Map Placard Installed at Main Switchgear
- "Safe to Operate" letter hung on the NGOM panel


WARNING
ELECTRIC SHOCK HAZARD
DO NOT TOUCH TERMINALS
TERMINALS ON BOTH THE LINE AND
LOAD SIDES MAY BE ENERGIZED
IN THE OPEN POSITION
PHOTOVOLTAIC SYSTEM
EQUIPPED WITH
RAPID SHUTDOWN
NET GENERATION
OUTPUT METER
1120 NESTOR WAY, SAN
DIEGO, CA 92154


FLOW
N
UTILITY
UTILITY
UTILITY
UTILITY
UTILITY
UTILITY


CURRENT FLOW


ON
SIEMENS
OFF


PHOTOVOLTAIC AC DISCONNECT
RATED AC OUTPUT CURRENT
NOMINAL OPERATING AC VOLTAGE
PV AC DISCONNECT #3
PV AC DISCONNECT FOR UTILITY OPERATIONS GENERATOR SIDE
PHOTOVOLTAIC SYSTEM EQUIPPED WITH RAPID SHUTDOWN
WARNING
TURN OFF PHOTOVOLTAIC AC DISCONNECT PRIOR TO WORKING INSIDE PANEL
WARNING
ELECTRIC SHOCK HAZARD
ON
SIEMENS
General Duty Safety Switch
Interrupteur de sécurité général
OFF


PHOTOVOLTAIC AC DISCONNECT
RATED AC OUTPUT CURRENT 120A
NOMINAL OPERATING AC VOLTAGE 480V
PV AC DISCONNECT #3
PV AC DISCONNECT FOR UTILITY OPERATIONS GENERATOR SIDE
PHOTOVOLTAIC SYSTEM EQUIPPED WITH RAPID SHUTDOWN
⚠WARNING⚠ TURN OFF PHOTOVOLTAIC AC DISCONNECT PRIOR TO WORKING INSIDE PANEL
⚠WARNING⚠ ELECTRIC SHOCK HAZARD
DO NOT TOUCH TERMINALS TERMINALS ON BOTH THE LINE AND LOAD SIDES MAY BE ENERGIZED IN THE OPEN POSITION
ON
SIEMENS
General Duty Safety Switch
Interrupteur de sécurité général
400 A 240 VAC 250 VDC
OFF


WARNING
ELECTRIC SHOCK HAZARD
DO NOT TOUCH TERMINALS
TERMINALS ON BOTH THE LINE AND LOAD SIDES MAY BE ENERGIZED IN THE OPEN POSITION
PHOTOVOLTAIC SYSTEM EQUIPPED WITH RAPID SHUTDOWN
NET GENERATION OUTPUT METER
1120 NESTOR WAY, SAN DIEGO, CA 92154
CalSolarInc


SIEMENS
MAIN SWITCHBOARD
1120 NESTOR WAY
HM
1120 NESTOR WAY
PEV
SPARE
TO DPI DIS.
SPARE


--
Thank you for your time,

**John Young**
Design Engineer | Interconnection Engineer II
JohnIX@calsolarinc.com

[calsolarinc.com]

**Los Angeles | Oakland | San Diego**

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--
Thank you for your time,

**John Young**
Design Engineer | Interconnection Engineer II
JohnIX@calsolarinc.com

[calsolarinc.com]

**Los Angeles | Oakland | San Diego**

---

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Exhibit V

Outlook

# PRE-PTO VNM: 463973 - 1120 NESTOR WAY CG SAN DIEGO (Corrected Allocation Form)

**From** VNMApplications <VNMApplications@sdge.com>
**Date** Fri 3/8/2024 7:10 AM
**To** NEMAGG <NEMAGG@semprautilities.com>

2 attachments (722 KB)
Nestor Senior - Allocation Sheet - Meter Numbers.xlsx; Nestor Senior - Allocation Form - Signed.pdf;

Good morning,

Allocation form attached for review. Thank you.

**Rosie Matanane**
Customer Generation Advisor
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2022 CYBER STAR

# Exhibit W

Outlook

## 1120 NESTOR CG SAN DIEGO

**From** Contreras, Victor <VContreras2@sdge.com>
**Date** Tue 5/21/2024 10:40 AM
**To** Emosups <Emosups@semprautilities.com>
**Cc** Matanane, Rosina <RMatanane@sdge.com>

Turned down due to no voltage after operating utility side disconnect. Verified no voltage at utility breaker or generation breaker, this would mean there is a second breaker ahead of utility breaker that needs to be operated to get voltage to the utility breaker. This second breaker ahead of the utility breaker should be labeled as well. Only the CT set order was in completed. Customer Stuart at 858-833-0352 is aware and was unable to get tech out today to operate today.

Exhibit X



## POI 1 - EAST SIDE - ALL EXTERIOR EQUIPMENT

NTS

sunrun

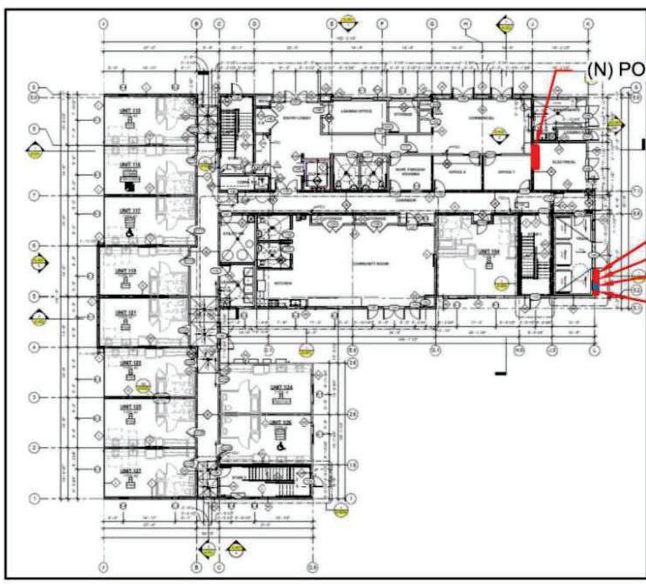
SDG&E PV METER ADDRESS: 563 GREENBRIER DR, OCEANSIDE, CA 92054 CG, COOPER B-LINE, 122015 W/ 6067 HA CT BASE (OR EQUIVALENT), 400 A, SERVICE 3 PHASE 4 WIRE 120/208 VOLT WYE, NEMA 3R

PROJECT:
GREENBRIER VILLAGE
563 GREENBRIER DR,
OCEANSIDE, CA 92054

PROJECT NUMBER:
PROP-000886

REV: F 10/1/2025

PAGE POI-1 PROPOSAL


# POI 1 - EAST SIDE - INTERIOR AC DISCONNECT

NTS

sunrun

SDG&E PV METER ADDRESS: 563 GREENBRIER DR, OCEANSIDE, CA 92054 CG, COOPER B-LINE, 122015 W/ 6067 HA CT BASE (OR EQUIVALENT), 400 A, SERVICE 3 PHASE 4 WIRE 120/208 VOLT WYE, NEMA 3R

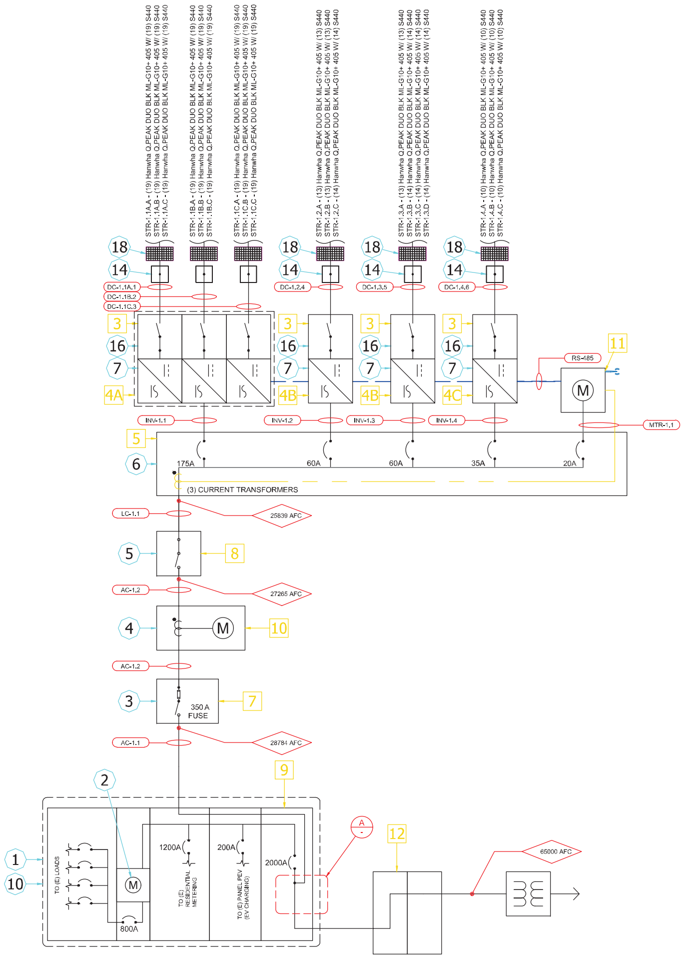
PROJECT:
GREENBRIER VILLAGE
563 GREENBRIER DR,
OCEANSIDE, CA 92054

PROJECT NUMBER:
PROP-000886

REV: F 10/1/2025

PAGE POI-1 PROPOSAL

## SYSTEM SUMMARY | 94.60 ACKW | 119.88 DCKW | 108.20 CECKW





A SUPPLY SIDE CONNECTION LOCATION

NTS

NET - NO EXCEPTIONS TAKEN
MUST MEET SDG&E SERVICE STANDARDS

CUSTOMER CONDUCTORS MUST NOT BE IN UTILITY PORTION OF SECTION

CUSTOMER TO VERIFY TAP LOCATION IS CONSISTENT WITH PV METERING APPLICATION

REVIEW FOR BUS TAP ONLY
COORDINATE WITH CUSTOMER GENERATION FOR PV PANEL/DISCONNECT LOCATIONS

Manuel Gonzalez
I have reviewed this document
mgonzal5@sdge.com
2025.10.15
07:41:43-07'00'

### POI-1 DC STRING SCHEDULE

| TAG | DESTINATION | STR-A CIRCUIT LENGTH ² | STR-A VD% | STR-A MODULE WATTAGE | STR-A MODULE QTY | STR-A OPTIMIZER | STR-A MIN/MAX MODULES | STR-B CIRCUIT LENGTH ² | STR-B VD% | STR-B MODULE WATTAGE | STR-B MODULE QTY | STR-B OPTIMIZER | STR-B MIN/MAX MODULES | STR-C CIRCUIT LENGTH ² | STR-C VD% | STR-C MODULE WATTAGE | STR-C MODULE QTY | STR-C OPTIMIZER | STR-C MIN/MAX MODULES | STR-D CIRCUIT LENGTH ² | STR-D VD% | STR-D MODULE WATTAGE | STR-D MODULE QTY | STR-D OPTIMIZER | STR-D MIN/MAX MODULES |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DC-1.1A.1 | INV-1.1A | 100 | 0.75% | 405 | 19 | S440 | 10 / 19¹ | 120 | 0.83% | 405 | 19 | S440 | 10 / 19¹ | 135 | 1.01% | 405 | 19 | S440 | 10 / 19¹ | -- | -- | -- | -- | -- | -- |
| DC-1.1B.2 | INV-1.1B | 60 | 0.45% | 405 | 19 | S440 | 10 / 19¹ | 85 | 0.59% | 405 | 19 | S440 | 10 / 19¹ | 120 | 0.89% | 405 | 19 | S440 | 10 / 19¹ | -- | -- | -- | -- | -- | -- |
| DC-1.1C.3 | INV-1.1C | 60 | 0.45% | 405 | 19 | S440 | 10 / 19¹ | 70 | 0.49% | 405 | 19 | S440 | 10 / 19¹ | 90 | 0.67% | 405 | 19 | S440 | 10 / 19¹ | -- | -- | -- | -- | -- | -- |
| DC-1.2.4 | INV-1.2 | 140 | 0.71% | 405 | 13 | S440 | 10 / 19¹ | 140 | 0.66% | 405 | 13 | S440 | 10 / 19¹ | 140 | 0.77% | 405 | 14 | S440 | 10 / 19¹ | -- | -- | -- | -- | -- | -- |
| DC-1.3.5 | INV-1.3 | 140 | 0.71% | 405 | 13 | S440 | 10 / 19¹ | 140 | 0.71% | 405 | 14 | S440 | 10 / 19¹ | 140 | 0.77% | 405 | 14 | S440 | 10 / 19¹ | 140 | 0.77% | 405 | 14 | S440 | 10 / 19¹ |
| DC-1.4.6 | INV-1.4 | 250 | 0.98% | 405 | 10 | S440 | 8 / 19¹ | 250 | 0.91% | 405 | 10 | S440 | 8 / 19¹ | 250 | 0.98% | 405 | 10 | S440 | 8 / 19¹ | -- | -- | -- | -- | -- | -- |

¹ MAXIMUM STRING LENGTH IS USING MANUFACTURES EXCEPTION
² LENGTHS ARE ESTIMATED FOR CALCULATIONS, CONTRACTOR IS RESPONSIBLE FOR MEASUREMENTS AND TAKEOFFS
³ WHERE EXPOSED TO PHYSICAL DAMAGE #6 TO BE USED PER NEC 250.120(C)

### POI-1 DC WIRE SCHEDULE

| TAG | WIRE GAUGE | CONDUCTOR MATERIAL | CONDUCTOR JACKET | MAX OPTIMIZER OUTPUT | 1.25 X MAX CIRCUIT AMPS | CIRCUIT FUSE RATING | CURRENT CARRYING CONDUCTORS PER CONDUIT | MAX AMBIENT TEMP (C) | C.O.U TEMP. DERATE | C.O.U CONDUIT FILL DERATE | 75°C AMPACITY | COMPLIES WITH 690.8(B)(1) | 90°C AMPACITY WITH C.O.U | COMPLIES WITH 690.8(B)(2) | FAULT CURRENT FROM PARALLEL STRINGS | COMPLIES WITH 690.9(A) | GROUNDING PER CONDUIT | GROUNDING ³ | ALLOWABLE CONDUIT FILL | EMT | RMC | PVC 40 | PVC 80 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DC-1.1A.1 | 10 AWG | CU | THWN2 | 15 | 18.75 | 25 A | 6 | 25 | 104% | 80% | 35 | YES | 33.3 | YES | 25 | YES | 3 | 10 AWG | 40% | 3/4" | 3/4" | 3/4" | 1" |
| DC-1.1B.2 | 10 AWG | CU | THWN2 | 15 | 18.75 | 25 A | 6 | 25 | 104% | 80% | 35 | YES | 33.3 | YES | 25 | YES | 3 | 10 AWG | 40% | 3/4" | 3/4" | 3/4" | 1" |
| DC-1.1C.3 | 10 AWG | CU | THWN2 | 15 | 18.75 | 25 A | 6 | 25 | 104% | 80% | 35 | YES | 33.3 | YES | 25 | YES | 3 | 10 AWG | 40% | 3/4" | 3/4" | 3/4" | 1" |
| DC-1.2.4 | 10 AWG | CU | THWN2 | 15 | 18.75 | 25 A | 6 | 25 | 104% | 80% | 35 | YES | 33.3 | YES | 25 | YES | 3 | 10 AWG | 40% | 3/4" | 3/4" | 3/4" | 1" |
| DC-1.3.5 | 10 AWG | CU | THWN2 | 15 | 18.75 | 25 A | 8 | 25 | 104% | 70% | 35 | YES | 29.1 | YES | 25 | YES | 4 | 10 AWG | 40% | 1" | 1" | 1" | 1" |
| DC-1.4.6 | 10 AWG | CU | THWN2 | 15 | 18.75 | 25 A | 6 | 25 | 104% | 80% | 35 | YES | 33.3 | YES | 25 | YES | 3 | 10 AWG | 40% | 3/4" | 3/4" | 3/4" | 1" |

### POI-1 AC WIRE SCHEDULE

| TAG | DESTINATION | ICONT TOTAL | ICONT X 1.25 | OCP | NOMINAL VAC | C.O.U TEMP. DERATE | C.O.U CONDUIT FILL DERATE | CONDUCTOR MATERIAL | CONDUCTOR JACKET | CONDUIT QTY | CONDUCTORS PER PHASE | PHASE CONDUCTOR | NEUTRAL CONDUCTOR | GROUNDING CONDUCTOR | 75°C AMPACITY | 90°C AMPACITY WITH C.O.U | CIRCUIT LENGTH ² | VD% | DC/AC RATIO | ALLOWABLE CONDUIT FILL | EMT | IMC | PVC 40 | PVC 80 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| INV-1.1 | LC-1.1 | 138.8 | 173.5 | 175 | 208 | 104% | 100% | CU | THWN2 | 1 | 1 | 2/0 AWG | 6 AWG | 6 AWG | 175 | 202.8 | 130 | 1.38% | 138.5% | 40% | 1 1/2" | 1 1/2" | 1 1/2" | 2" |
| INV-1.2 | LC-1.1 | 48.0 | 60.0 | 60 | 208 | 104% | 100% | CU | THWN2 | 1 | 1 | 6 AWG | 10 AWG | 10 AWG | 65 | 78.0 | 40 | 0.72% | 93.6% | 40% | 3/4" | 3/4" | 3/4" | 1" |
| INV-1.3 | LC-1.1 | 48.0 | 60.0 | 60 | 208 | 104% | 100% | CU | THWN2 | 1 | 1 | 6 AWG | 10 AWG | 10 AWG | 65 | 78.0 | 80 | 1.44% | 128.8% | 40% | 3/4" | 3/4" | 3/4" | 1" |
| INV-1.4 | LC-1.1 | 27.8 | 34.7 | 35 | 208 | 104% | 100% | CU | THWN2 | 1 | 1 | 8 AWG | 8 AWG | 8 AWG | 50 | 57.2 | 80 | 1.33% | 121.5% | 40% | 3/4" | 3/4" | 3/4" | 1" |
| LC-1.1 | AC-1.2 | 262.6 | 328.3 | 350 | 208 | 104% | 100% | CU | THWN2 | 1 | 1 | 400 KCMIL | 3 AWG | 3 AWG | 335 | 395.2 | 5 | 0.04% | -- | 40% | 2 1/2" | 2 1/2" | 3" | 3" |
| AC-1.2 | AC-1.1 | 262.6 | 328.3 | 350 | 208 | 104% | 100% | CU | THWN2 | 2 | 2 | 2/0 AWG | 1/0 AWG | 3 AWG | 350 | 405.6 | 5 | 0.05% | -- | 40% | 2" | 2" | 2" | 2" |
| AC-1.1 | POI-1 | 262.6 | 328.3 | 350 | 208 | 104% | 100% | CU | THWN2 | 2 | 2 | 2/0 AWG | 1/0 AWG | 2 AWG | 350 | 405.6 | 50 | 0.50% | -- | 40% | 2" | 2" | 2" | 2" |
| MTR-1.1 | LC-1.1 | 0.1 | 0.13 | 20 | 208 | 104% | 100% | CU | THWN2 | 1 | 1 | 12 AWG | 12 AWG | 12 AWG | 25 | 31.2 | 15 | -- | -- | 40% | 3/4" | 3/4" | 3/4" | 3/4" |

## EQUIPMENT NOTES

1. PV MODULES (296)HANWHA Q.PEAK DUO BLK ML-G10+ 405
2. (296) SOLAREDGE DC OPTIMIZER S440
3. DC CONNECTION UNIT W/INTEGRAL LOAD BREAK DISCONNECT
4. 4A: (1) SOLAREDGE INVERTER MODEL - SOLAREDGE SE50KUS, 50000W, 208VAC, 3ø, 4W

   4B: (2) SOLAREDGE INVERTER MODEL - SOLAREDGE SE17.3KUS, 17300W, 208VAC, 3ø, 4W

   4C: (1) SOLAREDGE INVERTER MODEL - SOLAREDGE SE10KUS, 10000W, 208VAC, 3ø, 4W
5. (N) AC LOAD CENTER 'LC-1' 400A, 208VAC, 42K AIC, NEMA 3R
6. NOT USED
7. (N) ACDS-1 SYSTEM UTILITY AC DISCONNECT SWITCH, SQUARE D, HU365R, 600V RATED, 208V OPERATIONAL, 400A, 3 POLE, NON-FUSIBLE, NEMA 3R, 65K AIC RATING, OR EQUIVALENT ON THE UTILITIES APPROVED LIST.
8. (N) ACDS-2 SYSTEM UTILITY AC DISCONNECT SWITCH, SQUARE D, HU365R, 600V RATED, 208V OPERATIONAL, 400A, 3 POLE, NON-FUSIBLE, NEMA 3R, 42K AIC RATING
9. (E) CUSTOMER OWNED MAIN SERVICE EQUIPMENT: 3 PHASE 4 WIRE 120/208 VOLT WYE, 2000A, 3 ø
10. (N) SDG&E PV PRODUCTION METER SOCKET ADDRESS: 563 GREENBRIER DR, OCEANSIDE, CA 92054 CG, COOPER B-LINE, 122015 W/ 6067 HA CT BASE (OR EQUIVALENT), 400A, SERVICE: 3 PHASE 4 WIRE 120/208 VOLT WYE, METER TYPE CP1SAL9, 15 CLIP, NEMA 3R, EUSERC: 314, 329A
11. (N) CELL-B-R05-US-S-S4 COMMERCIAL CELL CARD OR EQUIVALENT
12. UTILITY OWNED UNDERGROUND PULL SECTION. 3 PHASE 4 WIRE 120/208 VOLT WYEV, 2000A, 3 Ø
    3 PHASE 4 WIRE 120/208 VOLT WYE, NEMA 3R

## KEYED NOTES

1. (E) MAIN SWITCHGEAR AND (N) POINT OF AC INTERCONNECTION. ALL CONNECTIONS MADE INSIDE (E) SWITCHGEAR AT OTHER THAN CIRCUIT BREAKERS OR FUSED SWITCHES LISTED FOR USE WITH THAT SWITCHGEAR SHALL BE PERFORMED FOLLOWING MANUFACTURERS INSTRUCTIONS OR BE RE-LISTED BY A NRTL. ALL TERMINATIONS OF ALUMINUM CONDUCTORS SHALL BE WITH HIGH PRESS CRIMP LUGS ONLY. WARNING LABEL DETAIL 1/WARNING LABELS SHEET
2. (E) UTILITY TENANT LOAD METER. UTILITY REFERENCE METER NUMBER: TBD
3. (N) PV SYSTEM UTILITY AC DISCONNECT "ACDS-1". WARNING LABEL DETAIL 2/WARNING LABELS SHEET
4. (N) UTILITY OWNED DEDICATED PV PRODUCTION KWH METER.
5. (N) PV SYSTEM MAINTENANCE AC DISCONNECT "ACDS-2". WARNING LABEL DETAIL 2/WARNING LABELS SHEET
6. (N) AC SWITCHGEAR FOR COMBINING INVERTER OUTPUT. WARNING LABEL DETAIL 1/WARNING LABELS SHEET
7. (N) GRID-INTERACTIVE PV INVERTER LISTED TO UL 1741 WITH GROUND FAULT DETECTION & INTERRUPTION. WARNING LABEL DETAIL 8/WARNING LABELS SHEET
8. NOT USED
9. NOT USED
10. INSTALL INVERTER BACK FEED CIRCUIT BREAKER AT OPPOSITE END OF BUS BAR FROM MAIN FEED PER ART 690.64(B)(7)/705.12(D)(7). WARNING LABEL DETAIL 11/WARNING LABELS SHEET
11. CONDUCTORS RUN IN PARALLEL SHALL BE INSTALLED PER ART 310.4/310.10(H) AND 250.122 (F)
12. INSTALL 5/8"X8' CU AUX GND ROD FOR LIGHTNING PROTECTION PER ART 250.54. CONNECT TO EQUIPMENT GROUND BAR WITH #6 BARE CU.
13. NOT USED
14. NEW PULL/JUNCTION BOXES, PROVIDE SERVICE LOOP IN ALL DC BRANCH CONDUCTORS RUN DOWN FROM ROOFTOPS, MIN LOOP RADIUS = 12X CONDUCTOR DIAMETER.
15. (N) INVERTER INTERNAL FUSED DC BRANCH COMBINER.
16. (N) DC DISCONNECT SWITCH(ES) LOCATED AT INVERTER. WARNING LABEL DETAIL 3/WARNING LABELS SHEET
17. (N) PV SOURCE CIRCUIT DC COMBINER BOXES WITH INTEGRATED LOAD-BREAK DISCONNECT SWITCH AND KLKD SERIES 1000VDC FAST-ACTING PHOTOVOLTAIC MIDGET FUSES. WARNING LABEL DETAIL 4/WARNING LABELS SHEET
18. (N) PV MODULE LISTED TO UL 1703.
19. EXTRA MODULES THAT ARE UNABLE TO BE PAIRED WILL HAVE THEIR OWN OPTIMIZER
20. PV GENERATOR'S TOTAL FAULT CURRENT : 403 A
21. NOT USED
22. NOT USED
23. NOT USED
24. NOT USED
25. NOT USED
26. NOT USED

CONTRACTOR:

SUNRUN

225 BUSH ST #1400, SAN FRANCISCO, CA 94104
CA CL #750184

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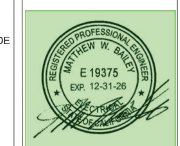
GREENBRIER VILLAGE
563 GREENBRIER DR, OCEANSIDE, CA 92054
APN:151-010-44-00
DEVELOPER:
NATIONAL CORE

PROJECT DETAILS:

PV SYSTEM:
119.88 kW DC
94.6 kW AC
108.203 CEC AC

ENGINEERING APPROVAL:




| DESCRIPTION | DATE | REV |
|---|---|---|
| ORIGINAL | 10/17/23 | 0 |
| AHJ COMMENTS | 2/29/24 | A |
| AHJ COMMENTS | 3/28/24 | B |
| AHJ COMMENTS | 4/16/24 | C |
| CARPORT DOWNSIZE | 06/13/24 | D |
| UTILITY COMMENT | 2/13/25 | E |
| POI UPDATE | 10/01/25 | F |

SHEET SIZE: 36" X 24" (ARCH D)

SHEET TITLE: POI-1 ONE LINE

SHEET NUMBER: E600

REVISION: F

PM: CAMERON GOODWIN

DESIGNER: TIM BRUCKNER

PJT #: PROP-000886

CONTR #: 3002009655

# Exhibit Y

## deBoer, Krista S

**From:** Adam Hammill <adam@aliveindustries.com>
**Sent:** Wednesday, November 1, 2023 5:23 PM
**To:** VNMApplications
**Cc:** Dan Wert; Aaron Spoelhof; Patrick Meredith
**Subject:** [EXTERNAL] Re: VNEM for Valley Senior Village 337 E. Valley Pkwy., Escondido 92025 APP # 439513
**Attachments:** Site Plan for SDGE.pdf; SLD for SDGE 1 copy.pdf

**Follow Up Flag:** Follow up
**Flag Status:** Completed

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Dear VNM Team,

I believe we submitted the requested information back on April 3rd, but I also believe we were instructed to do some of the next steps outside the normal order because of the then-impending NEM-ST deadline (see below).

Now that we have the house meter and billing information, I've updated the SLD and site diagram to reflect the correct and most up-to-date information, and I've attached them to this email.

We'd love to set up a site meeting at the earliest possible opportunity, as the PV installation and CG meter panel and disconnects have already passed AHJ inspection.

Please let us know how best to proceed.

Sincerely,
Adam Hammill

**Adam Hammill**
Owner/President
**ALIVE Industries, Inc.**
P: (760) 892-5483 x 1M: (760) 877-4759F: (760) 892-5483
A: 2557 Dundee Glen, Escondido, CA 92026
W: www.aliveindustries.com [aliveindustries.com]E: adam@aliveindustries.com
CA Lic.: #983966
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On Nov 1, 2023, at 3:42 PM, VNMApplications <VNMApplications@sdge.com> wrote:

Hello Adam,

The VNM process is outlined below. The submittal process is highlighted for quick reference as to your next step.

1. Customer submits a complete VNM request per this process:
    a. *Email all new VNM/NGOM requests to vnmapplications@sdge.com Please do not combine multiple requests for different sites. (Multiple installations located on one property can be combined in one email submission.)*
    b. ***A complete submittal includes**:*
        1. *Site map identifying electric panel location(s).*
        2. *Complete SLD to include: address, existing SDGE HM meter number, NGOM meter amperage, and system size in AC CEC KW. Disconnects to be labeled as "VISIBLE LOCKABLE" and to be installed directly on either side of NGOM meter panel as per SDGE Service Guide page 806.6. https://www.sdge.com/sites/default/files/SGe%20%284%29.pdf*
        3. *Confirm customer name as shown on their most recent SDGE bill.*
2. **SDGE Advisor will review the submittal. Contractor will be advised of requested revisions if applicable.*
3. *Once the submittal is accepted, an **INITIAL site meeting** is scheduled to establish an approved NGOM meter location, verify field conditions, and discuss installation requirements.
4. SDGE then provides a **CG account number** via email.
5. Solar contractor **submits application via DIIS** using provided CG account number. (Note: Meter number is not required to submit application). **Customer to email application ID number to VNMApplications@sdge.com to proceed.**
6. ****SDGE will then initiate all "issues" (requirements) in DIIS**. SDGE will forward allocation form for review/approval and initiate "Distribution Planning" review to verify transformer is adequate for new PV system. Upon approved allocation form, SDGE will create all required customer docs, costing information, and payment invoice.
7. Customer to complete all "issues" and obtain AHJ inspection clearance for **both PV and CG address.**
8. Contractor to request **FINAL SDGE inspection** via email to VNMApplications@sdge.com. Prior to scheduling final inspection, contractor to submit photos (.jpg or .pdf) of the installation for review to VNMApplications@sdge.com. Photos to include: 1) Entire NGOM installation in one frame with STO letter displayed (both disconnects, NGOM panel, working space showing ground in front of meter). 2) Individual photo of NGOM meter panel showing

required CG address placard. 3) Photos of each disconnect showing required placards with correct verbiage. 4) Photo of site map placard installed at main switchgear. (Note: Second placard on NGOM meter panel if not within line of sight of main switchgear.) 5) Photo of inside of NGOM panel in one frame clearly displaying conductor labels and current flow sticker* (*for CT rated installations). Customer to verify all items on checklist are completed and ensure a qualified electrical worker is present for a voltage test at the final inspection.

9. Upon FINAL SDGE inspection approval, **a meter set will be scheduled**. ETA will be provided to customer. PTO to follow.

- ***Submittal review and site meeting lead times are subject to current workload.
- ****All outstanding issues are visible and can be identified in DIIS.
- All VNM inquiries are to be submitted to VNMApplications@sdge.com. Please include site address and app ID (if available) in subject line.

**SDGE VNM Team**
**E** VNMApplications@sdge.com <image006.png>

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---

**From:** Adam Hammill <adam@aliveindustries.com>
**Sent:** Tuesday, October 31, 2023 1:16 PM
**To:** Netmetering <netmetering@sdge.com>
**Cc:** Dan Wert <danw@aliveindustries.com>; Aaron Spoelhof <aspoelhof@nationalcore.org>; Patrick Meredith <pmeredith@nationalcore.org>; VNMApplications <VNMApplications@sdge.com>
**Subject:** [EXTERNAL] Re: VNEM for Valley Senior Village 337 E. Valley Pkwy., Escondido 92025 APP # 439513

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Dear Netmetering,

We have just received final approval from the AHJ (Escondido) and we have the account and meter numbers as well. You should have received sign-off from the City of Escondido electronically.

The account number is 210000908145

The meter number is 06892738

The account holder name is Ivy Valley Housing Partners LP

Please let us know next steps for completing the VNEM process and getting the NGOM installed.

Sincerely,
Adam Hammill


**Adam Hammill**
Owner/President
**ALIVE Industries, Inc.**
P: (760) 892-5483 x 1M: (760) 877-4759F: (760) 892-5483
A: 2557 Dundee Glen, Escondido, CA 92026
W: www.aliveindustries.com [aliveindustries.com]E: adam@al
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On Apr 12, 2023, at 1:40 PM, VNMApplications <VNMApplications@sdge.com> wrote:

Please see the attached document for instructions on how to submit an interconnection application for a new construction project.

## Requirements:

- Submit the application as "Traditional" (in Step 5)
- A permanent account number for the established premise address must be received by Customer Generation via email (netmetering@sdge.com) before scheduling the Authority Having Jurisdiction (AHJ) inspection for the installation. This will ensure the inspection release is posted to the premise.

## Notices:

- Errors on the name portion of the application will not be corrected. If you provide an incorrect address, it will not be corrected. A new application will be required.
- Increases to system sizes after the application is reviewed and processed will be cancelled. A new application will be required.

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<image007.jpg>

VNM Team / Customer Generation

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---

**From:** Adam Hammill <adam@aliveindustries.com>
**Sent:** Monday, April 3, 2023 10:59 AM
**To:** VNMApplications <VNMApplications@sdge.com>
**Cc:** Dan Wert <danw@aliveindustries.com>; Tiffany Williams <tiffany@aliveindustries.com>; Aaron Spoelhof <aspoelhof@nationalcore.org>; Patrick Meredith <pmeredith@nationalcore.org>
**Subject:** [EXTERNAL] Re: VNEM for Valley Senior Village 337 E. Valley Pkwy., Escondido 92025

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attachments, or provide credentials. Don't delete it. **Report it by using the REPORT SPAM option!**

I apologize for our confusion. Please find site plan and SLD attached. I believe I've added all the notes requested to the single SLD page. Please let me know if anything further is needed, of if you need me to further refine these in any way.

Sincerely,
Adam Hammill

**Adam Hammill**
Owner/President
**ALIVE Industries, Inc.**
P: (760) 892-5483 x 1M: (760) 877-4759F: (760) 892-5483
A: 2557 Dundee Glen, Escondido, CA 92026

W: www.aliveindustries.com [aliveindustries.com]E: adam@aliveindustries.com
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On Apr 3, 2023, at 10:29 AM, VNMApplications <VNMApplications@sdge.com> wrote:

Hi Adam,
All the requested information must be contained on the SLD on one sheet. The SLD is utilized by other departments for reference, therefore, we ensure we are sending accurate information on the one single sheet. Information submitted on emails or additional sheets are difficult to track.

Here is an example of a recent submittal:

<image001.png>

As you can see, the NGOM information is clearly drawn in and labeled. You mention there is no existing HM meter number, you can list "TBD" there. Please add a note with the AC CEC KW rating on this sheet as well. One other note, SDGE does not work with 350-amp panels; it's either 200 or 400 amps.

Please revise accordingly and resubmit. Thank you.

<image002.jpg>

**Rosie**
VNM Team / Customer Generation

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*<image003.jpg>*[facebook.com] <image004.jpg>[twitter.com] <image005.jpg>[link

**From:** Adam Hammill <adam@aliveindustries.com>
**Sent:** Monday, April 3, 2023 9:55 AM
**To:** VNMApplications <VNMApplications@sdge.com>
**Cc:** Dan Wert <danw@aliveindustries.com>; Tiffany Williams <tiffany@aliveindustries.com>; Aaron Spoelhof <aspoelhof@nationalcore.org>; Patrick Meredith <pmeredith@nationalcore.org>
**Subject:** [EXTERNAL] Re: VNEM for Valley Senior Village 337 E. Valley Pkwy., Escondido 92025

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Good morning!

The tap *is,* in fact right there on the yellow line you've highlighted on the SLD, signified by the small "x" marked number 10, and most of the other items you've requested are included in the drawings submitted. I will attach them again here with those areas highlighted.

The customer has not received any bills, as service has not yet been established at the site nor is there en existing meter number, since no meters have been installed. The name on the account should be: **National Community Renaissance**

Please see drawings below where the items in question have been made more clear, and please let me know if anything further is needed in order to proceed.

Sincerely,
Adam Hammill

**Adam Hammill**
Owner/President
**ALIVE Industries, Inc.**
P: (760) 892-5483 x 1M: (760) 877-4759F: (760) 892-5483
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On Apr 3, 2023, at 7:33 AM, VNMApplications <VNMApplications@sdge.com> wrote:

Good morning Adam,
I will work with you to ensure you are able to submit the DIIS application by the 4/14 deadline. Has the house meter been set? If so, please confirm the meter # and the customer of record on the SDGE bill.

Here is what is typically required for a complete VNM submittal:

a. ***A complete submittal includes***:

   1. *Site map identifying electric panel location(s).*

   2. *Complete SLD to include: address, existing SDGE HM meter number, NGOM meter amperage, and system size in AC CEC KW.*

   3. *Customer name as per their most recent SDGE bill.*

   4. **SDGE Advisor will review the submittal.*

After review of the SLD submitted, here is my feedback:

The SLD does not depict a correct tap location for VNM installations:
<image001.png>

As per SDGE Service Standards & Guide page 806.6, the tap is to be located ahead of the main breaker:

<image002.png>

In addition to the tap shown in the wrong location for VNM, the SLD does not depict the NGOM meter and required disconnects. Please revise the SLD to show this information, including the NGOM amperage.

(Here is the link to the SDGE Standards for reference:https://www.sdge.com/sites/default/files/SGe%20%284%29.pdf Generation is in section 800.)

<image003.jpg>

**Rosie**
VNM Team / Customer Generation

Follow us:

*<image004.jpg>*[facebook.com] <image005.jpg>[twitter.com] <image006.j

---

**From:** Adam Hammill <adam@aliveindustries.com>
**Sent:** Sunday, April 2, 2023 6:38 PM
**To:** VNMApplications <VNMApplications@sdge.com>
**Cc:** Dan Wert <danw@aliveindustries.com>; Tiffany Williams <tiffany@aliveindustries.com>; Aaron Spoelhof <aspoelhof@nationalcore.org>; Patrick Meredith <pmeredith@nationalcore.org>
**Subject:** [EXTERNAL] VNEM for Valley Senior Village 337 E. Valley Pkwy., Escondido 92025

**CAUTION! EXTERNAL SENDER - STOP, ASSESS, AND VERIFY**

Do you know this person? Were you expecting this email, any links or attachments? Does the content make sense? If suspicious attachments, or provide credentials. Don't delete it. **Report it by using the REPORT SPAM option!**

Hello,

Sherise Blackwood suggested I send an email to start the VNM process for a project we're working on. I'm sorry to bring you in so late in the process, but we only just recently realized the their utility consultant hadn't included VNM in the services he was providing.

We have been unable to get the account number assigned to the project, so we're hoping you can help us with the temporary account number.

The address is 337 E. Valley Pkwy., Escondido 92025.
This system will be connecting to the main house meter.

Construction is well underway, and we're ready to begin installation of the rooftop PV installation.

The city plan checker required us to install a disconnect outside the building for some unknown reason, but we'd prefer to install the disconnect/meter/disconnect in the electrical room ahead of the custom-designed panel with a factor-integrated line-side tap, if that is acceptable.

Please see attached single-line drawings for the building and the PV. This includes a rooftop and carport PV system that are being permitted separately from each other.

Our most urgent need is to get this locked in for NEM 2, but also, we need to find out exactly what type of virtual net meter will be installed so we can order the correct meter panel.

Please let me know what else is needed in order to proceed.

Sincerely,
Adam Hammill

**Adam Hammill**
Owner/President
**ALIVE Industries, Inc.**
P: (760) 892-5483 x 1M: (760) 877-47
A: 2557 Dundee Glen, Escondido, CA
W: www.aliveindustries.com[aliveindus
CA Lic.: #983966
[facebook.com] [twitte
[linkedin.com] [instagram.com]
**GET QUOTE [ALIVESOLAR.COM]**

This email originated outside of Sempra. Be cautious of attachments, web links, or requests for information.

# Exhibit Z

## deBoer, Krista S

**From:** VNMApplications
**Sent:** Tuesday, November 4, 2025 8:49 AM
**To:** Katie Lahey
**Cc:** MF Interconnections Inbox; Richard Thompson
**Subject:** 1663 Dairy Mart Rd CG -CG ACCT #
**Attachments:** Allocation Form NBT-V Form 142-02784.pdf

Hello,
Thank you for completing the initial joint meet and site walk. During this meeting, the initial NGOM checklist was completed with your team to outline specific installation requirements. The original checklist was provided to the installer in the field.
To help ensure a successful installation, please share this checklist with your team for their reference and alignment.

Please find the CG account number(s) for the following address(es):

- **DIIS Application:**
  - Please proceed to submit application(s) in DIIS ASAP. Attached is a blank NBT-V allocation. A completed NBT-V allocation form will need to be uploaded to each application in step 6.
  - Please submit the DIIS application using the CG address and CG account number provided below
    - Select Virtual-NBT in Step 1 section B of the application.
    - Leave the meter number blank in step 1.
- **Virtual NBT-V Allocation form 142-02784:**
  - Please use the CG assigned address as the GENERATOR address and leave the Generator meter number blank
  - Proceed with submitting the completed Virtual allocation form by uploading to the application in step 6.

| APP ID | CG ACCOUNT # | CG ADDRESSS |
|---|---|---|
| | 210001890569 | 1663 Dairy Mart Rd CG, San Ysidro |

**To avoid delays, reply to this email with the DIIS Application ID number(s) once the application(s) is submitted in DIIS for our team to proceed.**

Thank you,

**Berenice McNamara**
Electric Distribution Analyst
**Customer Generation Department**
E VNMApplications@sdge.com
Follow Us:

For more information about privacy at SDG&E visit sdge.com/privacy.

Exhibit AA

LexisNexis

**User Name:** Krista DeBoer

**Date and Time:** Thursday, November 6, 2025 5:31 PM EST

**Job Number:** 267369376

## Document (1)

1. In the Matter of the Application of Southern Californian Gas Company (U 904 G) for authority to increase rates charged for gas service based on test year 1990 and to include an attrition allowance for 1991 and 1992.  And Related Matter, 1992 Cal. PUC LEXIS 288, 43 CPUC2d 483, Decision No. 92-03-041, Application No. 88-12-047 (Filed December 27, 1988), Investigation No. 89-03-032 (Filed March 22, 1989)

**Client/Matter:** -None-

**Search Terms:** Decision 92-03-041, 1992 Cal. PUC LEXIS 288

**Search Type:** Natural Language

**Narrowed by:**

| Content Type | Narrowed by |
| --- | --- |
| | -None- |

## [1992 Cal. PUC LEXIS 288; 43 CPUC2d 483]

California Public Utilities Commission

March 11, 1992

Decision No. 92-03-041, Application No. 88-12-047 (Filed December 27, 1988), Investigation No. 89-03-032 (Filed March 22, 1989)

***CA Public Utilities Commission*** ***Decisions***

**Reporter**
1992 Cal. PUC LEXIS 288 *; 43 CPUC2d 483

# In the Matter of the Application of Southern Californian Gas Company (U 904 G) for authority to increase rates charged for gas service based on test year 1990 and to include an attrition allowance for 1991 and 1992. And Related Matter

## Core Terms

customer, meter, base line, was, dwelling unit, has, lifeline, heat, multi-family, backbilling, tariff, notify, notification, refund, burden of proof, space, complaint, mail, pipe, eligibility, appliance, residential, electric, water heater, hot water, configure, dwell, verification, retention, message

## Counsel

(See D.90-01-016 for List of Appearances.)

Additional Appearance

John McDonald, for Utility Audit Company, interested party.

**Panel:** Daniel Wm. Fessler, President; John B. Ohanian, Patrica M. Eckert, Norman D. Shumway, Commissioners

**Initial *Decision*:**

## Opinion

OPINION

Summary

This ***decision*** reviews nine meter accounts for alleged failure by Southern California Gas Company (SoCalGas) to assign the correct baseline allowance to a variety of multi-family dwellings.

The Commission grants relief to complainant J. Patrick Costello (Costello) in three cases involving multi-family housing for self sufficient elderly which have individual electric cooking facilities and optional central cooking and dining facilities. In granting the relief the Commission finds that the questions asked by SoCalGas in taking applications for service were not sufficient to make an informed rate assignment.

The Commission denies relief in the remaining six cases because the complainant failed to meet his burden of proof.

Procedural History

On May 8, 1989 Costello filed a complaint in SoCalGas' general rate case (A.88-12-047) alleging that the utility had failed to assign the correct rate schedule and/or provide correct baseline **[*2]** allowances to a variety of multi-family dwellings. This complaint was severed from the rate case and set for separate hearing by the presiding Administrative Law Judge (ALJ). Due to the large number of individual customers Costello represented (approximately 230), SoCalGas sought by motion filed on March 12, 1990 to bifurcate the hearing and consider common questions of law prior to hearing the facts of each individual case. The ALJ ruled on May 4, 1990 that the hearing on Costello's complaint would be limited to a review of nine representative accounts. Both parties agreed to the conduct of the hearing in such manner and submitted written testimony.

Hearing on the nine representative accounts was held before the presiding ALJ on June 28, 1990 in Los Angeles. Opening briefs were filed by Costello and SoCalGas on August 15, 1990. SoCalGas filed a closing brief on October 12, 1990.

Background

In 1976, the Commission established lifeline quantities of electricity and gas necessary to supply the minimum energy needs of average residential users for the end uses specified in the Miller-Warren Energy Lifeline Act (1975). (D.86087, affirmed by D.88651.)

In 1980, the Commission **[*3]** concluded that when a "central facility" [1] provides space heating, water heating, or cooking services to a multi-family complex with individually metered dwelling units, the lifeline allowance for these services should be shifted from the meter serving the dwelling units to the meter serving the central facility (D.92498). [2]

In 1985, the Commission replaced lifeline rates with baseline rates (D.84-12-066). Essentially, baseline rates are a simplification of lifeline rates. Lifeline is end-use oriented. Baseline is not. Baseline is concerned only with the number of dwelling units. It merely requires the application of the authorized baseline allowance per dwelling unit. For purposes of this discussion, it may be assumed that lifeline **[*4]** and baseline are the same.

Gas billed at baseline rates currently costs 48 cents per therm, and at non-baseline rates costs 80 cents per therm. Therefore, it is important to the multi-family complex customer that each meter account be billed its correct baseline allowance.

Discussion

The Commission has issued ***decisions*** in two SoCalGas multi-family baseline billing error cases: D.89-08-008 in Frank Eck v. SoCalGas; and, D.89-09-101, as modified by D.89-12-055, in V. J. Schrader v. SoCalGas. We will summarize the holdings since both parties in this proceeding contend that those ***decisions*** support their respective positions.

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[1] Central facilities are broadly defined by SoCalGas as gas service through a single meter supplying water heating or space heating or both to two or more living units which also have separate meters. Or central facilities may also serve, or only serve, laundry rooms, pools, saunas, recreation buildings/rooms, etc., used by the tenants of a multi-unit complex.

[2] The Commission did not address master metered dwelling units in D.92498.

In Eck, the Commission recognized that a complainant whose own mistake results in his failure to take advantage of a favorable rate under Schedule GM is not eligible for a refund because the utility has billed such a customer in complete accordance with its tariff. And, in denying the complaint, the Commission stated:

"Under SoCalGas' tariff, the central facilities baseline allocation was to operate only prospectively from the date the central facilities customer provided the necessary information to SoCalGas. The notice and customer response **[*5]** requirements embodied in SoCalGas' tariff have been approved by the Commission. Therefore, we cannot require SoCalGas to retroactively adjust complainant's rates and refund him the overcharges resulting from his error." (D.89-08-008, p. 10.)

In Schrader, the customer presented evidence that showed he had provided accurate customer information to SoCalGas albeit years before lifeline was instituted. The Commission made it clear in Schrader that the customer has the duty to show either he had provided accurate information to SoCalGas or that SoCalGas had erred. In finding for Schrader, the Commission, in its order modifying D.89-08-101, stated:

"The preponderance of the little evidence we have in this case leads us to infer that SoCal was notified of the correct number of units but for some reason used a lesser number in calculating the baseline allowance. We, therefore, find that there was a billing error. Tariff Rule 16, which governs the adjustment of SoCal's bills, provides that the utility shall issue a refund or credit to a customer for the result of an overcharge where the utility overcharges a customer as the result of a billing error. Schrader has satisfied **[*6]** his burden of proof in his complaint seeking refunds by demonstrating that a billing error occurred. The complainant does not have the burden of explaining how SoCal's error occurred." (D.89-12-055.)

The evidentiary problem in most multi-family baseline billing error cases is that, due to the utility's document retention policies, the original documents related to the meter accounts are no longer available.

Costello argues that Schrader amounts to a precedent establishing that the burden of proof in determining who is responsible for a billing error lies with the defendant utility, once a customer demonstrates that an error has occurred. As support for his position, Costello notes that the Commission states: "[The complainant] has satisfied his burden of proof in his complaint seeking refunds by demonstrating that a billing error occurred. The complainant does not have the burden of explaining how SoCal's error occurred." (D.89-12-055, p. 2, emphasis added.)

We believe that Costello misconstrues Schrader. In that case the complainant offered a hypothesis as to how SoCalGas made the error at issue. The Commission merely states that it is not necessary for the complainant **[*7]** to offer such hypotheses because the complainant did meet his burden of proof by offering into evidence a main and service construction document which shows that the utility made an error.

Also, Costello argues that in a situation such as the instant case, "where it is established that the customer was not billed according to the Tariff, " the burden simply must be placed on the utility to explain how the error occurred. If SoCalGas can prove that the customer affirmatively caused the error (such as by submitting incorrect appliance information to the utility), a refund should not be issued to the customer. However, according to Costello, if there is no proof as to how the original incorrect baseline allowance was assigned, the utility, as the stronger of the parties to the contract (tariff) , must be held to the higher standard and ordered to pay refunds to the affected customer.

First, we believe that Costello appears to be under the erroneous impression that simply because a customer did not receive all applicable baseline allowances, "it is established that the customer was not billed according to the Tariff. " This is not so. The mere fact that the customer did not receive **[*8]** all applicable baseline allowances does not ipso facto establish that the customer was not billed in accordance with the Tariff. As we discuss later, the customer has the responsibility to provide the utility with all necessary information so that the utility can correctly bill the customer.

Second, as we understand Costello's argument, the utility would be required to indefinitely retain all customer records; and, if the utility failed to produce any documents when called upon to do so, then it must pay refunds if the customer did not receive the correct baseline allocation. We are not persuaded that a utility should be required to retain customer records indefinitely simply for purposes of refuting possible customer claims. In this instance, SoCalGas' record retention period is reasonable.

Third, in a complaint case the burden of proof rests with the complainant. Costello's proposal amounts to holding the utility absolutely liable. We believe that a finding for the complainant, based on absolute liability of the utility, is not consistent with the legislative intent underlying Schedule GM and is not equitable to all ratepayers since they pay such refunds. Further, Public **[*9]** Utilities (PU) Code § 1702 requires that the complaint "[set] forth any act or thing done or omitted to be done by any public utility, including any rule or charge heretofore established or fixed by or for any public utility, in violation or claimed to be in violation, of any provision of law or of any order or rule of the commission."

Rate Schedule GM was a response to Assembly Bill (AB) 167 passed by the Legislature at its 1975-76 regular session, which added Section 739 to the PU Code. The legislative intent underlying AB 167 and PU Code § 739 was analyzed in the Commission ***decisions*** that established *Lifeline Quantities of Electricity and Lifeline Volumes of Gas, 80 CPUC 182*, D.86087 (1979). In D.86087, this Commission recognized the legislative intent underlying AB 167 and PU Code § 739 as follows:

"Presumably the Legislature thought that lower lifeline rates would be passed on to the ultimate utility users through lower rents." (Emphasis added.) *80 CPUC at page 189*.

In the billing disputes now before us, any refund ordered by the Commission would be borne by other ratepayers through the balancing account; [3] and, the property owner or manager complainant would **[*10]** receive a windfall which is not likely to flow through to the utility users (tenants) through lower rents. Such a result would be contrary to the intent of AB 167.

Further, we believe that professionals in the business of apartment building management have a duty to review bills for accuracy. Aside from the various letters and notifications sent to multi-family complex customers by SoCalGas since the inception of lifeline and baseline, customers' bills for Schedule GM have the number of dwelling units receiving baseline allowances clearly printed across the bill. Thus, multi-family complex customers do receive reasonable notice on a monthly basis. On balancing the equities, we are not persuaded that the negligence or oversight of apartment owners or managers should be overlooked to the detriment of all ratepayers.

In summary, complainant has the burden of proving that SoCalGas failed to comply with the provisions of its tariff in rendering its bills and that **[*11]** the alleged overbillings resulted from errors committed by SoCalGas as opposed to those committed by complainant. Stiles v. Pacific Bell, et al., CPUC ***Decision*** 87-12-036, 1987 Cal. CPUC Lexis 80 (1987); Southern California Gas Company Tariff Rule 16; Eck v. Southern California Gas Company, CPUC ***Decision*** 89-08-008 (August 1989).

We now turn to the nine representative cases on which evidence was received.

Case I 19-4325-903-269-18 1244 Valley View Glendale

This is a gas meter account for a separately metered central facility that provides hot water to 31 multi-family dwelling units. Each dwelling unit has an individual meter.

Since September 1986, SoCalGas used 30 multi-family units to determine the daily baseline allowance to the central facility. In April 1988, Costello notified SoCalGas that this account should be billed using 31 multi-family units. SoCalGas verified the claim and billed accordingly as of the following meter reading date.

Costello contends that the account should be backbilled for three years prior to the notification because SoCalGas erred in not billing the correct baseline allocation.

---

[3] In Schrader, while balancing the equities, we erroneously assumed that SoCalGas stockholders would be the beneficiaries. This error is not sufficient to require reversal of Schrader (D.89-09-101, p. 4).

Further, Costello argues that SoCalGas' efforts to ensure **[*12]** that customers are allocated the correct rate and baseline allowance are inadequate. He points out that a central facility meter and the individual meters in a multi-family complex are given related account numbers; therefore, SoCalGas has the ability to cross check the number of dwelling units. Since SoCalGas does not do so, Costello submits that SoCalGas must be held responsible for not assigning the correct number of dwelling units to this central facility.

Costello asserts that aside from mass mailings made in December 1980 and September 1984 when lifeline was implemented, SoCalGas made no additional mass mailings of baseline allowance eligibility questionnaires. Also, SoCalGas employed no follow-up measures with customers who did not return completed forms in 1980 and 1984.

This customer initiated service on October 10, 1975, before lifeline was in effect. The turn-on application, which would show how the customer planned to use gas, is not available. Due to SoCalGas' document retention policy, this type of order is held only five years. There are no other orders on file (i.e., Central Facilities Verification Form, New Business Service Order) that indicate that the customer **[*13]** did not provide the information that caused SoCalGas to assign the account 30 dwelling units instead of 31.

In response to Costello's assertions, SoCalGas states that it attempted to notify all possible customers who may have been affected by lifeline or baseline rate implementation and changes.

In November 1975, SoCalGas sent a letter to all potential master-metered customers, based on premises code and/or billing qualifier (i.e., laundry room, central water heater, etc.) advising customers of the probability of a new multi-family rate becoming effective upon the Commission's ***decision*** to be issued later. The letter stated that the new rate schedule may result in a lower cost per dwelling unit, and the customer was requested to provide information regarding the number of dwelling units served.

In early 1976, SoCalGas sent a second letter to the previously identified customers who did not respond to the November 1975 letter. This second letter asked for a response by August 1976.

In early 1976, SoCalGas sent a letter to those customers who had responded to one of the prior letters. This letter asked for more extensive information by August 1976.

Next, SoCalGas had two mailings **[*14]** in December 1980. In the first mailing, letters and questionnaires were sent to 50,000 probable central facility customers requesting information needed to code their accounts properly. In the second, business reply postcards were mailed as bill inserts to 1,100,000 possible central facility accounts. Bill messages appeared at the same time addressing the issue.

When a postcard was returned, SoCalGas mailed a central facility questionnaire to the responding customer to provide SoCalGas with the information necessary to properly code the account.

In March 1981, SoCalGas mailed bill inserts to individually metered tenants explaining the possible reduction of lifeline allowances with the next bill.

In April 1981, SoCalGas printed a reduction of lifeline allowance message on affected tenants' bills. The message continued until all lifeline allowance reductions had occurred.

During July and August 1984, SoCalGas conducted an "inhouse" premises code survey. The survey attempted to identify each premises as Individually Metered Residential, Master Metered Residential, or Non-residential. Corrections to rates were made where applicable and central facility accounts identified during **[*15]** the survey were coded and rebilled.

SoCalGas initiated another mass mailing of central facility questionnaires, the same as those mailed in 1980, in September 1984.

Starting in August 1987 and thereafter, all first bills of newly active accounts show a message explaining under which rate that account is billed.

Beginning in 1988, on an annual basis, bill messages appear on all GR (Residential) , GMC (Multi-family, non-essential common facility), GME (Multi-family, essential common facility), and GN10 (commercial) accounts explaining the rate at which the accounts are billed. GS (submetered) accounts receive an annual bill insert.

In addition, since lifeline went into effect, each bill has shown the number of master-metered dwelling units and/or central facility units receiving the multiple baseline allowance clearly printed in large block letters on the face of each monthly bill. Therefore, SoCalGas contends that this customer received notification, for 20 months, that the baseline credit was for 30 dwelling units, not 31 units.

SoCalGas' argues that there is no evidence of utility error; therefore, there should be no backbilling.

We conclude that complainant has not established **[*16]** that the utility made a billing error. Simply because a billing error has occurred, that does not ipso facto constitute "utility billing error". Further, we are not persuaded by the complainant's argument that the utility has a duty to crosscheck all the accounts in a multi-family complex. That would shift the responsibility to the utility.

Under SoCalGas Tariff Schedule GM Special Condition 3, baseline allowances are available to qualified customers after they notify the utility of the number of dwelling units. Schedule GM Special Condition 4 requires the customer to notify the utility of any change in the number of units.

Further, we believe that SoCalGas has made a reasonable effort to notify multi-family complex customers of the availability of baseline allowances. The tariff is clear that it is the customers' responsibility to notify the utility regarding the correct number of dwelling units. Therefore, we conclude that a complainant whose own mistake or oversight results in his failure to take advantage of a favorable rate is not eligible for a refund. The utility has billed the customer in accordance with its tariff. The complainant has not met his burden **[*17]** of proof; therefore, we deny complainant's request for backbilling.

Case II 10-3296-747-22 349 S. Arroyo San Gabriel

This is an account for a separately metered central facility that provides hot water to 12 multi-family dwelling units which receive gas for cooking and space heating from another master meter.

In July 1981, based on a form completed by the customer, SoCalGas assigned the account to Rate Schedule GM-C (non-baseline) on the basis that the meter only provided swimming pool heating and laundry room services, which do not qualify for baseline allowances. According to the completed form, this central facility did not provide water heating to the multi-family units; therefore, the central facility meter did not receive a baseline allowance. Instead, the full baseline allowance was applied to the master meter serving the 12 multi-family units. As a result, the meter serving the central facility was billed a large amount of expensive non-baseline therms for water heating, while the master meter that serves cooking and space heating needs was assigned an "unusable" baseline allowance.

Costello notified SoCalGas in July 1988, that this account qualified for the baseline **[*18]** allowance since it was a central facility providing hot water to 12 multi-family dwelling units. SoCalGas verified the notification and the meter account was billed accordingly as of the following meter reading date. The baseline allowance of the master meter serving the 12 dwelling units was reduced to reflect the shift of the baseline allowance to the central facility.

Costello does not contest SoCalGas' refusal to backbill in this instance. He agrees that in a similar situation, where it was shown that the customer provided incorrect information, the Commission ruled against the customer (Eck v. SoCalGas, D.89-08-008). However, Costello believes that this account is not typical. He asserts that in 300 or more claims, SoCalGas has produced evidence of incorrect information submitted by the customer in 6 instances only.

SoCalGas submits that the error was clearly the customer's and, as such, it is not considered a billing error under its Rule 16.C.

As conceded by complainant, we agree that there should be no backbilling.

Case III 05-2434-727-600-17 7215 S. Bright Ave. Whittier

This is an account for a central facility that provides hot water and serves central **[*19]** cooking and dining room facilities to a 155-unit residential facility housing self-sufficient elderly on a permanent basis. The dwelling units are self-contained and each is equipped with individual electric cooking facilities. The building has electric space heating. Service was initiated in 1973. The turn-on application is no longer available.

Prior to 1984 this account was on Schedule GM and did receive a lifeline allowance for providing gas water heating to a multi-family complex.

SoCalGas inspected the facilities in December 1983 and concluded that this was a retirement home and that meals were included in the rent. Therefore, based on its Tariff Rule 1, Definitions, Family Dwelling Unit, SoCalGas concluded that this was a business use of gas and reassigned the account to Schedule GN1, which does not have a baseline allowance.

This rate assignment was not disputed until an informal complaint was filed with the Commission staff on April 24, 1986 by a Thomas Hobbs. The investigation sustained what had been determined in 1984 and the Commission staff closed its file on the complaint in June 1986.

Costello notified SoCalGas in March 1988 that he believed this account should **[*20]** be billed under Rate Schedule GM and receive a baseline allowance. Based on the previous investigation, SoCalGas denied the request. Due to Costello's insistence, SoCalGas performed another field inspection on December 18, 1989. Based on that inspection, the account was assigned the GM rate and rebilled from May 1986 (when the informal complaint was filed with the staff) to January 1990.

SoCalGas' explanation for the different conclusion is that the December 1989 inspection determined that the costs for the central dining facilities are not included in the tenants' rent. The residents pay only for the residential apartment use and, therefore, should receive a baseline allowance. Nevertheless, based on the original information provided by the customer in 1983-84, SoCalGas believes there was no error on the utility's part.

Costello disagrees. First, Costello argues that the SoCalGas form used in 1983-84 does not ask the right questions so that the utility can make an informed rate assignment (Exhibit 257, Attachment 14). The form does not ask if the dwelling units are self-contained, whether there are individual cooking facilities in each unit or whether there are individual **[*21]** electric appliances (of any kind) in the dwelling units. Costello, believes that this information is crucial, since without individual cooking facilities, this establishment would not meet the Tariff Rule 1 definition of Family Dwelling Unit and, consequently, would be assigned to Rate Schedule GN, instead of the much more favorable baseline Rate Schedule GM.

Secondly, according to Costello, SoCalGas has consistently misinterpreted Tariff Rule 1 in rate assignments for Housing and Urban Development subsidized housing establishments for the elderly that are equipped with both optional central cooking facilities and individual electric cooking facilities. SoCalGas was classifying such buildings as "rest homes". It was not until Costello clarified the discrepancy between SoCalGas' rate assignments for these types of establishments and residential hotels that this account was placed on the correct rate.

Therefore, Costello argues that the account should be backbilled 3 years from May 1986, when the informal complaint was filed.

We agree with Costello that SoCalGas has a responsibility to provide and use forms that request all the necessary information so that the utility may make **[*22]** an informed rate assignment. Failure to do so is utility billing error.

Also, we believe that in 1983, SoCalGas' standard questions for taking applications from such customers resulted in routine disqualification from baseline allowances. One of the first questions asked by the utility representative is, "Will this be business or residential service?" If told by the applicant that "it will be business", the applicant had little likelihood of receiving a baseline allowance because SoCalGas was routinely denying baseline benefits to such establishments "because gas was used for business purposes."

Further, this customer was correctly on the GM schedule prior to 1984 before SoCalGas, following its inspection, reassigned the account to a non-lifeline rate schedule. Apparently, SoCalGas was unduly influenced by the presence of commercial cooking equipment and central dining facilities; therefore, it overlooked the individual electric cooking facilities.

In summary, we believe that SoCalGas' 1983 questionnaire for signing up new customers did not adequately address the intent of lifeline/ baseline legislation that each self-contained residential dwelling unit receive a lifeline/ baseline **[*23]** allowance (D.86087, affirmed by D.88651).

We conclude that complainant has met his burden of proof; therefore, complainant's request for backbilling is granted.

Case IV 06-2803-381-290-28 (F4) 8600 Denver Ave. Los Angeles

This account is one of 15 meters at an apartment complex known as Sonya Gardens.

Costello reviewed the gas bills for this complex and determined that the meters serving the central water heaters were not receiving the appropriate master meter baseline allowance for the dwelling units served. According to Costello, the 15 accounts were receiving baseline allowances for only 52 dwelling units instead of 60 dwelling units.

On January 26, 1988, Costello requested backbilling on the meter accounts with central water heaters. Also, he requested that all consumption on the 15 meters be combined for future billings because "no one has been able to pinpoint which units and which appliances are serviced by each meter. "

Costello argues that SoCalGas must be held responsible for knowing that the gas plumbing configuration at this complex is not specifically addressed by its tariff. The tariff does not specifically address a situation where a central water heater **[*24]** connected to a master meter serving a block of dwelling units supplies hot water to another block of dwelling units that have their separate master meter. As a result, the customer is billed at higher non-baseline rates for therms used for hot water heating which should be billed at baseline rates.

SoCalGas denied Costello's request for backbilling and future combined meter reading for billing.

SoCalGas states that this particular account is comprised of eight family dwelling units served by one meter. According to SoCalGas, the account is billed appropriately under Rate Schedule GM.

Of the other 14 accounts in the same apartment complex, SoCalGas contends that all are also appropriately billed under Rate Schedule GM. Three of the 14 accounts are comprised of multi-family dwelling structures, with each structure served by a single meter. The groups respectively serve two, four, and nine dwelling units.

Five other accounts in the complex are billed according to Special Condition 3 of Rate Schedule GM. These five accounts consist of four individually metered dwelling units each with its own cooking and heating. The fifth meter serves a combination of the central water **[*25]** heater for the four individually metered accounts plus cooking, heating, and water heating for one unit on the same meter.

The last six accounts are comprised of two groups of three family dwelling units. Each of these groups is served by a single meter. Each meter receives its daily baseline allowance times the number of dwelling units on its meter, in accordance with Rate Schedule GM. There is, however, only one water heater for each group of three.

SoCalGas acknowledges that the customer's piping configuration is not specifically covered in its current tariff. However, SoCalGas contends that the accounts are billed in accordance with its filed Tariff Rate Schedule GM, there is no billing error by the utility and, therefore, backbilling is not justified.

As we stated with regard to Case I above, it is the customer's responsibility to notify the utility of the correct appliances connected to each meter in a multi-family complex. This responsibility was recognized by the Commission in the lifeline ***decision*** (D.86087, p. 57). Also SoCalGas' Tariff Rule 19 states:

"Customers may be eligible for service under new and optional schedules or rates subsequent to notification by **[*26]** the customer and verification by the Utility of such eligibility". (Tariff Rule 19, emphasis added.)

Further, we conclude that the lack of a tariff option that allows this customer to take full advantage of all baseline allowances in conjunction with his particular gas piping configuration does not constitute utility billing error. It is the customer's responsibility to install all piping necessary to take advantage of available utility tariffs.

Complainant has failed to sustain his burden of proof to establish that SoCalGas did not bill in accordance with its filed tariff; therefore, we deny complainant's request for backbilling.

Case V 05-7370-460-532-54 474 S. Hartford Los Angeles

In December 1987, Costello notified SoCalGas that this central facility master meter account should receive 24 baseline billing units instead of 20. SoCalGas verified the request, made the change, and billed the account accordingly as of the following meter reading date.

Service was initiated in 1974, before lifeline was in effect. Due to SoCalGas' records retention policy, the turn-on application is not available. There are no other orders on file that indicate the customer did not **[*27]** provide the information which caused SoCalGas to assign the 20 units. Based on the billing code, SoCalGas contends that it would have sent the customer the letters discussed previously requesting information on appliances and central facilities. Costello contends that such letters were not received by the customer.

The customer's bills from at least December 5, 1980 through December 1987 displayed, "Multiplied For 20 Central Facility Units". (The same message appears currently with 24 as the number of units served.) Therefore, SoCalGas argues that the customer received monthly notification, at least 85 times that it was given credit for 20 units, not 24.

SoCalGas contends that there is no utility error; therefore, backbilling is not justified.

We do not find Costello's argument persuasive. First, we believe that SoCalGas' tariff is clear; the customer is entitled to receive service under new or optional rates "subsequent to notification by the customer" (Tariff Rule 19).

Second, we are not persuaded by complainant's assertions that the customer did not receive the letters sent by SoCalGas notifying the customer regarding the availability of lifeline/ baseline allowances. **[*28]** Regardless, the customer certainly received notification on his bill of the number of dwelling units used for billing purposes each month. We believe that apartment owners and managers should be held to a duty of due care to scrutinize their bills carefully. In weighing the equities, we are not persuaded that the ratepayers should be expected to bear the financial burden of negligence or oversight on the part of apartment owners or managers.

Complainant has failed in his burden of proof to establish that there is utility billing error; therefore, we deny complainant's request for backbilling.

Case VI 14-4322-845-472-12 1256 Boynton Glendale

Since the introduction of lifeline in 1976, this central facility account was not allocated the correct number of baseline units. After being notified, SoCalGas verified the request and corrected the account from Schedule GR (single unit master meter) to Schedule GM with a water heating baseline allowance for 20 units. The correction was made in October 1987.

The 20 dwelling units, which are individually metered, each received a full baseline allowance before the correction. Thereafter, the baseline component for water heating was **[*29]** shifted to the central facility.

Costello points out that the central facility was erroneously assigned to Schedule GR. For such accounts, the billing assumptions were not printed on the bill. It was not until 1988 that SoCalGas began printing an annual bill message to inform the (GR) customer about the schedule he was on. Costello argues that the customer did not contribute to the error or fail to read his bills carefully; therefore, he requests backbilling.

Service was established in 1965, before lifeline was in effect. Because of SoCalGas' document retention policy, the turnon document is not available.

SoCalGas asserts that based on the customer's billing code, the customer would have been sent the letters discussed previously, which explained lifeline and requested information on the customer's appliances and central facilities. SoCalGas points out that the second letter requests a response by August 27, 1976, and it states ". . . without this information we must assume each meter serves one dwelling unit and, in accordance with the California Public Utilities Commission order, can only assign one 'lifeline' allowance. " Therefore, when this customer did not respond to **[*30]** either mailing in 1975 or 1976, SoCalGas assigned the account to Schedule GR which provides only one lifeline allowance.

SoCalGas contends that there is no utility error; therefore, there should be no rebilling.

We are not persuaded by complainant's argument that because the meter account was "erroneously" on Schedule GR, and since meter accounts on that rate schedule did not have the same monthly notice as for Schedule GM, the responsibility for informing the utility regarding the customer's plant equipment should be overlooked. As we stated with regard to Case I and Case IV above, it is the customer's responsibility to notify the utility (Tariff Rule 19).

Complainant has failed in his burden of proof to establish that SoCalGas did not bill in accordance with its filed tariff; therefore, we deny complainant's request for backbilling.

Case VII 06-2104-714-100-18 (E1) 600-12 N. Broadway Los Angeles

The establishment is a 270-unit residential facility housing self-sufficient elderly on a permanent basis. The units are self-contained, and each is equipped with individual electric cooking facilities. This meter provides gas to both central water heating and central heating/ cooling **[*31]** appliances. Also, the establishment has a central cooking facility which receives gas through a different meter.

Service was initiated in December 1984. The turn-on application indicates that gas will be used to serve senior citizen housing that has six commercial ranges, three steam tables, eight dryers, two boilers, and two furnaces. Based on the commercial appliance information on the application, SoCalGas concluded that the account did not qualify for a residential rate. SoCalGas billed it under Schedule GN-1 which is a commercial rate that is not allocated a baseline allowance.

In November 1987, Costello informed SoCalGas that the account was billed under the wrong rate schedule. SoCalGas verified the information and changed the account to Schedule GM (with 270 master meter baseline units) as of the following meter reading date.

Costello requests backbilling to the date of turn-on. He states that since the 1984 turn-on date, there has been no change in the nature or character of service at this establishment. This account has met all requirements for assignment to Schedule GM with a master meter baseline allowance for 270 units.

Costello argues that a primary cause **[*32]** of the error was the inadequacy of the form used by SoCalGas to collect rate eligibility information concerning this type of establishment. As discussed with regard to Case III, the form does not ask if the dwelling units are self-contained and have individual electric cooking appliances.

As we concluded in Case III above, it is the responsibility of the utility to provide and use forms that request all the necessary information so that the utility may make an informed rate assignment. Such failure is utility billing error.

As in Case III, SoCalGas appears to have been unduly influenced by the presence of commercial cooking equipment, and overlooked the individual electric cooking facilities.

We conclude that complainant has met his burden of proof; therefore, complainant's request for backbilling is granted.

Case VIII 05-2434-727-6001-7 7215 S. Bright Ave. Whittier

This is the same establishment discussed under Case III above; therefore, the facts will not be repeated.

As we decided in Case III, this account should be backbilled because the SoCalGas questionnaire did not ask the right questions so that an informed rate assignment could be made. The complainant has **[*33]** met his burden of proof.

Case IX 01-2622-931-464-32 725 Garnet Street Torrance

This establishment is a residential apartment building with four master meters. There are 61 dwelling units on the premises. Each unit receives gas for cooking and space heating from one of the four master meters, as well as hot water from one of two central gas water heaters on the premises.

-- Meter (A) 01-2622-931-4603-6 provides gas for cooking and space heating to 21 units.

-- Meter (B) 01-2622-931-462-34 provides gas to a central water heater serving 14 units. This meter also supplies gas directly to the 14 units for cooking and space heating.

-- Meter (C) 01-2622-931-464-32 provides gas to a central water heater serving 47 units. This meter also supplies gas directly to 11 of the 47 units for cooking and space heating.

-- Meter (D) 01-2622-931-466-30 provides gas to 15 units for cooking and space heating. (Exhibit 257, pp. 37 and 38.)

Prior to July 1987, SoCalGas billed each meter separately and assigned: Meter (A) a 21-unit master meter baseline allowance, Meter (B) a 14-unit master meter baseline allowance, Meter (C) an 11-unit master meter baseline allowance, and Meter (D) a 15-unit **[*34]** master meter baseline allowance. The cumulative baseline allowance assigned to the four accounts totaled 61 master meter baseline units, which corresponds exactly to the total number of dwelling units and overall appliance configuration at the building (all 61 dwelling units do receive gas for cooking and space heating as well as hot water from central gas hot water heaters).

However, Costello argues that in reality, the baseline allowance assigned to the complex was in error because three of the four meters were assigned incorrect individual baseline allowances. Meters (A) and (D) received a baseline allowance for cooking, space heating, and water heating, although they are only providing gas for cooking and space heating. Thus, the customer was allocated baseline allowance on the two meters that he rarely, if ever, used. Meter (C) represents the opposite situation. This meter received a baseline allowance for serving only 11 units with gas for cooking, space heating, and water heating. Actually, this meter served an additional 36 dwelling units with water heating. As a result, the customer was always billed for a large amount of expensive non-baseline therms on Meter (C), **[*35]** while he was assigned an excessive unusable baseline allowance on Meters (A) and (D). The net result was that the customer was significantly overcharged for gas used at the complex.

Costello contends that SoCalGas made an error because it did not assign the proper master meter baseline allowance to one of the four meter accounts -- Meter (C), which should receive 47 baseline units instead of 11.

According to Costello, SoCalGas should know that there are fewer central water heaters on the premises than there are master meters. Therefore, SoCalGas should be held responsible for knowing, from the day the meters were installed, that its Rate Schedule GM did not specifically accommodate such a metering configuration. He requests backbilling for three years from the date of notification.

As an accommodation to the customer, after notification and verification, SoCalGas in October 1987 combined the meter readings of the four master meters in the complex so that the full baseline allowance could be utilized by the central facilities. The accommodation was made because the present Rate Schedule GM does not specifically accommodate central facilities that serve dwelling units served **[*36]** by another master meter.

Service was initiated in August 1974, before lifeline was in effect. Because of SoCalGas' document retention policy, the original turn-on documents are not available. SoCalGas asserts that based on its premises code, this account would have been mailed one or more of the notifications discussed previously, that informed customers of the new Rate Schedule GM and requested information on appliances and meters.

SoCalGas' position is that this account has been billed according to Rate Schedule GM and there has been no billing error by the utility. Therefore, backbilling the account prior to notification in August 1987 under combined billing is not justified.

Essentially, Costello's argument is that SoCalGas' tariff provides baseline allowances equal to the number of units served from the meter, without regard to service provided by other master meters. On the other hand, SoCalGas' interpretation of its tariff is that there should be no more baseline allowances than there are dwelling units.

In other words, notwithstanding that there are 61 dwelling units in the complex, Costello contends that pursuant to SoCalGas' tariff, the customer should receive **[*37]** 97 baseline allowances; SoCalGas' position is that the customer received 61 baseline allowances, which corresponds with the number of dwelling units in the complex.

For example, taking Costello's argument to its logical conclusion, if an apartment building within a complex receives gas service from three separate master meters for each of these functions: cooking, water heating, and space heating, respectively, the building would receive 3 times more baseline allowances than there are living units. This result is obviously unfair to all SoCalGas' other ratepayers who would subsidize the additional baseline allowances. Also, we are certain that the Legislature did not intend such a result when it enacted lifeline and baseline legislation.

Service to this apartment complex is provided under Schedule GM Multi-family Service -- Special Condition 2 applicable to dwelling units that are not separately metered. Special Condition 2 does not contain the statement: "[eligibility] for service under this provision is available subsequent to notification by the customer and verification by Utility." However, Special Condition 3, applicable to dwelling units that are separately metered, **[*38]** does contain this language. However, we are not persuaded that the absence of such language in Special Condition 2 shifts the responsibility to the utility of ascertaining the customer's own piping configuration so that the utility may allocate baseline allowances. [4]

Also, SoCalGas' Tariff Rule 19 states:

". . . In the event of the adoption by the Utility of new or optional schedules or rates, the Utility will take such measures as may be practicable to advise those of its customers who may be affected that such new or optional rates are effective. Customers may be eligible for service under new and optional schedules or rates subsequent to notification by the customer and verification by the Utility of such eligibility. . . ." (Rule 19, effective June 5, 1982, emphasis added.)

We are not persuaded that absence of the "subsequent to notification" language in Special Condition 2 is significant since SoCalGas Rule 19, in effect, governs service taken under Special Condition 2 or 3.

Further, Schedule GM-Special Condition 4 states:

"It is the responsibility of the customer to advise the Utility within 15 days following any change in the submetering arrangements or the number **[*39]** of dwelling units or mobile home spaces provided gas service." (Special Condition 4, emphasis added.)

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[4] Schedule GM-Special Conditions 2 and 3 provide baseline allowances "per residence".

There is no reason why Special Condition 4 should not apply to service taken under either Special Condition 2 or 3.

We discussed previously the steps SoCalGas took to advise apartment owners of the availability of lifeline and baseline allowances. We believe that the record in this proceeding fully supports a finding that SoCalGas took reasonable measures to notify building owners, managers, and landlords. One of the many notices states:

"Attention -- Building Owners, Managers, Landlords.

"The California Public Utilities Commission has ordered us to modify our rate schedules for lifeline uses of gas served through one meter to two or more dwelling units. This change provides that the therms allowed in each usage block will be multiplied by the number of qualified dwelling units served by one meter.

"If the gas meter which supplies the service address shown on the enclosed bill provides gas service to two or more dwelling units, please complete and mail this postpaid card now. **[*40]** We will mail a verification form to obtain the additional information required to determine the appropriate rate schedule for this meter. . . ." (Exhibit 260, Attachment 4, business reply card (emphasis added).)

Furthermore, Costello does not contend that the customer provided SoCalGas with information on the customer's piping arrangement. Costello simply contends that SoCalGas should have found out regarding the unique piping arrangements. We are not persuaded that a utility is required to look beyond the meter to ascertain the customer's piping arrangements, unless specifically requested to do so by the customer. The record is clear that in October 1987, when Costello notified SoCalGas, it did accommodate the customer after receiving notification.

As we concluded for Case IV, the lack of a tariff option that allows a customer to take full advantage of all baseline allowances in conjunction with his/her particular gas piping configuration is not utility billing error. It is the customer's responsibility to install all piping necessary to take advantage of available utility tariffs and to inform the utility of the piping arrangement.

Complainant has failed in his burden of **[*41]** proof to establish that SoCalGas did not bill in accordance with its filed tariff; therefore, we deny complainant's request for backbilling.

Findings of Fact

1. The meter accounts reviewed in this ***decision*** involve complaints of alleged failure by SoCalGas to assign the correct baseline allowance to central facilities which provide hot water to a variety of multi-family dwellings.

2. Complainant, in effect, argues that SoCalGas is absolutely responsible for correctly applying baseline allowances to each of its multi-family complex customers' particular circumstances.

3. SoCalGas' Tariff Rule 19 states:

"Customers maybe eligible for service under new and optional or rates subsequent to notification by the customer and verification by the utility of such eligibility." (Rule 19, effective 1982, emphasis added.)

4. Under SoCalGas Tariff Schedule GM Special Condition 3, baseline allowances are available to qualified customers after they notify the utility of the number of dwelling units. Schedule GM Special Condition 4 requires the customer to notify the utility of any change in the number of units. Special Condition 2 does not contain the "notification" language. **[*42]**

5. In Eck and Schrader, the Commission affirmed that where a customer has failed to notify SoCalGas of the proper number of dwelling units served, there will be no backbilling to adjust for the customer's error or failure to notify the utility.

6. Complainant alleges that SoCalGas has not properly communicated the availability of lifeline/ baseline allowances to multi-family complex customers.

7. SoCalGas has provided a detailed summary of its efforts to communicate the availability of lifeline/ baseline allowances to multi-family complex customers (Exhibit 259).

8. Since lifeline went into effect, each month, customer bills for Schedule GM multi-family service have this sentence in block letters across the bill: "MULTIPLIED FOR -- MASTER METER LIVING UNITS".

Conclusions of Law

1. SoCalGas' efforts since 1975 to communicate the availability of lifeline/ baseline allowances to multi-family complex customers are reasonable.

2. In 1983, the forms used by SoCalGas to make rate assignments for residential facility housing for self-sufficient elderly were not adequate to allow informed ***decisions*** to be made on lifeline/ baseline eligibility.

3. It is the customer's **[*43]** responsibility to advise the utility of the correct number of living units in an apartment complex and to notify the utility of piping arrangements involving special facilities.

4. SoCalGas' customer records retention period is reasonable.

5. Simply because a multi-family customer does not receive all baseline allowances, that ipso facto is not utility billing error.

6. The failure of a multi-family customer to take advantage of a rate or condition of service is not utility billing error.

7. The lack of a tariff option that enables a customer to take maximum advantage of available baseline allowances in conjunction with the customer's particular piping configuration is not utility billing error. It is the customer's responsibility to install all piping necessary to take advantage of available utility tariffs.

8. SoCalGas' Tariff Schedule GM, in conjunction with Rule 19, requires the customer to inform the utility of the correct number of dwelling units, or any change in the number, to receive the proper baseline allowance.

9. The customer obligations contained in SoCalGas Schedule GM in Rule 19 are reasonable. Since it is the owner or manager of a multi-family complex **[*44]** who is in the best position to ascertain the number of dwelling units on his property, it is reasonable to place the burden on such customers to accurately notify SoCalGas as to the number of units attached to each master meter.

10. The burden of proof is on the complainant to show that the utility has not billed in accordance with its filed tariff.

11. In weighing the equities, it is not reasonable to overlook the negligence or oversight of apartment owners or managers in scrutinizing their bills, since any refunds are charged to all ratepayers.

12. Complainant has met his burden of proof in Case III, Case VII, and Case VIII (which is the same establishment as in Case III). Failure of the utility to use adequate forms, so that an informed rate assignment can be made, is utility billing error.

13. In Case III, SoCalGas should backbill up to 3 years from the date of notification, which is May 1986 when the informal complaint was filed.

14. In Case VII, SoCalGas should backbill for 3 years from the date of notification which is November 1987.

15. Since Case VIII involves the same facility as Case III, the backbilling for Case VIII should be in conjunction with the backbilling **[*45]** for Case III.

16. Complainant has not met his burden of proof with respect to Case I, Case II, Case IV, Case V, Case VI, and Case IX. There should be no backbilling in these cases.

17. The nine cases in which evidence was received are representative of approximately 230 cases pending by Costello. SoCalGas should settle those cases on the basis of the Commission's findings in this ***decision***.

18. All refunds should reflect the time value of money and should be made with interest at the three-month commercial paper rate up to the date of refund.

ORDER

IT IS ORDERED that:

1. With respect to Case III, Case VII, and Case VIII, Southern California Gas Company (SoCalGas) shall backbill these accounts up to 3 years from the date of notification that the account was entitled to a baseline allowance. The refund shall be made with interest up to the date of refund.

2. SoCalGas shall backbill and make refunds with interest, on all accounts that are similar to Case III and Case VII.

3. With respect to Case I, Case II, Case IV, Case V, Case VI, and Case IX, there shall be no backbilling on these cases and other similar cases.

4. Consistent with the Commission's findings in **[*46]** the nine cases reviewed, SoCalGas shall expeditiously backbill where appropriate and inform Costello with regard to the disposition of the pending cases, within 60 days of the date of this ***decision***.

5. All refunds shall be made with interest at the 3-month commercial paper rate published by the Federal Reserve Bank (G-13).

This order is effective today.

Dated March 11, 1992, at San Francisco, California.

CA Public Utilities Commission ***Decisions***

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End of Document

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**User Name:** Krista DeBoer

**Date and Time:** Thursday, November 6, 2025 5:31 PM EST

**Job Number:** 267369376

## Document (1)

1. In the Matter of the Application of Southern Californian Gas Company (U 904 G) for authority to increase rates charged for gas service based on test year 1990 and to include an attrition allowance for 1991 and 1992. And Related Matter, 1992 Cal. PUC LEXIS 288, 43 CPUC2d 483, Decision No. 92-03-041, Application No. 88-12-047 (Filed December 27, 1988), Investigation No. 89-03-032 (Filed March 22, 1989)

**Client/Matter:** -None-

**Search Terms:** Decision 92-03-041, 1992 Cal. PUC LEXIS 288

**Search Type:** Natural Language

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| Content Type | Narrowed by |
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| | -None- |

# [1992 Cal. PUC LEXIS 288; 43 CPUC2d 483]

California Public Utilities Commission

March 11, 1992

Decision No. 92-03-041, Application No. 88-12-047 (Filed December 27, 1988), Investigation No. 89-03-032 (Filed March 22, 1989)

***CA Public Utilities Commission*** ***Decisions***

**Reporter**
1992 Cal. PUC LEXIS 288 *; 43 CPUC2d 483

## In the Matter of the Application of Southern Californian Gas Company (U 904 G) for authority to increase rates charged for gas service based on test year 1990 and to include an attrition allowance for 1991 and 1992. And Related Matter

## Core Terms

customer, meter, base line, was, dwelling unit, has, lifeline, heat, multi-family, backbilling, tariff, notify, notification, refund, burden of proof, space, complaint, mail, pipe, eligibility, appliance, residential, electric, water heater, hot water, configure, dwell, verification, retention, message

## Counsel

(See D.90-01-016 for List of Appearances.)

Additional Appearance

John McDonald, for Utility Audit Company, interested party.

**Panel:** Daniel Wm. Fessler, President; John B. Ohanian, Patrica M. Eckert, Norman D. Shumway, Commissioners

**Initial *Decision*:**

## Opinion

OPINION

Summary

This ***decision*** reviews nine meter accounts for alleged failure by Southern California Gas Company (SoCalGas) to assign the correct baseline allowance to a variety of multi-family dwellings.

The Commission grants relief to complainant J. Patrick Costello (Costello) in three cases involving multi-family housing for self sufficient elderly which have individual electric cooking facilities and optional central cooking and dining facilities. In granting the relief the Commission finds that the questions asked by SoCalGas in taking applications for service were not sufficient to make an informed rate assignment.

The Commission denies relief in the remaining six cases because the complainant failed to meet his burden of proof.

Procedural History

On May 8, 1989 Costello filed a complaint in SoCalGas' general rate case (A.88-12-047) alleging that the utility had failed to assign the correct rate schedule and/or provide correct baseline **[*2]** allowances to a variety of multi-family dwellings. This complaint was severed from the rate case and set for separate hearing by the presiding Administrative Law Judge (ALJ). Due to the large number of individual customers Costello represented (approximately 230), SoCalGas sought by motion filed on March 12, 1990 to bifurcate the hearing and consider common questions of law prior to hearing the facts of each individual case. The ALJ ruled on May 4, 1990 that the hearing on Costello's complaint would be limited to a review of nine representative accounts. Both parties agreed to the conduct of the hearing in such manner and submitted written testimony.

Hearing on the nine representative accounts was held before the presiding ALJ on June 28, 1990 in Los Angeles. Opening briefs were filed by Costello and SoCalGas on August 15, 1990. SoCalGas filed a closing brief on October 12, 1990.

Background

In 1976, the Commission established lifeline quantities of electricity and gas necessary to supply the minimum energy needs of average residential users for the end uses specified in the Miller-Warren Energy Lifeline Act (1975). (D.86087, affirmed by D.88651.)

In 1980, the Commission **[*3]** concluded that when a "central facility" [1] provides space heating, water heating, or cooking services to a multi-family complex with individually metered dwelling units, the lifeline allowance for these services should be shifted from the meter serving the dwelling units to the meter serving the central facility (D.92498). [2]

In 1985, the Commission replaced lifeline rates with baseline rates (D.84-12-066). Essentially, baseline rates are a simplification of lifeline rates. Lifeline is end-use oriented. Baseline is not. Baseline is concerned only with the number of dwelling units. It merely requires the application of the authorized baseline allowance per dwelling unit. For purposes of this discussion, it may be assumed that lifeline **[*4]** and baseline are the same.

Gas billed at baseline rates currently costs 48 cents per therm, and at non-baseline rates costs 80 cents per therm. Therefore, it is important to the multi-family complex customer that each meter account be billed its correct baseline allowance.

Discussion

The Commission has issued ***decisions*** in two SoCalGas multi-family baseline billing error cases: D.89-08-008 in Frank Eck v. SoCalGas; and, D.89-09-101, as modified by D.89-12-055, in V. J. Schrader v. SoCalGas. We will summarize the holdings since both parties in this proceeding contend that those ***decisions*** support their respective positions.

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[1] Central facilities are broadly defined by SoCalGas as gas service through a single meter supplying water heating or space heating or both to two or more living units which also have separate meters. Or central facilities may also serve, or only serve, laundry rooms, pools, saunas, recreation buildings/rooms, etc., used by the tenants of a multi-unit complex.

[2] The Commission did not address master metered dwelling units in D.92498.

In Eck, the Commission recognized that a complainant whose own mistake results in his failure to take advantage of a favorable rate under Schedule GM is not eligible for a refund because the utility has billed such a customer in complete accordance with its tariff. And, in denying the complaint, the Commission stated:

"Under SoCalGas' tariff, the central facilities baseline allocation was to operate only prospectively from the date the central facilities customer provided the necessary information to SoCalGas. The notice and customer response **[*5]** requirements embodied in SoCalGas' tariff have been approved by the Commission. Therefore, we cannot require SoCalGas to retroactively adjust complainant's rates and refund him the overcharges resulting from his error." (D.89-08-008, p. 10.)

In Schrader, the customer presented evidence that showed he had provided accurate customer information to SoCalGas albeit years before lifeline was instituted. The Commission made it clear in Schrader that the customer has the duty to show either he had provided accurate information to SoCalGas or that SoCalGas had erred. In finding for Schrader, the Commission, in its order modifying D.89-08-101, stated:

"The preponderance of the little evidence we have in this case leads us to infer that SoCal was notified of the correct number of units but for some reason used a lesser number in calculating the baseline allowance. We, therefore, find that there was a billing error. Tariff Rule 16, which governs the adjustment of SoCal's bills, provides that the utility shall issue a refund or credit to a customer for the result of an overcharge where the utility overcharges a customer as the result of a billing error. Schrader has satisfied **[*6]** his burden of proof in his complaint seeking refunds by demonstrating that a billing error occurred. The complainant does not have the burden of explaining how SoCal's error occurred." (D.89-12-055.)

The evidentiary problem in most multi-family baseline billing error cases is that, due to the utility's document retention policies, the original documents related to the meter accounts are no longer available.

Costello argues that Schrader amounts to a precedent establishing that the burden of proof in determining who is responsible for a billing error lies with the defendant utility, once a customer demonstrates that an error has occurred. As support for his position, Costello notes that the Commission states: "[The complainant] has satisfied his burden of proof in his complaint seeking refunds by demonstrating that a billing error occurred. The complainant does not have the burden of explaining how SoCal's error occurred." (D.89-12-055, p. 2, emphasis added.)

We believe that Costello misconstrues Schrader. In that case the complainant offered a hypothesis as to how SoCalGas made the error at issue. The Commission merely states that it is not necessary for the complainant **[*7]** to offer such hypotheses because the complainant did meet his burden of proof by offering into evidence a main and service construction document which shows that the utility made an error.

Also, Costello argues that in a situation such as the instant case, "where it is established that the customer was not billed according to the Tariff, " the burden simply must be placed on the utility to explain how the error occurred. If SoCalGas can prove that the customer affirmatively caused the error (such as by submitting incorrect appliance information to the utility), a refund should not be issued to the customer. However, according to Costello, if there is no proof as to how the original incorrect baseline allowance was assigned, the utility, as the stronger of the parties to the contract (tariff) , must be held to the higher standard and ordered to pay refunds to the affected customer.

First, we believe that Costello appears to be under the erroneous impression that simply because a customer did not receive all applicable baseline allowances, "it is established that the customer was not billed according to the Tariff. " This is not so. The mere fact that the customer did not receive **[*8]** all applicable baseline allowances does not ipso facto establish that the customer was not billed in accordance with the Tariff. As we discuss later, the customer has the responsibility to provide the utility with all necessary information so that the utility can correctly bill the customer.

Second, as we understand Costello's argument, the utility would be required to indefinitely retain all customer records; and, if the utility failed to produce any documents when called upon to do so, then it must pay refunds if the customer did not receive the correct baseline allocation. We are not persuaded that a utility should be required to retain customer records indefinitely simply for purposes of refuting possible customer claims. In this instance, SoCalGas' record retention period is reasonable.

Third, in a complaint case the burden of proof rests with the complainant. Costello's proposal amounts to holding the utility absolutely liable. We believe that a finding for the complainant, based on absolute liability of the utility, is not consistent with the legislative intent underlying Schedule GM and is not equitable to all ratepayers since they pay such refunds. Further, Public **[*9]** Utilities (PU) Code § 1702 requires that the complaint "[set] forth any act or thing done or omitted to be done by any public utility, including any rule or charge heretofore established or fixed by or for any public utility, in violation or claimed to be in violation, of any provision of law or of any order or rule of the commission."

Rate Schedule GM was a response to Assembly Bill (AB) 167 passed by the Legislature at its 1975-76 regular session, which added Section 739 to the PU Code. The legislative intent underlying AB 167 and PU Code § 739 was analyzed in the Commission ***decisions*** that established *Lifeline Quantities of Electricity and Lifeline Volumes of Gas, 80 CPUC 182*, D.86087 (1979). In D.86087, this Commission recognized the legislative intent underlying AB 167 and PU Code § 739 as follows:

"Presumably the Legislature thought that lower lifeline rates would be passed on to the ultimate utility users through lower rents." (Emphasis added.) *80 CPUC at page 189*.

In the billing disputes now before us, any refund ordered by the Commission would be borne by other ratepayers through the balancing account; [3] and, the property owner or manager complainant would **[*10]** receive a windfall which is not likely to flow through to the utility users (tenants) through lower rents. Such a result would be contrary to the intent of AB 167.

Further, we believe that professionals in the business of apartment building management have a duty to review bills for accuracy. Aside from the various letters and notifications sent to multi-family complex customers by SoCalGas since the inception of lifeline and baseline, customers' bills for Schedule GM have the number of dwelling units receiving baseline allowances clearly printed across the bill. Thus, multi-family complex customers do receive reasonable notice on a monthly basis. On balancing the equities, we are not persuaded that the negligence or oversight of apartment owners or managers should be overlooked to the detriment of all ratepayers.

In summary, complainant has the burden of proving that SoCalGas failed to comply with the provisions of its tariff in rendering its bills and that **[*11]** the alleged overbillings resulted from errors committed by SoCalGas as opposed to those committed by complainant. Stiles v. Pacific Bell, et al., CPUC ***Decision*** 87-12-036, 1987 Cal. CPUC Lexis 80 (1987); Southern California Gas Company Tariff Rule 16; Eck v. Southern California Gas Company, CPUC ***Decision*** 89-08-008 (August 1989).

We now turn to the nine representative cases on which evidence was received.

Case I 19-4325-903-269-18 1244 Valley View Glendale

This is a gas meter account for a separately metered central facility that provides hot water to 31 multi-family dwelling units. Each dwelling unit has an individual meter.

Since September 1986, SoCalGas used 30 multi-family units to determine the daily baseline allowance to the central facility. In April 1988, Costello notified SoCalGas that this account should be billed using 31 multi-family units. SoCalGas verified the claim and billed accordingly as of the following meter reading date.

Costello contends that the account should be backbilled for three years prior to the notification because SoCalGas erred in not billing the correct baseline allocation.

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[3] In Schrader, while balancing the equities, we erroneously assumed that SoCalGas stockholders would be the beneficiaries. This error is not sufficient to require reversal of Schrader (D.89-09-101, p. 4).

Further, Costello argues that SoCalGas' efforts to ensure **[*12]** that customers are allocated the correct rate and baseline allowance are inadequate. He points out that a central facility meter and the individual meters in a multi-family complex are given related account numbers; therefore, SoCalGas has the ability to cross check the number of dwelling units. Since SoCalGas does not do so, Costello submits that SoCalGas must be held responsible for not assigning the correct number of dwelling units to this central facility.

Costello asserts that aside from mass mailings made in December 1980 and September 1984 when lifeline was implemented, SoCalGas made no additional mass mailings of baseline allowance eligibility questionnaires. Also, SoCalGas employed no follow-up measures with customers who did not return completed forms in 1980 and 1984.

This customer initiated service on October 10, 1975, before lifeline was in effect. The turn-on application, which would show how the customer planned to use gas, is not available. Due to SoCalGas' document retention policy, this type of order is held only five years. There are no other orders on file (i.e., Central Facilities Verification Form, New Business Service Order) that indicate that the customer **[*13]** did not provide the information that caused SoCalGas to assign the account 30 dwelling units instead of 31.

In response to Costello's assertions, SoCalGas states that it attempted to notify all possible customers who may have been affected by lifeline or baseline rate implementation and changes.

In November 1975, SoCalGas sent a letter to all potential master-metered customers, based on premises code and/or billing qualifier (i.e., laundry room, central water heater, etc.) advising customers of the probability of a new multi-family rate becoming effective upon the Commission's ***decision*** to be issued later. The letter stated that the new rate schedule may result in a lower cost per dwelling unit, and the customer was requested to provide information regarding the number of dwelling units served.

In early 1976, SoCalGas sent a second letter to the previously identified customers who did not respond to the November 1975 letter. This second letter asked for a response by August 1976.

In early 1976, SoCalGas sent a letter to those customers who had responded to one of the prior letters. This letter asked for more extensive information by August 1976.

Next, SoCalGas had two mailings **[*14]** in December 1980. In the first mailing, letters and questionnaires were sent to 50,000 probable central facility customers requesting information needed to code their accounts properly. In the second, business reply postcards were mailed as bill inserts to 1,100,000 possible central facility accounts. Bill messages appeared at the same time addressing the issue.

When a postcard was returned, SoCalGas mailed a central facility questionnaire to the responding customer to provide SoCalGas with the information necessary to properly code the account.

In March 1981, SoCalGas mailed bill inserts to individually metered tenants explaining the possible reduction of lifeline allowances with the next bill.

In April 1981, SoCalGas printed a reduction of lifeline allowance message on affected tenants' bills. The message continued until all lifeline allowance reductions had occurred.

During July and August 1984, SoCalGas conducted an "inhouse" premises code survey. The survey attempted to identify each premises as Individually Metered Residential, Master Metered Residential, or Non-residential. Corrections to rates were made where applicable and central facility accounts identified during **[*15]** the survey were coded and rebilled.

SoCalGas initiated another mass mailing of central facility questionnaires, the same as those mailed in 1980, in September 1984.

Starting in August 1987 and thereafter, all first bills of newly active accounts show a message explaining under which rate that account is billed.

Beginning in 1988, on an annual basis, bill messages appear on all GR (Residential) , GMC (Multi-family, non-essential common facility), GME (Multi-family, essential common facility), and GN10 (commercial) accounts explaining the rate at which the accounts are billed. GS (submetered) accounts receive an annual bill insert.

In addition, since lifeline went into effect, each bill has shown the number of master-metered dwelling units and/or central facility units receiving the multiple baseline allowance clearly printed in large block letters on the face of each monthly bill. Therefore, SoCalGas contends that this customer received notification, for 20 months, that the baseline credit was for 30 dwelling units, not 31 units.

SoCalGas' argues that there is no evidence of utility error; therefore, there should be no backbilling.

We conclude that complainant has not established **[*16]** that the utility made a billing error. Simply because a billing error has occurred, that does not ipso facto constitute "utility billing error". Further, we are not persuaded by the complainant's argument that the utility has a duty to crosscheck all the accounts in a multi-family complex. That would shift the responsibility to the utility.

Under SoCalGas Tariff Schedule GM Special Condition 3, baseline allowances are available to qualified customers after they notify the utility of the number of dwelling units. Schedule GM Special Condition 4 requires the customer to notify the utility of any change in the number of units.

Further, we believe that SoCalGas has made a reasonable effort to notify multi-family complex customers of the availability of baseline allowances. The tariff is clear that it is the customers' responsibility to notify the utility regarding the correct number of dwelling units. Therefore, we conclude that a complainant whose own mistake or oversight results in his failure to take advantage of a favorable rate is not eligible for a refund. The utility has billed the customer in accordance with its tariff. The complainant has not met his burden **[*17]** of proof; therefore, we deny complainant's request for backbilling.

Case II 10-3296-747-22 349 S. Arroyo San Gabriel

This is an account for a separately metered central facility that provides hot water to 12 multi-family dwelling units which receive gas for cooking and space heating from another master meter.

In July 1981, based on a form completed by the customer, SoCalGas assigned the account to Rate Schedule GM-C (non-baseline) on the basis that the meter only provided swimming pool heating and laundry room services, which do not qualify for baseline allowances. According to the completed form, this central facility did not provide water heating to the multi-family units; therefore, the central facility meter did not receive a baseline allowance. Instead, the full baseline allowance was applied to the master meter serving the 12 multi-family units. As a result, the meter serving the central facility was billed a large amount of expensive non-baseline therms for water heating, while the master meter that serves cooking and space heating needs was assigned an "unusable" baseline allowance.

Costello notified SoCalGas in July 1988, that this account qualified for the baseline **[*18]** allowance since it was a central facility providing hot water to 12 multi-family dwelling units. SoCalGas verified the notification and the meter account was billed accordingly as of the following meter reading date. The baseline allowance of the master meter serving the 12 dwelling units was reduced to reflect the shift of the baseline allowance to the central facility.

Costello does not contest SoCalGas' refusal to backbill in this instance. He agrees that in a similar situation, where it was shown that the customer provided incorrect information, the Commission ruled against the customer (Eck v. SoCalGas, D.89-08-008). However, Costello believes that this account is not typical. He asserts that in 300 or more claims, SoCalGas has produced evidence of incorrect information submitted by the customer in 6 instances only.

SoCalGas submits that the error was clearly the customer's and, as such, it is not considered a billing error under its Rule 16.C.

As conceded by complainant, we agree that there should be no backbilling.

Case III 05-2434-727-600-17 7215 S. Bright Ave. Whittier

This is an account for a central facility that provides hot water and serves central **[*19]** cooking and dining room facilities to a 155-unit residential facility housing self-sufficient elderly on a permanent basis. The dwelling units are self-contained and each is equipped with individual electric cooking facilities. The building has electric space heating. Service was initiated in 1973. The turn-on application is no longer available.

Prior to 1984 this account was on Schedule GM and did receive a lifeline allowance for providing gas water heating to a multi-family complex.

SoCalGas inspected the facilities in December 1983 and concluded that this was a retirement home and that meals were included in the rent. Therefore, based on its Tariff Rule 1, Definitions, Family Dwelling Unit, SoCalGas concluded that this was a business use of gas and reassigned the account to Schedule GN1, which does not have a baseline allowance.

This rate assignment was not disputed until an informal complaint was filed with the Commission staff on April 24, 1986 by a Thomas Hobbs. The investigation sustained what had been determined in 1984 and the Commission staff closed its file on the complaint in June 1986.

Costello notified SoCalGas in March 1988 that he believed this account should **[*20]** be billed under Rate Schedule GM and receive a baseline allowance. Based on the previous investigation, SoCalGas denied the request. Due to Costello's insistence, SoCalGas performed another field inspection on December 18, 1989. Based on that inspection, the account was assigned the GM rate and rebilled from May 1986 (when the informal complaint was filed with the staff) to January 1990.

SoCalGas' explanation for the different conclusion is that the December 1989 inspection determined that the costs for the central dining facilities are not included in the tenants' rent. The residents pay only for the residential apartment use and, therefore, should receive a baseline allowance. Nevertheless, based on the original information provided by the customer in 1983-84, SoCalGas believes there was no error on the utility's part.

Costello disagrees. First, Costello argues that the SoCalGas form used in 1983-84 does not ask the right questions so that the utility can make an informed rate assignment (Exhibit 257, Attachment 14). The form does not ask if the dwelling units are self-contained, whether there are individual cooking facilities in each unit or whether there are individual **[*21]** electric appliances (of any kind) in the dwelling units. Costello, believes that this information is crucial, since without individual cooking facilities, this establishment would not meet the Tariff Rule 1 definition of Family Dwelling Unit and, consequently, would be assigned to Rate Schedule GN, instead of the much more favorable baseline Rate Schedule GM.

Secondly, according to Costello, SoCalGas has consistently misinterpreted Tariff Rule 1 in rate assignments for Housing and Urban Development subsidized housing establishments for the elderly that are equipped with both optional central cooking facilities and individual electric cooking facilities. SoCalGas was classifying such buildings as "rest homes". It was not until Costello clarified the discrepancy between SoCalGas' rate assignments for these types of establishments and residential hotels that this account was placed on the correct rate.

Therefore, Costello argues that the account should be backbilled 3 years from May 1986, when the informal complaint was filed.

We agree with Costello that SoCalGas has a responsibility to provide and use forms that request all the necessary information so that the utility may make **[*22]** an informed rate assignment. Failure to do so is utility billing error.

Also, we believe that in 1983, SoCalGas' standard questions for taking applications from such customers resulted in routine disqualification from baseline allowances. One of the first questions asked by the utility representative is, "Will this be business or residential service?" If told by the applicant that "it will be business", the applicant had little likelihood of receiving a baseline allowance because SoCalGas was routinely denying baseline benefits to such establishments "because gas was used for business purposes."

Further, this customer was correctly on the GM schedule prior to 1984 before SoCalGas, following its inspection, reassigned the account to a non-lifeline rate schedule. Apparently, SoCalGas was unduly influenced by the presence of commercial cooking equipment and central dining facilities; therefore, it overlooked the individual electric cooking facilities.

In summary, we believe that SoCalGas' 1983 questionnaire for signing up new customers did not adequately address the intent of lifeline/ baseline legislation that each self-contained residential dwelling unit receive a lifeline/ baseline **[*23]** allowance (D.86087, affirmed by D.88651).

We conclude that complainant has met his burden of proof; therefore, complainant's request for backbilling is granted.

Case IV 06-2803-381-290-28 (F4) 8600 Denver Ave. Los Angeles

This account is one of 15 meters at an apartment complex known as Sonya Gardens.

Costello reviewed the gas bills for this complex and determined that the meters serving the central water heaters were not receiving the appropriate master meter baseline allowance for the dwelling units served. According to Costello, the 15 accounts were receiving baseline allowances for only 52 dwelling units instead of 60 dwelling units.

On January 26, 1988, Costello requested backbilling on the meter accounts with central water heaters. Also, he requested that all consumption on the 15 meters be combined for future billings because "no one has been able to pinpoint which units and which appliances are serviced by each meter. "

Costello argues that SoCalGas must be held responsible for knowing that the gas plumbing configuration at this complex is not specifically addressed by its tariff. The tariff does not specifically address a situation where a central water heater **[*24]** connected to a master meter serving a block of dwelling units supplies hot water to another block of dwelling units that have their separate master meter. As a result, the customer is billed at higher non-baseline rates for therms used for hot water heating which should be billed at baseline rates.

SoCalGas denied Costello's request for backbilling and future combined meter reading for billing.

SoCalGas states that this particular account is comprised of eight family dwelling units served by one meter. According to SoCalGas, the account is billed appropriately under Rate Schedule GM.

Of the other 14 accounts in the same apartment complex, SoCalGas contends that all are also appropriately billed under Rate Schedule GM. Three of the 14 accounts are comprised of multi-family dwelling structures, with each structure served by a single meter. The groups respectively serve two, four, and nine dwelling units.

Five other accounts in the complex are billed according to Special Condition 3 of Rate Schedule GM. These five accounts consist of four individually metered dwelling units each with its own cooking and heating. The fifth meter serves a combination of the central water **[*25]** heater for the four individually metered accounts plus cooking, heating, and water heating for one unit on the same meter.

The last six accounts are comprised of two groups of three family dwelling units. Each of these groups is served by a single meter. Each meter receives its daily baseline allowance times the number of dwelling units on its meter, in accordance with Rate Schedule GM. There is, however, only one water heater for each group of three.

SoCalGas acknowledges that the customer's piping configuration is not specifically covered in its current tariff. However, SoCalGas contends that the accounts are billed in accordance with its filed Tariff Rate Schedule GM, there is no billing error by the utility and, therefore, backbilling is not justified.

As we stated with regard to Case I above, it is the customer's responsibility to notify the utility of the correct appliances connected to each meter in a multi-family complex. This responsibility was recognized by the Commission in the lifeline ***decision*** (D.86087, p. 57). Also SoCalGas' Tariff Rule 19 states:

"Customers may be eligible for service under new and optional schedules or rates subsequent to notification by **[*26]** the customer and verification by the Utility of such eligibility". (Tariff Rule 19, emphasis added.)

Further, we conclude that the lack of a tariff option that allows this customer to take full advantage of all baseline allowances in conjunction with his particular gas piping configuration does not constitute utility billing error. It is the customer's responsibility to install all piping necessary to take advantage of available utility tariffs.

Complainant has failed to sustain his burden of proof to establish that SoCalGas did not bill in accordance with its filed tariff; therefore, we deny complainant's request for backbilling.

Case V 05-7370-460-532-54 474 S. Hartford Los Angeles

In December 1987, Costello notified SoCalGas that this central facility master meter account should receive 24 baseline billing units instead of 20. SoCalGas verified the request, made the change, and billed the account accordingly as of the following meter reading date.

Service was initiated in 1974, before lifeline was in effect. Due to SoCalGas' records retention policy, the turn-on application is not available. There are no other orders on file that indicate the customer did not **[*27]** provide the information which caused SoCalGas to assign the 20 units. Based on the billing code, SoCalGas contends that it would have sent the customer the letters discussed previously requesting information on appliances and central facilities. Costello contends that such letters were not received by the customer.

The customer's bills from at least December 5, 1980 through December 1987 displayed, "Multiplied For 20 Central Facility Units". (The same message appears currently with 24 as the number of units served.) Therefore, SoCalGas argues that the customer received monthly notification, at least 85 times that it was given credit for 20 units, not 24.

SoCalGas contends that there is no utility error; therefore, backbilling is not justified.

We do not find Costello's argument persuasive. First, we believe that SoCalGas' tariff is clear; the customer is entitled to receive service under new or optional rates "subsequent to notification by the customer" (Tariff Rule 19).

Second, we are not persuaded by complainant's assertions that the customer did not receive the letters sent by SoCalGas notifying the customer regarding the availability of lifeline/ baseline allowances. **[*28]** Regardless, the customer certainly received notification on his bill of the number of dwelling units used for billing purposes each month. We believe that apartment owners and managers should be held to a duty of due care to scrutinize their bills carefully. In weighing the equities, we are not persuaded that the ratepayers should be expected to bear the financial burden of negligence or oversight on the part of apartment owners or managers.

Complainant has failed in his burden of proof to establish that there is utility billing error; therefore, we deny complainant's request for backbilling.

Case VI 14-4322-845-472-12 1256 Boynton Glendale

Since the introduction of lifeline in 1976, this central facility account was not allocated the correct number of baseline units. After being notified, SoCalGas verified the request and corrected the account from Schedule GR (single unit master meter) to Schedule GM with a water heating baseline allowance for 20 units. The correction was made in October 1987.

The 20 dwelling units, which are individually metered, each received a full baseline allowance before the correction. Thereafter, the baseline component for water heating was **[*29]** shifted to the central facility.

Costello points out that the central facility was erroneously assigned to Schedule GR. For such accounts, the billing assumptions were not printed on the bill. It was not until 1988 that SoCalGas began printing an annual bill message to inform the (GR) customer about the schedule he was on. Costello argues that the customer did not contribute to the error or fail to read his bills carefully; therefore, he requests backbilling.

Service was established in 1965, before lifeline was in effect. Because of SoCalGas' document retention policy, the turnon document is not available.

SoCalGas asserts that based on the customer's billing code, the customer would have been sent the letters discussed previously, which explained lifeline and requested information on the customer's appliances and central facilities. SoCalGas points out that the second letter requests a response by August 27, 1976, and it states ". . . without this information we must assume each meter serves one dwelling unit and, in accordance with the California Public Utilities Commission order, can only assign one 'lifeline' allowance. " Therefore, when this customer did not respond to **[*30]** either mailing in 1975 or 1976, SoCalGas assigned the account to Schedule GR which provides only one lifeline allowance.

SoCalGas contends that there is no utility error; therefore, there should be no rebilling.

We are not persuaded by complainant's argument that because the meter account was "erroneously" on Schedule GR, and since meter accounts on that rate schedule did not have the same monthly notice as for Schedule GM, the responsibility for informing the utility regarding the customer's plant equipment should be overlooked. As we stated with regard to Case I and Case IV above, it is the customer's responsibility to notify the utility (Tariff Rule 19).

Complainant has failed in his burden of proof to establish that SoCalGas did not bill in accordance with its filed tariff; therefore, we deny complainant's request for backbilling.

Case VII 06-2104-714-100-18 (E1) 600-12 N. Broadway Los Angeles

The establishment is a 270-unit residential facility housing self-sufficient elderly on a permanent basis. The units are self-contained, and each is equipped with individual electric cooking facilities. This meter provides gas to both central water heating and central heating/ cooling **[*31]** appliances. Also, the establishment has a central cooking facility which receives gas through a different meter.

Service was initiated in December 1984. The turn-on application indicates that gas will be used to serve senior citizen housing that has six commercial ranges, three steam tables, eight dryers, two boilers, and two furnaces. Based on the commercial appliance information on the application, SoCalGas concluded that the account did not qualify for a residential rate. SoCalGas billed it under Schedule GN-1 which is a commercial rate that is not allocated a baseline allowance.

In November 1987, Costello informed SoCalGas that the account was billed under the wrong rate schedule. SoCalGas verified the information and changed the account to Schedule GM (with 270 master meter baseline units) as of the following meter reading date.

Costello requests backbilling to the date of turn-on. He states that since the 1984 turn-on date, there has been no change in the nature or character of service at this establishment. This account has met all requirements for assignment to Schedule GM with a master meter baseline allowance for 270 units.

Costello argues that a primary cause **[*32]** of the error was the inadequacy of the form used by SoCalGas to collect rate eligibility information concerning this type of establishment. As discussed with regard to Case III, the form does not ask if the dwelling units are self-contained and have individual electric cooking appliances.

As we concluded in Case III above, it is the responsibility of the utility to provide and use forms that request all the necessary information so that the utility may make an informed rate assignment. Such failure is utility billing error.

As in Case III, SoCalGas appears to have been unduly influenced by the presence of commercial cooking equipment, and overlooked the individual electric cooking facilities.

We conclude that complainant has met his burden of proof; therefore, complainant's request for backbilling is granted.

Case VIII 05-2434-727-6001-7 7215 S. Bright Ave. Whittier

This is the same establishment discussed under Case III above; therefore, the facts will not be repeated.

As we decided in Case III, this account should be backbilled because the SoCalGas questionnaire did not ask the right questions so that an informed rate assignment could be made. The complainant has **[*33]** met his burden of proof.

Case IX 01-2622-931-464-32 725 Garnet Street Torrance

This establishment is a residential apartment building with four master meters. There are 61 dwelling units on the premises. Each unit receives gas for cooking and space heating from one of the four master meters, as well as hot water from one of two central gas water heaters on the premises.

-- Meter (A) 01-2622-931-4603-6 provides gas for cooking and space heating to 21 units.

-- Meter (B) 01-2622-931-462-34 provides gas to a central water heater serving 14 units. This meter also supplies gas directly to the 14 units for cooking and space heating.

-- Meter (C) 01-2622-931-464-32 provides gas to a central water heater serving 47 units. This meter also supplies gas directly to 11 of the 47 units for cooking and space heating.

-- Meter (D) 01-2622-931-466-30 provides gas to 15 units for cooking and space heating. (Exhibit 257, pp. 37 and 38.)

Prior to July 1987, SoCalGas billed each meter separately and assigned: Meter (A) a 21-unit master meter baseline allowance, Meter (B) a 14-unit master meter baseline allowance, Meter (C) an 11-unit master meter baseline allowance, and Meter (D) a 15-unit **[*34]** master meter baseline allowance. The cumulative baseline allowance assigned to the four accounts totaled 61 master meter baseline units, which corresponds exactly to the total number of dwelling units and overall appliance configuration at the building (all 61 dwelling units do receive gas for cooking and space heating as well as hot water from central gas hot water heaters).

However, Costello argues that in reality, the baseline allowance assigned to the complex was in error because three of the four meters were assigned incorrect individual baseline allowances. Meters (A) and (D) received a baseline allowance for cooking, space heating, and water heating, although they are only providing gas for cooking and space heating. Thus, the customer was allocated baseline allowance on the two meters that he rarely, if ever, used. Meter (C) represents the opposite situation. This meter received a baseline allowance for serving only 11 units with gas for cooking, space heating, and water heating. Actually, this meter served an additional 36 dwelling units with water heating. As a result, the customer was always billed for a large amount of expensive non-baseline therms on Meter (C), **[*35]** while he was assigned an excessive unusable baseline allowance on Meters (A) and (D). The net result was that the customer was significantly overcharged for gas used at the complex.

Costello contends that SoCalGas made an error because it did not assign the proper master meter baseline allowance to one of the four meter accounts -- Meter (C), which should receive 47 baseline units instead of 11.

According to Costello, SoCalGas should know that there are fewer central water heaters on the premises than there are master meters. Therefore, SoCalGas should be held responsible for knowing, from the day the meters were installed, that its Rate Schedule GM did not specifically accommodate such a metering configuration. He requests backbilling for three years from the date of notification.

As an accommodation to the customer, after notification and verification, SoCalGas in October 1987 combined the meter readings of the four master meters in the complex so that the full baseline allowance could be utilized by the central facilities. The accommodation was made because the present Rate Schedule GM does not specifically accommodate central facilities that serve dwelling units served **[*36]** by another master meter.

Service was initiated in August 1974, before lifeline was in effect. Because of SoCalGas' document retention policy, the original turn-on documents are not available. SoCalGas asserts that based on its premises code, this account would have been mailed one or more of the notifications discussed previously, that informed customers of the new Rate Schedule GM and requested information on appliances and meters.

SoCalGas' position is that this account has been billed according to Rate Schedule GM and there has been no billing error by the utility. Therefore, backbilling the account prior to notification in August 1987 under combined billing is not justified.

Essentially, Costello's argument is that SoCalGas' tariff provides baseline allowances equal to the number of units served from the meter, without regard to service provided by other master meters. On the other hand, SoCalGas' interpretation of its tariff is that there should be no more baseline allowances than there are dwelling units.

In other words, notwithstanding that there are 61 dwelling units in the complex, Costello contends that pursuant to SoCalGas' tariff, the customer should receive **[*37]** 97 baseline allowances; SoCalGas' position is that the customer received 61 baseline allowances, which corresponds with the number of dwelling units in the complex.

For example, taking Costello's argument to its logical conclusion, if an apartment building within a complex receives gas service from three separate master meters for each of these functions: cooking, water heating, and space heating, respectively, the building would receive 3 times more baseline allowances than there are living units. This result is obviously unfair to all SoCalGas' other ratepayers who would subsidize the additional baseline allowances. Also, we are certain that the Legislature did not intend such a result when it enacted lifeline and baseline legislation.

Service to this apartment complex is provided under Schedule GM Multi-family Service -- Special Condition 2 applicable to dwelling units that are not separately metered. Special Condition 2 does not contain the statement: "[eligibility] for service under this provision is available subsequent to notification by the customer and verification by Utility." However, Special Condition 3, applicable to dwelling units that are separately metered, **[*38]** does contain this language. However, we are not persuaded that the absence of such language in Special Condition 2 shifts the responsibility to the utility of ascertaining the customer's own piping configuration so that the utility may allocate baseline allowances. [4]

Also, SoCalGas' Tariff Rule 19 states:

". . . In the event of the adoption by the Utility of new or optional schedules or rates, the Utility will take such measures as may be practicable to advise those of its customers who may be affected that such new or optional rates are effective. Customers may be eligible for service under new and optional schedules or rates subsequent to notification by the customer and verification by the Utility of such eligibility. . . ." (Rule 19, effective June 5, 1982, emphasis added.)

We are not persuaded that absence of the "subsequent to notification" language in Special Condition 2 is significant since SoCalGas Rule 19, in effect, governs service taken under Special Condition 2 or 3.

Further, Schedule GM-Special Condition 4 states:

"It is the responsibility of the customer to advise the Utility within 15 days following any change in the submetering arrangements or the number **[*39]** of dwelling units or mobile home spaces provided gas service." (Special Condition 4, emphasis added.)

[4] Schedule GM-Special Conditions 2 and 3 provide baseline allowances "per residence".

There is no reason why Special Condition 4 should not apply to service taken under either Special Condition 2 or 3.

We discussed previously the steps SoCalGas took to advise apartment owners of the availability of lifeline and baseline allowances. We believe that the record in this proceeding fully supports a finding that SoCalGas took reasonable measures to notify building owners, managers, and landlords. One of the many notices states:

"Attention -- Building Owners, Managers, Landlords.

"The California Public Utilities Commission has ordered us to modify our rate schedules for lifeline uses of gas served through one meter to two or more dwelling units. This change provides that the therms allowed in each usage block will be multiplied by the number of qualified dwelling units served by one meter.

"If the gas meter which supplies the service address shown on the enclosed bill provides gas service to two or more dwelling units, please complete and mail this postpaid card now. **[*40]** We will mail a verification form to obtain the additional information required to determine the appropriate rate schedule for this meter. . . ." (Exhibit 260, Attachment 4, business reply card (emphasis added).)

Furthermore, Costello does not contend that the customer provided SoCalGas with information on the customer's piping arrangement. Costello simply contends that SoCalGas should have found out regarding the unique piping arrangements. We are not persuaded that a utility is required to look beyond the meter to ascertain the customer's piping arrangements, unless specifically requested to do so by the customer. The record is clear that in October 1987, when Costello notified SoCalGas, it did accommodate the customer after receiving notification.

As we concluded for Case IV, the lack of a tariff option that allows a customer to take full advantage of all baseline allowances in conjunction with his/her particular gas piping configuration is not utility billing error. It is the customer's responsibility to install all piping necessary to take advantage of available utility tariffs and to inform the utility of the piping arrangement.

Complainant has failed in his burden of **[*41]** proof to establish that SoCalGas did not bill in accordance with its filed tariff; therefore, we deny complainant's request for backbilling.

Findings of Fact

1. The meter accounts reviewed in this ***decision*** involve complaints of alleged failure by SoCalGas to assign the correct baseline allowance to central facilities which provide hot water to a variety of multi-family dwellings.

2. Complainant, in effect, argues that SoCalGas is absolutely responsible for correctly applying baseline allowances to each of its multi-family complex customers' particular circumstances.

3. SoCalGas' Tariff Rule 19 states:

"Customers maybe eligible for service under new and optional or rates subsequent to notification by the customer and verification by the utility of such eligibility." (Rule 19, effective 1982, emphasis added.)

4. Under SoCalGas Tariff Schedule GM Special Condition 3, baseline allowances are available to qualified customers after they notify the utility of the number of dwelling units. Schedule GM Special Condition 4 requires the customer to notify the utility of any change in the number of units. Special Condition 2 does not contain the "notification" language. **[*42]**

5. In Eck and Schrader, the Commission affirmed that where a customer has failed to notify SoCalGas of the proper number of dwelling units served, there will be no backbilling to adjust for the customer's error or failure to notify the utility.

6. Complainant alleges that SoCalGas has not properly communicated the availability of lifeline/ baseline allowances to multi-family complex customers.

7. SoCalGas has provided a detailed summary of its efforts to communicate the availability of lifeline/ baseline allowances to multi-family complex customers (Exhibit 259).

8. Since lifeline went into effect, each month, customer bills for Schedule GM multi-family service have this sentence in block letters across the bill: "MULTIPLIED FOR -- MASTER METER LIVING UNITS".

Conclusions of Law

1. SoCalGas' efforts since 1975 to communicate the availability of lifeline/ baseline allowances to multi-family complex customers are reasonable.

2. In 1983, the forms used by SoCalGas to make rate assignments for residential facility housing for self-sufficient elderly were not adequate to allow informed ***decisions*** to be made on lifeline/ baseline eligibility.

3. It is the customer's **[*43]** responsibility to advise the utility of the correct number of living units in an apartment complex and to notify the utility of piping arrangements involving special facilities.

4. SoCalGas' customer records retention period is reasonable.

5. Simply because a multi-family customer does not receive all baseline allowances, that ipso facto is not utility billing error.

6. The failure of a multi-family customer to take advantage of a rate or condition of service is not utility billing error.

7. The lack of a tariff option that enables a customer to take maximum advantage of available baseline allowances in conjunction with the customer's particular piping configuration is not utility billing error. It is the customer's responsibility to install all piping necessary to take advantage of available utility tariffs.

8. SoCalGas' Tariff Schedule GM, in conjunction with Rule 19, requires the customer to inform the utility of the correct number of dwelling units, or any change in the number, to receive the proper baseline allowance.

9. The customer obligations contained in SoCalGas Schedule GM in Rule 19 are reasonable. Since it is the owner or manager of a multi-family complex **[*44]** who is in the best position to ascertain the number of dwelling units on his property, it is reasonable to place the burden on such customers to accurately notify SoCalGas as to the number of units attached to each master meter.

10. The burden of proof is on the complainant to show that the utility has not billed in accordance with its filed tariff.

11. In weighing the equities, it is not reasonable to overlook the negligence or oversight of apartment owners or managers in scrutinizing their bills, since any refunds are charged to all ratepayers.

12. Complainant has met his burden of proof in Case III, Case VII, and Case VIII (which is the same establishment as in Case III). Failure of the utility to use adequate forms, so that an informed rate assignment can be made, is utility billing error.

13. In Case III, SoCalGas should backbill up to 3 years from the date of notification, which is May 1986 when the informal complaint was filed.

14. In Case VII, SoCalGas should backbill for 3 years from the date of notification which is November 1987.

15. Since Case VIII involves the same facility as Case III, the backbilling for Case VIII should be in conjunction with the backbilling **[*45]** for Case III.

16. Complainant has not met his burden of proof with respect to Case I, Case II, Case IV, Case V, Case VI, and Case IX. There should be no backbilling in these cases.

17. The nine cases in which evidence was received are representative of approximately 230 cases pending by Costello. SoCalGas should settle those cases on the basis of the Commission's findings in this ***decision***.

18. All refunds should reflect the time value of money and should be made with interest at the three-month commercial paper rate up to the date of refund.

ORDER

IT IS ORDERED that:

1. With respect to Case III, Case VII, and Case VIII, Southern California Gas Company (SoCalGas) shall backbill these accounts up to 3 years from the date of notification that the account was entitled to a baseline allowance. The refund shall be made with interest up to the date of refund.

2. SoCalGas shall backbill and make refunds with interest, on all accounts that are similar to Case III and Case VII.

3. With respect to Case I, Case II, Case IV, Case V, Case VI, and Case IX, there shall be no backbilling on these cases and other similar cases.

4. Consistent with the Commission's findings in **[*46]** the nine cases reviewed, SoCalGas shall expeditiously backbill where appropriate and inform Costello with regard to the disposition of the pending cases, within 60 days of the date of this ***decision***.

5. All refunds shall be made with interest at the 3-month commercial paper rate published by the Federal Reserve Bank (G-13).

This order is effective today.

Dated March 11, 1992, at San Francisco, California.

CA Public Utilities Commission ***Decisions***

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